NEXTBRIDGE INFRASTRUCTURE

January 4, 2013

VIA RESS AND COURIER

Ms. Kirsten Walli
ONTARIO ENERGY BOARD
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: EB-2011-0140; Upper Canada Transmission, Inc., operating as NextBridge Infrastructure - Application for Designation to Develop the East-West Tie Line

Upper Canada Transmission, Inc. (UCT) is pleased to submit its application to the Ontario Energy Board (OEB or Board) for designation as the electricity transmitter to develop the East-West Tie Line Project (EWT Line).

UCT was specifically created by NextEra Energy Canada ULC (NextEra) to participate in the Ontario (Province) transmission market and help the OEB and Ontario ratepayers gain the benefits of transmission infrastructure developed through a competitive process. In December 2012 each of Enbridge Inc. (Enbridge) and Borealis Infrastructure Management (Borealis) acquired a 25% interest in UCT (through Enbridge Transmission Holdings Inc. (ETHI) and Borealis EWT Inc. (BEWTI) respectively). UCT adopted the trade name NextBridge Infrastructure (NextBridge), to reflect the considerable strengths of these three large, global energy and infrastructure businesses. It is the combined strength of these three accomplished and capable infrastructure development and operation companies that NextBridge proposes to bring to Ontario's transmission sector through designation in this proceeding.

I am submitting this letter as an officer of NextBridge, and on behalf of all the owners of NextBridge, and, in order to make the representations below, have familiarized myself with the content of NextBridge's application. Accordingly, I can confirm that, as required by section 1.6 of the *Filing Requirements East-West Tie Designation Applications* attached as Appendix A to the Board's EB-2011-0140 *Phase 1 Decision and Order* dated July 12, 2012 (Filing Requirements), NextBridge's application for designation is complete and accurate to the best of my information and belief. In addition, as required by section 1.5 of the Filing Requirements, I confirm that NextBridge is committed to the completion of the development of the EWT Line, and, if selected, would be dedicated to the filing of a leave to construct application for the EWT Line, to the best of its ability.

NextBridge has assembled a team of professionals that is experienced in the development of transmission lines and other large energy infrastructure projects. The total development costs are anticipated to be $22.4 million (CAD) with an anticipated leave to construct filing date in

October 2014. We are confident that we will be able to provide a high-quality project at great value to the Province, as we bring to this project extensive experience in successfully developing challenging projects in Ontario and throughout North America. The NextBridge partners have recently been involved in permitting a number of infrastructure projects in Ontario. Our transmission experience, including both the permitting and regulatory processes such as the Board's leave to construct, is direct, recent and relevant to the EWT Line. In addition, the NextBridge partners' significant experience from outside the Province will help to bring new ideas in transmission development and cost management to Ontario's transmission sector, to the benefit of the electricity ratepayers of the Province.

The NextBridge team has significant experience in all of the competencies needed to successfully develop the project, including working with First Nation and Métis communities, whom we welcome as economic partners in the project; consultations with landowners, municipalities and surrounding communities; environmental and other permitting processes; engineering and construction in varied geographies, terrains, and climates; operating and maintaining critical high-voltage transmission assets; and managing regulated businesses with related governing bodies.

Through the analysis and preliminary engineering assessment completed in support of this Designation Application, NextBridge has found a combination of technology, route and structure that provides the required performance at a significantly lower cost than the Reference Plan. We will use an integrated project schedule and management structure that incorporates and tracks all major milestones, activities and dependencies. Our identified cost-saving opportunities include:

- Use of innovative, lower-cost Guyed-Y tower structures;
- Established supplier networks and the scale of purchasing conducted by NextEra and Enbridge will allow NextBridge to procure materials, equipment and services in reduced timeframes and at preferred prices; and
- Utilizing in-house staff seconded to NextBridge from our three partner organizations, thereby limiting recruiting and training costs.

The NextBridge application sets forth a compelling case for why our proposal provides the greatest value to Ontario. I highlight in particular the following three features of our proposal:

- Competitive Construction Cost: The $397 million construction cost forecast we put forward in our Recommended Plan is a very competitive cost forecast for placing the EWT Line into service within the time frame assumed in the Reference Plan (by the end of 2017).
- Organizational Strengths and Track Record Supporting the Forecast: The internal organizational strengths and proven track records that the NextBridge partners bring to the project would ensure that the competitive construction cost forecast put forward is in fact achievable and that delivery of the project is on time.
- Willingness and Ability to Assume Construction Cost Risk and Share Benefits with Ontario: The ability and willingness of NextBridge to assume some risk with respect to its

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construction cost forecast, and to share the benefits of the project with Ontario, could result in both lower cost and lower risk for Ontario's electricity consumers.

NextBridge is aware of the skills, experience, time and cost-sensitivity needed to make the project a reality, and is confident that if selected, we will successfully complete development of the EWT Line and thereby provide value to the Province consistent with the Board's goals.

Sincerely,



Cindy Tindell
Director**,** NextBridge Infrastructure

390 Bay Street, Suite 1720 | Toronto, ON | M5H 2Y2 | 1-888-767-3006 |www.NextBridge.ca

EB-2011-0140

ONTARIO ENERGY BOARD

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF A Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

APPLICATION FOR DESIGNATION TO DEVELOP

THE EAST-WEST TIE LINE

UPPER CANADA TRANSMISSION, INC.

operating as

NEXTBRIDGE INFRASTRUCTURE

NEXTera ENERGY CANADA

ENBRIDGE

BOREALIS Infrastructure

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Introduction

Upper Canada Transmission, Inc. (UCT) submits this proposal to the Ontario Energy Board (OEB or Board) in response to its request for applications for designation in the East-West Tie (EWT) Line proceeding (EB-2011-0140). UCT was specifically created by NextEra Energy Canada ULC (NextEra) to participate in the Ontario transmission market and to provide the OEB and Ontario (Province) ratepayers with the benefits of transmission infrastructure developed through a competitive process.

In mid-2012 each of Enbridge Inc. (Enbridge) and Borealis Infrastructure Management Inc. (Borealis) began working with UCT on the EWT Line Project (Project), and in December 2012 each acquired from NextEra a 25% interest in UCT (through Enbridge Transmission Holdings Inc. (ETHI) and Borealis EWT Inc. (BEWTI) respectively). UCT adopted the trade name NextBridge Infrastructure (NextBridge), to reflect the considerable strengths of these three large, global energy and infrastructure businesses. It is the combined strength of these three accomplished and capable infrastructure development and operation companies that UCT/NextBridge proposes to bring to Ontario through designation in this proceeding.

Ontario has, for several years, been addressing how to introduce competition into the development of its electricity infrastructure, including its electricity transmission system. In its August 26, 2010 policy report in EB2010-0059 – *Framework for Transmission Project Development Plans* – the OEB set out a framework for enlisting the forces of new entry and competition for transmission development, to the benefit of Ontario's electricity ratepayers. This policy is guiding this process, and NextBridge's application. Primary among the OEB's express policy objectives was an aim to "encourage new entrants to transmission in Ontario bringing additional resources to project development; and support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers." The OEB further noted in its policy the belief that "economic efficiency will be best pursued by introducing competition in transmission service to the extent possible within the current market and regulatory system." The policy framework also set forth a process to follow in designating transmitters to undertake development for new Ontario transmission infrastructure.

On March 29, 2011, the Minister of Energy, the Hon. Brad Duguid, issued a letter to the OEB Chairperson Cynthia Chaplin, requesting that the OEB use the designation process to select the most qualified and cost-effective transmission company to develop the EWT Line. Following a June 30, 2011 report by the

Ontario Power Authority (OPA) confirming that there is a need to proceed with development of the EWT Line, the OEB initiated this proceeding. As a result of earlier analysis and deliberations, in its Phase 1 Decision and Order, the OEB identifies its primary objective as selecting the most qualified transmission company to develop, and to bring a leave to construct application for, the EWT Line.

Accordingly, this proceeding is the culmination of several years of discussion on how and when to introduce competition into transmission development in Ontario. NextBridge does not believe competition should be introduced for the sake of competition. Rather, competition brings efficiency and discipline in cost management; promotes innovative and effective solutions; and serves as a reminder to incumbents that they should perform to the highest levels, otherwise giving new entrants opportunities to provide greater value to the ratepayers. As discussed in this Designation Application (Application), NextBridge is exceptionally well-positioned to successfully develop the EWT Line cost-effectively while meeting all reliability, scheduling, and other Project requirements, thereby paving the way for NextBridge to become a significant player in the Ontario transmission space, and to participate in further designation or other transmission processes as they may arise.

NextBridge has assembled a team of professionals that is experienced in the development of transmission lines and other large energy infrastructure projects. We bring to the Project extensive experience in developing challenging projects in Ontario and elsewhere in North America. The NextBridge partners have recently been involved in permitting a number of infrastructure projects in Ontario, including transmission lines for connection of new generation. In addition, the NextBridge partners' significant experience from outside the Province will bring new approaches to transmission development, as well as cost and project management. NextBridge has outlined in this Application a plan to successfully develop the EWT Line with anticipated development costs of $22.4 million (CAD) and a projected leave to construct filing date in October 2014.

Throughout this Application we demonstrate that the OEB can meet its objective by selecting NextBridge for the development, construction, operation and maintenance of the EWT Line. In particular, we demonstrate that NextBridge has the capability and commitment required to make the EWT Line not only a successful Project, but also a benchmark for future projects. We are confident of this because we offer strengths that are enabled by a unique NextBridge partnership and a compelling value proposition through:

- **Competitive Construction Cost:** The $397 million (CAD) construction cost forecast we have put forward in our Recommended Plan is a very competitive cost forecast for placing the EWT Line into service within the time frame assumed in the Reference Plan (by the end of 2017).
- **Organizational Strengths and Track Record Supporting the Forecast:** The internal organizational strengths and proven track records that NextBridge partners bring to the Project will ensure that the competitive construction cost forecast put forward is in fact achievable and that delivery of the Project is on time.
- **Willingness and Ability to Assume Construction Cost Risk and Share Benefits with Ontario:** The ability and willingness of NextBridge to assume some risk with respect to its construction cost forecast, and to share the benefits of the Project with Ontario, could result in both lower cost and lower risk for Ontario's electricity consumers.

Who We Are

NextBridge's three owners have a strong tradition of each owning, managing and operating all of their assets over the long-term. NextBridge brings together the extensive resources of its three partners in our plan for development, financing, construction, operation, and maintenance of the Project, together with a well-aligned interest in owning and operating the EWT Line over the course of its useful life. Our vision is to become a significant player in the Ontario transmission space, and participate in further designation or other transmission processes as they may arise. NextBridge is committed to increasing the competiveness and cost effectiveness of providing transmission service to the ratepayers of Ontario. The background of each of the partners is further described below with additional information provided via annual reports in Appendix 1: NextBridge Partner Annual Reports and Other Supplementary Reports.

FIGURE 1: NEXTBRIDGE PARTNER CORPORATE SUMMARIES

NEXTera ENERGY CANADA

- NextEra Energy is a leading clean-energy company with revenues of more than $15.3 billion (USD), 13,300 circuit km of transmission, more than 41,000 MW of generating capacity, and approximately 15,000 employees in 24 U.S. states and 4 Canadian provinces.
- Florida Power & Light Company, a subsidiary of NextEra Energy, serves approximately 4.6 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the United States.
- Lone Star Transmission, our regulated Texas transmission subsidiary is building 1,024 circuit km 345 kV transmission line.
- Recent Awards: Fortune Magazine top 10 most socially responsible companies in the world; Ranked 1st overall among electric and gas utilities for an unprecedented 6th consecutive year; Dow Jones Sustainability Index: Listed; Ethisphere magazine "World's Most Ethical Companies" 2010.
- In 2011, NextEra Energy employees dedicated more than 20,000 hours of time to various charitable organizations, raised more than $3 million in pledges for United Way, and sponsored the Susan G. Komen Race for the Cure for the 14th straight year. Other support includes 211 Information and Referral Services, Alliance for Aging, Alzheimer's Association, American Red Cross, Children's Home Societies, Consumer Credit Counseling, Meals on Wheels, Retired Senior Volunteer Program and Senior Resource Alliance.

ENBRIDGE

- Enbridge is a North American leader in delivering energy, operating the world's longest crude oil and liquids transportation system, and having close to 1,000 MW of renewable and alternative energy generating capacity.
- It is the longest-serving natural gas utility in Ontario with a 160 year history founded in 1848 owning and operating 35,000+ km of pipelines for transportation and distribution of gas and service pipes to customers.
- Enbridge employs almost 7,000 people, primarily in Canada and the U.S.. It is ranked as one of Canada's Greenest Employers, as well as one of the Top 100 Canadian Companies to Work For.
- Recent Awards: Dow Jones Sustainability North American and World Indexes; The Global 100 Most Sustainable Companies; FTSE4Good Index; Carbon Disclosure Leadership Index; The Best 50 Corporate Citizens.
- In the Ontario community, our support includes: United Way, Enbridge Ride to Conquer Cancer, Enbridge CN Tower Climb for United Way, Junior Achievement, Pollution Probe, Ontario Fire Marshall's Public Fire Safety Council, Mackenzie Health Foundation, Eva's Initiatives, Niagara Health System Foundation and Volunteer in Partnership Program ; Enhances and supports over 350 local events in its franchise area each year, such as: Markham Village Music Festival, Ottawa Winterlude, Niagara Grape & Wine Festival, Peterborough Little Lake Music Festival .

BOREALIS Infrastructure

- Borealis Infrastructure invests in major infrastructure assets on behalf of the Ontario Municipal Employees Retirement System (OMERS), one of Canada's largest pension plans with approximately $55 billion in net assets .
- OMERS was established in 1962 to serve local government employees across Ontario. Today, it represents 947 employers and almost 420,000 members, retirees and survivors, including municipal workers, children's aid society workers, firefighters, emergency services staff, police, non-teaching school board staff, transit workers and hydro workers.
- Borealis ranks as one of the world's largest and most respected infrastructure investors with a proven track record in identifying, investing and actively managing infrastructure assets and holds a current portfolio of over 20 investments across Canada, the U.S. and the UK.
- Recent Awards: Pension Fund of the Year, Canada, Best 50 Employers in Canada, Best Employers in the Greater Toronto Area.
- Employees of OMERS consistently demonstrate their growing desire to give back to the community. In addition to formal fundraising programs for United Way and Free The Children, OMERS has teams that support the Heart & Stroke Big Bike ride, the Terry Fox Run and the Alzheimer Society Walk for Memories. Employees from across the OMERS enterprise also participate in Volunteer Days, providing a variety of types of support to the community.

NEXTBRIDGE INFRASTRUCTURE

Together, the NextBridge Infrastructure partners are well-positioned to:

- Deliver the project on-time and on-budget;
- Bring additional resources and innovative ideas to transmission project development, construction and operations in Ontario; and
- Support competition in transmission to drive economic efficiency in Ontario's transmission sector for the benefit of the Ontario electricity ratepayer.

NextEra: NextEra Energy Canada ULC is a wholly owned indirect subsidiary of NextEra Energy, Inc. NextEra Energy, Inc. (NextEra Energy) is a Fortune 200 corporation, trading on the New York Stock Exchange (trading symbol NEE). It is a leading North American clean-energy company with 2011 revenues of more than $15.3 billion (USD); 13,300 circuit km of transmission; more than 41,000 MW of generating capacity; and approximately 15,000 employees in 24 U.S. states and 4 Canadian provinces. Its major subsidiaries are Florida Power & Light (FPL) Company and NextEra Energy Resources LLC (NEER). A third subsidiary, NextEra Energy Transmission (NEET), manages regulated transmission utilities in Texas and New England, and develops transmission projects across North America. NextEra brings several key strengths to the Project, including:

- Extensive transmission development experience from throughout North America;
- Superior technical and project management capabilities in development, construction, and operations & maintenance (O&M) in various physical geographies;
- Experience with ensuring reliability in transmission infrastructure;
- Intimate knowledge of environmental and safety considerations; and
- Broad consultation experience with Aboriginals and landowners.

Enbridge: Enbridge is a North American leader in energy delivery. Enbridge Inc. trades on the Toronto Stock Exchange and the New York Stock Exchange (trading symbol ENB), and had 2011 revenues of over $19.4 billion while employing approximately 7,000 employees. As a transporter of energy, Enbridge operates the world's longest crude oil and liquids transportation system. Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. Enbridge is expanding its interests in renewable and green energy technologies, including wind, solar and geothermal energy, as well as hybrid fuel cells. Enbridge is currently building the Montana-Alberta Tie-Line (MATL) power transmission project, which is a 330 km, 300 MW, 230 kV electrical transmission line to allow the movement of power between Alberta and Montana. Enbridge brings several key strengths to the Project, including:

- Considerable experience developing, constructing, and operating large scale infrastructure projects;
- Extensive consultation experience with First Nation and Métis communities and landowners;
- Significant knowledge of relevant regulatory processes related to major infrastructure projects; and
- Demonstrated capability to finance and effectively manage major projects.

Borealis: The Ontario Municipal Employees Retirement System (OMERS) is one of Canada's largest pension plans with approximately $55 billion in net assets. Borealis is the infrastructure investment arm of OMERS. Established in the late 1990s, Borealis was the first group formed by a Canadian pension plan with a mandate to invest in infrastructure as a separate asset class. Today, Borealis has approximately $10 billion invested in over 20 investments that have a total enterprise value of approximately $50 billion. Borealis takes an active role in the management of its infrastructure assets. OMERS sponsorship enables Borealis to be a long-term, buy-and hold investor. Borealis brings several key strengths to the Project, including:

- Experience as an active manager of large infrastructure assets in North America and the United Kingdom (UK) across energy, transportation, institutional facilities and government regulated services sectors;
- Significant experience with partnership based projects and structuring partnership agreements particularly with public-private-partnerships (P3) for infrastructure;
- Ability to finance large scale infrastructure projects; and
- Well established relationships with lenders, other investors, and members of the business community that will assist NextBridge in transmission development in Ontario.

Together the NextBridge partners bring the strength and experience of over 22,000 employees with experience across North America managing assets worth over $100 billion. In 2013, we will collectively place over $1.5 billion in transmission infrastructure into service, demonstrating our ability to successfully develop, finance, construct and operate these projects.

Representative Projects

Throughout this proposal, we refer to various past projects that showcase the experience of the NextBridge partners. These projects demonstrate the breadth of our experience and illustrate how NextBridge partners have successfully tackled challenges that are relevant to development of the EWT Line. Leading examples of these projects include the following:

- **Ontario Feed-in-Tariff Wind Projects:** NextEra is constructing eight wind farms in Ontario totaling over 600 MW of generation and 100 km of associated transmission between 115 and 500 kV – a

total investment of over $1.5 billion, which demonstrates NextEra's Ontario experience in Aboriginal relations, land acquisition, permitting, OEB regulatory processes and technical capabilities.

- **Blythe Transmission Project:** NextEra's affiliate developed a 108 km, 230 kV transmission line to connect Blythe Energy, a 520 MW natural gas power plant, to a new interconnection point. The estimates were $95 million and 18 months. It was completed 15% under budget and 6 weeks early.
- **Texas Clean Energy Express:** From project conception to commercial operation, NextEra's affiliate completed a 344 km, 345 kV transmission line with two 345 kV and six 138 kV substations in 15 months. Work included permitting, land acquisition, design, engineering, procurement, and construction. NextEra's affiliate negotiated 270 landowner and 504 crossing agreements without access to expropriation.
- **Lone Star Transmission:** In March 2013, NextEra Energy's Texas rate-regulated subsidiary is expected to complete an $800 million, 512 km, double circuit 345kV line and five 345kV substations, on time and under budget. It will be part of the Electric Reliability Council of Texas' (ERCOT) Competitive Renewable Energy Zones (CREZ) initiative, mandated by the Public Utility Commission of Texas.
- **Florida Power and Light:** NextEra Energy's Florida rate-regulated utility Florida Power and Light (FPL) is one of the largest in the United States, serving 4.6 million customers, owning 10,700 circuit km of transmission, over 24,000 MW of generation and over 110,000 circuit km of distribution. FPL consistently outperforms national averages for service reliability while keeping customer bills significantly below the national average.
- **Montana-Alberta Tie-Line:** Enbridge is currently constructing a 330 km, 230 kV transmission line connecting Lethbridge, Alberta to Northwestern Energy System in Great Falls, Montana. Enbridge has employed technical, regulatory, project management, and stakeholder relations expertise to advance this cross-border project.
- **Alberta Clipper**: Enbridge's 36-inch crude oil pipeline extends 1,600 km from Hardisty, Alberta to Superior, Wisconsin, crossing six provincial and state boundaries (AB, SK, MB, ND, MN, WI) and the U.S.-Canada border. It demonstrates Enbridge's ability to manage permitting, land acquisition, procurement, and contractors, as well as its experience in Aboriginal consultation and employment.
- **Bruce Power**: Borealis is a significant investor in Canada's first private nuclear generator, located on the shores of Lake Huron and generating a total of 6,300 MW. Bruce Power employs approximately

4,000 people and has been the single largest private investor in Ontario's electricity system for the past 11 years with a total injection of $7 billion.

- **Greenwich Wind Farm:** Enbridge owns a 99 MW wind energy project on the northern shore of Lake Superior. Two local First Nations were engaged, culminating in Agreements that provide sustainable benefits flowing from the project to each of the First Nations. The project also hired community members during construction with First Nation members providing almost 7,500 hours of labour as well as ongoing road maintenance services. Agreements with local Métis organizations included support for community development and a restriction on the use of chemical herbicide sprays in vegetation-clearing activities in response to concerns expressed by the Métis Nation of Ontario.
- **New Hampshire Transmission Seabrook Substation Upgrade:** To address reliability concerns, NextEra initiated a high priority major project to upgrade the Seabrook Nuclear Plant 345 kV gas-insulated substation, a crucial component of the New England bulk electrical system. Following 14 months of preparation, two months of construction began near energized 345 kV equipment, which significantly increased the complexity of the project. The final changeover was completed during a nuclear refueling outage, which imposed a strict, non-negotiable 30 day schedule for completion.
- **Oncor Electric Delivery Company:** As an investor in Oncor, Borealis has access to information about its innovative smart grid technology. Oncor is currently installing three million advanced meters (smart meters) that allow customers to better understand how they are using electricity to reduce consumption and manage costs. Oncor's investment in smart meters will give Texas one of the most technologically advanced grids in the United States.

In addition, NextEra Energy is North America's largest constructor and owner of wind generation. During the past two years, NextEra has constructed nearly $3 billion (USD) worth of wind projects, which all include transmission and interconnection components. Nearly all were completed ahead of schedule, below the original cost estimate, or both. A representative sample of on-time, on-budget construction projects is included in Section 8.

Our Value Proposition

NextBridge intends to provide significant value to Ontario and communities affected by the EWT Line. NextBridge is providing a construction cost forecast, which we believe will be very competitive for putting the Project into service by the end of 2017 – the time frame assumed in the Reference Plan and

also achieved in our Recommended Plan. We demonstrate internal organizational strengths and proven track records that will ensure that the competitive construction cost forecast put forward is in fact reasonable and achievable. Finally, we have the ability and willingness to assume some risk in respect of our cost forecasts, and to share with Ontario's electricity ratepayers the benefits of our effective and efficient implementation and operation of the Project.

Competitive Construction Cost

Construction costs are forecast at $430 million for the Reference Plan and $397 million for the NextBridge Recommended Plan. NextBridge believes that its construction cost forecasts are competitive, and combined with the development costs of $22.4 million, compare favourably to the over $600 million cost benchmark (on a comparably scoped basis) previously developed by Hydro One Networks Inc. (Hydro One). NextBridge's alternative forecasts offer reductions ranging from 25% to 30% from this initial reference point. NextBridge also wishes to emphasize that while considerable time and expense has been incurred in preparing our proposal to date, NextBridge will not request recovery of these costs – an estimated 6,000 person hours of internal resources and $1.4 million in external services. This decision is intended to indicate our commitment to the Ontario transmission market and our intent to provide cost savings for Ontario ratepayers.

NextBridge's construction cost forecast is based on a thorough review of all potential options for developing, constructing and maintaining the line in a systematic manner, taking into consideration First Nation and Métis participation and consultation; land acquisition; environmental approvals; other permitting and regulatory processes; engineering and construction; accessibility and constructability; schedule; cost; as well as power security, reliability and quality. A thorough internal and third party analysis of the Reference Plan resulted in the proposal of alternative structures which use Guyed-Y steel-lattice (Guyed-Y) towers (the NextBridge Recommended Plan) in place of the self-supported steel-lattice towers. The use of these alternative structures reduces cost by approximately $33 million while maintaining the same performance relative to the existing self-supported steel-lattice towers – as less steel is needed, tower foundations are smaller and transportation costs are lower.

Organizational Strengths and Track Record Supporting the Forecast

The NextBridge partners have a long history of building and operating well-engineered, reliable infrastructure projects, and in particular linear projects and electric power transmission lines, in Canada,

the United States and Spain. The expertise developed over the course of these projects affords us access to a significant body of knowledge and project experience. This knowledge and experience ranges across areas from route optimization and stakeholder relations to project management, engineering, and ultimately, commissioning and operation. It also provides a foundation for developing innovative solutions such as examining new routes, proposing new materials for construction, designing with flexibility built-in to allow for expansion, and adopting financial structures that maximize financial market access options and will enhance the value of the line for ratepayers. We also outline in our proposal our strong technical merits and the processes, standards and practices that we follow.

NextBridge's collective experience will also allow us to effectively manage costs and mitigate risks associated with complex projects. Each of our partner companies has experience with developing, owning and reliably operating mission-critical infrastructure. Our record of on-time, on-budget delivery and our commitment to accountability – with community support and considerable deference to the affected natural and social environment – is exemplified by the major projects referenced in this proposal.

To summarize, the NextBridge partners bring:

- An overall depth of experience in Ontario and several other jurisdictions in successful development of regulated and unregulated infrastructure projects, including electricity transmission and other electricity sector projects;
- A proven ability to manage the complex permitting and approvals processes that require prosecution and timely coordination in whichever jurisdiction new electrical infrastructure is developed;
- Recognition of the interests of First Nations and Métis communities in the Project and the opportunities it presents, together with the experience and readiness to work collaboratively with these communities, as evidenced by the formation of the NextBridge Aboriginal Advisory Board described in Section 2 of the Application and the Plans described in Sections 3 and 10; and
- Benefits of new entry of resources and expertise into the Ontario transmission sector.

Willingness and Ability to Assume Cost Risk and Share Benefits with Ontario Electricity Ratepayers

NextBridge's preference, subject to OEB approval following the development phase, is for performance-based ratemaking under which it would, among other things, accept some risk for an approved construction cost budget. NextBridge intends to develop such a mechanism through consultations with affected stakeholders, and bring its proposal forward in the context of the refined construction budget to be presented during the leave to construct process.

If designated, NextBridge will provide significant contributions to the ratepayers and economy of Ontario. This investment in the Province is bolstered by our strong relationships with key stakeholders, including regulators such as the OEB, and with local communities that we service, support and engage through ongoing operations in Ontario. Furthermore Ontario pensioners will see beneficial returns on this project through Borealis.

Our cost forecast and corresponding recovery proposal for the Project lifecycle are summarized below.

FIGURE 2: COST FORECAST AND RECOVERY PROPOSAL SUMMARY

Phase	Cost Forecast ($ millions CAD)	Recovery Proposal
Designation	$1.4	No recovery sought
Development	$22.4	Excess subject to prudence
Construction	$430 (Reference Plan) $397 (Recommended Plan)	Sharing of risk and benefits; cash return on CWIP
Operations	$4.4 (annual OM&A)	Performance-based regulation

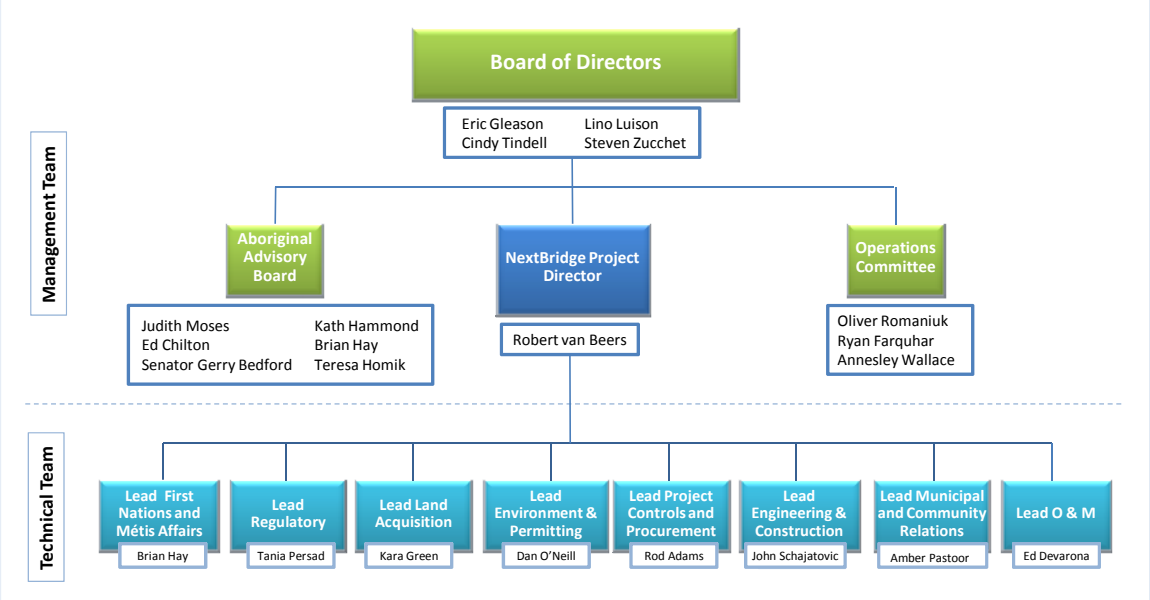
Our Capabilities

NextBridge brings strong management capabilities, extensive experience with First Nation and Métis project participation, a significant breadth and depth of technical capabilities, and extensive financial capacity – all to support the validity and ultimately the success of its Recommended Plan.

Management Organization for the Project

The project team dedicated to the Project will be composed of experienced professionals working together as a single entity with a common objective. NextBridge possesses the necessary expertise to complete major portions of the work with in-house resources seconded to NextBridge from its partner organizations, that will also manage any third-party contracts.

FIGURE 3: NEXTBRIDGE PROJECT ORGANIZATION



Our Project organization, discussed more fully in Section 2 of this proposal, consists of a Management Team with a seasoned, cross-partner Board of Directors; an Aboriginal Advisory Board (AAB) with highly qualified and well regarded members of Ontario First Nation and Métis communities; an Operations Committee with experienced executives who will provide day-to-day support for the Project; and a Project Director to ensure co-ordination and accountability. Our Technical Team, led by the Project Director, is composed of experienced subject matter experts who will lead the eight work streams shown in the organization structure. These Leads will select engineers, technicians and other required personnel to staff their respective teams for the Project.

To supplement these internal teams, NextBridge intends to engage qualified third parties for the following major work: environmental assessment, engineering resources, and land acquisition support during the development phase; as well as construction contract(s) and materials and equipment procurement contracts during the construction phase. Once in the operations phase NextBridge will have an O&M contract with NextEra, and the Project Director will be replaced by a President of NextBridge to reflect the change in nature of the role.

First Nation and Métis Participation

NextBridge is committed to seeking alignment between its interests and the interests of affected First Nation and Métis communities through meaningful, direct participation, including as economic partners in the Project. Our approach to participation is based on providing each community with opportunities to enhance its economy; its employment options; its education and skills base; and its social programs. The AAB has provided valuable preliminary assistance in developing various approaches to participation in the Project, and will continue to provide advice and guidance throughout all phases of the Project.

NextBridge understands that six First Nation communities that have a historical interest in the EWT Line have joined together to form Bamkushwada LP, which is now a partner in the EWT Partnership that is a participant in this designation process. NextBridge recognizes that the formation of Bamkushwada is a very positive step toward facilitating economic participation by these six communities, and as a result, we would seek to meet with Bamkushwada, or a successor entity, immediately upon designation as the selected proponent in order to develop a strong business relationship, and to jointly explore mutually acceptable approaches to economic participation in the Project. This would be an important step in our engagement process, and we would expect it to form the foundation of our overall First Nation and Métis Participation Plan.

As the consultation process unfolds, our team of experienced and qualified individuals will work with each community to determine its capacity for, and interest in, the different types of participation that are discussed in further detail in Section 3. These include economic participation, education and training, employment opportunities, procurement and contracting opportunities, and strategic community investment. NextBridge is committed to working with communities in seeking access to available sources of regional, provincial, federal and community financing programs and other business management and advisory services.

Technical Capability

NextBridge partners have demonstrated capabilities in a number of technical areas essential to successful execution of the Project in Northern Ontario including: environmental and other permitting processes; engineering and construction in varied geographies, terrains and climates; and operating and maintaining mission-critical high voltage transmission assets. These capabilities are further discussed in Section 4.

NextBridge's partners have permitted and are in the process of permitting a number of infrastructure projects in Ontario, which gives us direct, recent and relevant transmission experience, including both the permitting and regulatory processes such as the OEB's leave to construct requirements.

Through NextEra Energy, Enbridge, and their affiliates, NextBridge has 13,600 circuit km of transmission construction and operation experience across North America. Accordingly, we have constructed, operated and maintained comparable assets in a wide variety of geographies, terrains and climates.

The project management experience in the NextBridge partner companies is extensive, and covers general linear infrastructure as well as power generation and transmission projects in a variety of jurisdictions.

Financial Capacity

NextBridge's partners are each well-capitalized entities with collectively over $100 billion in assets and with access to significant financial resources. As such, NextBridge has ample financial capacity to finance, develop, construct, operate and maintain the EWT Line. As a newly formed entity NextBridge does not, as yet, have an independent credit rating. However, each partner company has investment grade credit ratings, and will support NextBridge until such time as it may access the capital markets as a stand-alone entity. NextBridge expects to start construction using internal resources contributed from its owners and if favourable conditions exist, obtain stand-alone debt when it can be obtained on attractive terms. NextBridge currently intends to target a ratio of 60% debt/40% equity during construction and operations. NextBridge may seek to introduce preference shares or other hybrid capital, should that prove to be an attractive vehicle for First Nation or Métis investment. NextBridge is committed to working collaboratively with its stakeholders to develop a performance-based ratemaking construct that rewards NextBridge with premium returns in the event that it provides superior outcomes and value for the Province's ratepayers. We outline our financial capacity and financial plan further in Section 5.

Our Plan for the EWT Line

NextBridge has developed a proposed design for the Project, an associated schedule and costs, and has formed a plan for consultation with First Nation and Métis communities, as well as landowners, municipalities and surrounding communities.

Proposed Design

NextBridge evaluated a number of different technology, routing and structural options while developing its proposed design for the Project. As mentioned earlier, our evaluations took into account First Nation and Métis participation and consultation; land acquisition; environmental approvals; other permitting and regulatory processes; engineering and construction; accessibility and constructability; schedule; cost; as well as power security, reliability and quality. Through our analysis and preliminary engineering assessment, NextBridge has devised a proposal that provides the required performance at significantly lower cost. Based on this evaluation NextBridge's Recommended Plan for the EWT Line, as detailed in Section 6, is as follows. Our Recommended Plan:

1. **Technology:** Adopts the Reference Plan 230kV AC double circuit technology;
2. **Route:** Adopts the Reference Route, but incorporates specific, limited contingent variants from that route should it be determined through consultation that these variant routes may be preferable; and
3. **Structure:** Specifies Guyed-Y towers, which provide better lightning performance and a projected cost saving of $33 million relative to the conventional self-supported steel-lattice towers used in the existing transmission system.

Schedule

Built into our Project schedule, and based on our experience in other projects, are a number of factors that allow us to compress the timeline and develop a timeline buffer by:

- Conducting activities across work streams in parallel to the extent possible;
- Preparing Requests for Proposal (RFPs) in advance of a final OEB decision for leave to construct allowing NextBridge to expedite procurement processes;
- Working with counterparties who already know and understand the EWT Line;
- Increasing constructability through lighter structures that simplify access and construction; and
- Considering route variants in three locations – Pukaskwa National Park, Pays Plat First Nation Reserve and Michipicoten First Nation Reserve – where the ease of accessibility is currently unknown and where permitting processes may be lengthy or the level of community support is not yet known.

NextBridge and its third party contractors will use an integrated Project schedule that incorporates all major milestones, activities and dependencies. NextBridge will also work with Hydro One to schedule milestone activities and specific construction dates to facilitate the interconnection of the new transmission lines into Hydro One's existing substations. Careful monitoring of the schedule will help us control construction costs. We will track any risks to the Project schedule such as land acquisition and permitting risk. We will also consider early material acquisition (of structural steel, conductor, insulator procurement, etc.) and scheduling of equipment (sky crane) so as to manage costs.

The ability to limit the cost risk for Ontario ratepayers is directly related to the quality of the Project scope, budget and schedule, and execution of our plan. Sophisticated tools are required for monitoring progress of linear projects, and based on NextBridge partners' experience, we plan to use new Geographical Information Systems (GIS) based project management software. As discussed in Section 4, this will enhance data collection, reporting, document management and quality assurance.

Costs

Our plan offers the OEB a competitive, cost-effective alternative to its existing approach to transmission in Ontario. We have embedded in our plan numerous cost saving opportunities which include:

- Innovative, lower cost Guyed-Y towers;
- Established supplier networks and the scale of purchasing conducted by NextEra and Enbridge which will allow NextBridge to procure materials, equipment and services in reduced timeframes or at preferred prices; and
- Use of in-house staff seconded to NextBridge by our three partner organizations, thereby limiting recruiting and training costs.

As detailed in Section 8, our costs for the development phase are estimated at $22.4 million. Our construction costs are estimated at $397 million for the Recommended Plan and $430 million for the Reference Plan.

Capital expenditures will be carefully monitored and controlled by tracking estimated and actual costs regularly and reporting on a monthly basis. We will analyze factors such as internal labour-spend rates and contractor progress versus project cash flows, amongst others, on a regular basis to flag any potential areas where labour costs may be at risk of exceeding estimates. NextBridge will only use

experienced engineering and construction contractors who have the necessary experience and processes in place to accurately estimate and control their own costs and adhere to the Project schedule and budget.

As discussed above, at the leave to construct phase, NextBridge intends to present the OEB with a comprehensive proposal for performance-based ratemaking, whereby NextBridge is incented to reduce risk for, and deliver superior value to, ratepayers.

Consultation Approach

Our plan recognizes the importance of consultation with affected First Nation and Métis communities, as well as affected landowners, municipalities and surrounding communities. The strengths of our consultation approach include:

- The Aboriginal Advisory Board (AAB) which can provide NextBridge with advice and insight into First Nation and Métis interests;
- Establishing open and meaningful relationships with landowners and other communities;
- Early initiation of communication and dialogue, which has already begun, with First Nation and Métis communities, landowners, other communities and intervenors; and
- Local benefits through opportunities for economic participation, employment, training and strategic community investment.

Landowner, Municipal, and Community Consultation

Our consultations with landowners, municipalities and surrounding communities will enable effective and meaningful engagement with these stakeholder groups. These groups will receive initial Project notification followed by regular mail and web-based Project updates. Above and beyond this general information sharing, NextBridge representatives will seek personal meetings with representatives of these groups. We have outlined in Section 9 our consultation approach, our methodology for acquiring land rights and different payment structures available to landowners.

First Nation and Métis Consultation

As the Crown's delegate with respect to the procedural aspects of consultation, NextBridge will undertake thorough and well-documented consultation efforts with respect to the First Nation and Métis communities affected by the Project. NextBridge believes that positive relationships with

Aboriginal communities, based on shared respect, are of mutual benefit and importance. Our approach adheres to key principles for relations with Aboriginal communities, including respect for traditional ways and land; heritage sites; the environment; and traditional knowledge.

Our First Nation and Métis Consultation Plan involves a range of communication activities including mail outs; community open houses; face-to-face meetings and Project presentations; community visits and information drop offs; and ongoing issues tracking and follow up activities. The details of our consultation plan are set out in Section 10.

In Summary

NextBridge's three owners are each large infrastructure investment companies, whose goal is to own, manage and operate their assets over the long-term. NextBridge brings this long-term, buy-and-hold approach to this Project. We believe we are offering a compelling value proposition for selection as the Designated Transmitter to implement the EWT Line namely:

- **Our competitive construction cost forecast;**
- **Our organizational strengths and track records that support this forecast**; **and**
- **Our willingness and ability to assume some cost risk and share benefits with Ontario electricity ratepayers.**

Throughout the balance of this Application, we demonstrate our Project organization; our technical capabilities and resources; our financial capacity; and our proposed plan for the Project – all of which collectively reiterate that NextBridge is exceptionally well positioned to lead this Project from development, through construction, to operations and maintenance, and to thereby help bring the benefits of competition and innovation to the development of transmission in Ontario.

Section A: Capability of the Applicant

1 Background Information

1.1 The applicant's name

Upper Canada Transmission Inc. (UCT), operating as NextBridge Infrastructure (NextBridge), hereby applies for designation to develop the East-West Tie (EWT) Line Project (Project).

1.2 Applicant's OEB transmission license number

UCT holds Ontario electricity transmission license ET-2011-0222. By letter dated December 19, 2012, UCT advised the Ontario Energy Board (OEB) of its registration of the trade name NextBridge Infrastructure. A copy of the license is in Appendix 2: NextBridge Ontario Electricity Transmission License.

1.3 Any change in information provided as part of the transmitter's license Application

UCT submitted its license application on June 3, 2011 and the license was granted on November 28, 2011. UCT was created as a wholly owned subsidiary of NextEra Energy Canada (NextEra), in turn an indirectly wholly owned subsidiary of NextEra Energy Resources LLC, to pursue electrical transmission development opportunities in Ontario, and initially to apply for designation as the developer of the Project.

In December 2012 each of Enbridge Inc. (Enbridge) and Borealis Infrastructure Management (Borealis) acquired a 25% interest in UCT (through Enbridge Transmission Holdings Inc. (ETHI) and Borealis EWT Inc. (BEWTI) respectively). The remaining 50% interest in UCT continues to be held by NEC's subsidiary.

UCT has adopted the business name NextBridge Infrastructure to reflect this partnership between three leading global energy and infrastructure businesses. NextBridge will pursue development of the Project through a limited partnership (NextBridge Infrastructure LP), in which UCT, operating as NextBridge, will be general partner and will remain the entity responsible for the Project. This limited partnership has been structured to allow each of the three business partners to contribute their respective strengths to the success of the Project, as detailed in the balance of this Application.

1.4 Confirmation that the applicant has not previously had a license or permit revoked and is not currently under investigation by any regulatory body

NextBridge has not previously had a license or permit revoked and is not under investigation by any regulatory body.

1.5 Confirmation that the applicant is committed to the completion of the development work for the East-West Tie line, and to the filing of a Leave to Construct Application for the line, to the best of its ability

As reflected in the introductory letter prefacing this Application and executed by Cindy Tindell, a senior executive of NextBridge, the applicant confirms its commitment to the completion of the development work for the Project, and to the filing of a leave to construct application for the line, to the best of its ability.

1.6 A statement from a senior officer that the Application for designation is complete and accurate to the best of his/her information and belief

As reflected in the introductory letter prefacing this Application and executed by Cindy Tindell, a senior executive of NextBridge, the applicant confirms this Application is complete and accurate to the best of her information and belief.

1.7 An indication of whether the applicant is willing to be named as a runner up designated transmitter and a statement of any conditions necessary to this role.

NextBridge does not request consideration for runner-up status in this proceeding.

1.8 A description of any co-ordination or co-operation with other parties that has contributed to this Application

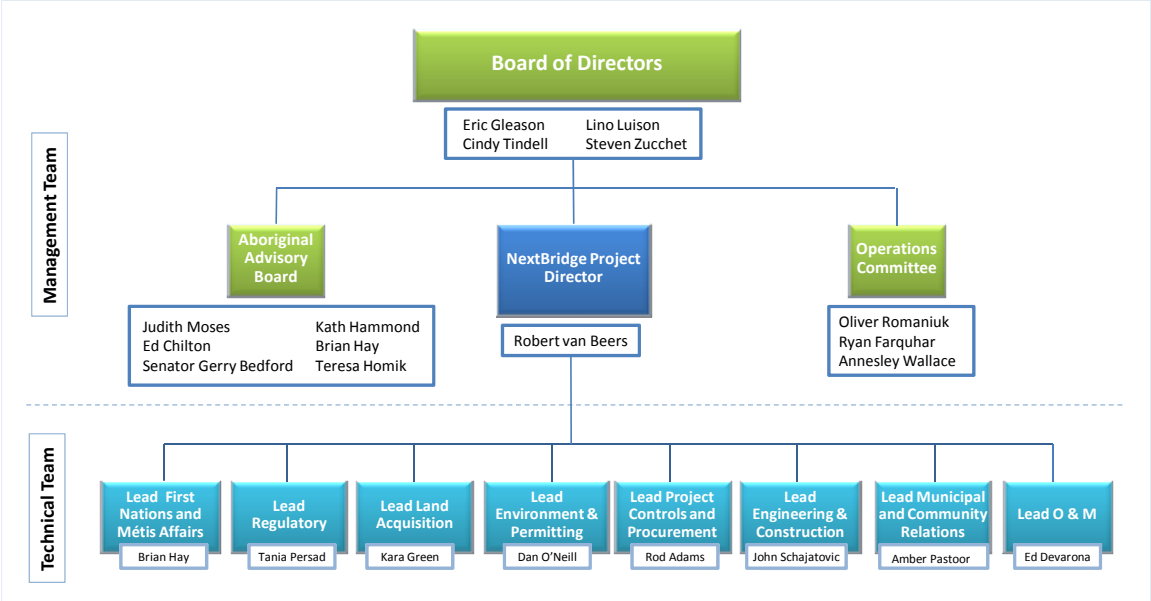
NextBridge has not coordinated preparation of this Application with any other party.

2 Organization

2.1 An overview of the organization plan for undertaking the Project

As the designated developer for the EWT Line, NextBridge will draw from its three partner organizations to establish a Project team. This team will be composed of a Management Team and a dedicated Technical Team with relevant subject matter experts, as identified below. The Project Director is a member of the Management Team and will oversee the Technical Team which will, in turn, staff its respective work streams with engineers, technicians, and other staff to form the full Project team. Technical team members will be selected from the extensive expertise and resources resident in each of the three partner businesses, drawing on the particular strengths of each partner.

FIGURE 4: NEXTBRIDGE PROJECT ORGANIZATION STRUCTURE



In the balance of this Application, references to NextBridge capabilities and resources reflect this deep and broad collective talent pool that will be on the Project at various stages from development through to operation. Ultimate responsibility for managing the Project will rest with the Ontario-based Project Director who, in turn, will report to the NextBridge Board of Directors. In addition, the NextBridge

Board of Directors has formed two committees to support this Project – namely an Aboriginal Advisory Board (AAB) and an Operations Committee.

NextBridge partners have a history of successfully delivering large infrastructure and transmission projects, including public-private-partnership (P3) projects. Therefore, NextBridge is keenly aware of the importance of both good governance practices and a collaborative culture – two principles that have informed our thinking in developing the Project organization structure illustrated above.

The Project structure was chosen for its efficiency and stability. It will allow NextBridge to:

- Apply the respective commercial and operational strengths of each NextBridge partner;
- Use our strong partnering experience to work as a functional, experienced partnership with the complementary competencies needed to deliver the Project;
- Adopt the best proven approaches and business practices from respective partners, in areas ranging from partnership governance to project management, development, construction, stakeholder relations, procurement, financing, as well as operations and maintenance (O&M);
- Bring together astute, experienced executives and managers from across the partnership that can provide a balance of perspectives to the governance and the delivery of the Project;
- Ensure a single point of accountability for day-to-day Project delivery via the Project Director;
- Draw from the talented internal personnel already available to us within our organizations to lead and staff the Technical Team; and
- Offer the Project Director, the Leads and all Project team members an escalation path for major risks, issues and decisions that may go beyond the Technical Team level.

Management Team: Our Management Team is composed of the Board of Directors, the AAB, the Operating Committee, and the Project Director. We have described the roles and responsibilities of these groups below. Management Team members are identified in Section 2.2 with full resumes included in Appendix 3: Key Project Resource Resumes.

- **Board of Directors:** The Board of Directors is composed of four nominees from our NextBridge partners – two from NextEra, one from Enbridge, and one from Borealis. The Board of Directors will meet regularly, and at a minimum monthly, during early phases of the Project. Its primary responsibilities will include:

- Ensuring that the highest standards of good business practices and quality assurance are met;
- Remaining abreast of Project status, scope, budget and timelines;
- Supporting the resolution of major risks and issues that may impact delivery of the Project; and
- Remaining accountable for any major decisions impacting the Project throughout its lifecycle.

- **Aboriginal Advisory Board**[1]**:** The AAB is composed of three members who are well-regarded, highly qualified First Nation and Métis individuals, with experience in different disciplines. The AAB is the cornerstone of our First Nation and Métis Consultation Plan, which addresses both participation and consultation matters (as detailed in Section 3 and Section 10). While the AAB will play a critical advisory role, it will not be directly involved with engagement, consultation or participation activities. Rather, it will provide independent oversight of those activities. The AAB will meet quarterly, at a minimum, and on an as-needed basis at other times throughout the Project lifecycle. The AAB meetings will generally be attended by three NextBridge representatives who have expertise in Aboriginal relations and are shown in the NextBridge Project Organization Structure. NextBridge has already conducted meetings with the AAB to seek guidance during the preparation of this Application. Its primary responsibilities will include:
  - Providing independent and objective insight and advice to NextBridge management with respect to First Nation and Métis interests and options for participation in NextBridge projects in Ontario;
  - Supporting communication and knowledge sharing activities by publication of an annual report accessible to the public on the NextBridge website;
  - Advising on NextBridge's engagement with First Nation and Métis organizations and with specific First Nation and Métis communities in Ontario, including any consultation and/or accommodation activities;

[1] In the context of the AAB the term "Aboriginal" refers to First Nation and Métis communities and peoples, as defined by s. 35 of the *Constitution Act*, 1982. We have chosen to use "Aboriginal" only to refer to the AAB or when describing past projects which dealt with different Aboriginal communities. All other references are to First Nation and Métis communities.

- Advising NextBridge on its relationships with relevant First Nation and Métis peoples, including those of a commercial, business, cultural, or educational nature;
- Advising NextBridge on dealings with First Nation and Métis interests, including any participation in the delivery of projects and/or accommodation in respect of same;
- Acting as a sounding board for NextBridge policies and practices with respect to First Nation and Métis peoples and communities;
- Assisting the NextBridge Management Team in fostering awareness of First Nation and Métis interests among all NextBridge personnel;
- Working with NextEra's and Enbridge's First Nation and Métis Affairs groups to shape the best course of action by NextBridge in specific situations; and
- Providing appropriate and constructive challenges to the assumptions of the NextBridge Management Team regarding First Nation and Métis matters.

- **Operations Committee:** The Operations Committee is composed of three senior members, one from each of our NextBridge partner organizations. The Operations Committee is the day-to-day, hands-on working committee that will support the Project Director in driving the Project forward. Each of the Operations Committee members will have access to their respective partner organization's resources to provide any necessary insights, knowledge, intellectual capital, and other support required by the Project Director and the Technical Team. The Operations Committee will meet weekly, at a minimum, particularly during inception, and as needed at different stages of the Project. In areas where Operations Committee members have specific knowledge or expertise, or have made particular recommendations to the Board of Directors, the Board of Directors will delegate to the Operations Committee decision-making authority to enable prompt and efficient resolution of day-to-day Project risks and issues. The primary responsibilities of the Operations Committee will include:

  - Resolving day-to-day Project risks, issues and changes and accessing additional resources within NextBridge partner organizations as required;
  - Providing hands-on oversight of Project scope, budget and schedule management;
  - Working with and supporting the Project Director in Project management activities; and

- Communicating key risks and issues to the Board of Directors where resolution within the Operations Committee, Project Director and Technical Team is not possible.

- **Project Director:** Leading the Technical Team will be the Project Director, a critical role providing a single point of accountability for day-to-day Project activities. Reporting to the NextBridge Board of Directors, the Project Director will be responsible for all aspects of the Project. The Project Director will be the spokesperson for the Project and will interface directly with the Board of Directors, AAB, Operations Committee and key external and internal stakeholders. The Project Director will have authority to oversee all Leads and Project resources. Once in the operations phase, the Project Director will be replaced by a President of NextBridge Infrastructure to reflect the change in nature of the role.

Technical Team: Our Technical Team reports to the Project Director and comprises eight key subject matter experts who are Leads for the following work streams: i) First Nation and Métis Affairs; ii) Regulatory; iii) Land Acquisition; iv) Environment and Permitting; v) Project Controls and Procurement; vi) Engineering and Construction; vii) Municipal and Community Relations; and viii) Operations and Maintenance. This team will work in Toronto and at the Project site in Northern Ontario. NextBridge will establish an office in the Project region, most likely in Thunder Bay, to support the Technical Team at the site. The Technical Team will have authority to utilize support staff from across the partner organizations on a full or part-time basis as needed according to the evolving needs of the Project. We describe the Technical Team here at a high level, with additional information on roles, responsibilities and resource names provided in Section 4.2.

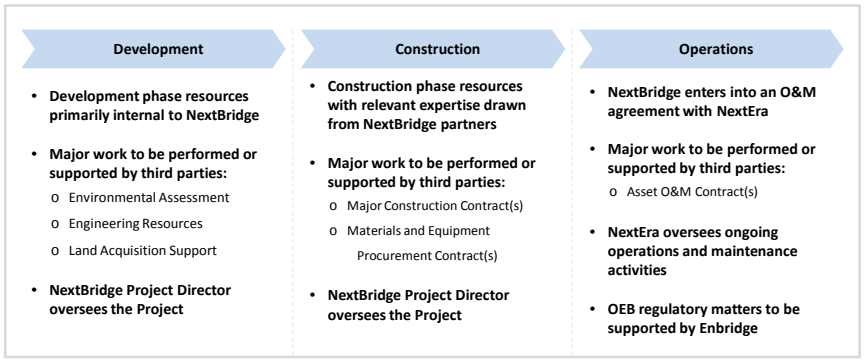
- **Leads:** The eight works streams described above will be managed by Leads who are seasoned, subject matter experts currently working within our partner organizations with past experience delivering similar projects. These individuals will lead the day-to-day activities of their respective work streams. The Leads and their staff members will remain active throughout the development and construction phases of the Project.

Partnerships or Contracting for Significant Work and Identification and Description of the Role of Third Parties Proposed for Major Work

At appropriate stages throughout the Project lifecycle, NextBridge anticipates the need to engage key third party contractors in areas such as licensing, permitting, engineering and construction. We describe below our approach to procuring such third party contracts and highlight areas where we typically engage third parties. Specific vendors will be determined and selected by way of a Request for Proposal (RFP) process as the Project progresses. The following is an identification of NextBridge responsibilities and of the major third party contracts anticipated for the Project.

FIGURE 5: SUMMARY OF EXPECTED PROJECT RESOURCING

THIRD PARTY OVERVIEW



Development Phase:

- **Environmental Assessment:** As a proposed 230 kV transmission line longer than 50 km, the Project will require a full environmental assessment (EA). This process is a critical path activity in the development phase. Therefore, we will be contracting third parties to support this work. NextBridge has already started to work with Ontario-based firms (Dillon Consulting in Toronto and Northern Bioscience in Thunder Bay) seeking advice regarding the routing analysis and environmental approvals process in support of the preparation of this Application.
- **Engineering Resources:** Engineering resources will be required to develop the Project to the point where a leave to construct application can be brought before the OEB. NextBridge has access to highly qualified, internal transmission engineering resources who will manage additional third party engineering resources. From past projects, the NextBridge partners have learned that having robust resource capacity at this first stage of the Project lifecycle will help to ensure the longer-term

success of the Project. NextBridge has started work with Burns and McDonnell (B&M), a leading design and construction firm, to assist with the review of various transmission line route evaluations; the development of design criteria; geotechnical support; as well as the development of structure and foundation alternatives.

- **Land Acquisition Support:** NextBridge will engage local agents under the direction of its Land Acquisition Lead to assist in working with affected landowners.

Construction Phase:

- **Construction Contract(s):** The most significant third party contract NextBridge anticipates for this Project is the construction contract. We will select a construction contractor through a formal RFP process, evaluating contractor proposals from technical, quality and commercial perspectives, including an assessment of the First Nation and Métis employment plan. Considerable emphasis will be placed on demonstrating a track record for successful completion of projects, on-time and on-budget. In addition, we anticipate structuring the contract such that there are incentives to achieve certain performance milestones, including engagement of First Nation and Métis. This will ensure that there is an alignment of interests between NextBridge, the construction contractor and other interested parties.

- **Materials and Equipment Procurement Contracts:** NextBridge will procure and manage the most qualified, cost-effective and proven materials and equipment suppliers and related vendors to support its work. NextBridge will draw on the significant resources and robust processes of its partner organizations for procurement of goods and services for the Project. We will engage experienced internal procurement personnel to: manage the overall procurement process; provide supplier bid evaluations for review by NextBridge's internal engineers, estimators and management; negotiate prices, terms and conditions; award contracts; and manage suppliers and required change orders. During the procurement process we will leverage NextEra's and Enbridge's scale and purchasing experience to negotiate competitive prices for materials and equipment.

Operations Phase:

In the Operations Phase, NextBridge intends to enter into an O&M agreement with NextEra. NextBridge will have access to NextEra's personnel, material resources and technical expertise for operating and maintaining NextBridge's Ontario facilities after they are placed in service. NextEra Energy has an impressive track record of providing technical support, remote condition assessment and monitoring of facilities. It has provided and continues to provide ongoing field operations and maintenance expertise to its NextEra affiliates in 24 U.S. states and 4 Canadian provinces. This expertise includes the operation of multiple, long-distance high voltage transmission lines up to 500 kV. In addition, NextEra Energy owns, operates and maintains transmission assets throughout North America and in Spain. Regulatory matters will be managed by Enbridge during this phase, drawing on its experience in this area, particularly with the OEB.

2.2 Identification of the specific Management team for the project, with résumés for key Management personnel

In the table below, we have identified the individuals who comprise our Management Team. Summaries of their resumes are below; their full resumes are included in Appendix 3: Key Project Resource Resumes.

FIGURE 6: MANAGEMENT TEAM RESOURCES

Name	Project Responsibility
Eric Gleason	Board of Directors
Cindy Tindell	Board of Directors
Steven Zucchet	Board of Directors
Lino Luison	Board of Directors
Judith Moses	Aboriginal Advisory Board, Independent
Ed Chilton	Aboriginal Advisory Board, Independent
Gerry Bedford	Aboriginal Advisory Board, Independent
Kath Hammond	Aboriginal Advisory Board, NextBridge
Brian Hay	Aboriginal Advisory Board, NextBridge
Teresa Homik	Aboriginal Advisory Board, NextBridge
Robert van Beers	Project Director
Oliver Romaniuk	Operations Committee
Ryan Farquhar	Operations Committee
Annesley Wallace	Operations Committee

Eric Gleason, Board of Directors

Eric Gleason is President of NextEra Energy Transmission, LLC, an indirect wholly-owned subsidiary of NextEra Energy, Inc. NextEra Energy Transmission is the parent company of Lone Star Transmission, LLC and New Hampshire Transmission LLC. He has extensive experience in developing, owning and operating regulated transmission lines, senior executive management and finance.

Cindy Tindell, Board of Directors

Cindy Tindell is Vice President of NextEra Energy Transmission, LLC. She has extensive experience is developing, owning and operating power generation and transmission assets and businesses, and has senior management experience.

Steven Zucchet, Board of Directors

Steven Zucchet is a Senior Vice President with Borealis with extensive experience in asset management for large infrastructure assets, including sitting on the Board of Directors for Bruce Power and Oncor. Prior to joining Borealis in 2003, he held the position of Chief Operating Officer of Enwave District Energy.

Lino Luison, Board of Directors

Lino Luison is Vice President Financial Partnerships at Enbridge Inc. He has been with Enbridge since 1994 and has held a variety of senior management roles. He is responsible for developing innovative financial structures for Enbridge and is currently leading the company's transmission-related activities.

Judith Moses, Aboriginal Advisory Board, Independent

A registered member of Six Nations from the Delaware tribe, Judith is a recognized governance expert. As Vice President of the Institute of Governance, an Ontario non-profit organization, she has led major initiatives in labour market employment and training, Aboriginal affairs and rural development.

Ed Chilton, Aboriginal Advisory Board, Independent

Born in Moosonee of Cree heritage, well-known and respected in Ontario's power industry, Ed was a key player in the development, construction and operations of Five Nations Energy Inc. Ed Chilton is the principal of Edward W. Chilton Consultants, and has worked with First Nation communities in the area of

infrastructure development for most of his professional career. For the last 15 years, he has been Project Coordinator for Five Nations Energy.

Senator Gerry Bedford, Aboriginal Advisory Board, Independent

Born near Timmins, Ontario, Gerry was elected a Métis Senator from the Credit River Métis Council (Region 8) in 2003. He is a member of the Métis Nation of Ontario (MNO) and sat on the Provincial Council of the MNO from 2005 to 2012. He has been an active spokesperson for over a decade.

Kath Hammond, Aboriginal Advisory Board, NextBridge

Kath Hammond is Vice President, Legal at Borealis where she provides transactional legal support to investment and management teams with a focus on infrastructure. Prior to joining Borealis she worked for OPG, where she held several business and legal roles, including leading the development of various hydroelectric projects in Northern Ontario and the negotiation of OPG's first ever commercial partnership agreement with a First Nation.

Brian Hay, Aboriginal Advisory Board, NextBridge

Brian Hay is the Director of Aboriginal Relations for NextEra Energy Canada ULC and its associated companies. He previously managed initial outreach to Ontario's First Nation and Métis communities as the founding Director of First Nation and Métis Relations Department of the Ontario Power Authority.

Teresa Homik, Aboriginal Advisory Board, NextBridge

Teresa Homik, Manager of Aboriginal Affairs at Enbridge, is responsible for managing National Policies and Programs. Prior to joining Enbridge, Teresa practiced law with a focus on Treaty and Aboriginal Rights and land claims issues for First Nation, Government (INAC and the Indian Claims Commission), and Industry clients for 17 years.

Robert van Beers, Project Director

Robert van Beers is the Senior Director of Power Transmission within Enbridge. Formerly founder and later CEO of publicly-traded Tonbridge Power Inc., Robert played a leading role in the financing and development of the Montana-Alberta Tie-Line (MATL), the first cross-border merchant electric transmission line in North America.

Oliver Romaniuk, Operations Committee

Oliver Romaniuk is a Project Manager at NextEra Energy Transmission LLC. He is responsible for managing the development process for new competitive transmission projects in North America and is a registered Professional Engineer in Ontario.

Ryan Farquhar, Operations Committee

Ryan Farquhar is a Director of Power Transmission at Enbridge. He is responsible for developing Enbridge's power transmission business platform and was previously Vice President and General Counsel of Tonbridge Power Inc.

Annesley Wallace, Operations Committee.

Annesley Wallace is an Assistant Vice President at Borealis, responsible for pursuing new infrastructure investments and asset management. Prior to joining Borealis she worked for an engineering and construction company leading operations for major energy projects.

2.3 Overview of Experience

Experience in management of similar projects

NextBridge partners hold assets exceeding $100 billion in aggregate and have repeatedly delivered large infrastructure projects with characteristics similar to this Project – reliably, on-time, and on-budget. We highlight below a set of such leading projects successfully delivered by NextBridge partners, based on capabilities that are relevant to the Project. We provide additional information on each of these projects in

Appendix 4: Detailed Case Studies, describing the project, identifying key strengths demonstrated by the project, and information on core capabilities that are relevant to this Project.

- **Ontario Feed-in-Tariff Wind Projects (NextEra):**
  - NextEra has been awarded eight wind energy contracts under the Ontario Power Authority's Feed-in-Tariff (FIT) program, totalling over 600 MW and $1.5 billion in investment;
  - Currently engaged with 14 First Nation and 3 Métis councils;

- Major project milestones include: commercial operation on one project, one successful OEB leave to construct application, two successful Renewable Energy Approvals with an additional six in late stage permitting;
- Projects include a total of 100 km of transmission and multiple substations, from 115 to 500 kV;
- Right-of-way acquisition is ongoing and demonstrates willingness to work with landowners;
- Working closely with the Ministry of Environment to simultaneously permit three projects with common transmission connection infrastructure, a first for Ontario renewable energy projects.

- **Blythe Transmission Project (NextEra Energy Resources):**

- Developed and built a 108 km, 1,100 MW, 230 kV transmission line to connect Blythe Energy, a 520 MW natural gas power plant, to a new interconnection point;
- Original construction cost and schedule estimates were $95 million and 18 months, respectively;
- The project was completed 15% under budget and six weeks ahead of schedule.

- **Texas Clean Energy Express (NextEra Energy Resources):**
  - Private generator tie-line constructed to transmit electric power from wind farm generation;
  - 15 months to fully develop and build a 344 km of 345kV transmission line, including two 345kV substations and six 138kV substations;
  - Major tasks completed between July 2008 and October 2009 included permitting, land acquisition, design, engineering, procurement and construction;
  - 270 landowner and 504 crossing agreements privately negotiated without expropriation;
  - Existing vendor relationships allowed for significant expediting of material and equipment.
- **Lone Star Transmission (NextEra Energy Transmission):**
  - NextEra Energy's Texas rate-regulated transmission subsidiary is building 512 km of double circuit 345kV transmission lines and five high voltage transmission substations;
  - Lone Star's system will be part of the Electric Reliability Council of Texas (ERCOT's) Competitive Renewable Energy Zones (CREZ) initiative, mandated by the Public Utility Commission of Texas;
  - $800 million project currently trending to be on-time and under budget with commercial operation expected in early 2013.

- **Florida Power and Light (NextEra Energy):**
  - Largest electric utility in Florida and one of the largest rate-regulated utilities in the United States serving 4.6 million customers, owning over 10,700 circuit km of transmission, over 24,000 MW of generation, and 110,000 circuit km of distribution;
  - Consistently outperforms national averages for service reliability while keeping customer bills low, 24% below the US national average in 2012;
  - FPL exhibited top-decile transmission reliability performance in a recent, well recognized benchmarking study involving utilities from across the United States (2011 SGS Transmission Reliability Benchmarking Study, by SGS Statistical Services);
  - The Transmission Performance & Diagnostic Center serves as a hub for harnessing the institutional knowledge of the FPL Transmission Services Group in support of its FPL departments and NextEra affiliates to design and implement transmission problem solutions.
- **Montana-Alberta Tie-Line (Enbridge):**
  - 330 km, 230 kV transmission line connecting Lethbridge, Alberta to the Northwestern Energy system in Great Falls, Montana;
  - As a cross-border merchant line it was developed by a non-utility developer under both Canadian and U.S. permitting regimes;
  - Managed significant technical, regulatory and land acquisition processes in two countries and multiple jurisdictions.
- **Alberta Clipper (Enbridge)**:
  - 36-inch crude oil pipeline extending 1,600 km from Hardisty, Alberta to Superior, Wisconsin;
  - Crosses six provincial and state (AB, SK, MB, ND, MN, WI) boundaries and the U.S.-Canada international border;
  - Demonstrates Enbridge's ability to manage and integrate complex processes in the areas of consultation, permitting, land acquisition, procurement, and management of contractors;
  - Noted for its success in both training and employment of Aboriginal people.
- **Bruce Power (Borealis)**:
  - Canada's first private nuclear generator, located on 2,300-acres on the shores of Lake Huron;
  - Bruce A and B each hold 4 CANDU reactors, generating a total of 6,300 MW;

- Over the past decade, Bruce Power has refurbished all four units at its Bruce A station, returning 3,000 MW of low-cost, reliable electricity to Ontario consumers;
- Bruce Power employs approximately 4,000 people and in the last 11 years has been the single largest private investor in Ontario's electricity system with a total injection of $7 billion.

- **Greenwich Wind Farm (Enbridge)**:
  - In 2010 Enbridge entered into an agreement to ultimately own a 99 MW wind energy project on the northern shore of Lake Superior. It entered commercial operation in November 2011;
  - Two local First Nations, the Red Rock Indian Band and the Fort William First Nation, were engaged, culminating in Agreements that provide sustainable benefits flowing from the project;
  - The project hired community members during construction and First Nation members provided almost 7,500 hours of labour to the project in 2011;
  - First Nation owned contractors will provide road maintenance services on an ongoing basis;
  - Agreements with local Métis organizations include financial support to facilitate communication regarding the project between three local Métis Community Councils and their members and to support Métis community development, as deemed appropriate by Community Councils;
  - In response to concerns expressed by the Métis Nation of Ontario, chemical herbicide sprays are restricted in vegetation clearing activities on project land during operation.
- **New Hampshire Transmission Seabrook Substation Upgrade (NextEra Energy Transmission)**:
  - NextEra Energy's New Hampshire rate-regulated transmission subsidiary;
  - The Seabrook Nuclear Plant 345 kV gas-insulated substation is a crucial component of the New England bulk electrical system. Reliability concerns triggered an upgrade initiative by NextEra;
  - Operation of the nuclear facility necessitated partial construction in proximity to live 345 kV equipment, with the final changeover occurring during a refueling outage;
  - 14 months of development and preparation was followed by a 2 month execution window;
  - Final construction was successfully performed during a non-negotiable 30 day refueling window.
- **Oncor Electric Delivery Company (Borealis):**
  - Borealis manages OMERS investment in Oncor Electric Delivery Company (Oncor), which is a regulated electric transmission and distribution service provider that serves 10 million customers across Texas;

- By the end of 2013, Oncor expects to complete the construction of more than 1,600 km of transmission lines, alleviating grid congestion and delivering cleaner sources of energy;
- Oncor is leading the industry through a technology transformation in support of its smart grid technology, as it is currently installing three million advanced meters (smart meters) that allow customers to better understand how they are using electricity to reduce consumption and manage costs;
- Over two years, the advanced meters eliminated the need to drive more than 24 million km, saved almost 3.8 million litres of fuel and prevented over 12,000 tons of carbon dioxide from being released into the atmosphere.

Experience with regulatory processes and approvals related to similar projects

NextBridge partners have Ontario-specific experience in regulated power generation assets and gas utilities:

- NextEra has completed permitting and is in construction on 148 MW of wind projects. Additionally, NextEra is in the late stages of environmental assessments and permitting for an additional six projects totaling 468 MW. These wind farms have approximately 100 km of associated transmission lines and six substations, including a new 500kV substation directly connected to the Hydro One Bruce to Longwood 500kV transmission line.
- Enbridge, through its local subsidiary Enbridge Gas Distribution, has a lengthy history with the OEB with a reputation of high performance as a regulated utility, providing natural gas storage and distribution. Throughout its history with the OEB, Enbridge has set high standards of performance, cooperation and transparency. It has established significant benchmarks for customer and stakeholder communications and involvement. Enbridge continues to be a strong advocate for the regulatory process in Ontario, supporting OEB objectives and processes aimed at protecting the interests of Ontario's energy consumers, while maintaining a viable energy industry.
- Borealis has partnered with the Ontario government and its regulatory bodies through a number of its investments in Ontario, including Bruce Power, Teranet and Lifelabs. In addition, Borealis' ownership in Enersource provides relevant and current experience with the OEB in electricity

distribution. Its ongoing relationship with Ontario regulatory bodies is important to its future success and allows Borealis to bring strong regulatory experience to the Project.

NextBridge partners also possess relevant regulatory experience in many other jurisdictions, including: Florida Power and Light under the auspices of the Florida Public Service Commission; Lone Star Transmission and Oncor under the Public Utilities Commission of Texas; the Montana-Alberta Tie-Line project under Alberta, Montana and Federal jurisdictions; as well as New Hampshire Transmission under the New Hampshire Public Utilities Commission and ISO-New England.

These projects illustrate experience with different forms of rate regulation and regulatory compliance under governing bodies including: the U.S. Federal Energy Regulatory Commission; North American Electric Reliability Corporation; and the Northeast Power Coordinating Council. These reliability organizations are trans-border entities with jurisdiction and/or oversight that extend into Ontario.

2.4 Relevance of Applicant's Experience to the Project

NextBridge partners' past project experience, summarized above and in Appendix 4: Detailed Case Studies has allowed us to develop a number of key capabilities that are relevant to the Project including:

- **On-Time, On-Budget Delivery Experience:** Holding assets exceeding $100 billion in aggregate, NextBridge's partners and their affiliates have a track record for developing, constructing and operating high quality infrastructure projects – specifically linear projects and electric power transmission lines. Our project management experience is extensive and well regarded by competitors and customers in each of the industries represented by our respective partners. Our past project experience will also distinguish our ability to understand and skillfully manage the scope of the Project – along with the opportunities, challenges and nuances that need to be addressed on such projects. Our strong oversight, tracking and scope management capabilities have allowed us to consistently deliver projects on-time and on-budget, and will serve us well when delivering this Project.
- **O&M Experience:** In contracting with NextEra for the operations and maintenance of its facilities, NextBridge will benefit from established standardized practices and procedures which ensure operational excellence of its assets. NextEra's approach – which includes O&M programs based on

condition assessment, diagnostics, comprehensive event response and follow-up, as well as proactive asset management – ensures operational reliability and efficiency.

- **First Nation and Métis Relations:** We bring knowledge of First Nation and Métis interests, an appreciation for their economic imperatives and needs, as well as proven approaches to engaging, consulting with, and encouraging participation by these communities.
- **Stakeholder Management Experience:** Through our portfolio of projects, we have demonstrated our capability to successfully work with a number of parties including a large number of landowners, municipalities and other community stakeholders, particularly in the acquisition of land.
- **Regulatory and Permitting Experience:** All of our projects involve some element of licensing, permitting and working with regulatory bodies. Our generation and transmission experience, both on permitting and regulatory processes (such as the OEB's leave to construct process), is direct, recent and relevant, with many of the Management and Technical Team members for the Project, currently working on other Ontario-based projects.
- **Transmission Experience in and outside of Ontario:** Our experience with transmission projects in various jurisdictions has allowed us to develop best-in-class capabilities in areas including: engineering and construction; procurement; and management of large, complex, long-term projects. We also have access to some of the best expertise in the field via our strong working relationships with third party contractors, built through past projects. NextBridge brings a wealth of transmission specific knowledge, methodologies and tools that will allow us to better manage the risks and issues inherent in the Project lifecycle. We are also able to draw from our rich project history to develop innovative solutions (e.g. examining new routes, proposing new materials for construction phase, design flexibility to allow for expansion, etc.) that will enhance the value of the Project to ratepayers.

  Our project experience has taken us across varied geographies, terrains, and climates. Our Technical Team has performed work across Canada and the United States, encountering a wide range of above-surface and below-surface conditions and challenges. In every case, NextBridge partners have successfully overcome these terrain and climate challenges. Many of our partners' projects

have been successfully executed and currently operate in geographical regions that exhibit similar conditions to those expected in Northern Ontario, including coincident extreme ice and wind events.

- **Partnership Experience:** NextBridge is well versed in partnership based projects. Our past experience has allowed us to develop effective agreements amongst the NextBridge partners. It will also allow us to better navigate through any joint decisions that the Board of Directors will make during the course of the Project.

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3 First Nation and Métis Participation

3.1 Arrangements Made for First Nation and Métis Participation

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3.2 Planned Arrangements for First Nation and Métis Participation

NextBridge is committed to seeking alignment between its interests and the interests of First Nation and Métis communities, through meaningful, direct participation in this Project. Our approach to participation is based on providing each community with opportunities to enhance its economy; its employment options; its education and skills base; and its social programs. As our consultation process unfolds, we will work with each community to determine its capacity for, and interest in, different types of participation.

As a partnership comprised of three strong organizations, NextBridge draws on the experiences of its partners to drive Project success. This is particularly true in the area of Aboriginal Relations, where each of NextEra, Enbridge, and Borealis have brought our collective expertise and experience to the table to formulate a preliminary plan that is specific to the Project. We have looked beyond our own teams to collect input from the wider community by creating the AAB – the Aboriginal Advisory Board described in Section 2. The same spirit of openness and our willingness to listen will support success in the next phase of the plan, as NextBridge engages directly with the relevant First Nation and Métis communities.

NextBridge recognizes the critical importance of relationships with the Aboriginal communities affected by our projects. The NextBridge partners have extensive relationships with Aboriginal communities. For example, Enbridge's systems and assets are in proximity to 60 Aboriginal communities in Canada. As a result, Enbridge pursues a number of engagement activities with Aboriginal communities, including: ongoing communication; presentations at band council and other government meetings; community open houses; job fairs; emergency preparedness exercises; as well as community investments and sponsorships. Enbridge has been recognized at the Silver Level in the Progressive Aboriginal Relations Certification offered by the Canadian Council for Aboriginal Business (CCAB), a national standard that reflects Enbridge's achievements in this area. The achievement of this national standard reflects the number of best practices Enbridge has in place and Enbridge's progress towards achieving a sustainable

level of integration with First Nation and Métis organizations. Enbridge was recognized for progressive improvement in Aboriginal relations in the four key performance areas measured by the CCAB: employment; business development; community investment; and community engagement. Enbridge will play a leading role in the execution of the First Nation and Métis Consultation Plan in the Project, utilizing the expert staff and contract resources of its Aboriginal Affairs department, as appropriate.

NextEra is also a member of the CCAB and is regularly involved in working with Aboriginal communities across a number of projects in Canada and the United States. Of most relevance to the Project, NextEra is currently engaged with 14 First Nation and 3 Métis councils as it develops eight wind energy projects in Southwestern Ontario. NextEra has built up its internal team to ensure that it has the requisite experience to manage these relationships successfully.

Drawing on each partner's previous work with Aboriginal communities, we have integrated our most successful past strategies and participation programs into our participation plan for this Project. However, we recognize that each new project is different and that each affected community is unique in its specific economic and cultural circumstances. The consultation processes outlined in Section 10, will bring forth dialogue and insight that will result in a more robust participation plan. Until such dialogue has occurred, NextBridge prefers to refer to its participation plan as a "Preliminary First Nation and Métis Participation Plan".

Nature of the Planned Participation

- **Economic Participation:** NextBridge intends to offer negotiated economic participation in the Project to some or all of the affected First Nation and Métis communities. There is no single accepted method for establishing the basis for such participation, and NextBridge understands that the method or methods selected for the Project must be economically sustainable. NextBridge, in consultation with the AAB, has developed a preliminary set of approaches set out Appendix 5: Approaches to Economic Participation.

  NextBridge welcomes the opportunity to explore these approaches with the First Nation and Métis communities affected by the Project, as well as with other stakeholders, before arriving at a recommendation that will be negotiated prior to the submission of the leave to construct application.

NextBridge understands that six First Nation communities that have a historical interest in the EWT Line have joined together to form Bamkushwada LP, which is now a partner in the EWT Partnership that is a participant in this designation process. NextBridge recognizes that the formation of Bamkushwada is a very positive step toward facilitating economic participation by these six communities, and as a result, we would seek to meet with Bamkushwada, or a successor entity, immediately upon designation as the selected proponent in order to develop a strong business relationship, and to jointly explore mutually acceptable approaches to economic participation in the Project. This would be an important step in our engagement process, and we would expect it to form the foundation of our overall First Nation and Métis Participation Plan.

- **Employment Opportunities:** Employment opportunities will be available under terms and conditions that align with NextBridge's commitment to a safe work environment. This includes terms and conditions to ensure that each person hired and contracted to work on the Project possesses the necessary skills and abilities to perform the work for which they have been employed. During Construction and Operations, NextBridge will continue to inform affected First Nation and Métis communities and organizations of potential contracting and employment opportunities. NextBridge will track and report the number of First Nation and Métis individuals employed on the Project. NextBridge will also ensure that there is sufficient support for First Nation and Métis individuals employed, such as sensitivity to cultural traditions, to help ensure retention and development of these individuals. Included in the Project budget is provision for the hiring of a First Nation and Métis construction liaison to ensure that contractors fulfill commitments to First Nation and Métis employment and training.

- **Education and Training:** NextBridge understands there is a need for advance preparation in order to optimize the number of employment opportunities made available to First Nation and Métis individuals throughout the Project lifecycle. Once detailed engineering is available, NextBridge will provide projected labour force requirements to the First Nation and Métis communities for construction and operations of the Project. Working with the First Nation and Métis communities, NextBridge will assess the existing capacity to meet the projected needs, and will also identify areas where some targeted training could increase the opportunities for future employment on the Project. NextBridge will look to local educational and training institutions to explore opportunities

for integration between the training provided to First Nation and Métis people and the potential apprenticeship and other opportunities offered by the Project. In addition NextBridge will also look at provision of scholarships and other financial support for such training. NextBridge will work with local institutions, such as Confederation College, Cambrian College, Canadore College and Algoma College.

- **Procurement and Contracting Opportunities:** NextBridge will proactively identify opportunities to offer service, materials and equipment contracts to local First Nation and Métis businesses or joint ventures. This may be achieved through initiatives such as set-aside contracts where capacity and skills exist, which may be directly with NextBridge or as subcontracts with one of our primary contractors. NextBridge will also work with First Nation and Métis organizations to identify and develop a list of qualified First Nation and Métis businesses, services and individuals across affected communities and will work with these businesses on pre-qualifying to be eligible to bid on Project work. This list will be made available to any primary third-party contractors engaged by NextBridge during the construction and operations of the Project. In selecting third-party contractors, NextBridge will assess such contractors' experience and capability in successfully working with First Nation and Métis individuals and businesses. Project contracts will require that construction personnel working on the Project participate in cultural sensitivity training.

  NextBridge will track economic participation over the course of the Project by measuring the sum of:

  a. The total value of contracts directly awarded to First Nation and Métis individuals and organizations; and
  b. The total value of indirect contracts to First Nation and Métis individuals and organizations. Indirect contracts refer to subcontracts awarded to First Nation and Métis contractors by a non-Aboriginal prime contractor.

- **Strategic Community Investment:** NextBridge believes in making strategic community investments that result in long-term, sustainable benefits. NextBridge will consult with First Nation and Métis communities to identify meaningful, strategic investment opportunities – in sectors such as education, environment, health and safety, and culture. Such investment may involve NextBridge providing a grant or other funding to support programs in local schools, health programs,

community organizations or environmental organizations that focus on re-forestation and preservation of natural habitats.

- **Access to Supporting Programs:** NextBridge will work with communities in seeking access to available sources of regional, provincial, federal and community financing programs and other business management and advisory services including, but not limited to, the following:
  - Ontario Power Authority (OPA) – Aboriginal Energy Partnership Program;
  - Ontario Power Authority (OPA) – Aboriginal Transmission Fund;
  - Ontario Financing Authority (OFA) – Aboriginal Loan Guarantee Program;
  - Ministry of Northern Development and Mines (MNDM) – Infrastructure and Community Development Program;
  - FedNor, Aboriginal Affairs and Northern Development Canada (AANDC) – Aboriginal Business Canada;
  - Ministry of Aboriginal Affairs (MAA) – New Relationship Fund;
  - Indian and Northern Affairs Canada (INAC) – First Nation Infrastructure Fund;
  - Canadian Council for Aboriginal Business;
  - Ontario First Nation Technical Services Corp.;
  - Canadian Executive Services Overseas (Aboriginal section); and
  - Aboriginal Human Resource Council.

Plan for First Nation and Métis Participation in the Project including Schedule for Seeking Participation

FIGURE 7: PRELIMINARY FIRST NATION AND MÉTIS PARTICIPATION PLAN

Preliminary First Nation and Métis Participation Plan
Stage 1: Prior to Designation
• NextBridge has established the AAB as the cornerstone of our First Nation and Métis Consultation Plan, which addresses both consultation as well as financial participation. • The AAB has provided preliminary assistance to NextBridge in identifying and evaluating alternatives for effective participation in the Project. The first two meetings of the AAB were held on November 20, 2012 and December 19, 2012. • The AAB will continue to support this type of evaluation throughout the Project as we learn more from First Nation and Métis communities during consultation.

Preliminary First Nation and Métis Participation Plan
Stage 2: Development
• During the development stage of the Project, NextBridge anticipates that the above-noted opportunities for participation will be explored through discussions with the relevant First Nation and Métis communities, although the specific opportunities will vary by community. • NextBridge will negotiate and finalize a proposal for Economic Participation during this phase that will be put forward as part of the leave to construct process. • Education and training and employment opportunities activities will focus on long lead items such as identifying and supporting the relevant educational and training programs and developing a skills inventory. There may also be employment opportunities associated with the various Development Phase activities, such as the environmental assessment. • NextBridge has already engaged an Aboriginal owned organization – Spirit Creative – for maintaining the NextBridge website as it evolves. Spirit Creative has also been responsible for the design and production of our corporate stationery (letterhead, business cards, etc.) and will be responsible for future graphic design services in latter stages of the Project. • NextBridge will finalize a procurement plan that will include: o Identified opportunities to offer service, materials and equipment contracts to local qualified First Nation and Métis businesses or joint ventures. o Selection criteria that include a First Nation and Métis Participation Plan that demonstrates, in detail, how to engage First Nation and Métis businesses and individuals. • Specific Strategic Community Investment opportunities will be identified, although implementation will likely occur in the Construction Phase.
Stage 3: Construction
• The focus of participation activities will be employment and/or procurement and contracting opportunities. • NextBridge will execute contracts specifically for First Nation and Métis communities for services based on the availability of qualified First Nation and Métis contractors. • In addition, NextBridge will work directly with its primary third party contractors to ensure that they are making every effort to optimize the degree of First Nation and Métis participation at each phase of the Project. o NextBridge will receive reporting on actual First Nation and Métis economic participation during construction.
Stage 4: Operations
• NextBridge will focus on seeking employment and procurement opportunities for and entering into long-term contracts with qualified First Nation and Métis owned businesses to provide services during EWT operations.

The Planned Benefits to First Nation and Métis Communities from Participation

Our Preliminary First Nation and Métis Participation Plan provides the following three key benefits for communities affected by the Project:

- **Increased Employment and Business Growth:** NextBridge is committed to offering employment and service contracts to qualified individuals and businesses (where capacity exists) either directly or through our primary third-party contractors. The Project has the capacity to provide communities with a long-term, stable source of employment and business. Examples of typical goods and services NextBridge might procure include construction crews and equipment for

transmission lines; right-of-way (ROW) clearing and associated facilities; accommodation; communications services and equipment; office equipment; fuel and supply; safety, security and medical services; and equipment and logistics services.

- **Enhanced Education, Training and Certification:** NextBridge will work collaboratively with First Nation and Métis organizations, as well as local educational and training institutions, to develop opportunities for education, training and certification that may not otherwise be available. For example, providing access to training and apprenticeship opportunities in specific trades could increase individual employability both by the Project in the short term and local businesses in the long term. In addition, NextBridge will also work collaboratively to determine opportunities to provide scholarships, bursaries or other funding.
- **Long Term Source of Revenues:** Economic Participation in the Project will yield long term revenues for the participating First Nation and Métis communities. The form of participation, as well as the identification of the communities participating, cannot be finally established until NextBridge has the opportunity to engage directly with the communities, however Appendix 5: Approaches to Economic Participation gives an overview of some financial approaches that could be considered.

3.3 If no First Nation or Métis participation in the project is planned, detailed reasons for this choice.

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4 Technical Capability

4.1 A Discussion of Resource Types including Relevant Capability

NextBridge is committed to staffing the Project with the most qualified personnel from across NextBridge's partner organizations, which together have approximately 22,000 employees in the energy sector. Between 2007 and 2013, NextBridge partners will have completed over 1,400 circuit km of new transmission line construction at voltages ranging from 69 kV to 500 kV and from 100 km to 500 km in length. This work has been done in various geographic regions including Alberta, Montana, Colorado, California and Texas, demonstrating that we are able to execute outside our core regulated markets. With the complementary expertise of our partner organizations, NextBridge offers the best combination of talent, skill and experience to meet the OEB's requirements and to fulfill the objectives of this Project. We understand the complexity of development and the interplay of stakeholders, First Nation and Métis communities, land acquisition, permitting, design, engineering and construction as well as their impact on cost and schedule, and have a demonstrated capability to manage these many aspects of the Project.

Across our partner organizations, we have the following resource capabilities in different areas of expertise to draw upon:

- 180+ design, engineering and construction professionals with transmission experience
- 40+ materials and equipment procurement experts
- 65+ environmental assessment, licensing and permitting experts
- 40+ regulatory affairs professionals
- 50+ land acquisition experts and technical supporting staff
- 20+ consultation experts
- 500+ transmission operations and maintenance field personnel
- 35+ dedicated safety experts

Design & Engineering: NextEra Energy and Enbridge both have substantial engineering organizations that will be accessed for the execution of the Project. NextBridge will utilize engineering management experience and capabilities to engage third party engineering firms to execute detailed engineering. NextBridge's design and engineering capabilities include:

- In-house engineering expertise in transmission line and substation engineering and design; civil and structure engineering; protection and control and communications systems expertise.
- Experienced transmission line designers and subject-matter experts that will develop the scope of work documents for the construction plan, including structure drawings, plan and profile drawings and construction specifications.
- Long-standing, collaborative relationships with many of the most experienced engineering firms in the power industry, which are already being used to support wind, solar, fossil, and transmission projects in development – bringing NextBridge cost certainty and execution confidence.

NextBridge has already engaged Burns and McDonnell (B&M), an internationally recognized consulting firm, to perform preliminary engineering assessment and analysis for this project. This work, which has now been completed, included route analysis, road access, structure design, foundation design, conductor evaluations and material selection, as well as development of line design criteria. In completing this recent assignment, B&M was able to draw upon its extensive and recent experience with 345kV projects in the both U.S. and Canadian markets.
Beyond B&M, NextBridge has also engaged the expertise of DiGioia Gray for preliminary foundation design. Tony DiGioia and Dick Gray are well recognized experts in foundation design. For their achievements in the field of civil engineering, Dr. DiGioia and Mr. Gray were named Distinguished Members of the American Society of Civil Engineers (ASCE), an honor bestowed on only 530 members of ASCE since the society was founded in 1852.

Material and equipment procurement: NextBridge brings strong technical capabilities, significant experience and buying power to all procurement activities. Our capabilities in procurement include the following:

- Experienced in-house procurement staff with the ability to work though vendor selection and management processes to choose suppliers with the best and most relevant qualifications for the Project;
- Long-standing relationships with vendors and significant buying power that allows us to access better pricing from reputable suppliers, as well as expedite purchase and delivery during critical times;
- Established procurement processes that incorporate quality, cost, reliability, financial stability, delivery, field support, safety track record, commitment to continuous improvement and innovation when selecting suppliers; and
- Practice of often buying major and critical equipment in advance, mitigating risks such as delivery delays or material cost escalation.

Licensing and permitting: All three NextBridge partners have experience with licensing and permitting processes in Ontario, as well as other jurisdictions. Through its partners, NextBridge has access to over 65 staff members who are specifically focused on permitting and licensing activities, and have the following capabilities:

- Experience developing strategy and planning for emerging Federal and Provincial, State legislative and regulatory developments that have the potential to impact ongoing activities;
- Ability to evaluate compliance with the appropriate adherence to Federal, Provincial, State and local environmental requirements including environmental audits;
- Expertise in identifying and obtaining required licenses and regulatory agency approvals to construct new non-utility fossil and renewable energy generating facilities, gas infrastructure and transmission facilities;
- Experience in performing environmental due diligence for potential acquisitions, divestitures and financings; and
- Experience promoting environmental relationships with external environmental groups, and integrating and communicating sustainability.

Completion of environmental and other regulatory approvals: Both NextEra and Enbridge have full-time environmental professionals who work solely on new project development activities. They are involved in projects from the project concept stage through the first year of operation and bring the following capabilities:

- An emphasis on environmental sustainability and responsibility for assessing environmental issues and developing mitigation strategies; ensuring the timely receipt of environmental approvals; assisting project teams in understanding environmental regulatory requirements and ensuring environmental compliance during construction; and liaising with regulators;
- In-house expertise in aquatic environment experts, soils experts, wildlife biologists, geotechnical engineers and environmental engineers;
- Established environmental compliance monitoring program via a permit condition compliance matrix, regular compliance team meetings and formal environmental audits; and
- Relationships with qualified and trained environmental inspectors to monitor work being completed on the ROW, and specifically to identify any additional mitigation to ensure compliance.

For this Project, NextBridge has completed an environmental critical-issues analysis to review necessary permits, schedules, constraints mapping, permitting costs and identification and mitigation of environmental issues and challenges. A report summarizing this analysis was created by Dillon Consulting and Northern Bioscience, who have worked on other Ontario transmission projects in the past, such as the recent Bruce to Milton Line. The report also provided routing analyses and optimization to minimize environmental, cultural and economic impacts.

NextBridge manages environmental compliance and commitments through three key activities:

- Creating a project specific Environmental Protection Plan (EPP) which becomes part of the contractual documents for the construction phase of our projects and provides guidance on environmental requirements to all project personnel;
- Following standard environmental guidelines for construction; and
- Conducting onsite inspections and assessments of construction activities.

In addition to linear projects NextBridge partners have developed many other infrastructure projects, which include electrical substations, pipeline pump stations, bulk oil storage facilities (tank farms), natural gas processing plants, sub-sea oil pipelines, and wind and solar power generation facilities.

In addition, both NextEra Energy and Enbridge have regulatory teams with experience in filing regulatory applications with the OEB as well as other regulators in jurisdictions across North America. The regulatory capabilities of NextBridge include the following:

- In house teams that include regulatory affairs staff, development staff and counsel with experience in the licensing and permitting process for energy projects in Ontario; and
- Nationally recognized external regulatory counsel for advisement, and for help in preparing and filing regulatory approval requests.

NextBridge partners interact with, and are regulated by, a broad spectrum of regulatory bodies throughout its respective regions. We have policies and procedures in place which establish a "compliance culture". These efforts include regular environmental compliance monitoring via a permit condition compliance matrix, regular compliance team meetings, and formal environmental audits. We regularly communicate with employees regarding these policies and procedures. NextBridge partners routinely assess and take all actions necessary to ensure compliance at all levels.

Consultations, both with First Nation and Métis, and other communities: As more fully described in Section 3 and Section 10 of this Application, NextBridge can draw on over 60 years of linear project

experience through which it has gained expertise in communication and consultation with landowners, communities and First Nation and Métis communities. Our capabilities include:

- In-house Aboriginal and community consultation groups with experience working in communities across Canada and the United States, including developing printed communications, holding open houses and establishing open lines of communication;
- Existing relationships with third party organizations that are experienced in community consultation.

Construction: NextBridge brings depth of experience in construction of transmission and substation facilities. Our team has proven capabilities in constructing and managing high voltage transmission line projects of similar size, type, and technology as this Project – in compliance with the design, reliability, and operation standards set forth by a variety of authorities in North America and elsewhere. This is exemplified by our Spain Solar project where NextEra Energy completed a 20 km, 230 kV and a 20 km, 400 kV transmission line in Extremadura, Spain to integrate two 50 MW solar thermal power plants into Spain's national electric grid.

Between 2007 and early 2013, NextBridge partners will have completed over 1,400 circuit km of new transmission line construction at voltages ranging from 69kV to 500 kV and from 100 km to over 500 km in length, in locations such as Alberta, Montana, Colorado, California and Texas.

Operations and Maintenance: NextBridge will leverage partner internal resources and contractor resources for the safe, reliable and efficient operations and maintenance of the Project. NextEra will take a lead role in the Operations Phase. We highlight our O&M capabilities below:

- We plan to implement well-established O&M practices and standardized processes that already exist at our operating transmission facilities which are discussed further in Section 4.4.
- We have access to over 180 power system professionals including technicians and other staff with expertise in all aspects of transmission and substation equipment installation, maintenance and repair. Many of these personnel will provide support to NextBridge through our Transmission Performance & Diagnostics Center (TPDC), which serves as a hub for technical knowledge, as well as remote condition assessment and field asset health information in support of operations.
- Our staff oversees a large number of projects annually, including major system upgrades and maintenance initiatives at operating facilities, and supports O&M services to Florida Power and Light

(FPL), affiliates in 4 Canadian provinces and 24 U.S. states, and regulated transmission utilities in the ISO-New England and ERCOT (Texas) systems.

- We have an excellent record of transmission and substation reliability which includes robust design and O&M programs based on condition assessment, diagnostics, and asset management for effective and efficient investment of resources and capital.
- As part of our experience in the Florida peninsula, we have faced and overcome a wide variety of operating challenges ranging from hurricanes, tornados, and other high wind conditions, to salt spray contamination, avian interaction, lightning, and managing a peninsular system at the edge of the Eastern Interconnection. For example, every outage in the FPL transmission system is followed up by an Event Response Process in which we use diagnostic techniques to identify the root cause of a problem in order to prevent reoccurrence.
- Solutions to transmission O&M problems include new designs, new conditions assessment processes, and/or new products. We often work directly with equipment manufacturers to develop these solutions in order to continually improve the reliability of our transmission systems. This background prepares us well to manage extreme geographic and climate conditions that we are likely to face in this Project.

NextBridge partners own and operate over 13,600 circuit km of transmission lines across North America through subsidiaries such as FPL (10,720 circuit km; 4.6 million customers), NextEra Energy Resources (NEER) (1,552 circuit km), Lone Star Transmission (1,024 circuit km) and expected in early 2013, MATL (330 circuit km). From 2003 through 2010, the FPL average number of minutes that a customer is without service ("SAIDI") due to transmission and substation reliability impacts was consistently below 5.2 minutes per year. In 2011 this key reliability metric was 3.2 minutes. More directly in the bulk power area, FPL exhibited top-decile transmission reliability performance in a recent, well recognized benchmarking study (2011 SGS Transmission Reliability Benchmarking Study, by SGS Statistical Services), which assessed utilities from across the United States.

Our extensive experience, deep capabilities and excellent track record will allow NextBridge to achieve significant operational efficiencies for the Project, provide reliable and safe transmission service, and meet the anticipated needs of the Ontario electricity market. We have further outlined our operations and maintenance plan in Appendix 6: NextBridge O&M Plan for the Project.

Project Management: NextBridge has developed a disciplined approach to project management. We have seasoned engineering and construction personnel who have managed numerous large scale infrastructure projects successfully using rigorous project management processes.

We identify a project controls lead at the inception of each project to support the Project Director. The project controls lead has access to experienced project management and project controls staff responsible for establishing, communicating and managing common project management processes across the project team, which include:

- The master schedule and work breakdown structure (WBS), which will integrate the schedules of NextBridge and all third parties responsible for delivery of Project activities;
- Project Budget Management;
- Risk and Issue Log Management; and
- Change Control Processes.

A recent development in the management of linear projects is the advent of Geographic Information Systems (GIS) based project management software. NextEra Energy is currently using this software to manage the Lone Star Transmission project in central Texas. The project management software is used to:

- Coordinate and track progress of land acquisition, engineering, line construction, substation construction;
- Integrate a wide range of real-time data ranging from construction status reports and land acquisition to resident inquiries in an Internet-enabled dashboard tool;
- Reduce errors on the job site by efficiently delivering critical information needed by all decision-makers and stakeholders resulting in lower costs and faster completion.

NextBridge proposes to use GIS software to enhance its project management capabilities on this Project.

GIS In Action – Examples of How GIS can be used day-to-day on projects

- Digital forms are used to track several project activities in the field and uploaded to the GIS system at the end of a day.
- Each day, contractors also complete online forms to capture their work completed.
- Activity-based reports and overall project performance reports can be generated using this real-time data.
- This allows the Project Director to identify and address performance issues, better manage invoices, and coordinate related activities.
- Documents (including engineering, environmental, construction) are stored in one place and can be accessed through an Internet connection. Easement documents and special conditions related to land acquisitions are available as well.
- Requests for Proposal (RFPs) can also be managed and tracked through the system.
- Quality assurance and quality control forms are digital pen forms that are completed in the field and stored for anyone with authorized access to view. Items not meeting quality standards can be tracked and corrective action can be implemented.

Smart grid Technology: NextBridge has experience in smart grid technology through experience gained implementing smart grid projects in the U.S. By the end of the 1st Quarter 2013, NextEra Energy's FPL will complete one of the largest and most comprehensive of the U.S. Department of Energy's, Smart Grid Investment Grant projects. As part of our $800 million Energy Smart Florida project, FPL has installed more than 10,000 intelligent monitors, sensors, and controls on our transmission and distribution grids. These improvements are already producing benefits in terms of enhanced reliability. Our Performance and Diagnostics Centers collect and interpret data from substation smart devices, detecting problems before they occur and preventing outages, which is enhancing service reliability for our customers. The total budget of $800 million included $200 million in DOE funds. Regulatory process included extensive negotiations with the U.S. Department of Energy as well as the Florida Public Utilities Commission. In addition, Borealis has access to information about Oncor's innovative smart grid technology. Oncor is currently installing three million advanced meters (smart meters) that allow customers to better understand how they are using electricity to reduce consumption and manage costs. Oncor's investment in smart meters will give Texas one of the most technologically advanced grids in the United States.

4.2 Résumés for Key Technical Team Personnel

In this section we outline the responsibilities of our Technical Team as well as named resources. Resumes for key Technical Team resources listed below can be found in Appendix 3: Key Project Resource Resumes. The Project Director and Technical Team Leads will select experienced, highly qualified engineers, technicians and other staff for secondment to the Project under specific work streams.

FIGURE 8: TECHNICAL TEAM RESOURCES

Name	Project Responsibility
Robert van Beers	Project Director, Member of Management Team
John Schajatovic	Lead Engineering & Construction
Ed Devarona	Lead Operations & Maintenance
Brian Hay	Lead First Nation and Métis Affairs
Tania Persad	Lead Regulatory
Kara Green	Lead Land Acquisition
Dan O'Neill	Lead Environment & Permitting
Amber Pastoor	Lead Municipal and Community Relations
Rod Adams	Lead Project Controls and Procurement

Robert van Beers, Project Director

Robert van Beers is the Senior Director of Power Transmission within Enbridge. Formerly founder and later CEO of publicly-traded Tonbridge Power Inc., Robert played a leading role in the financing and development of the Montana-Alberta Tie-Line, the first cross-border merchant electric transmission line in North America. As the point of Project accountability, Robert's primary responsibilities across the development and construction phases will include:

- Overseeing the day-to-day activities of the Project including management of scope, budget and schedule;
- Adhering to the necessary standards of business practice while carrying out Project activities;
- Working with all Leads and their respective work streams on activities where there are dependencies, sharing knowledge and information as appropriate;
- Supporting the Leads in their work with First Nation and Métis communities, landowners, and municipalities;
- Managing or supporting Leads in the management of relationships and contracts with third parties; and
- Providing regular project updates to the Board of Directors, and working with the AAB and Operations Committee to highlight any major risks or issues that require input from or decision-making by the Management Team.

John Schajatovic, Lead Engineering & Construction

John Schajatovic is a Project Manager for NextEra Energy Resources responsible for early stage management within the Engineering and Construction Department. As the Lead for Engineering and Construction on this Project, he will be responsible for the completion of the engineering design for the Project and ensuring it incorporates the necessary constructability considerations.

Eduardo DeVarona, Lead Operations and Maintenance

Eduardo DeVarona is Director of Operations at NextEra Energy Transmission, LLC. As the O&M Lead on this Project, he will be responsible for developing the operations strategy for the facilities post Commercial Operations Date (COD). He will ensure that operational considerations are included in the development, engineering and construction phases. He will also develop an operating strategy which will include operations and maintenance staffing estimates, third party resource estimates and an O&M budget. He will ensure execution of the operating strategy during the pre-COD period and coordinate Project commissioning activities with the construction team to ensure a successful transition to operations. In addition, he will coordinate with the Lead for Regulatory on this Project in managing compliance with IESO market rules and reliability standards.

Brian Hay, Lead First Nation and Métis Affairs

Brian Hay is the Director of Aboriginal Relations for NextEra Energy Canada ULC and its associated companies. As the Lead for First Nation and Métis Affairs on this Project, he will consult with the affected First Nation and Métis communities to validate and further develop our Consultation Plan and our Participation Plan for the Project. He will also be responsible for making recommendations to the Board of Directors related to First Nation and Métis consultation and participation. Throughout the development phase, he will be available to interface regularly with First Nation and Métis communities and to respond to any questions and concerns that arise.

Tania Persad, Lead Regulatory

Tania Persad is the Senior Legal Counsel and Gas Distribution Compliance Officer with Enbridge Gas Distribution Inc. As the Lead for Regulatory on this Project, she will be responsible for applications to the OEB for leave to construct and for approved rates once the facility is transitioned into service. In addition, she will manage obligations under the Transmission License with respect to new connections

(as applicable), record keeping and reporting, and all other ongoing regulatory obligations. She will also be responsible for communications with and applications to the OEB about regulatory proceedings and requirements applicable to the Project. She will coordinate NextBridge and external resources, as required, to develop regulatory applications and compliance mechanisms to ensure appropriate accounting, operations and oversight in accordance with applicable OEB orders, laws, regulations and guidelines.

Kara Green, Lead Land Acquisition

Kara Green is a Senior Land and Right-of-Way Specialist with Enbridge Pipelines Inc. As the Lead for Land Acquisition for this Project, she will be responsible for constraints-based optimization of the route, collecting the information related to the land requirements along the selected route and managing the process for acquiring the necessary rights to the land for the purpose of executing the Project. She will also work with the Environment & Permitting Lead on this Project on route planning and minimizing impact to affected parties along the route.

Dan O'Neill, Lead Environment & Permitting

Dan O'Neill is the Senior Environmental Analyst, Environment, Lands & Right-of-Way for Canadian Projects with Enbridge. As the Lead for Environment and Permitting for this Project, he will be responsible for obtaining all Project permits in accordance with the Project schedule to allow for engineering and construction to proceed as planned. He will interface directly with the Ministry of Environment and other organizations to identify, review and address potential issues and implement resolutions as required. He will also be responsible for assisting in route planning to minimize environmental impact along the route.

Amber Pastoor, Lead Municipal and Community Relations

Amber Pastoor is a Senior Strategist, Stakeholder Relations with Enbridge Pipelines Inc. As the Lead for Municipal and Community Relations for this Project, she will be responsible for developing and executing a public consultation program throughout the life of the Project. This includes providing strategic stakeholder relations and public consultation counsel and expertise to the Project team to fulfill all legal/regulatory requirements for public consultation. She will engage stakeholders early in the development planning process to learn about community interests and perspectives, and take those

into account in decision-making; and will develop and maintain ongoing dialogue with stakeholders through all Project stages to increase knowledge of the effects of its business activities, develop balanced standards and expectations, and seek solutions to problems.

Rod Adams, Lead Project Controls and Procurement

Rod Adams is the Director, Business Services of NextEra Energy Transmission LLC. As the Lead for Project Controls and Procurement on this Project, he will be responsible for the cost and schedule for the development phase, as well as third party contracts required during the development phase. He will work closely with all the Technical Team Leads to ensure that the most current Project information is communicated to the Project Director and Management Team. This role also involves identifying and communicating potential cost saving or schedule efficiency opportunities.

4.3 A description of sample projects, and other evidence of experience in Ontario and/or other jurisdictions

Having over $100 billion in assets under management, the NextBridge partners have repeatedly delivered large infrastructure projects with characteristics similar to this Project – reliably, on-time, and on-budget. We have profiled several of our leading projects delivered successfully using NextBridge partners' competencies and capabilities that are relevant to the Project in Section 2.3 and in Appendix 4: Detailed Case Studies. For each project, we have prepared a detailed case study which provides an overview of the project, identifies key strengths demonstrated by the project, and information on core capabilities that are relevant to this Project.

4.4 Evidence that the applicant's business practices are consistent with good utility practices

As NextBridge is a new participant in the Ontario market, it demonstrates consistency with good utility practices through a discussion of its own plans as well as the track record of the NextBridge partners. The clear result is that NextBridge's business practices are consistent with good utility practices, and build on a strong foundation of adherence to good utility practices by the NextBridge partners.

Corporate social responsibility: NextBridge partners have received significant recognition for leadership in corporate social responsibility. Some third parties that have recognized NextEra include:

- Fortune World's Most Admired Companies: In 2012, NextEra Energy was named No. 1 in its sector for an unprecedented sixth straight year on Fortune magazine's listing of the "World's Most Admired Companies." In the 2011 Fortune survey, the company was also named one of the top 10 most socially responsible companies in the world in 2011, and one of the top 10 most innovative companies in the world in 2010.
- Ethisphere Most Ethical Companies: For the fifth straight year, NextEra Energy in 2011 has been named one of the World's Most Ethical Companies by the Ethisphere Institute. Of the 110 firms named to the World's Most Ethical Companies list this year, only two were from the U.S. energy and utility sector. NextEra Energy is one of just 24 companies worldwide to receive the Ethisphere honor all five years it has existed.

Others parties that have recognized Enbridge for its long-standing commitment to corporate social responsibility include: The Global 100 Most Sustainable Companies; Carbon Disclosure Leadership Index Corporate Knights Best 50 Corporate Citizens in Canada; Jantzi-Sustainalytics 50 Most Responsible Corporations in Canada; and membership in the FTSE4Good Index. In addition, Enbridge`s Neutral Footprint Program exemplifies our commitment to corporate social responsibility. More information on this program is in Appendix 7: Enbridge Neutral Footprint Program. The following are our intended "Neutral Footprint" commitments:

- We will plant a tree for every tree we remove to build new facilities.
- We will conserve an acre of land for every acre of wilderness we permanently impact.
- We will generate a kilowatt of renewable energy for every kilowatt our operations consume

Other accolades of NextBridge partners include: Dow Jones Sustainability North American and World Indexes (NextEra and Enbridge); Pension Fund of the Year (Borealis); Best 50 Employers in Canada (Borealis); and Best Employers in the Greater Toronto Area (Borealis).

Design & Engineering: NextBridge understands that this Project will play a critical role in maintaining a reliable supply of energy to the Northwest Ontario electrical system. The use of NextBridge's best practices for design and engineering will ensure that the design of the EWT Line complies with good utility practices, and meets or exceeds the Minimum Technical Requirements as described by the OEB Filing Requirements for the Designation Process. The design will also respect all North American Electric

Reliability Corporation (NERC), North East Power Coordinating Council (NPCC) and the Independent Electricity System Operator (IESO) reliability standards.

NextBridge will design (and construct, commission, and operate) the facilities related to the Project in compliance with all applicable regulations and reliability standards. Numerous examples can be given of NextBridge partners' adherence to regulations and reliability standards in design and engineering, with a recent example being the Lone Star transmission facility. The engineering designs will meet or exceed all applicable local and provincial codes, relevant standards, and procedures while complying with the requirements of the Canadian Standards Association (CSA), industry standards such as those from the American Society of Civil Engineers (ASCE), and the Institute of Electrical and Electronics Engineers (IEEE), and all applicable safety codes. Further, all design and engineering drawings and technical studies and reports will be performed by or under the supervision of a Professional Engineer, registered with Professional Engineers Ontario.

In addition to NextBridge's plans regarding detailed technical engineering of structures and components as discussed above, we point to the evidence of overall good utility practice by NextEra Energy entities. In the area of design and engineering, evidence of good utility practice is demonstrated through the overall reliability of the power system and the end-customer's reliability and quality of service. This is shown by FPL's customer service reliability which was 99.98% in 2012, and has led to recent awards from customer groups. For example, FPL earned first place in the national 2011 E SOURCE Gap and Priority Benchmark survey for value provided to its large business customers. FPL received high scores in all categories, including satisfaction with account representatives and value provided relative to the price paid for energy.

Material and equipment procurement: A procurement process consistent with good utility practices relies on competitive bidding of major purchases and expenditures, including for the engineering, procurement and construction related activities on the Project. Our competitive bids will include all engineering, civil and structural design contracts; all major equipment purchases including structures, conductor, optical ground wire and overhead shield wire; ground surveys, geotechnical surveys, civil works and construction labour. Consistent with this, NextBridge will use a robust procurement process that has strict guidelines for competitive bidding, including appropriate and detailed technical and

performance requirements, in order to control capital costs. Specific mechanisms to ensure an effective procurement process will include:

- Third party contracts will include Scope of Work (SOW) statements that will outline specifications and contracted terms and conditions (T&Cs) between NextBridge, its equipment suppliers and its engineering and construction contractors. Specific SOWs and T&Cs may vary for different types of vendors.
- The legally binding T&Cs ensure that NextBridge, its suppliers and contractors understand the division of responsibility, contracted price, invoicing terms, payment date requirements, contract scope change process and scheduled due dates.
- Managerial oversight and regular reporting will allow for frequent monitoring of costs and timely resolution of any cost related issues.
- NextBridge will seek competitive bids for the engineering, procurement and construction related activities on the Project, further ensuring competitive costs. Competitive bids will include all engineering, civil and structural design contracts; all major equipment purchases including structures, conductor, optical ground wire and overhead shield wire; ground surveys, geotechnical surveys, civil works and construction labour.
- NextBridge will evaluate individual bids and award contracts based on a number of factors including: lowest evaluated cost, best production capabilities, supplier performance, safety, prior experience, delivery schedule, quality control and financial capabilities.

In addition to the methods and processes utilized to ensure a desirable procurement outcome, NextBridge will have access to the existing supply chain that has been built through the experience of numerous prior projects by its partners, many of which are of the same scale as this Project or even larger. Examples of the benefits include:

- **Strategic sourcing with key suppliers and contractors to create a "win-win" relationship:** Despite market fluctuations, because of the NextBridge partners' relative size and scope in many equipment and services suppliers markets, they are consistently able to get better pricing and delivery times in tight markets and get the best suppliers for each project. Suppliers are viewed as partners and work closely to develop the best overall solutions for project success. Additionally, experienced construction contractors and supervisors are carefully selected to manage construction activities

and enforce specifications and standards. The Lone Star Transmission project is a prominent example of where strategic sourcing and purchasing power allowed NextEra to obtain better than market pricing.

- **Buy major/critical equipment in advance:** Advance purchasing provides NextBridge with the ability to mitigate risks such as delivery delays or material cost escalation. Equipment capacity is secured by purchasing equipment early in the Project and using NextBridge partners' collective buying power to negotiate the initial price, delivery guarantees and raw material price index.

Right-of-way and other land use acquisitions: NextBridge partners possess a wealth of experience and expertise in land acquisition and execution of major projects throughout Canada and the United States, and have consistently performed these acquisitions consistent with good utility practices.

- NextBridge's land services professionals hold licenses in areas including land planning, environment, legal representation, dispute resolution land surveying, and real estate. These professionals will be drawn upon during the planning, engineering, development, and construction of the Project.
- These professionals also have expertise in: route and site selection; site due diligence; off ROW access; title services; document preparation and examination; land acquisition; right of entry; records and database management; support for permitting; survey coordination; land negotiations and dispute resolution; damage and claim settlement; support for environmental research efforts; ROW valuation; and support for pre/post, construction activities.
- The success of ROW acquisition is dependent not only on our qualified land team, but also the support of experienced staff. We have a team of experts who support our agents with geographic information systems (GIS) and mapping, engineering and design; legal opinion and document preparation; environmental evaluation, construction advice, accounting, payments, and customer service.
- By integrating in-house support staff with our field team, our land agents will focus on the task of preparing for and visiting property owners to successfully complete land acquisition activities.

Many of our partners' projects such as the Ontario Feed-in-Tariff Wind Projects, Lone Star Transmission and the Montana-Alberta Tie-Line demonstrate our experience with land acquisition. For example, NextEra, as part of Lone Star Transmission, is in the final stages of completing a successful land acquisition process for over 512 km of transmission ROW and land parcels for five 345 kV electrical

substations. This process has involved all aspects of land acquisition including legal, regulatory, land owner relations, siting, surveying and permitting and is being completed within established budgets and scheduled milestones. We managed this process with dedicated personnel as well as third party contractors and coordinated all necessary reviews and approvals with the local utility commission and reliability organizations.

Licensing and Permitting: The NextBridge partners have successfully completed licensing and permitting on major infrastructure projects in Ontario and elsewhere. A long record of obtaining licenses and permits of various kinds in numerous jurisdictions would not be possible if the NextBridge partners did not comply with good utility practices.

Of the $100 billion in assets currently owned by the NextBridge partners, a significant portion has been greenfield developments requiring detailed and effective licensing and permitting processes being utilized at every step in order to result in such consistently positive results.

Our past projects described in Appendix 4: Detailed Case Studies give specific examples in the areas of linear and power transmission infrastructure. NextEra has recently completed, or is in the process of completing, a number of Renewable Energy Approvals through the Ministry of Environment (MOE). In one instance, NextEra is actively working with the MOE to permit the common transmission infrastructure of three wind generation facilities under a common application, a first for renewable energy projects in Ontario.

Consultations, both with First Nation and Métis, and other communities: Our extensive interactions with First Nation and Métis communities have helped us to build and maintain respectful relationships with these and other groups including landowners and other community members impacted by our projects. NextBridge will work with affected communities to identify local projects that will benefit from our support and actively use design and construction techniques that avoid impact to threatened/endangered species and habitat in the corridor. We also ensure that all construction sites will be restored according to legal requirements and our agreements with landowners. Our approach to facilities operation is driven by our commitment to building lasting relationships; acting ethically and responsibly; and supporting the needs of communities, investors, governments, employees and other stakeholders, whose success is inextricably linked to our own.

Construction: A good outcome in construction is largely the result of good utility practices in a number of other areas. These areas are primarily engineering, procurement, project management, including cost and schedule control, and safety. Evidence of good utility practice in each of these areas is provided throughout this section. Successfully executing in each of these areas in a comprehensive and coordinated manner results in a successful construction project overall.

Operations and maintenance: Evidence of the use of good utility practice in the area of O&M is reflected in a utility's overall reliability record. NextBridge will base its O&M practices on that of FPL, which has an excellent record of transmission and substation reliability. As outlined in Section 4.1, from 2003 through 2012, the average number of minutes that an FPL customer was without service ("SAIDI") due to transmission and substation reliability concerns was consistently below 5.2 minutes per year. In 2011 this key reliability metric was 3.16 minutes. Of further relevance to this Project is the performance of FPL's bulk power system. FPL has exhibited top-decile transmission reliability performance, as demonstrated in a recent, well recognized benchmarking study (2011 SGS Transmission Reliability Benchmarking Study, by SGS Statistical Services), involving utilities from across the United States. FPL has consistently utilized a philosophy of continuous improvement and manages its business through application of sound business practices, quality assurance and Six Sigma concepts to drive customer satisfaction and reliability while reducing costs. Because of this philosophy, FPL is the lowest cost service provider in Florida, and has excellent transmission service reliability.

These attributes and practices will be leveraged to ensure NextBridge is a top performer in the area of operations and maintenance practices.

Project management: The ability of the NextBridge partners to routinely execute on large infrastructure projects, on-time and under budget, demonstrates the use of good utility practices in project management. Evidence to support these claims is provided in Sections 7.4 and Section 8.10, describing track records of adhering to cost and schedule estimates.

The specific processes, methodologies and actions utilized, are based on industry standard project management theory and have been honed through project execution experience. Appendix 8: Total Cost Management is an example of such management theory applied to the control of project costs, as it describes the Total Cost Management framework, which is a systematic approach to managing cost

throughout the life cycle of the Project. A proprietary variant of this framework, which was developed for use on NextEra's transmission projects, will be used by NextBridge on the Project.

As part of the ongoing development of project management processes, new tools and techniques are continuously being introduced in order to increase effectiveness. An example is the use of Geographic Information System (GIS) based project management software to provide real time performance information. As mentioned in Section 4.1 NextEra is currently using GIS to coordinate all land acquisition, environmental and cultural assessments, as well as monitor engineering and construction activities on Lone Star Transmission development and construction.

NextBridge's Core Safety Principles

- Never put production before safety
- Don't perform a task until it can be safely done
- Support and continuously improve safe work practices
- Provide recognition for safe work practices and accomplishments

Safety: NextBridge's safety vision is predicated on establishing and promoting the message that zero injuries is the only acceptable safety goal. NextEra`s "Zero Today!" Safety program focuses on a zero-injury environment both at home and at work. This is a testament to our commitment to safety, and, above all, to our customers, employees and the community. Enbridge also has a long record of using safety programs for its own employees as well as contractors, and frequently benchmarks its safety indicators against industry standards to help achieve continuous improvements. More information on these NextEra and Enbridge programs is in Appendix 9: NextEra and Enbridge Safety Information.

NextBridge through its partners has a long history of commitment to safety, recognizing that safety is beneficial to the employee, the family, the community, and the customer. We are committed to providing a safe and healthy work environment for all employees and require that safety not be compromised for any other business priority. We expect companies providing services to NextBridge to have the same high standards of safety and health.

The core of our safety culture is a robust risk assessment framework, which is applied to evaluate every risk to safety associated with a particular job, with the objective of mitigating risks prior to beginning any work. This is followed up by a peer assessment program. The success of these programs is evident in the fact that 24 of NextEra's generation and transmission operating sites have achieved STAR status in the Operational Safety Health Administration (OSHA) Voluntary Protection Program (VPP). In addition, Enbridge has developed a 3 year corporate strategy to be best in class in a number of areas, including

safety performance. Enbridge's belief is that a safe operation is a reliable, productive and sustainable operation.

The remote site work, particularly during the initial field studies and environmental / cultural surveys, will use a remote site safety plan to ensure continuous monitoring of the safety status of personnel in the field. The use of work plans, cell phone updates, SPOT GPS emergency devices and other procedures will be incorporated into a Safety Plan for the Project.

Ensuring a safe work environment will ultimately lead to lower risk of workplace injuries and associated costs. All project field crews are trained and random internal audits are carried out to ensure that personnel comply with the health, environmental and safety elements of NextBridge Safety Plan.

In summary, evidence of good utility practice in safety is shown through the resulting safety statistics, which for the NextBridge partners are significantly below national averages as shown in Appendix 9: NextEra and Enbridge Safety Information. This culture of active safety mindedness has been adopted by NextBridge.

Environmental Compliance: NextBridge is committed to the use of good utility practices with respect to environmental compliance. This includes evaluating our environmental performance, verify compliance with company policy and legal and regulatory requirements, and communicate results to corporate management.

Our Commitment to the Environment

- Comply with the spirit and intent, as well as the letter, of environmental laws, regulations and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance and take appropriate action.

Our principal mechanism for verifying environmental compliance is the environmental audit. Such an audit comprises a planned and systematic, documented, periodic and objective evaluation of the performance of the organization (including management systems and equipment designed to protect the environment). The goal on an environmental audit is to facilitate management control of environmental practices; and assess compliance with existing environmental regulatory requirements and company policies. In general, audits will be conducted every two to three years on the Project, in keeping with our partners' practice on other NextBridge partner projects.

In addition to the periodic audit, significant resources will be dedicated to ensure Project compliance and environmental stewardship. Environmental compliance activities include dedicated environmental monitors who will be engaged in daily construction and post-construction compliance activities. Regular compliance communication updates, environmental meetings, and compliance procedures will be implemented for the Project.

Further, a construction and operations environmental compliance matrix will be developed to track all permit conditions concerning compliance status, persons responsible, schedule and issues. Regular Project site compliance inspections will also be conducted and communicated with applicable regulatory agencies and an Environmental Protection Plan will be used to ensure that all relevant procedures are followed.

In addition, listed here are examples of recognition that NextBridge partners have received for environmental commitment, above and beyond those of mandated environmental compliance:

- **Dow Jones Sustainability Index:** An index of the leading companies in North America for corporate sustainability, selecting the top 20 percent in sustainability performance from the 600 largest companies in North America. NextEra was named to this list in 2012, 2011, 2010 and 2009. Enbridge was named in 2012. Both NextEra and Enbridge have repeatedly been named to this index.
- **TreeLine USA:** For nine consecutive years through 2011, FPL has been recognized as a Tree Line USA utility. Sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters, the recognition is afforded utilities that demonstrate quality tree care practices, annual worker training, and public education programs such as FPL's Right Tree, Right Place campaign.
- **Global 100 Most Sustainable Large Corporations in the World:** A list of top large capitalization companies assessed for corporate sustainability and announced annually at the World Economic Forum in Davos, Switzerland. Enbridge was a member of the inaugural list in 2005, and has reappeared on the list from 2006-2007 and 2010-2012.

Regulatory Compliance: NextBridge will draw resources and expertise from NextEra Energy's available Compliance & Responsibility Organization (CRO) which is responsible for comprehensive oversight and management of regulatory compliance activities on projects. The CRO oversees Federal Energy Regulatory Commission (FERC) compliance activities, including Standards of Conduct and Market Manipulation as well as NERC Reliability Standards. CRO provides functional oversight, guidance, and

training, for various compliance execution programs. NextBridge's compliance program will leverage existing CRO oversight processes and the centralized management of regulatory updates, internal auditing support and coordination with regional regulatory groups and NERC.

Enbridge Gas Distribution (EGD), Enbridge's Ontario-based consumer facing gas distribution utility is the longest-serving natural gas utility in Ontario with a 160-year history. It owns and operates over 35,000 km of pipelines for the transportation and distribution of gas, plus service pipes to transfer gas to meters on customer premises. EGD has consistently demonstrated good utility practice during its long history with the OEB.

Additionally, NextBridge employees will be required to adhere to Canadian, U.S. and international anti-bribery and corruption laws and regulations. CRO administers the compliance program for these laws, including procedures regarding due diligence on international business parties, reporting requirements and training that addresses restrictions on international gifts and hospitality as well as restrictions on international charitable contributions.

The results of the CRO's efforts to date have been externally recognized by Ethisphere magazine. Ethisphere magazine provides third-party verification of compliance programs and ethical cultures. It conducted a review of NextEra Energy's compliance program against federal guidelines and designated it with "Compliance Leader Verification" through Dec. 31, 2013. According to Ethisphere, this designation recognizes companies with "best-in-industry compliance programs," and those that "proactively invest resources in compliance, sending a clear signal to key stakeholders that your company takes compliance and ethics seriously."

4.5 Challenges and Related Plans

In this section we outline the challenges involved in achieving the required capacity and reliability of the EWT Line, including challenges related to terrain and weather. We outline our plan for addressing these challenges through the design and construction of the EWT Line, as discussed below:

- **Cold Climate/ Ice Loading**: Northwest Ontario experiences severe weather which may have a significant impact on the EWT Line's performance and/or reliability. In addition, periodically within North America, extreme weather events result in damaged structures and possible cascade structure failures. To mitigate this risk NextBridge has indicated that, during the development

phase, it will investigate the incremental cost and benefit to the ratepayers of increasing the combined ice/wind weather event to a 1 in 100 year load case. Preliminary analyses have determined that this could be accomplished for an incremental cost of 1-1.5% of the Project cost. In its proposed cost estimate, NextBridge has included the cost of "stop-structures" or "anti-cascade structures". In the preliminary design, there is either a dead-end or stop structure every 16 km to limit possible damage from an extreme weather event.

- **Variability of Terrain:** The Project traverses rocky ledges and undulating terrain. The preliminary design is based on 10-metre contour data. Based on past experience with such preliminary design information, using this low resolution data, a 2-metre clearance buffer was included to ensure that the tower heights and spacing utilized would not be dramatically impacted when final design is underway.
- **Forced Outages:** Data provided by Hydro One indicates an average of 3 to 4 outages per year on the Wawa to Marathon circuits of the existing EWT Line; and 3.7 to 5.9 outages per year on the Marathon to Lakehead circuits. A large number of outages on the Marathon to Lakehead circuits were due to an ice storm in 2009. Other outage causes are not identified. While we have considered a number of viable mitigation strategies, without more extensive study of the area and more detail on outage cause identification, it is not possible to fully determine all the mitigations strategies to ensure that the new EWT Line will have better performance in the same environment.

  If not implemented already, NextBridge would encourage the use of fault locators at the substation end of existing lines as well as the new EWT Line. NextBridge will incorporate cause identification by well-trained high voltage leads with high quality optics to identify flash marks, evidence of avian interaction etc. NextBridge partner NextEra is well versed in outage cause identification and reliability improvements and will support NextBridge personnel through the utilization of an Asset Management Program and Event Response processes to establish and track outage cause codes and implement mitigation measures responsive to the reliability exposure.
- **Grounding and lightning outages:** During a field visit in September, 2012, evidence of counterpoise grounding schemes were seen at some towers. Towers are predominately installed on rock outcroppings where obtaining good grounds is difficult. Without soil resistivity data along the route, it is not possible to determine if the OEB specified 20 ohm tower grounds can be achieved with

reasonable effort. High tower footing resistance can result in more back flashovers from lightning. Possible mitigation would be the use of arrestors.

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5 Financial Capacity

5.1 Capital resources sufficient to develop, finance, construct, operate & maintain the line

NextBridge's three owners are each well-capitalized entities. In aggregate they hold assets exceeding $100 billion in value. These three large, experienced investors are fully committed to this Project, giving NextBridge access to substantial capital resources and to the significant additional liquidity available to each of its owners.

5.2 Current credit rating of the applicant and its associated companies

As a newly formed entity NextBridge does not, as yet, have an independent credit rating. It does, however, have full support from its three owners, each of which has investment grade credit ratings. NextEra Energy Capital Holdings, Inc. is rated A- by Standard and Poor's (S&P), Baa1 by Moody's, and A- by Fitch Ratings. Enbridge is rated A- by S&P, Baa1 by Moody's, and A (Low) by Dominion Bond Rating Service (DBRS). OMERS enterprise and counterparty credit rating is AAA (S&P and DBRS).

Although it will be owned and backed by financially stable entities with strong track records, NextBridge intends to structure its financing to secure a strong, stand-alone, investment-grade credit rating. A strong credit rating for NextBridge will enable stand-alone access to debt on cost-effective terms. Ultimately, leverage on the EWT Line will be supported by the Project's strong stand alone credit fundamentals, as well as the credibility of the sponsoring NextBridge owners.

5.3 Evidence that financing, construction, operation and maintenance of the line will not have adverse impact on applicant's credit worthiness or financial condition

Although the capital costs associated with the EWT Line will be significant, they would nevertheless constitute a small portion of the asset base for each of NextBridge's partner companies, and an even smaller fraction of their combined asset base. Consequently, financing, operating and maintaining the EWT Line will not have an adverse impact on NextBridge's financial resources, nor on the respective credit worthiness and ratings of each partner. As at December 31, 2011, the partner companies had the following asset values: NextEra Energy with $57 billion; Enbridge with $34 billion; and Borealis with $10 billion under management (and OMERS having an asset base of $55 billion). Additional information,

including audited financial statements of the partners, is in Appendix 1: NextBridge Partner Annual Reports and Other Supplementary Reports.

5.4 Financing Plan including estimated proportions and costs of debt and equity

Capitalization: NextBridge currently intends to target a ratio of 60% debt/40% equity during construction and operations, in line with other transmission utilities in Ontario and the OEB's existing guidelines. NextBridge believes 40% equity is the minimum equity proportion that is consistent with the strong investment grade credit ratings necessary to ensure access to low-cost debt financing under all market conditions, and therefore is consistent with the goal of providing the lowest overall financing cost for ratepayers. While this is the currently intended target capital structure, NextBridge may seek to introduce preference shares or other hybrid capital, should that prove to be an attractive vehicle for First Nation or Métis investment.

Cost of Debt: NextBridge expects to start construction using internal resources contributed from its owners. During this period, we would seek to receive the OEB's deemed cost of debt. At some point during the course of construction, NextBridge may put in place construction financing, if such can be obtained on attractive terms. Such a facility could offer the advantage of locking in attractive interest rates for a period of several years. In the event such a financing were put in place, NextBridge would thenceforth seek recovery of its actual cost of debt rather than the OEB's deemed cost of debt. We note that financing a project through internal resources at the outset, and subsequently raising a construction financing, often results in a lower overall cost of borrowing as lenders have the benefit of financing a more advanced project.

Cost of Equity: For this opportunity, as with typical revenue-requirement hearings for established utilities, the OEB is faced with having to balance the needs of the proponents who are providing the investment capital to finance the Project, with those of the power consumers of Ontario who derive benefits from using the infrastructure, and who ultimately pay for the cost of such services. NextBridge recognizes that delivering value to these customers through better performance is an important priority for the OEB. NextBridge embraces that philosophy, and commits to working collaboratively to develop one or more viable alternatives to the conventional ratemaking model, suitable to a new-entrant transmission utility.

As documented throughout this Application, NextBridge possesses an abundance of the knowledge, skills, financial wherewithal, and experience required to plan and execute the proposed line. As a result, we are confident that we will be able to deliver the Project within a narrow band of budget and schedule outcomes after having completed the development phase. As a result, we are prepared to be held accountable for achieving results, by exposing our potential return to the risk associated with a performance-based ratemaking construct. Such an approach would reward NextBridge with premium returns only in the event that we provide superior outcomes – that is, value – for the Province's ratepayers.

NextBridge intends to address the specific details of its performance-based ratemaking proposal at the leave to construct. We expect our detailed proposal will reflect the following general features:

- **Stepwise, consultative development of a performance-based ratemaking construct:** We envision that, as a matter of practicality, conventional returns would be generated during the construction period; and that thereafter, performance-based returns would be realized, based upon actual outcomes measured following the completion of the Project. To lay the appropriate groundwork at the leave to construct, NextBridge would develop benchmarks for such performance metrics as total project cost, completion date, and potentially other metrics including those related to safety. We would then engage in discussions with OEB staff and other stakeholders to develop an appropriate relationship between risk allocation, performance outcomes and return on equity.
- **Allowed returns commensurate with risk and linked to performance:** The initial allowed Return on Equity (ROE) post-commercial operation would vary based on two key elements:

  1. The degree to which NextBridge assumes risk during the construction period relative to what it proposes in its leave to construct application (e.g. depending on whether it offers a fixed price or a narrow price band at one extreme vs. complete flow-through of actual costs at the other extreme); and
  2. NextBridge's performance relative to the agreed-upon performance metrics.

  We anticipate that this initial ROE will persist for several years, reflecting the importance of the construction phase on the long-term value proposition for customers. But at some point, the allowed ROE would vary on a periodic basis, depending on NextBridge's performance in such areas

as operating costs (including overheads), reliability performance, and other appropriate metrics – again, developed in consultation with OEB staff and other stakeholders – and also potentially to reflect changes in interest rates. Overall, NextBridge would seek to design a construct that produces a reasonable prospect for it to realize an ROE in the range of 9.5-9.9%, assuming similar risk-free interest rate levels and industry spreads as exist today. However, depending on the degree to which NextBridge meets its performance targets, thereby producing value for its customers, the range of potential ROE outcomes could be wider than this.

- **Superior value for the electric customers of Ontario:** As compared with what would otherwise be achieved by incumbents under the status-quo regulatory regime, performance-based ratemaking should result in a lower revenue requirement for the citizens of Ontario. For example, as illustrated in the table below a hypothetical 10% decrease in construction cost, in return for a 100 basis point ROE adder, would generate revenue requirement savings for customers of almost 5%. We provide supporting calculations in Appendix 10: Supporting Calculations for Performance Based Rate-Making.

FIGURE 9: PERFORMANCE-BASED RATEMAKING EXAMPLE

In $millions	Case 1	Case 2
Capital Cost	$600	$540
ROE	9.0%	10.0%
Revenue Requirement (RR)	63.8	60.8
Change in RR		(2.9)
% Change in RR		-4.6%

With the exception of construction work-in-progress, discussed in Section 5.8 below, recovery will occur once the line goes into service, when the evaluation of success can be measured. Our objective will be to develop a ratemaking construct that aligns the interests of both the shareholders and customers of NextBridge, and ultimately delivers a superior value proposition versus the incumbent utility and ratemaking status quo.

5.5 Applicant's ability to access debt and equity markets

NextBridge intends to use internal financing from its owners to meet its Project obligations up to the start of commercial operations, subject to capitalizing on favourable construction financing opportunities. In any event, NextBridge will not need to directly access the debt or equity markets to fund the Project.

Each of NextBridge's owners brings extensive treasury and financing expertise that will be readily available to NextBridge should it be advantageous. For example, in 2011, NextEra Energy raised $7.3 billion in capital including $6.8 billion in debt and $0.5 billion in common and tax equity. In 2011, Enbridge raised over $1.5 billion in capital. Borealis' investable allocation currently stands at over $12 billion.

5.6 Ability to finance the project in the case of cost overruns, delay in completion of the project and other factors that may impact the financing plan

As outlined above, NextBridge stands ready to use internal financing from its owners to meet its Project obligations up to the start of commercial operations. Enbridge and NextEra Energy are publicly-listed companies with strong investment grade credit ratings and can therefore access debt and equity capital markets to raise financing, if required, to cover the cost of overruns or delays. Further, both organizations can access liquidity under standby credit lines. As of June 30, 2012, NextEra's net available liquidity position was $ 5.2 billion and Enbridge's was $8.7 billion. Borealis can access an allocation of over $12 billion as required.

5.7 Experience in financing similar projects

Each of the NextBridge partners can cite numerous examples of financing similar projects. In 2011 alone, NextEra raised $7.3 billion in capital including $6.8 billion in debt and $0.5 billion in common and tax equity. In one example, Lone Star Transmission, LLC, an indirect wholly owned subsidiary of NextEra Energy Capital Holdings, Inc., entered into an approximately $387 million principal amount senior secured limited-recourse variable rate loan agreement maturing in November 2016. Below is a table of other recent NextEra Energy Company financings.

FIGURE 10: RECENT EXAMPLES OF NEXTERA PROJECT FINANCINGS

Project	Amount $ (USD)	Details
Spain Solar	$1.2 billion	Limited recourse term facility used to fund a 99.8 MW solar project currently under construction in Spain. Won the European Solar Concentrated Solar Power Deal of the year award from Project Finance Magazine.
Desert Sunlight	$1.6 billion	A US DOE guaranteed loan used to fund construction of a 550 MW solar PV project in California. Project is an unconsolidated joint venture with GE in which NextEra Energy holds a 50% interest. Bonds have an 18 year weighted average life. Won the North American Solar Deal of the Year award from Project Finance Magazine.
Genesis	$852 million	A US DOE guaranteed loan used to fund construction of a 250 MW solar thermal project in California. Proceeds were received upfront by accessing the institutional market; bonds have a 22 year weighted average life.
Lone Star Transmission	$387 million	Proceeds to fund the build out of a 320 mile 345 kV transmission line in Texas. Lone Star is a rate regulated utility in Texas. One of eight sponsors selected to build out Texas transmission to support renewable energy.
Redwood Trails	$234 million	Financing for a portfolio of three wind projects totaling 237 MW located in Oklahoma and California. Consortium of banks provided the financing which included an 18 year term.
Baldwin	$82 million	Financing for a 102 MW wind project located in North Dakota. Accessed institutional project debt market with a 20 year term.
White Oak	$70 million	Financing for a 150 MW wind project located in Illinois. Tax Equity was also raised on this asset.

Recently Borealis has invested in significant infrastructure assets, including Midland Cogeneration Venture, a 1,633 MW cogeneration plant in Michigan, and four wind farms in the United States with a total capacity of 599 MW. In addition to new investments, it continuously supports its existing investments to "obtain" new financing. High Speed One and Associated British Ports, both United Kingdom investments, completed significant refinancing activities in 2012.

5.8 The identification of any alternative mechanisms (e.g., rate treatment of construction work in progress) that the applicant is requesting or likely to request.

While the owners of NextBridge are fully prepared to fund 100% of the cost of construction for the EWT Line, as discussed above, we envision that the utility will ultimately have its own third party debt financing, and that this could be advantageously put in place during the construction phase. We therefore propose to receive a return on construction work-in-progress (CWIP) during the construction

phase, in line with the OEB's *Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario* policy [January 15, 2012 Report of the Board in EB-2009-0152] (Infrastructure Investment Policy). We envision that a return on CWIP would be earned at the weighted average cost of capital (WACC), reflecting standard 60% debt, standard market rate interest (or actual cost of debt if a construction financing is obtained), and standard ROE. Placing CWIP in rates is appropriate for a single asset company with a large multi-year construction program, which would otherwise produce no cash flow until completion. Such rate treatment is credit supportive, and should therefore enable NextBridge to borrow funds during construction on more attractive terms than would otherwise be possible. Given NextBridge's cost-based rates, ultimately this benefit would be expected to flow through to customers.

As noted above, NextBridge also intends to develop with its Ontario stakeholders a performance-based ratemaking construct. This construct could be viewed as a form of project-specific return on equity incentive, in line with the OEB's *Infrastructure Investment Policy.*

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Section B: Plan for the East-West Tie Line

6 Proposed Design

6.1 Overview of Proposed Design

The Reference Plan for the EWT Line is defined in *Attachment 1: Project Definition for Designation for the East-West Tie Line* attached to the OEB's December 20, 2011 memo to the electricity transmitters registered in this process. The Reference Plan meets the requirements specified in Attachment 2 to the same memo - *Minimum Technical Requirements for the Reference Option of the E-W Tie Line*, November 9, 2011, including Appendix A to the Minimum Technical Requirements document which Appendix A is entitled *Appendix A Minimum Design Criteria for the Reference Option of the E-W Tie Line*.

The Reference Plan, includes the following main features:

- A total of 400 km of double circuit 230kV line parallel and adjacent to the existing Hydro One double circuit 230kV line between Thunder Bay and Wawa, in Ontario.
- The total length of the line is divided into two segments; one from Wawa Transmission Substation (TS) to Marathon TS, and the other from Marathon TS to Lake Head TS. Each segment terminates on a dead-end structure within 250 metres of the existing Hydro One substations.
- The dead-ends are the demarcation points for the purposes of ownership and control. The slack span between the dead-end structure and the Hydro One substation incorporates a mid-span opener consisting of an insulator and a jumper that can be manually opened.
- Communication as well as protection and control systems incorporated by Hydro One at each of the substations.

NextBridge assumes that the Designated Transmitter will have access to telemetry and measurement data from Hydro One to allow the transmitter to monitor the assets under its ownership and responsibility.

We summarize below how NextBridge's Recommended Plan meets these Project requirements. In our analysis, we also included a cost for the development and subsequent execution of the Reference Plan in the event it is deemed the most desirable option by the OEB following the Designation Hearing, as well as for comparison purposes.

FIGURE 11: SUMMARY OF HOW OUR PLAN MEETS REQUIREMENTS

Specification	Reference Plan	NextBridge Recommended Plan
Line Length	400 km	400 km
Number of circuits	2	2
Circuit Voltage (phase to phase)	230 kV nominal, 250 kV maximum	230 kV nominal, 250 kV maximum
Load carrying capacity	1,235 Amps	1,235 Amps
Summer continuous rating (MVA) Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 93ºC	466 MVA	466 MVA
Summer emergency rating (MVA) Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 127 ºC	599 MVA	599 MVA
Resulting total transfer capability for the East-West Tie line (MW)	650 MW	650 MW
Anticipated lifetime of the line	50 years	50 years
Number and average spacing of towers	1,012 towers with an average span of 395 metres.	1,012 towers with an average span of 395 metres.
Tower structure types (lattice, monopole, etc.) and composition (wood, steel, concrete, hybrid, etc.)	Self-Supported Steel-Lattice	Guyed-Y steel-lattice (Guyed-Y)
Conductor size and type	1192 kcmil ACSR 54/19 stranding "Grackle", one per phase	1192 kcmil ACSR 54/19 stranding "Grackle", one per phase
Protection against cascading failure and conductor galloping	NextBridge has incorporated anti-cascading structures and evaluated extreme weather events. The estimate assumes a dead-end structure every 16 km. Structure designs were based on phase spacing required by galloping study.	NextBridge has incorporated anti-cascading structures and evaluated extreme weather events. The estimate assumes a dead-end structure every 16 km. Structure designs were based on phase spacing required by galloping study.
Overall Impact on Existing Transmission System	Meets the benefits for the Reference Case as they are described in IESO's Feasibility Study: "An assessment of the westward transfer capability of various options for reinforcing the East-West Tie", dated August 18, 2011. (Final Version)	Meets the benefits for the Reference Case as they are described in IESO's Feasibility Study: "An assessment of the westward transfer capability of various options for reinforcing the East-West Tie", dated August 18, 2011. (Final Version)
Basic Right-of-Way Width	50 Metres	50-56 Metres
Typical Tower Height	50 Metres	43 metres

Note: Differences in the Plan Summary have been highlighted in green in the table above for emphasis

In developing its Plan for the Project, NextBridge evaluated a number of different technology, routing and structural options. Our evaluations considered: First Nation and Métis participation and consultation; land acquisition (both Provincial and Federal); environmental approvals (both Provincial and Federal); other permitting and regulatory processes; engineering and construction; accessibility and constructability; schedule; cost; as well as power security, reliability and quality. Through our analysis and preliminary engineering assessment, NextBridge has found a combination of technology, route and structure that provide the performance required by the OEB while optimizing cost. Based on this evaluation NextBridge's Recommended Plan for the EWT Line:

1. **Technology:** Adopts the Reference Plan 230kV AC double circuit technology;
2. **Route:** Adopts the Reference Route, but incorporates specific, limited contingent variants from that route should it be determined through consultation that these variant routes may be preferable; and
3. **Structure:** Specifies Guyed-Y towers, which provide better lightning performance, a smaller footprint, and a projected cost saving of $33 million, relative to the conventional self-supported steel-lattice towers in place on the existing transmission system.

- **Technology:** NextBridge's analysis began with the identification of a suite of possible technologies that could be implemented to achieve at a minimum, the Ontario Power Authority's desired capacity and reliability objectives. The options considered included:
  - Higher and lower AC voltages native to the Ontario system;
  - Voltages not native to the Ontario transmission system; and
  - High Voltage Direct Current (HVDC).

  These options were subjected to a planning level analysis performed by a respected third party electrical engineering firm, PTerra LLC. The complete *PTerra Technology Assessment* is in Appendix 11: PTerra Technology Assessment.

  For each listed technology, PTerra assessed and compared technical applicability to, and performance for, the EWT Line. It was determined that either a double circuit 230kV or an HVDC configuration could achieve the desired technical performance.

Additional analysis of these two configurations was conducted, including a full *IESO Feasibility Study* (Appendix 12: IESO Feasibility Study) analysis of the HVDC option, which was commissioned by NextBridge. NextBridge determined that, in almost every respect, both configurations provided similar performance. The HVDC did provide incremental benefits in the areas of: transmission line and overall system losses; voltage control; and black start capability, amongst others. However the value of these incremental benefits could not be outweighed by the capital cost differential between these options. An internal budgetary analysis found that for this application HVDC has a cost premium of approximately 50% to 70% over the Reference Plan. As such, NextBridge's Recommended Plan uses a double circuit 230kV configuration.

- **Route:** To study the route, NextBridge conducted a critical-issues analysis and subsequent constraints-based analysis on potential route alternatives. In addition to the existing Hydro One EWT Line corridor, NextBridge considered:
  - Other proximal linear infrastructure corridors including rail, road, other electric transmission corridors and pipeline right-of-ways (ROW); and
  - A Greenfield route for all or portions of the transmission line, including underwater solutions in some areas.

  Underwater solutions were rejected due to high preliminary cost estimates and installation concerns, primarily the ability to navigate cable laying ships of sufficient size through the Saint Lawrence Seaway. Similarly, other route options were considered and discarded due to cost and schedule impacts. The two best options were determined to be the existing Hydro One EWT Line corridor and a second route paralleling Highway 17 within approximately 1-3 km.

  A comparative constructability cost calculation was performed on both routes. Our analysis indicated that the accessibility and terrain advantages of the road route could not outweigh the cost associated with the incremental distances involved. In all, it was found that moving to the all-road route between Wawa and Marathon would add approximately 10-15% to the overall cost of the Project. As such, NextBridge concluded that the Reference Route is the preferred route. Our analysis did, however, identify two potential critical issues:

  - **Pukaskwa National Park:** The existing EWT Line transmission corridor traverses the Pukaskwa National Park and was constructed before the Park was created. The ability to widen the ROW

through the Park is in question. At this stage of pre-development, NextBridge cannot predict the decision that Parks Canada and/or the Federal Government will make regarding the Canadian *Environmental Assessment Act* permitting process. As well, the sheer size of the Park and associated cost implications would dictate that the consideration of a contingent variant be a prudent step in an early stage routing analysis in order to understand the potential impacts.

- **First Nation Reserve Lands Crossed by the Existing Route**: The existing corridor traverses Pays Plat and Michipicoten First Nation Reserve lands. Crossing Reserve land requires a Federal approvals process, which could result in an additional risk of permitting delays and impact to the Project schedule. If, after consultation with the affected First Nation communities, it is determined that it is preferable to circumvent the Reserve lands, NextBridge has identified two potential route variants:
  - A Pays Plat First Nation route variant is relatively short and is assumed to follow the Northern border of the Reserve, intersecting with the existing Hydro One corridor on the East and West borders of the Reserve. Details regarding actual and final routing of any bypass would be developed in conjunction with the affected First Nation community.
  - A Michipicoten First Nation route variant is made up of two sections: the North-South section runs largely parallel to a rural road and the East-West section is adjacent to an existing transmission corridor. This routing option attempts to maximize the use of existing linear corridors available in the area. Details regarding actual and final routing of any bypass would be developed in conjunction with the affected First Nation community.

Each of these three potential route variations to the proposed Reference Route was selected based on a combination of desktop analysis, representative site visits and/or area flyovers. Further refinement to the route is expected to occur during the development phase, including through consultation with Pukaskwa Park authorities and with the Pays Plat and Michipicoten First Nation communities. Maps for the Reference Route and the three potential route variants are below.



East West Tie Line Project
Route Overview
Figure 12: Reference Route Map with Variants

Albers Equal Area Conic 1:800,000

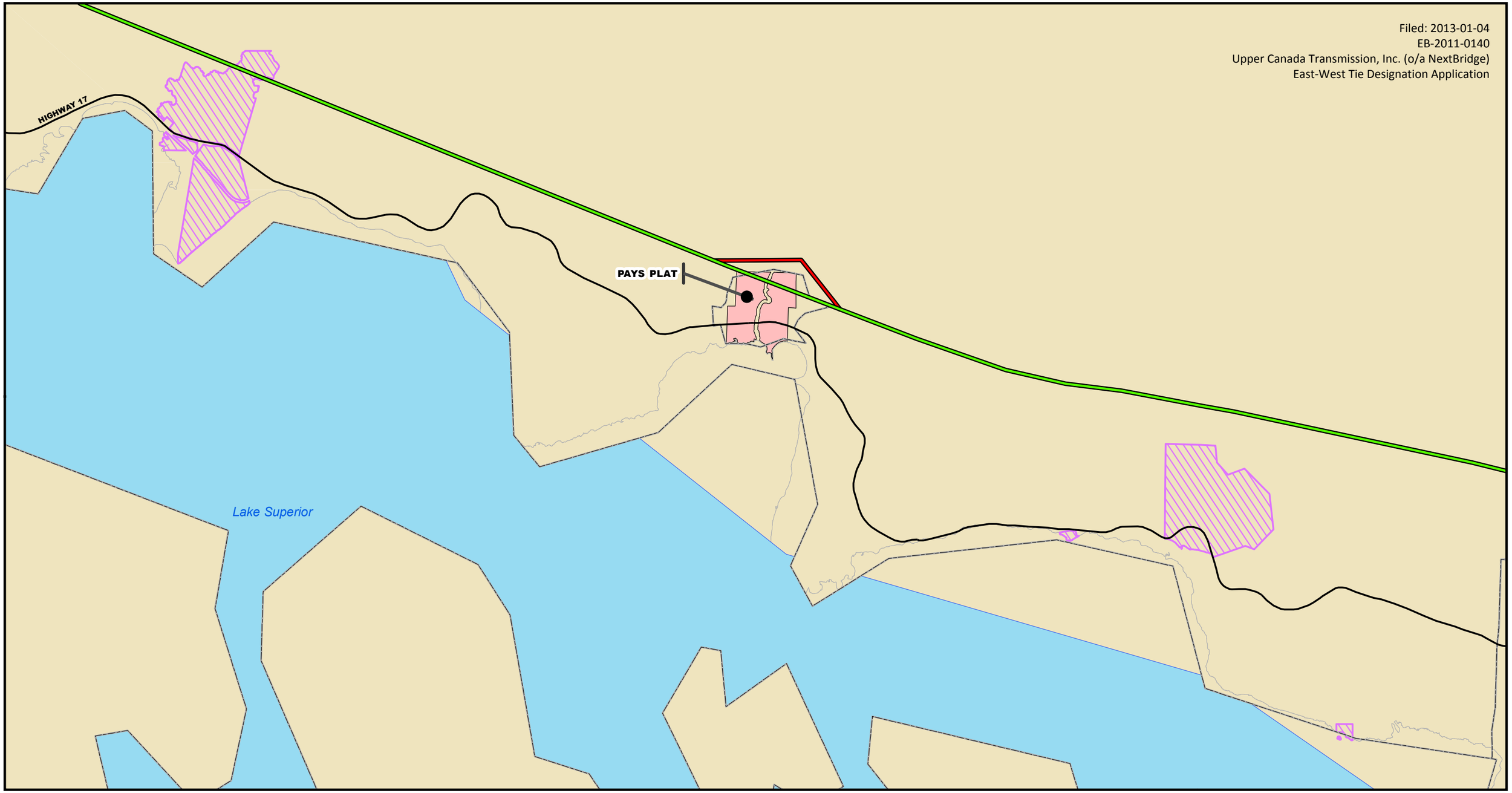
25 12.5 0 25 50 KM

File Name: East West Tie Line Project

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nations
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality
- International Border

NEXTBRIDGE INFRASTRUCTURE



POLAR Geomatic Solutions

East West Tie Line Project

Figure 13: Pays Plat First Nation Reserve - Route Variant

Albers Equal Area Conic

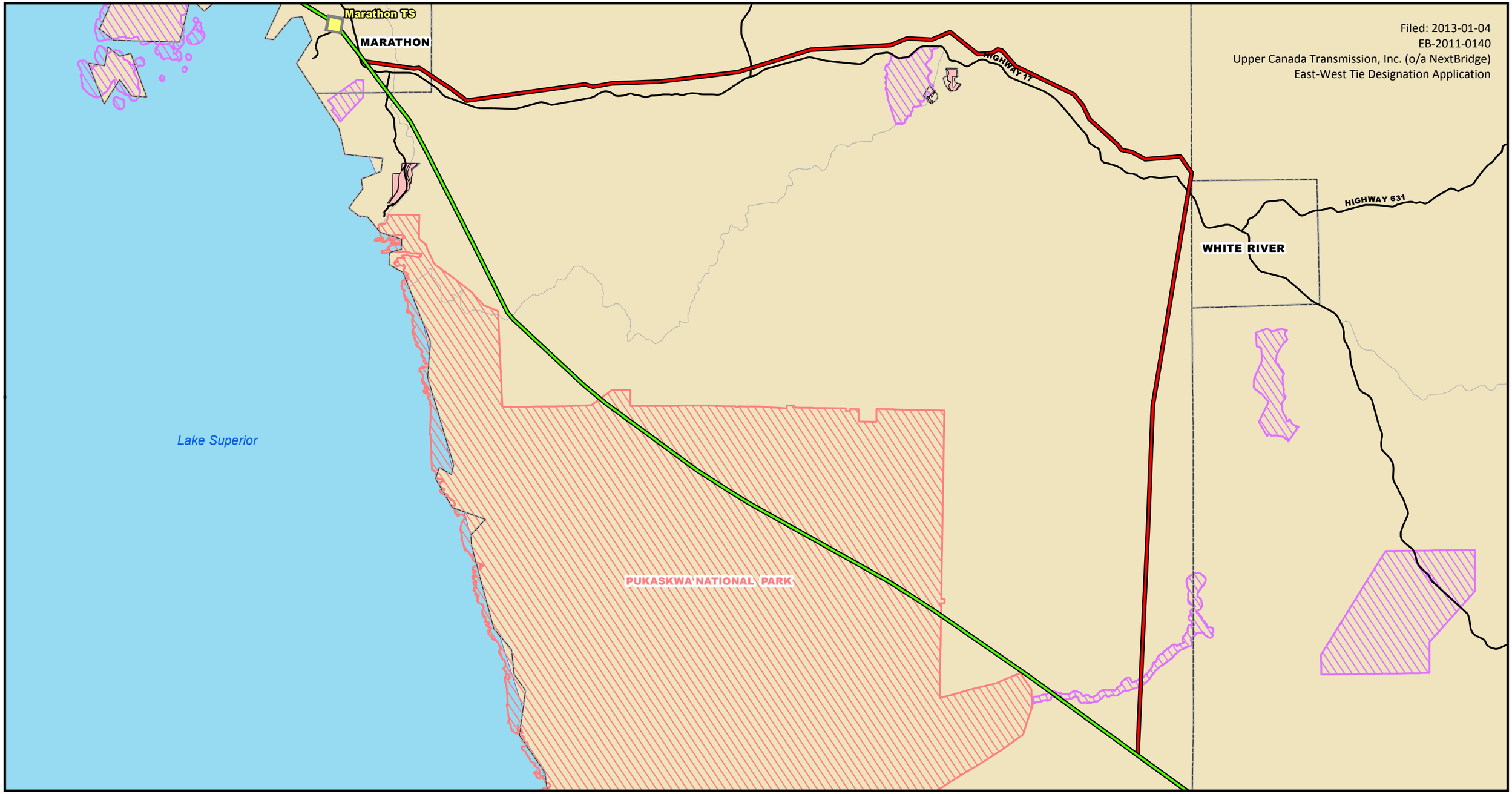
1:90,000

10 5 0 KM

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nation
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality

NEXTBRIDGE INFRASTRUCTURE



East West Tie Line Project

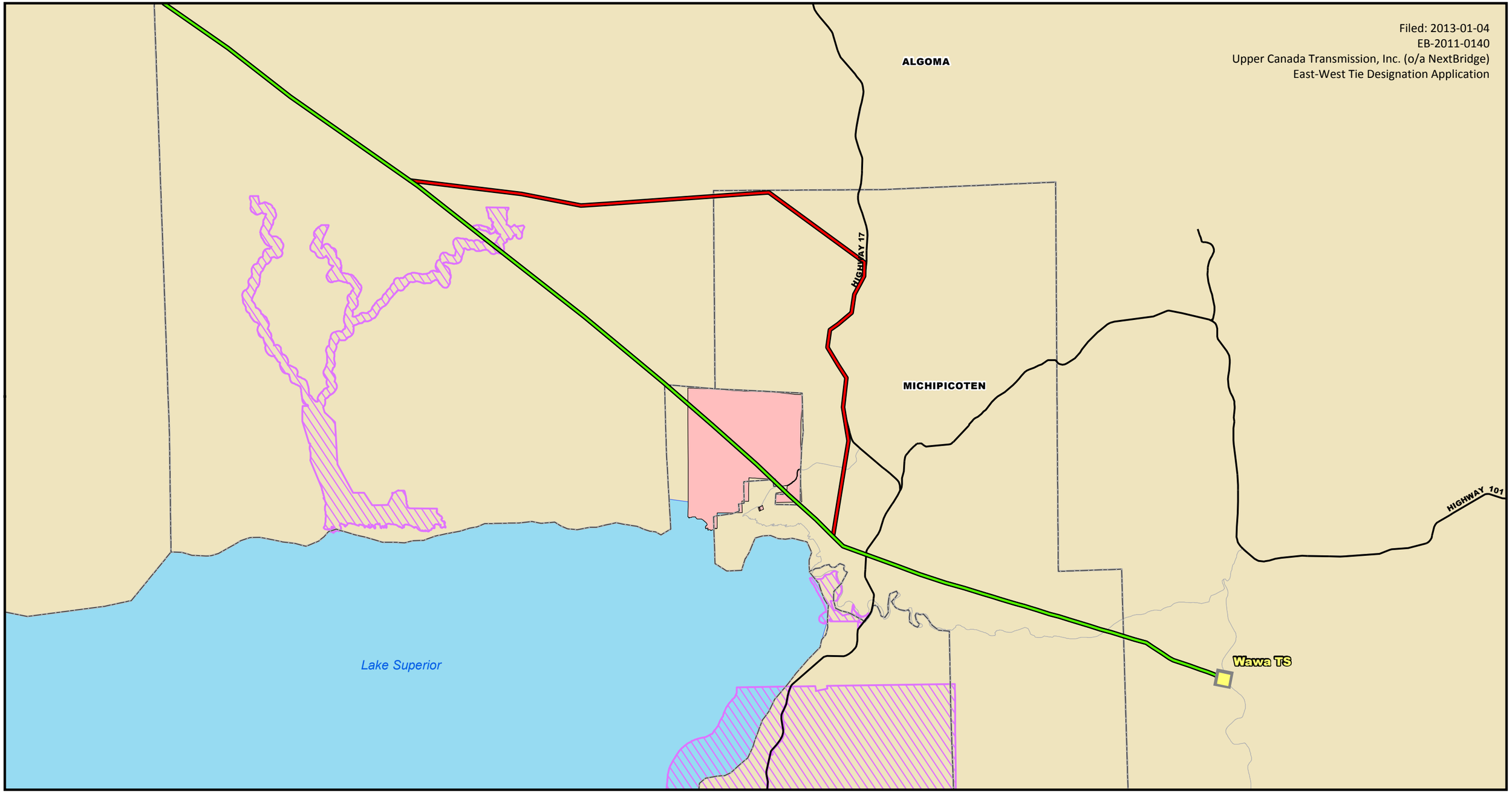
Figure 14: Pukaskwa National Park - Route Variant

Albers Equal Area Conic 1:300,000

10 5 0 10 20 Km

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nation
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality



POLAR Geomatic Solutions

East West Tie Line Project

Figure 15: Michipicoten First Nation Reserve - Route Variant

Albers Equal Area Conic

1:190,000

10 5 0 10 Km

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nation
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality

NEXTBRIDGE INFRASTRUCTURE

- **Structure:** NextBridge investigated a range of tower structures for this Project, some familiar to Ontario and others that have been successfully used in various regions outside of Ontario. A number of NextEra's electrical and structural engineers with extensive, cross-jurisdictional and tower design variation experience (concrete, hybrid, H-frame and numerous lattice structure variations, both guyed and self-supporting) were involved in this investigation. With guidance from these qualified individuals, NextBridge commissioned Burns and McDonnell (B&M) to conduct a more detailed structural analysis for this Project. As discussed in Section 2 and 4, NextBridge also engaged B&M to complete preliminary engineering work. The *B&M Structural Analysis Report* is in Appendix 13: Burns & McDonnell.

  The B&M analysis highlighted a number of constructability issues, based on which NextBridge determined that heavier structures such as concrete and hybrid, as well as steel monopoles, would not be economically viable candidates due to the inability to access remote locations with structures of such weight. Other issues included the lack of access roads over portions of the route, the maximum carrying capacity of helicopters and the weight of required construction equipment, ruggedness of terrain, environmental considerations associated with new access roads, among others. Designs, costs and construction risks were compared by NextBridge and B&M for the following three structures, listed here in order of decreasing cost:

  - Tubular Steel H-frame;
  - Self-supported steel-lattice; and
  - Guyed-Y.

  NextBridge concluded that the Guyed-Y tower best meets the technical requirements of the Project while delivering Project savings of $33 million relative to the conventional self-supported steel-lattice towers in place on the existing transmission system. Further, no issues caused by using a different structure were identified. Proper design will ensure that the performance of the Guyed-Y tower will meet all required parameters. In addition, given the nature of the local climate, NextBridge will investigate increasing the strength parameters of the Project to be able to withstand a 1 in 100 year combined ice and wind event. Current estimates indicate that the total cost would increase by approximately 1 to 1.5%. This change would essentially double the reliability in severe

weather events as compared to the minimum requirements proposed by the OEB. A diagram of a Guyed-Y tower is provided below.

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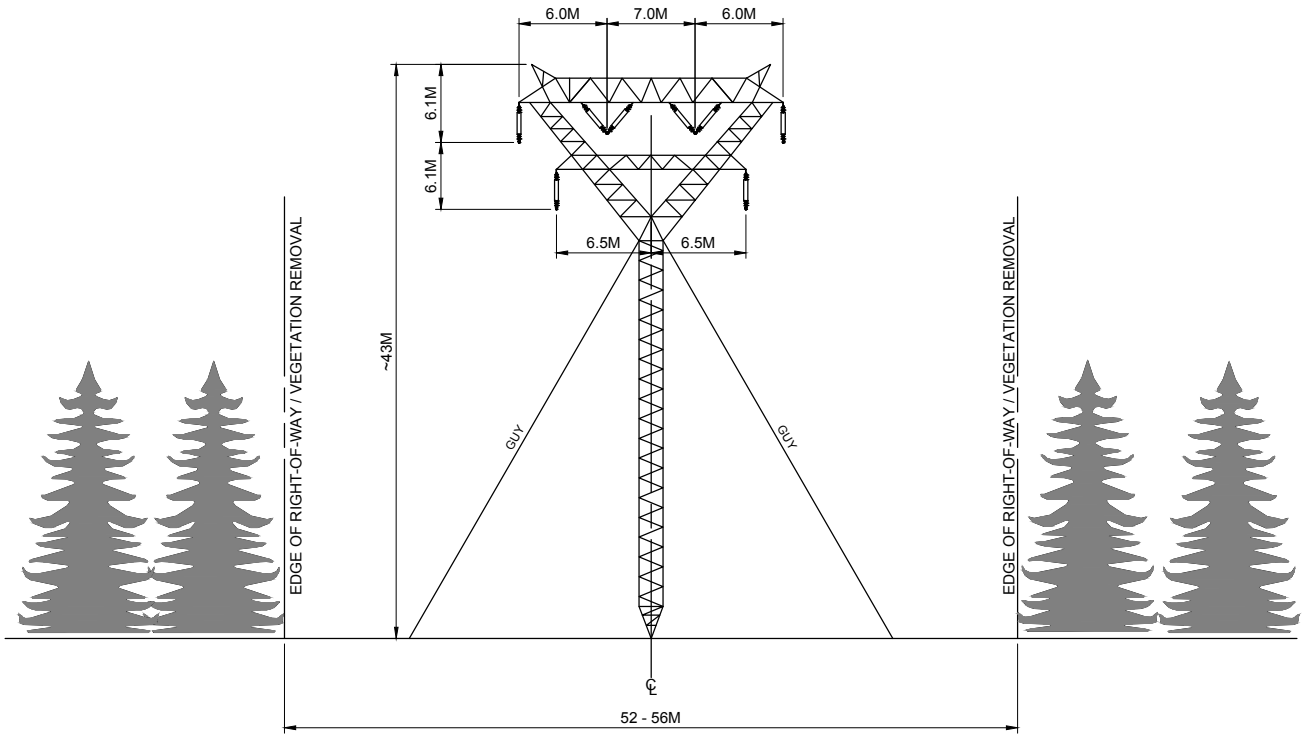

PRELIMINARY CROSS SECTION
NOT TO SCALE

NOTES:

1. PROPOSED STRUCTURE HEIGHTS ARE TYPICAL.
2. PROPOSED TYPICAL STRUCTURE HEIGHTS ARE SUBJECT TO CHANGE WITH THE COMPLETION OF FINAL LAYOUT DESIGN.
3. LATTICE TOWER SHOWN FOR INFORMATION ONLY. TUBULAR STEEL STRUCTURE OPTION MAY BE CONSIDERED.
4. RANGE OF RIGHT-OF-WAY WIDTHS BASED ON 500M MAX SPAN V-STRING (MIN) AND I-STRING (MAX).
5. ANCHORS WILL TYPICALLY BE LOCATED WITHIN RIGHT-OF-WAY, BUT MAY REQUIRE GUY EASEMENTS WITH STEEP TERRAIN.

PRELIMINARY

Figure 16

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
230-kV DOUBLE CIRCUIT GUYED Y
I-STRING

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N:\Nextera\69362 - Ontario East West Tie Line\Cadd\OH Transmission\Cross Sections\NexteraCross-Sect-I_String.dwg (XS-2) 11-27-2012 12:00 MJM B&McD

- **Design Assumptions:** We have outlined below the most critical assumptions in our design:
  - The OEB Minimum Technical Requirements were used as the basis of the transmission line design.
  - Desktop geotechnical investigation was utilized for foundation designs. NextBridge assumed 90% of foundations would be installed in competent rock. The remaining are assumed to be all soils, concrete drilled pier foundations.
  - Use and upgrading of existing Hydro One access roads will be permitted for construction access.
  - The Project demarcation will be at the final dead-end structure prior to entrance into any substation, and line reconfiguration/relocation at substation entries will be the responsibility of Hydro One as indicated by the OEB.
  - The grounding design assumes minimal rock will be encountered at the surface and that the required 20 ohm ground resistance is achievable with reasonable effort.
  - Telecommunications equipment will be provided by the interconnecting transmitter at each of the three interconnecting substations. Three fibre repeater sites will be required, evenly spaced at intermediate locations throughout the line.

6.2 Confirmation that the line will interconnect with existing transformer stations

NextBridge confirms that the double circuit 230kV transmission lines between Wawa, Marathon and Thunder Bay will dead-end on interconnection structures, which will be placed within 250 metres of the fence line of the existing Hydro One Wawa Transmission Substation (TS), Marathon TS and Lakehead TS. The 230kV double circuit line will terminate at Wawa TS and Lakehead TS and be switched at Marathon TS. NextBridge has assumed that Hydro One will be responsible for all substation and relay protection improvements required for the interconnection of these transmission circuits at these substations, as indicated in the Board's letter to Transmitters dated December 20, 2011, Attachment 1: Project Definition for Designation for the East-West Tie Line.

6.3 Affidavit regarding Reliability Standards and Minimum Technical Requirements

Appendix 14: Affidavit regarding Reliability Standards and Minimum Technical Requirements includes an affidavit confirming that the EWT Line will be designed to meet or exceed the:

- Existing NERC, NPCC and IESO reliability standards; and

- OEB's Minimum Technical Requirements.

6.4 Indication as to whether the Plan will be based on the Reference Option

NextBridge's Recommended Plan is based on the Reference Plan technology. NextBridge's Recommended Plan aligns with the Reference Route to the extent possible, as the optimal route is adjacent to the Hydro One route. However, as discussed in Section 6.1, our analysis recognizes that there may be difficulties with construction through Pukaskwa National Park and concerns regarding passage through Pays Plat and Michipicoten First Nation Reserves. In the event that a route adjacent to the existing Hydro One route cannot be utilized in those areas, NextBridge has identified route variants to bypass these areas of concern. A map of the contingent variants is provided in Section 6.1. The only major change in our Recommended Plan relative to the Reference Plan is in the structure. We discuss this structural change and its benefits below.

A description of the main differences between the Applicant's Plan and the Reference Option

NextBridge recommends a Guyed-Y tower instead of the self-supported steel-lattice tower in the Reference Plan. We outline below the key advantages of our selection of the Guyed-Y tower (with an 1192 ACSR conductor and 230 kV AC double circuit):

- The use of the Guyed-Y tower will result in a cost savings of approximately $33 million dollars, relative to the conventional self-supported steel-lattice towers in place on the existing transmission system. The cost differential of the Guyed-Y tower is explained by:
  - Reductions in the size and mobility of the required construction equipment (namely mobile drill equipment and helicopters for transporting equipment to the remote areas that comprise a significant portion of the EWT Line);
  - A significant reduction in the absolute tonnage of steel required to construct the line, reducing commodity cost;
  - The foundation design for the Guyed-Y tower requires only one major foundation per structure, compared to four foundations per structure for the self-supported steel-lattice tower in the Reference Option. This results in lower material costs as well as a higher productivity rate during construction.

- Based on an analysis of accessibility, constructability, scope, costs, bill of materials, foundation requirements, associated geotechnical factors, and construction methodologies, the Guyed-Y tower fares well or better than other candidate structures (such as H-Frame) and can be designed and constructed to meet the OEB's Minimum Requirements for safe and reliable electrical service, with similar construction and O&M timelines to those of other structures.
- Guyed-Y towers, and the similar Guyed-V towers, have been used in similar terrain, climates and voltages to the Project.
- The Guyed-Y tower has 40% better lightning performance than the self-supported steel-lattice tower when simulated using industry recognized IEEE FLASH software.

A description of the interconnection of the line with the relevant transformer stations

The same interconnection as described in the OEB's Reference Plan would apply to NextBridge's Recommended Plan. NextBridge will work closely with Hydro One to complete any studies and agreements required in order to obtain timely interconnection of the Project, including alignment and integration of key Project milestones.

A feasibility study performed by the IESO, or performed to IESO requirements

As discussed above, the main difference proposed in NextBridge's Recommended Plan is the use of the Guyed-Y tower. The IESO has confirmed that our recommended structural change will not impact the existing Reference Plan feasibility study and a new feasibility study is not required at this time. In the event that Pukaskwa National Park and/or the Pays Plat and Michipicoten First Nation Reserves will be bypassed, it is unlikely this would require a new feasibility study – however, this will need to be reconfirmed by the IESO as the development phase progresses.

6.5 Strengths of the Plan

The primary strengths of the NextBridge plan are:

- **Construction Cost Forecast:** NextBridge has developed a robust development budget, allowing us to perform all activities required to reach the leave to construct application – including capital costing, routing and land acquisition; First Nation and Métis relations; stakeholder consultation; as well as environmental assessment and permitting. In aggregate we expect the development stage of the Project to cost approximately $22.4 million, as described in Section 8.

NextBridge believes that its construction cost estimate of $430 million for the Reference Plan or $397 million for the Recommended Plan for the Project, in addition to the $22.4 million development costs, compares very favourably with the over $600 million cost estimate previously developed by Hydro One (for a similarly scoped project, and used as the effective benchmark to date in this proceeding). The main drivers behind NextBridge's ability to put forward with confidence a forecast significantly below the benchmark are:

- Major capital projects of this nature always benefit from an emphasis on the planning prior to mobilizing construction resources and activities. Therefore significant planning has been integrated for the development phase prior to starting construction;
- Access to their experienced engineering and construction team that have executed multiple projects in their own jurisdiction as well as others, and can therefore efficiently and effectively adapt to differing rules and regulations;
- Use of a Guyed-Y tower, which reduces the capital cost of the Project, while still meeting or exceeding the technical requirements of the Project. The Guyed-Y towers are further described in Sections 6.1 and 6.4;
- Competitive pricing for materials and equipment as a result of leveraging the NextBridge partners' relationships with suppliers; and
- Retaining flexibility to contract the construction work to the lowest cost contractor that meets technical, quality and safety requirements.

In addition to offering credible and competitive costing, we offer a competitive cost of capital. Our capital structure and cost of capital fairly reflect the risks of projects of this nature, and are competitive with similar projects regulated by the OEB. Specifically, our proposed capital structure – 60% debt and 40% equity – is consistent with the structure that the OEB currently deems appropriate for transmitters in Ontario.

- **Organizational Strengths and Track Record Supporting the Forecast:** NextBridge is composed of three large organizations that develop, build, finance and operate safe and reliable energy infrastructure, collectively managing over $100 billion in assets. For example, NextEra Energy operates 41,000 MW and 13,300 circuit km of transmission, serving 4.6 million customers with 99.98% service reliability. Within Ontario, NextEra is currently engaging with 14 First Nation and 3

Métis communities and organizations to develop over 600 MW of renewable energy from wind under the Feed-In-Tariff (FIT) program.

Enbridge operates the world's longest crude oil pipeline, serving as the United States' largest single physical source of crude oil. It also operates Canada's largest natural gas distribution system, located in Ontario, safely and reliably serving over 1.9 million customers. Moreover, Enbridge has long-standing experience operating with OEB regulation. In addition, Enbridge owns and operates 488 MW of wind and solar energy in Ontario.

Borealis has experience providing governance and management oversight in critical energy projects in Canada, the United States and the United Kingdom (UK), including the Bruce Power nuclear facility and Enersource in Ontario, Oncor Energy Delivery Company in Texas and Scotia Gas Networks in the UK. Bruce Power is Ontario's first private nuclear facility, safely providing 20% of Ontario's electricity. Enersource holds an Ontario Electricity distribution licence under which it services 200,000 residential and commercial electricity customers in Mississauga. Oncor is the largest electricity transmission distribution provider in Texas, and one of the largest in the United States. Scotia Gas Networks is the UK's largest gas distribution company and provides natural gas to 5.7 million customers in Scotland and the South and Southeast of England.

In addition to possessing significant experience successfully operating within regulated service territories and jurisdictions, NextBridge partners have also built and operated significant assets outside those areas. NextBridge is confident that the impressive resources of its partners combined with their proven project management abilities, will allow NextBridge to meet, and exceed, the representations put for this in this Application. In particular, the evidence provided in this proposal illustrates the following NextBridge resources and capabilities to successfully deliver the Project:

- Safety: Safety is a core value at all of the NextBridge partner organizations and is further discussed in Section 4.1. NextEra has been recognized for the safety of its generation and transmission facilities through the award of STAR status by the United States Occupational Health and Safety Organization to twenty-four of its generation and transmission facilities. Enbridge has developed a 3 year corporate strategy to be best in class in a number of areas, including safety performance. Enbridge's belief is that a safe operation is a reliable, productive and sustainable operation.

- Project Organization: As discussed in Section 2, we have a Project organization that reflects significant project experience, an effective governance structure and the strengths of each NextBridge partner.
- Project Management Capabilities: NextBridge has significant project management capabilities, and has developed an organizational structure that will ensure strong top management and board-level oversight. In Section 8.10 we list transmission projects that have been executed on-time and on-budget as a result of these strong organizational capabilities.
- Aboriginal Relations Experience: In addition to the engagement and consultation process described in Section 10, NextBridge has engaged the AAB – an Aboriginal Advisory Board, consisting of respected and qualified members of local Aboriginal communities, to guide its Aboriginal engagement, consultation and participation processes. The initial contributions of the AAB to this project are evidenced in Section 3 and Section 10, as well as Appendix 5: Approaches to Economic Participation.
- Project Stakeholder Management: The EWT Line will affect the lives of many people across Ontario. As discussed in Section 11, NextBridge has already begun its consultation process with intervenors to better understand key issues or areas of concern of various affected parties.
- Land Acquisition and Routing Expertise: We demonstrate in Section 6 and Section 9 that we have the ability to work through multiple options for route identification, ensuring that we select the best route option for all stakeholders. The identification of three route variants that can be implemented to mitigate Project risks demonstrates our ability to plan ahead and minimize delays.
- Permitting and Regulatory Expertise: NextBridge can access internal and external resources to ensure the timely securing of all necessary permits and efficient management of required regulatory processes. NextBridge partner organizations have permitted and guided similar projects through required approvals in a multiplicity of jurisdictions, and have successfully engaged and managed specialist external organizations to assist with critical environmental and other regulatory processes. NextEra Energy satisfies NERC and other reliability requirements on an ongoing basis. Enbridge has successfully managed regulatory processes at the OEB, and NextEra has successfully received one leave to construct in Ontario, has applied for a second,

and will be applying for additional Leaves as its Ontario Feed-in-Tariff projects near the completion of their environmental permitting processes.

- **Willingness and Ability to Assume Cost Risk and Share Benefits with Ontario**

  As detailed in Section 5, NextBridge is willing and able –and would in fact prefer– to assume some cost risk and share the benefits with Ontarians, pursuant to a comprehensive performance-based ratemaking proposal to be developed in consultation with stakeholders and submitted to the OEB at the leave to construct stage.

  Further, while considerable time and expense has been incurred to date in preparing our Application, we are not requesting recovery of these pre-development costs as an indication of our commitment to the Ontario transmission market. Consistent with our partner organizations' track records and alignment, we are committed to owning and operating the Project for the long-term, with the Project being the platform for further investment in Ontario transmission opportunities. This aspect of the NextBridge proposal provides, at minimum, an immediate $1.4 million benefit to the Ontario electricity ratepayers.

In addition to furthering the NextBridge partners' existing presence in Ontario, which includes over 3,000 employees and over $2.5 billion in revenues, benefits to Ontarians of NextBridge's plan include:

- Development and construction of the Project will be substantially locally based and flow benefits into those communities. As mentioned above and discussed further in Section 11, NextBridge has already commenced discussions with many intervenors to gain a better understand how the Project affects and can benefit Northern Ontario as well as ratepayers in general.
- NextBridge will source procurement locally to the extent possible. In addition, and as described in Section 3 and Section 10, we will work with First Nation and Métis communities to identify opportunities for participation in the Project. Enbridge has a strong history of Aboriginal procurement and community development, and expects to deploy relevant programs with First Nation and Métis communities along the EWT Line route.
- NextBridge partners are widely recognized for their contributions to responsibly and sustainably operating their businesses. NextEra Energy and Enbridge have frequently been recognized for investments in communities and the environment, through a variety of corporate social

responsibility initiatives. For example, NextBridge aims to deploy the Neutral Footprint Initiative on this Project (see Appendix 7: Enbridge Neutral Footprint Program).

- A final and important feature of the NextBridge partnership is the ongoing participation of a broad base of Ontarians in the Project. Through the participation of OMERS, 420,000 plan members will own a significant portion of the Project, which through Borealis will support these Ontarian's retirements.

6.6 Intention to Own and Operate

NextBridge's three owners are each large infrastructure investment companies, which own, manage and operate all of their assets over the long-term. NextBridge brings this long-term, buy-and-hold approach to this Project. NextBridge intends to own and operate the EWT Line over the course of its useful life. We envision becoming a significant player in the competitive Ontario transmission space, and participating in further Designation or other competitive processes as they may arise. NextBridge is committed to increasing the competiveness and cost effectiveness of providing transmission service to the ratepayers of Ontario, now and into the future.

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7 Schedule

7.1 Project Execution Chart showing major milestones for both line development and line construction phases of the Project

NextBridge has established a robust plan for the development and construction of the Project. In managing over $100 billion in infrastructure assets, NextBridge's partners have demonstrated their ability to develop realistic estimates of project timelines and deliver against those timelines on numerous past projects. While the timelines for the post development phases of the Project will be refined as additional information is gathered in the development phase, we are confident that we can deliver against all timelines that are ultimately adopted.

Our detailed Project execution chart is included in Appendix 15: NextBridge Project Execution Chart . We summarize below major milestones for the development and construction phases of the Project. We expect the Project timeline to span approximately 4.5 years – beginning with being named the Designated Transmitter in May 2013 through to completion of construction in December 2017.

FIGURE 17: HIGH LEVEL DEVELOPMENT AND CONSTRUCTION MILESTONES

Milestone	Estimated Date
Designated Transmitter Awarded	May 2013
Commence First Nation and Métis Engagement	June 2013
Substantial Land / Right-of-Way Rights Acquired	October 2014
Leave to Construct Decision	April 2015
Environmental Permits Received	September 2015
Unrestricted Construction Access	December 2015
Construction Complete	December 2017

7.2 Development Phase

We expect the development phase to be approximately 18 months in length, starting with selection of NextBridge as the Designated Transmitter and concluding with the filing of a leave to construct application in October 2014. In addition to development milestones, we discuss below our proposed reporting requirements; consequences for failure to meet milestones; and mitigation measures to address identified risks.

Detailed line development schedule identifying significant milestones that are part of the development phase of the Project, and estimated dates for completing these milestones

We summarize below the major milestones in the development phase, the details of which are again, provided in Appendix 15: NextBridge Project Execution Chart. Major activities during the development phase will include advanced engineering design and overall Project planning; furthering Provincial and Federal environmental assessments as necessary; as well as initiation of First Nation and Métis Participation and Consultation Plans, municipal and public consultation plans, and land assembly activities.

FIGURE 18: KEY DEVELOPMENT MILESTONES

Milestone	Date
Designated Transmitter Awarded	May 2013
Substantial Land / Right-of-Way Rights Acquired	October 2014
Provincial Environmental Assessment	
• Environmental Assessment Terms of Reference Complete	April 2014
• Environmental Assessment Consultation Report Complete	September 2014
• Environmental Assessment Submittal to Ministry of Environment	October 2014
• Environmental Assessment MOE Approval	September 2015
Federal Environmental Assessment (if required)	
• Project Description Complete	April 2014
• Federal Environmental Assessment Submittal	December 2014
• Federal EA Decision	August 2015
OEB Leave to Construct	
• LTC Submittal	October 2014
Engineering	
• Engineering Initiated	May 2013
• Engineering Completed	February 2016

Proposed reporting requirements for the development phase

NextBridge considers reporting and transparency of information to be fundamental to the successful implementation of this Project. We anticipate multiple levels of reporting throughout the duration of the Project, to various stakeholders – most notably to the OEB, and to our Management Team.

- **Proposed Reporting to the OEB:** NextBridge is prepared to provide the OEB with monthly status reports within 15 business days of the end of each month, which is consistent with industry practice on large infrastructure projects. We have chosen this timeline because it offers the OEB the benefit of sufficient information to effectively gauge Project progress, without being overwhelmed by the day-to-day operational details of the Project. The status reports will contain the following information provided by the Project Director and the Leads:
  - **Budget and Costs:** Reporting will be provided on actual cost and cost variance relative to the original Project budget, as well as an updated budget forecast projected out to Project completion.
  - **Schedule:** The schedule update will identify the major milestones completed and the status of milestones in-progress. For milestones that are overdue or delayed, an assessment of the milestones will be provided including the reasons behind the delay; the magnitude and impact of the delay on the broader Project schedule; and any mitigating steps that have or will be taken to complete the task.
  - **Risks and Issues Log:** As part of our active risk and issue management approach, items that could affect schedule, cost, or scope will be identified and tracked, typically in the form of a risk and issue log. The log will contain an assessment of the risk and issue itself, estimated risk exposure, potential impact on schedule, cost or scope, as well as potential options for mitigating or eliminating the risk or issue.
  - **Milestone Summary:** The status update will also contain a summary of progress against major milestones. The summary will include a description of the milestone, as well as the associated impact on scope, cost and schedule.

Reporting will begin in the first month after the OEB Designation decision. Based on the assumption that the Designation Process will conclude during the second quarter of 2013, NextBridge will file its first report with the OEB on July 15th, 2013.

In addition, we anticipate producing weekly internal Project status reports on budget, cost and schedule, within the Project team. Reporting from the Technical Team to the Operations Committee is expected to take place on a bi-weekly basis, and reporting to the NextBridge Board of Directors is expected to be on a monthly basis.

Proposed consequences for failure to meet the required performance milestones and reporting requirements for the development phase

NextBridge's Management Team and Project Director will continue to provide direction and oversight through all phases of the Project. During the development phase, the Project Director will closely monitor any milestones that are at risk of delay, and develop appropriate mitigation plans. NextBridge will notify the OEB prior to the scheduled milestone completion date that a milestone is likely to be delayed. NextBridge will document the cause of the expected delay; identify mitigation options; determine any associated variance to the Project budget; and, if required, develop a case for the prudency of the deviation if NextBridge determines that it may want to file for recovery of costs resulting from the deviation.

A chart of the major risks to achievement of the line development schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and a description of the applicant's strategy to mitigate or address the identified risks.

Based on our analysis of the Project requirements and our experience with risk management, we have compiled a consolidated risk matrix as shown below. This matrix captures major risks to both development and construction phases and indicates whether these risks impact the Project schedule, cost or both. This matrix will become part of our Project management process and will be tracked regularly and reported on in our status reports, as appropriate. Guidelines for the terms used in the risk matrix are in Appendix 16: Guidelines for Consolidated Risk Matrix.

FIGURE 19: CONSOLIDATED RISK MATRIX FOR DEVELOPMENT & CONSTRUCTION PHASES

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
1	Unavailable off ROW access due to landowner non participation	C and S	L	H	D	Early identification of off ROW access requirements needed to avoid significant civil work. Expropriate if necessary.	Project Director
2	Construction not permitted within Federal or Provincial Park Boundaries	C and S	L	H	D	Alternative alignments should be utilized to minimize schedule impacts. Engage Park officials early in project to assist in development of mitigation measures	Land Acquisition
3	Communication (OPGW) Regen Sites cannot be located near distribution power source	C	L	L	D	Identify Regen Sites as early as possible to provide time to determine alternative power sources.	Land Acquisition
4	Expropriation not completed on time. ROW/Access/ lay down/assembly areas not available to initiate engineering and construction work	C and S	L	H	D and C	Route adjustment may be required if land cannot be secured in a timely manner. Need to allow for additional off ROW access, (impact to land acquisition costs, civil costs). Contractor may need to move around areas not secured.	Project Director
5	Environmental permitting (EA & any other approvals) not received on time to initiate engineering and construction work	C and S	L	H	D and C	Submit permit applications as early as possible. Follow up as necessary.	Environment & Permitting

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
6	Delay in First Nation and Métis engagement and consultation	S	L	H	D and C	First Nation and Métis communities will be engaged early in development Route variants have been identified in the event during consultation it is determined that it is preferable to follow the variant.	First Nation & Métis Affairs
7	Existing access roads or existing ROW corridor (owned by Hydro One) are not allowed to be used for Project Construction or Maintenance	C	L	H	D and C	Hydro One should be engaged early in Project development for ways to resolve issues in a manner that benefits both parties (joint use access or ROW utilization agreements).	Land Acquisition
8	Protected Species Habitat Locations	C	L	H	D and C	Avoid if possible. Early identification of habitat / bird nesting areas to assure clearing is performed before return migration. Working in habitat areas will require environmental construction monitoring to mitigate risk. Additional contingency required for monitoring and possible skip or delay charges could result if birds or other species inhabit uncleared locations.	Environment & Permitting

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
9	Specific siting changes (route or soil conditions) impact engineering design	C	L	M	D and C	Finalize route early. Work with land services on design options. Ensure schedule allows for engineering adjustment of design and route	Project Director, Land Acquisition and Environment & Permitting
10	Landowners claim mineral or mining rights delays land acquisition	S	L	M	D and C	Engage early. Reroute if required. Purchase land in fee. Expropriate. Limit exposure to future mining rights issues through sufficient consultation.	Land Acquisition
11	Archaeological sites encountered	S	U	M	D and C	Engage local monitors to review structure locations & move as needed to avoid. Develop working relationship with regulators and preplan for occurrences.	Environment & Permitting

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
12	Transmission structure fabrication quality and timely deliveries	C and S	L	H	C	Implement early procurement strategy considering multiple supplier base and review on site QA/QC program and hold weekly conference calls with fabricator to ensure design and delivery compliance.	Project Director
13	Material supply fabrication and delivery (rock anchors, insulators, conductor, OPGW/OHGW etc)	S	L	H	C	Develop an early stage strategic sourcing and storage plan to mitigate material risk.	Project Controls & Procurement
14	Ensure adequate structure grounding	C	L	H	C	Early flash density studies performed to identify lightening frequency and intensity. Prepare implementation of counterpoise measures should design require. Possible use of lightning arresters.	Project Director
15	Civil work (clearing, access, pad prep & foundations) needs to be completed in timely order to support structure delivery and installation	S	L	H	C	Secure civil services contracts early with multiple contractors.	Project Director
16	Uncertain subsurface conditions could	C	L	M	C	Desktop study and field observations completed. Alternative foundation	Project Director

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
	affect foundation installations (Geotechnical work)					options prepared for all conditions, each with differing cost implications. Added contingency for unknown subsurface conditions.	
17	Reluctance of utilities or railroad to grant line energization without cathodic mitigation in place	C	L	M	C	Identify facility locations and initiate discussions with owner early so that locations and mitigation plan can be determined.	Project Director and Land Acquisition
18	Increase in equipment and material costs	C	L	M	C	Implement an early stage procurement strategy to secure future price increases. Plan for escalation.	Project Controls & Procurement
19	Weather or seasonal conditions affect construction	C and S	L	M	C	Schedule resources and activities around positive and negative weather events. Contingency increased to account for likely weather scenario. Alternative construction methodologies and associated cost implications to be investigated.	Project Director

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
20	Geotechnical contractor cannot get access to all required boring locations due to land access or terrain constraints; as a result rock depth can only be estimated	C	L	M	C	Alternative foundation designs have sufficient flexibility to accommodate variations without changing long lead materials. Construction contractor will be made aware of geotechnical investigation limitations.	Project Director
21	Highway / Road Repairs	C	L	L	C	Early identification of road use and access requirements. Develop alternative delivery routes/methods to allow for avoidance of subject roads. Where no alternatives routes consult with owners/authorities to ensure schedule coordination as required.	Project Director
22	Having adequate and qualified construction resources available to meet COD	S	U	H	C	Develop a strategic sourcing plan with large transmission contractor (s) familiar with this type of construction early in order to mitigate labour risk. Analyze local labour markets and develop active strategy to engage the local workforce.	Project Director

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
23	Having available helicopter resources which will be used for over 80% of line construction.	C and S	U	H	C	Secure contract with helicopter company and backup supplier in advance. Ensure lay down and tower erection areas are available and multiple crews are engaged to fabricate structures and minimize helicopter down time	Project Director
24	Reluctance of IESO to grant transmission line clearances to perform crossing activities	C	U	M	C	Early identification of all crossing locations. Early signed and executed consents with Hydro One. Minimize crossings through route alignment. Develop pulling plan to possibly work around if required. Redirect work to other locations.	Project Director and Land Acquisition
25	Concrete availability	S	U	M	C	Secure early binding performance contracts with ready mix companies or consider on-site batch plants if required.	Project Director
26	Hunting Season	S	U	L	C	Draft land agreements that preclude landowners from denying access and construction activities during hunting season.	Land Acquisition and Environment & Permitting

Risk Item #	Risk Item Description	Impact to cost (C) or schedule (S)	Probability of Occurrence Likely (L) or Unlikely (U)	Impact of Occurrence High (H) Medium (M) or Low (L)	Development (D) or Construction (C) Risk	Mitigation Plan	Mitigation Plan Work stream Lead
27	Offsite Service power and T1 communications installed at construction trailers	C	L	M	C	Early engagement of local utility to support need. Rural location may require significant work to provide service of both service power and communications. Diesel generators and satellite communication.	Engineering & Construction
28	Regulatory Delay beyond the timelines stated	C and S	L	H	D and C	Consult with the OEB at all phases of the project. Rely on in house regulatory counsel with OEB experience.	Project Director and Regulatory

7.3 Construction Phase

A preliminary line construction schedule identifying significant milestones that are part of the construction phase of the project, and estimated dates for completing these milestones

We have outlined below the key milestones related to the construction phase. We expect this phase to begin after filing the leave to construct application in October 2014 and end in December 2017 when commercial operation is achieved. Major activities during this period will be related to obtaining the leave to construct decision; awarding of the construction contract; mobilizing resources for construction; completing construction of the EWT Line; and transitioning the Project to commercial operation.

FIGURE 20: KEY CONSTRUCTION MILESTONES

Milestone	Date
LTC Decision	May 2015
Unrestricted Construction Access	December 2015
Construction Mobilization	January 2016
Clearing Complete	August 2016

Milestone	Date
Foundations Complete	December 2016
All Material Onsite	February 2017
Structure Assembly and Setting Complete	October 2017
Conductor Installation Complete	November 2017
Commissioning	December 2017

Proposed reporting requirements for the construction phase

During the construction phase, NextBridge will continue to follow the same reporting process as for the development phase – both to the OEB and internally to its Management Team and within the Project team – as outlined in Section 7.2. NextBridge expects to supplement these reports with additional dashboard summary reports specific to construction related indicators. These may include progress against construction milestones and activities; capital costs; utilization of resources; and any safety or environmental issues and associated mitigation plans.

Proposed consequences for failure to meet the required performance milestones and reporting requirements for the construction phase

Similar to the development phase, during construction NextBridge will continue to inform the OEB in advance of expected milestone delays and provide an assessment of the cause of the delay and any associated impacts on Project schedule and budget. As further described in Section 5, we are proposing that the impact of the construction phase will directly result in different financial outcomes once the Project is complete and our performance can be measured.

Proposed in-service date for the line (can be 2017 or another date)

The proposed in-service date for the Project is December 2017.

A chart of the major risks to achievement of the construction schedule, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the schedule (e.g. minor, moderate, major); and a description of the applicant's strategy to mitigate or address the identified risks.

The consolidated risk matrix in Section 7.2 identifies major risks for both development and construction, and for both schedule and cost.

7.4 Evidence of the applicant's past experience in completing similar transmission line or other infrastructure projects within planned time frames.

In Section 8.10 we highlight nine NextEra construction projects that were built 2011-2012 and were both ahead of schedule and under budget. In addition, our project experience is highlighted in Section 2.3 and in Appendix 4: Detailed Case Studies. In these case studies five in particular illustrate the ability to meet schedule within, or ahead of, estimated timeframes, some with expedited timelines or complicating circumstances – Texas Clean Energy Express, Florida Power and Light, Lone Star Transmission, Blythe Transmission and New Hampshire Transmission.

7.5 Any innovative practices that the applicant is proposing to use to ensure compliance with, or accelerate the line development and construction schedules

NextBridge knows that planning is the key to success for major capital projects. The experience of our partners is that additional time spent in early stages of a project can result in significant cost savings at later stages – particularly during construction, when the average daily spend on projects is significantly higher. NextBridge has already implemented or will implement the following practices to ensure compliance with, or to accelerate, the EWT Line development and construction schedules:

- **Aboriginal Advisory Board:** NextBridge has already conducted meetings with the AAB to seek guidance during the preparation of this Application. The groundwork already accomplished through these early discussions and the continuing availability and support of the AAB throughout the Project will allow NextBridge to proceed early and expeditiously with appropriate engagement and consultation processes – and thereby minimize the potential for schedule impacts resulting from the First Nation and Métis engagement, consultation and participation program.
- **Attracting construction labour:** NextBridge will engage with potential construction contractors early during the development phase to discuss estimated labour requirements and timeline, and to ensure availability of skilled workers as required. If any concerns are identified, alternate labour pools will be identified early in our Project planning activities.
- **Constructability review:** NextBridge will engage with construction contractors and rely on internal construction resources during the design portion of the Project. This will help to ensure that

constructability considerations are incorporated into our design, which will minimize changes during construction.

- **Risk Management:** NextBridge will continue to maintain its consolidated risk matrix for development and construction phases of the Project. This will allow the Management Team and Technical Team to plan ahead and mitigate any risks that arise as the Project moves forward, and as currently unknown risk factors become known.
- **Guyed-Y towers:** NextBridge's Recommended Plan is to use an alternate structure to that proposed in the Reference Plan. This will allow high productivity during the construction phase of the Project as a result of requiring less foundation materials and less complex equipment. This innovative structural approach (for Ontario) will result in savings of $33 million and an enhanced ability to address any scheduling delays during construction through a faster, more flexible construction process.
- **GIS:** NextBridge's use of Geographic Information Systems (GIS) to provide more accurate data (particularly field data) and act as a single repository for document management and reporting, will ensure compliance with, or potentially accelerate, the Project schedule.
- **Early start on environmental permitting**: NextBridge will complete surveys ahead of the Ministry of Environment Terms of Reference to ensure survey windows are not missed. In addition, consultation with regulatory bodies will be conducted early and regularly to ensure there are no gaps in the environmental assessment and other studies. This will allow the environmental assessment to be as complete as possible while ensuring that environmental issues are appropriately covered, and that sufficient engineering information is available to support mitigation.

8 Costs

8.1 The amount already spent for preparation of an Application for designation, and an estimate of remaining costs to achieve designation.

NextBridge has performed a number of pre-development activities including:

- Various analyses of the different elements of development and construction, in preparation for the expeditious progress of the development process after designation;
- Detailed planning exercises to arrive at realistic cost, schedule and risk estimates;
- Preparation of this proposal submission, including identification and retainer of qualified and specialized third party contractors;
- Travel to the Project site to engage in early discussion with some of the impacted stakeholders; and
- Engagement of the legal and regulatory resources relied upon in preparation of this Application.

By the end of the Designation Process, NextBridge is expecting to have invested approximately 6,000 person hours of internal time and associated resources and $1.4 million in external services.

NextBridge has determined that it is prepared to forgo recovery of its pre-development costs as a demonstration of our commitment to long-term investment and involvement in the transmission sector in Ontario.

8.2 The estimated total development costs of the line

NextBridge has relied on its cost estimation experience to develop detailed cost estimates for both the development and construction phases of the Project. We have provided annual costs for the development phase below. The total estimated cost of development is $22.4 million, regardless of whether the Reference Plan or the NextBridge Recommended Plan is developed. This cost includes investigating, and if necessary developing, the route variants. Consistent with the OEB's direction, development costs are those anticipated to be incurred prior to the submission of the leave to construct application. As noted above, NextBridge has determined that it is prepared to forego recovery of its pre-development costs as a demonstration of our commitment to long-term investment and involvement in the transmission sector in Ontario, and the development cost estimate noted above accordingly excludes all pre-designation costs.

The schedule in Section 7 forecasts the leave to construct application being submitted in October 2014. Therefore the development cost estimate represents costs incurred between May 2013 and October 2014. The estimate assumes the regulatory approval schedule as described in our table of milestones and other assumptions discussed in Section 8.3.

FIGURE 21: ANNUAL DEVELOPMENT PHASE COST ESTIMATES

DEVELOPMENT (x$1,000) CAD	May 2013 – December 2013	January 2014 – October 2014	TOTAL
REFERENCE PLAN (Self-Supported)	8,092	14,306	22,398
RECOMMENDED PLAN (Guyed-Y)	8,092	14,306	22,398

Major Components Breakdown (x$1,000) CAD	May 2013 – December 2013	January 2014 – October 2014	TOTAL
Land Acquisition and Aboriginal Affairs	1,556	2,655	4,210
Permitting, Licensing, Environmental	1,272	2,369	3,640
Engineering & Design	4,544	7,539	12,083
Materials & Procurement	0	0	0
Other Significant Expenditures (Including Legal, Project Management, Interconnection and O&M)	721	1,743	2,464

8.3 The basis for and assumptions underlying the development cost estimates, and a description of how the applicant plans to manage the cost of development

The overall development cost was produced using a 'bottom-up' methodology in which the development process was broken down into its constituent components. Each of these components was priced individually based on the costs expected to be incurred during the relevant timeframes in the Project schedule, including manpower loading and hourly estimates as well as internal and external resources. All the Leads in the Technical Team contributed to this costing exercise by providing the costs, schedule and assumptions for their respective work streams. The Leads then participated in multi-disciplinary joint costing and scheduling sessions to arrive at a total Project cost informed by the Project schedule, and to identify key assumptions and dependencies in our costing model. In these sessions, the estimates put forth were subject to review by subject-matter experts from each of the

three NextBridge partners, to allow additional vetting of figures. Once complete, the full schedule of development costs was reviewed by management across our three partner organizations.

Development costs will be managed day-to-day at the Lead level, with regular reporting to the Project Director and to the Operations Committee that will closely monitor any variance from the estimated Project budget. The following is a summary of key assumptions underlying the development cost estimates:

- **Land Acquisition and Aboriginal Affairs:** Includes cost estimates for resources that will be required during the development phase, including internal subject matter experts, consultants, surveys, costs related to obtaining certain private and Crown land acquisition rights, costs associated with supporting First Nation and Métis participation, consultation with landowners, municipalities, the public and First Nation and Métis communities. Although significant in value, there is currently no estimate included for First Nation and Métis land acquisition as this will be determined at a later date – after engagement and consultation have advanced.
- **Permitting, Licensing, Environmental:** Includes estimates for internal subject matter experts, consultants, permitting costs, environmental assessments, and other internal studies.
- **Engineering & Design:** Includes estimates for third party engineering and geotechnical resources, and internal support services and subject matter experts. Also includes costs associated with procurement activities during development.
- **Other Significant Expenditures:** Includes internal estimates for a NextBridge Project Management team, internal and external legal costs (including an estimate for filing the leave to construct), preliminary studies and field visits to scope O&M requirements, and IESO technical studies.
- **Exclusions and Assumptions:** Property taxes, sales taxes, other taxes and duties are excluded from these cost estimates. Regulatory costs assume that regulatory actions occur on or about the stated milestone dates discussed.

8.4 A schedule of development expenditures

Further to the summary of costs provided in Section 8.2, the following figure provides a quarterly schedule of expected expenditures during the development phase.

FIGURE 22: QUARTERLY DEVELOPMENT PHASE COST ESTIMATES

DEVELOPMENT (x$1,000) CAD	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	TOTAL
REFERENCE PLAN (Self-Supported)	688	3,675	3,730	3,572	4,659	4,418	1,657	**22,398**
RECOMMENDED PLAN (Guyed-Y)	688	3,675	3,730	3,572	4,659	4,418	1,657	**22,398**

Major Components (x$1,000) CAD	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	TOTAL
Land Acquisition and Aboriginal Affairs	284	473	798	513	941	696	506	**4,210**
Permitting, Licensing, Environmental	198	635	440	395	970	910	95	**3,640**
Engineering & Design	51	2,247	2,247	2,262	2,262	2,262	754	**12,083**
Materials & Procurement	0	0	0	0	0	0	0	**0**
Other Significant Expenditures (Including Legal, Project Management, Interconnection and O&M)	155	320	245	403	488	551	302	**2,464**

8.5 A chart of the major risks that could lead the applicant to exceed the line development budget, indicating the likelihood of the item (e.g. not likely, somewhat likely, very likely) and the severity of its effects on the budget (e.g. minor, moderate, major), and a description of the applicant's strategy to mitigate or address the identified risks

The consolidated risk matrix in Section 7.2 identifies major risks for both development and construction, and for both schedule and cost.

8.6 A statement as to the allocation between the applicant and transmission ratepayers of risks relating to costs of development

It is NextBridge's assumption that the development phase will be treated as a cost of service development Project under the standard regulatory oversight of the OEB. Such a model has been utilized extensively in the transmission development industry. NextBridge feels that the OEB and the ratepayers of Ontario will realize the benefits of competition during the Designation phase; and that the OEB will select the proponent that is best qualified to develop and execute the Project, including the proponent that is best positioned to propose an overall Project budget and achieve the Project goals within the provided budget. NextBridge assumes that its actual development costs will be recoverable,

subject to prudence review for any expenditures in excess of the development budget approved by the Board at the time of awarding development designation.

8.7 An estimated budget for the construction of the line. This budget and its elements may be expressed as a range. If a range is used, the applicant must provide an explanation for the width of the range

For the construction cost estimate provided below, we followed the same bottom-up methodology as we followed for derivation of the development cost estimates outlined in Section 8.2 and 8.3. Our construction cost estimate was informed by the institutional knowledge and experience of our partner organizations with projects of similar size and scope. Our estimated budget is centred at the mid-point of the range of costs we anticipate will be incurred in constructing the EWT Line. Our construction cost estimate assumes:

- Materials escalation is 1.5%, which will change with the actual market at the time of contracting and procurement;
- Payment related to Aboriginal land is not included in the estimate as engagement and consultation are not advanced enough to be able to properly estimate such values;
- Property taxes, other taxes and duties are excluded from the estimate; and
- Regulatory actions occur on or about the milestone dates described.

As we move through the development phase, we will be able to refine these costs as our understanding of the Project evolves. We have provided below a total cost for the construction phase amounting to approximately $430 million for the Reference Plan and $397 million for the Recommended Plan.

FIGURE 23: ESTIMATED BUDGET FOR CONSTRUCTION PHASE

CONSTRUCTION (x$1,000) CAD	Reference Plan	Recommended Plan
Land Acquisition and Aboriginal Affairs	23,503	23,503
Permitting, Licensing, Environmental	5,912	5,912
Engineering & Design	15,156	15,156
Materials & Procurement	75,186	56,499
Construction	302,968	288,751
Other Significant Expenditures (Including Legal, Project Management)	6,841	6,841
Total Construction Costs	**429,566**	**396,662**

8.8 If the Plan is not based on the Reference Option, evidence as to the difference in cost (positive or negative) of work required at the transformer stations to which the line connects, and at any other location identified by the IESO.

NextBridge's Recommended Plan is based on the Reference Plan, but uses a Guyed-Y tower in place of the self-supported steel-lattice tower. Our Recommended Plan is expected to deliver savings of approximately $33 million as a direct result of savings in the material and installation costs. Additional benefits of the Guyed-Y tower are outlined in Section 6.4.

If it becomes necessary to bypass Pukaskwa Park and/or Pays Plat or Michipicoten First Nation Reserves, there will be additional costs incurred as a result of the increased required length of the EWT Line. The increased length of the line resulting from the route variants is approximately: 30.5 km around Pukaskwa Park, 0.35 km around Pays Plat, and 12.5 km around Michipicoten.

Neither NextBridge's Reference Plan nor the Recommended Plan entail any incremental cost for connection to Hydro One's existing system.

8.9 A list of the major risks that could lead the applicant to exceed the line construction budget, and the applicant's strategies to mitigate or address those risks

The consolidated risk matrix in Section 7.2 identifies major risks for both development and construction, and for both schedule and cost.

8.10 Evidence of the applicant's past experience in completing similar transmission line projects within planned construction budgets. Such evidence could include a comparison of the budget filed with a regulator when seeking approval to proceed with a transmission line project and the actual costs of the project.

Drawing on its partners' experience in managing over $100 billion in assets, NextBridge emphasizes effective budget control and on-budget delivery on all of our projects. For NextEra Energy, the following examples highlight a track record of superior cost and schedule performance:

- **Lone Star Transmission (Texas):** For this Project, the CCN (Certificate of Convenience and Necessity) Final Order estimate was $796.9 million (USD). The current estimate filed with the Public Utilities Commission of Texas in October is $776.6 million (USD) for a net benefit to ratepayers of $20.3 million (USD). Note that both estimates include the cost of Lone Star Transmission's first rate case

filing. Although the current estimate is not the actual cost of the project as it has not yet been completed, it does consider actual costs incurred to date with an expected "placed into service" date of late Q1 2013.

- **Blythe Transmission Project:** Blythe Energy, LLC, a subsidiary of NextEra Energy, developed a transmission line in the vicinity of its Blythe Energy 520 MW natural gas fired electric-generating Power Plant located in the City of Blythe in Riverside County, California. The Blythe Energy Gen-tie project was built for the sole purpose of improving the long-term transmission paths available for delivery of the Blythe Energy Plant electrical output to the southern California ISO-controlled electrical transmission system. Construction of the 108 km, 1,100 MW, 230kV line began in February 2009 and is valued at over $80 million of CapEx. The Blythe Energy Gen-tie project was completed six weeks ahead of schedule and 15 % under budget with a commercial operation date of June 11, 2010. The Blythe transmission line and the Blythe Plant were sold to LS Power in December, 2011.

Finally, NextEra Energy Resources is North America's largest constructor and owner of wind generation. During the past two years, NextEra has constructed nearly $3 billion worth of wind projects, which all included transmission and interconnection components. Nearly all were completed ahead of schedule, below original cost estimate, or both. Below is a representative sample of NextEra Energy Resources' construction projects during 2011-2012.

FIGURE 24: NEXTERA ENERGY RESOURCES REPRESENTATIVE SAMPLE OF ON-TIME, ON-BUDGET CONSTRUCTION PROJECTS

			Budget ($ millions USD)		Variance to Plan	
Project Name	**Location**	**Days Ahead of Schedule**	**Planned**	**Actual**	**$MM**	**Percentage**
Montezuma II Wind Farm	**California**	12	$180.6	$173.7	($6.9)	-3.8%
Ensign Wind Farm	**Kansas**	38	$174.5	$173.3	($1.2)	-0.7%
Limon Wind Farm	**Colorado**	13	$355.7	$354.8	($0.9)	-0.3%
Limon II Wind Farm	**Colorado**	46	$287.3	$276.8	($10.5)	-3.7%
Majestic II Wind Farm	**Texas**	45	$150.5	$143.7	($6.8)	-4.5%
Blackwell Wind Farm	**Oklahoma**	16	$102.3	$102.1	($0.2)	-0.2%
Blue Summit Wind Farm	**Texas**	20	$238.8	$237.0	($1.8)	-0.8%
Altamont Wind Farm Repowering	**California**	14	$189.6	$185.5	($4.1)	-2.2%
Minco II Wind Farm	**Oklahoma**	27	$146.5	$145.1	($1.4)	-1.0%
Total			**$1,825.8**	**$1,792.0**	**($33.8)**	**-1.9%**

Enbridge's recent track record of successful projects highlights a rigorous project development process, leading to major projects being on-time and on-budget. On projects executed after 2007, Enbridge has demonstrated a level of cost performance accepted as industry best practice. When final project costs are compared to originally funded budgets, over 90% of projects exceed established accuracy expectations.

8.11 A statement as to the allocation between the applicant and transmission ratepayers of the risks relating to construction costs

As discussed above, at the leave to construct stage, NextBridge intends to present the OEB with a comprehensive proposal for performance-based ratemaking, whereby NextBridge is incentivized to deliver superior value for ratepayers.

8.12 The estimated average annual cost of operating and maintaining the line. This cost may be expressed as a range. If a range is used, the applicant must provide an explanation for the width of the range.

As depicted in Figure 25 below, our estimated annual operations and maintenance cost for the EWT Line, including administrative and regulatory costs, is approximately $4.4 million. The Project Operations, Maintenance and Administrative (OM&A) costs will consist of NextBridge personnel as well as maintenance contracts with third party vendors with resources in the Project area for transmission line maintenance, vegetation maintenance and right-of-way (ROW) maintenance activities. The OM&A costs are based on experience with similar activities across other regions in which NextBridge partners operate transmission assets, with appropriate assumptions and adjustments for performing these activities in the terrain and environment of this Project. Note that the costs exclude property and any other taxes.

NextBridge has not tested the market for these services and as such final OM&A costs will be subject to confirmation during the development phase once NextBridge goes out to market to obtain proposals. Post commercial operation annual costs include administrative expenses relating to: accounting, general administration, human resources, information technology, finance, legal and regulatory activities. Approximately 50% of the administration expenses are for costs related to annual rate applications, and the remainder for general administration expenses to support basic business needs typical for any transmission utility.

FIGURE 25: NEXTBRIDGE ESTIMATES OF ANNUAL OM&A COSTS

Annual OM&A Costs (x$1,000)	Estimated Cost
Operations and Maintenance	1,251
Administration and General	1,346
Regulatory Compliance	1,850
Total Annual Cost	**4,447**

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9 Landowner, Municipal and Community Consultation

9.1 Overview

NextBridge is committed to building and maintaining respectful relationships with landowners, municipalities and communities engaged in, and affected by, its projects. We make supporting the strength and vibrancy of these stakeholder communities a priority. NextBridge implements its projects and operates its facilities ethically and responsibly – supporting the needs of stakeholder communities, investors, governments, and employees. NextBridge is committed to using design and construction techniques that avoid impact on endangered species and habitat and to restoring the construction sites of our projects.

The NextBridge partners have extensive experience managing consultations with landowners, municipalities and local communities, and managing environmental investigation, approval, preservation and mitigation activities. With respect to environmental matters, NextBridge will have the benefit of subject matter experts by way of secondment from each of its partners. NextBridge's proposed Project team has substantial experience in successfully acquiring the land rights for our projects and in working with regulators, rights holders, landowners, government entities and industry. NextBridge has a solid understanding of the issues related to the routing of linear projects in Ontario. Additional information on our land acquisition and environmental capabilities is in Section 4.1.

Rights-of-way and Other Land Use Rights for Development, Construction, Operation and Maintenance of the East-West Tie Line

NextBridge's proposed transmission line corridor(s) will traverse many land types. The table below summarizes the rights-of-way and other land use rights that would need to be acquired for the purposes of the development, construction, operation and maintenance of the line, for both the Reference Route and for NextBridge's three route variants to the Reference Route should the use of variants become a necessity.

FIGURE 26: BREAKDOWN OF LAND TYPES ALONG REFERENCE ROUTES AND VARIANTS

Land Use	Reference Route	Reference Route with Variants
Private Land (Fee Simple)	22%	24.9%
Crown Land Provincial	64.5%	72.1%
Municipal Land	1.5%	1.4%
Provincial Parks	1%	0.6%
Federal Parks	9%	0%
Indian Reserve/Treaty Land Entitlement	2%	0%
No. of Municipalities	9	9

Plan for Obtaining Rights-of-Way and Other Land Use Rights

In developing our plan for obtaining land use rights and rights-of-way (ROW), we considered a number of factors including: land acquisition risks; required land and ROW activities including consultation requirements within Ontario; the schedule and budget for Project execution; appraisal reports to quantify Fair Market Value (FMV) of any given property; owner questions and concerns; and expropriation of land. We outline below the three key elements of our plan for obtaining lands and right-of-way (ROW) including: the assumptions made during the development of this plan; the methodology proposed to secure the necessary land rights; and our approach to assessing compensation and payment structures for affected landowners.

Assumptions in Developing our Lands and Right-of-Way Plan

- Project initiation point and route will be confirmed in the pre-development stage;
- The Project will be regulated by Provincial authorities in Ontario and, where applicable, through a harmonized process with the federal government;
- No significant landowner or rights holder objections, including Landowner Associations, will be encountered;
- The ROW is comprised of lands in the proportion listed in the table above;
- At maximum, a 56 metre permanent ROW corridor will be secured;
- Most construction activities will take place within the permanent ROW corridor;
- Some construction activities, such as tension stringing, will require additional rigging outside of the corridor. Temporary workspace sites (typically 30 metres x 30 metres) will be established at major inflection points along the transmission line route to set up tensioning and wire reel equipment during the conductor pull process;

- Additional temporary workspace may be secured for lay-down sites;
- If required, Surface Leases for proposed above ground facilities will be secured;
- On Crown Lands, Statutory Right-of-Way Agreements with the proposed transmission ROW will be secured; and
- NextBridge will secure third party consents for access, proximity, and crossing of foreign facilities.

Methodology Proposed to Secure Required Land Rights:

- **Land Rights – Provincial Crown Land:** Provincial Crown Land, or "public land" refers to land under the control and management of the Ontario Ministry of Natural Resources (MNR) including land managed under the *Ontario Public Lands Act* and *Ontario Provincial Parks and Conservation Reserves Act* and more specifically:
  - Ungranted public land (i.e. unpatented Crown land);
  - Acquired property which has been deemed to be public land in accordance with subsection 38 (2) of the *Public Lands Act*; and
  - Common and public highway in a territory without municipal organization.

  On Provincial Crown Land, NextBridge will apply for a Multi-Site Land Use Permit under the MNR Policy No. PL 4.10.03 Utility Corridors on Public Land. We will undertake the following activities in support of this application to MNR:

  - NextBridge will consult with the local Ministry field office in order to identify any land use issues or environmental and socio-economic constraints that may affect the corridor location;
  - Identify any proposed related infrastructure;
  - Rental rates for the Multi Site Land Use Permit will be based on the MNR Appendix A Formula for determining rent for utility corridors, which are based on the following factors: land value per hectare; area occupied; impact on fee simple ownership (see below); and an annual rate of return. The annual rent formula is based on the land value per hectare, multiplied by the area occupied (ha), multiplied by the impact on fee simple (expressed as a %) and multiplied by the established rate of return. The impact on fee simple land in the case of the EWT Line will be 75%, as it is a proposed 230 kV transmission line.

- Rent will be adjusted accordingly every five years based on MNR updated zonal studies, and will be adjusted based on the annual average Consumer Price Index.

- **Land Rights – Fee Simple:** Where the Project traverses private lands, NextBridge will engage landowners in an open and respectful manner, with a commitment to timely, meaningful and transparent dialogue. As it relates to landowner compensation, this process will be coordinated in an equitable and consistent manner. This will involve the development of a "fairness letter" that will be issued to all landowners indicating that similarly situated landowners will receive the same compensation, on a per acre basis, for the acquisition of land rights. This approach has been successfully employed by NextBridge partners on past projects – as it ensures maximum landowner harmony and enhances our long-term relationship with affected landowners.

- **Land Rights – Other:** In addition to the above activities, the Land Acquisition work stream on the Project will secure identified consents – such as road use, crossing, encroachment and proximity agreements – from existing facility and infrastructure owners for the construction and operation of the Project. This work stream will also secure surface leases (or similar dispositions) to support the construction for lay down, storage and stockpiling, as identified through detailed engineering processes.

Compensation and Payment Approach:

An important element of NextBridge's land acquisition strategy is the development of the compensation or payment structure that will be offered to the affected landowners for the ROW. We outline our approach to assessing compensation and payment structure below.

- **Overview:**
  - The generally accepted basis for the establishment of fair compensation relies upon the use of the FMV of the lands.
  - Factors that reflect elements such as assembly premiums and landowner inconvenience are applied to the FMV and a premium rate is developed.
  - What premium is paid (if any), is often dictated largely by the economic conditions at the time of acquisition and that premium will be adjusted accordingly based on recent land sales in the area.

- The FMV will be established by market valuations, a formal appraisal, that will establish the FMV by analyzing recent land transactions. The appraisers NextBridge retains will be members of the Accredited Appraiser Canadian Institute (AACI) and have a designation from the Appraisal Institute of Canada (AIC).
- The appraisers will also prepare a *Pattern of Dealings Report* for the lands in question. This report will outline what fee has been paid for similar ROW transactions and its relationship to FMV. The appraisers will then compare the FMV multiplier result with the pattern of dealings and, in most cases, will offer landowners the higher value.
- The appraisal report will be in a form that meets the requirements of section 25 of the *Ontario Expropriations Act*.

Upon completion of the market valuations, NextBridge will meet with landowners to provide notice of the market value and provide a formal offer. An individual ownership plan showing the property and acreage in question, in relation to the proposed corridor, will be provided at this time. Each landowner will be given sufficient time to review and consider the material provided, and NextBridge will commit to a 48-hour no-contact period prior to following up with the landowner. After receiving the NextBridge offer and in cases where a landowner requests an independent market value analysis, the landowner will be reimbursed up to $7,500 for such an analysis, upon the landowner notifying NextBridge of the request, in writing. The independent appraisal must be completed by an AACI-accredited appraiser and must be in a form that meets the requirements of section 25 of the *Ontario Expropriations Act*.

The formal offer will be available for a limited period of time and the landowner in question will be notified of this timeline. If parties are unable to agree to mutually acceptable terms by the time NextBridge files an application to seek expropriation authority status (pursuant to section 99 of the Ontario Energy Board 1998) then the formal offer provided by NextBridge will lapse. At this point NextBridge will proceed with the legislated expropriation process. A revised compensation offer will be provided to the landowner and will comply with the compensation requirements of the *Expropriations Act*, however it will no longer include the compensation incentives presented in the original offer as the regulatory expediency bonus will no longer apply in the new offer. Compensation for injurious affection will be provided when reductions in market value of the

remaining property interests are incurred as a result of the EWT Line. This amount will be prepared as part of the market valuation appraisal and provided as part of the formal offer.

- **Payment Structure:** Landowners will be offered an option agreement (option to purchase) and an incentive for regulatory expediency (a $1,000 increment to the consideration offered to the landowner for the option) at the time the agreement is signed. This agreement provides NextBridge with the sole and exclusive option to acquire an easement for the ROW across the property through a fee simple interest in the lands. Upon exercising the option, the option agreement becomes a binding contract of sale and purchase.

  Upon approval of the leave to construct application, NextBridge will exercise the rights of the option agreement. Landowners will be provided with the option of receiving the easement compensation as a lump sum payment, or as annual or periodic payments of equal or different amounts – over a duration set forth in a schedule to the option agreement as determined between the landowner and NextBridge. If the lump sum option is chosen, full payment shall be made prior to the start of construction.

- **Mandatory Buyouts:** If primary residences, farm buildings, and/or commercial/industrial buildings are located within the Project corridor, NextBridge will offer a one-time option to either acquire the landowner's entire property parcel on which the corridor is situated or to acquire only the portion of the property that is on the corridor and provide compensation for the loss of the primary residence or buildings, including reasonable relocation costs.

- **Damage Settlement:** NextBridge will compensate landowners for damages relating to the construction and operation of the Project. If compensation for damages cannot be agreed upon, the matter may be settled though alternative dispute resolution, arbitration, court action or the appropriate regulator. Generally damages will address inconvenience and loss of use suffered as a result of construction. The appropriate value is generally determined through negotiation and reliance on pattern of dealings. Damages can also include costs for tree replacement on private land where requested by the landowner, if shelter belts and ornamental trees are damaged or required to be cleared.

- **Trapper Payments:** In Ontario, Crown land is divided into registered areas called trap lines. Every trapper on Crown land is assigned a specific trap line and provided exclusive rights for the area. Along the proposed corridor for the Project there may be registered trappers actively participating in fur harvesting. NextBridge will determine which trappers, if any, may be negatively affected by the proposed corridor. Registered active trappers will be consulted and provided compensation if impacted by construction of the Project. This will include damage to trapper assets, general disturbance, adverse effects and impacts to trapping operations.

Description of Significant Issues Anticipated in Land Acquisition or Permitting and Mitigation Plan

No significant issues are anticipated in the acquisition of land rights from Crown Provincial or Fee Simple lands. The greatest risk to acquisition of land is related to National Parks and Indian Reserves/Treaty Entitlement Lands. This is due to the difficulties associated with acquiring rights on these lands and the potential risk to the Project in terms of timeline delays and or land costs.

To mitigate these potential risks, NextBridge has developed three route variants as contingencies, as outlined in Section 6.1: one at Pukaskwa National Park between Wawa and Marathon; and two variants to bypass Pays Plat and Michipicoten First Nation Reserves. While these contingent variations from the Reference Route would increase the cost of the Project, this cost would have to be weighed against any incremental land costs presented in these sensitive areas and any costs or other detriments associated with delays that might arise as a result of the negotiation and permitting issues associated with these areas. Site meetings were conducted with National Park staff and early indications suggest that the Park agency may have concerns with routing the Project through the park. The Reference Route and variants are discussed further in Section 9.3**.**

Apart from these negotiations and permitting challenges, the other significant permitting challenge will be to progress the Project through the *Ontario Environmental Assessment Act*. Under the Act this project will be considered a Class C project, requiring a complete environmental assessment. The key components of an individual environmental assessment include: consultation with government agencies and the public; consideration and evaluation of alternatives; and management of potential environmental effects. A Project concept design will also be required to complete the environmental assessment. It will be necessary to identify the location of all Project components including the transmission line corridor, access roads, construction staging/storage areas, fuel storage areas, etc. The

major steps to conduct an individual Ontario EA are discussed in Appendix 17: Major Steps in Environmental Assessment.

Other Licenses, Permits and Approvals

It is possible that additional environmental assessment work will be required on a route through the Pays Plat and Michipicoten First Nation Reserves and/or the Pukaskwa National Park. On July 1, 2012 a new *Canadian Environmental Assessment Act* (CEAA 2012) was introduced. The new Act requires the completion of a Federal environmental assessment for projects that are specified under regulation; or if the Federal Minister of the Environment determines that a project, not identified under regulation, has the potential for environmental effects in areas of Federal jurisdiction; or there are public concerns about such environmental effects.

Federal authorities responsible for carrying out or approving a project on Federal lands will be required to ensure that this Project does not cause significant adverse environmental effects. The Parks Canada Agency (PCA) is to have a process in place to meet the legal obligation under CEAA 2012 to:

- Ensure that projects in or on lands and waters administered by PCA, do not result in significant adverse environmental effects; and
- Identify when an assessment under CEAA 2012 may be warranted.

Based on the information that has been released about the CEAA 2012 process, it would appear that with a crossing of Pukaskwa National Park, PCA would have some responsibility to ensure that the Project would be done in an environmentally responsible manner. It is not clear whether this would require preparation of a Federal environmental assessment, or whether the interests of PCA could be satisfied through the Provincial environmental assessment. Consultation with PCA and the Canadian Environmental Assessment Agency to confirm Federal environmental assessment requirements for this Project will be required to route through Pukaskwa National Park.

In addition to the Ontario and potential Federal environmental assessment, other licenses, permits and approvals will be required for the Project. Approvals may be acquired at various times during development and construction, but they must be acquired prior to the relevant environmental features being affected by the undertaking. We provide a more detailed explanation of the approvals processes and timelines related to various environmental legislation in Appendix 18: Other Federal and Provincial

Licenses, Permits and Approvals Applicable to the Project**.** Due to recent federal legislation amendments, some approvals may not be applicable and applicability will be determined as this Project advances.

9.2 Landowner, Municipal, and Community Consultation Plan

Identification of the categories of parties to be consulted

The Project is expected to attract the attention of many agencies, interest groups and individuals. In the table below we summarize some of the stakeholders that will need to be notified and/or consulted with about the Project.

FIGURE 27: LANDOWNER, MUNICIPAL AND COMMUNITY STAKEHOLDERS

Individuals and Organizations
• Private Landowners, Industrial Landowners, Forest Management Agreement holders, Provincial Crown Landholders (Ontario Ministry of Natural Resources), Provincial and Federal Parks, Lakehead Region Conservation Authority, Utility Companies (e.g. CN Rail), Federal Regulatory Bodies – Environment Canada, Department of Fisheries and Oceans, Transport Canada, Canadian Environmental Assessment Agency, Local Chamber of Commerce, Tourism Associations and Operators, Local clubs and associations (e.g., hunting and fishing clubs, snowmobile clubs, etc.), Provincial and local level environmental organizations – Ministry of Environment, Mining and forestry companies and associations, and Municipal Governments (Townships and Municipalities).
Specific Districts
• Thunder Bay and Algoma Districts
Specific Townships
• MacGregor, McTavish, Dorion, Stirling, Lyon, Nipigon, Corrigal, Patience, McAllister, Wiggins, Yesno, Lahontan, Killraine, Priske, Strey, Syine, Tuuri, Walsh, Grain, Coldwell, McCoy, Marathon, Legarde, Levesque, Warpula, Andre, Bostwick, Lendrum, McMurray, Rabazo, Naveau, Nebonaionquet.
Additional Townships
• Pic, Bomby, Brothers, Laberge, McCron, Cecile, Knowles, Hunt, Abraham, Vasiloff, Alanen, Chapais, Dahl, Dambrossio, Lalibert, Menzies, and Bailloquet.
Single Tier Municipalities
• Thunder Bay, Shuniah, Dorion, Red Rock, Nipigon, Terrace Bay, Marathon, Michipicoten (and potentially White River depending on the final alignment of the route).

Consultation Plan including Methodology and Schedule

A core program of consultation strategies and tactics will be common to all landowners, municipalities, and communities. NextBridge will use proactive public communication and consultation programs to support two-way communication with affected parties. NextBridge's philosophy is to be as transparent

as possible with its stakeholders. This will be accomplished by undertaking timely, honest and open communication with stakeholders and communities that may be affected by the Project.

Our first step will be to implement a Public Involvement Program (PIP) that takes the unique aspects of this Project into account, including environmental sensitivities, private and public lands, and nearby neighbourhoods. The purpose of the PIP is to build public awareness and understanding, gather stakeholder input, answer questions, learn about community interests and perspectives and, where feasible, implement changes to Project design or scope to minimize adverse impacts.

As part of the PIP various parties proximal to the Project – landowners, First Nation and Métis communities, community residents, stakeholder organizations, public officials, chambers of commerce and community based media – will receive regular Project updates through channels such as letters, newsletters, regulatory compliance mailings, telephone calls, a website and in-person visits. A toll-free telephone line and email address have been established for the Project to provide community members with convenient access to NextBridge representatives.

Open houses will be held in communities along the Project route to provide community members a forum to speak directly with NextBridge subject-matter experts, and for NextBridge representatives to gather community input into the Project.

Interactions with stakeholders will vary depending on their level of interest in the Project. Some stakeholders may be satisfied to receive Project information at inception with periodic updates. Others may have interests or concerns that require personal consultations ranging from discussions of impact mitigation strategies with recreational users of public land, to engagement with multi-stakeholder advisory groups, to discussions about economic opportunities with local contractors.

NextBridge knows that its neighbours during construction will also be its neighbours for the many years that the Project will be in operation. Therefore, we welcome the opportunity to invest in long-term collaborative consultation relationships. We summarize below NextBridge's plan and schedule for consultation with stakeholder groups.

FIGURE 28: HIGHLIGHTS OF LANDOWNER, MUNICIPAL AND COMMUNITY CONSULTATION PLAN

Consultation Activities	Schedule
• As described above, a consultation program will be designed to enable effective and meaningful engagement with these stakeholder groups. • These groups will receive the initial Project notification followed by regular mail and web-based Project updates. • Above and beyond this timely information sharing, NextBridge representatives will seek personal meetings with representatives of these groups. • An early priority will be for NextBridge and different stakeholders to agree on the preferred mode and manner of contact moving forward. • Presentations, informal/ formal meetings and phone calls are all means to establish and develop mutually productive and respectful relationships. • NextBridge will seek to understand specific interests and, where feasible, incorporate into Project planning and execution to minimize adverse impacts and maximize benefits. • As the Project progresses through its lifecycle, NextBridge representatives will be accessible and responsive to stakeholder questions and concerns as they arise. • A Complaint Resolution Process will be instituted to manage and promptly address any community problems or concerns via telephone and email communication, as well as website updates.	• **June 2013:** Project notification and on-going project updates commencing June 2013, or upon confirmation of Project. Regular project updates will then be mailed to stakeholders along the transmission line ROW on a regular schedule throughout the development and construction phase of the project. • A Project website, toll free information line and email have been established and will be widely communicated at the outset of the project, and throughout the life of the Project, to ensure stakeholders have a variety of ways of reaching NextBridge representatives with questions or concerns as they arise. • Shortly following the notification mailing, NextBridge representatives will contact representatives from these groups (and other groups that may be identified or self-identify through the process) to offer to meet in person, to make introductions and discuss preferred means of communication moving forward. • **Jan-June 2015:** Two series of Community Open Houses are contemplated – one during the first six months of the project development phase (June – Nov 2013) and one in advance of construction beginning (Jan – June 2015)

Description of Significant Issues Anticipated in Consultation and Mitigation Plan

As with any consultation process, there can be a number of issues which must be carefully addressed. The previous experience of the NextBridge partners with such consultations has allowed NextBridge to define various effective mitigation strategies which could apply to the Project. We summarize below the key areas in which issues may be encountered. These issues are in addition to the major risks for both development and construction, identified in Section 7.2. A detailed issue and mitigation strategy listing is in Appendix 19: Detailed Issues and Mitigation Plans for Landowner, Municipal and Community Consultation.

FIGURE 29: HIGHLIGHTS OF ISSUES AND MITIGATION PLANS FOR LANDOWNER, MUNICIPAL AND COMMUNITY CONSULTATION

Issues	Mitigation Strategy
Diverse Property Ownership: The Project will pass through a variety of privately owned, public and crown lands that range from being completely developed to scarcely developed.	• The consultation plan will be tailored based on the information that is available about the landowners as well as the technology and access available to communicate with them, in an effective and timely manner. • Discussions with Parks Canada staff, to confirm their position on the feasibility of paralleling the existing corridor through the Park. • Undertake personal consultation with the residents and protected area custodians/agencies.
Permanent Loss of Land Resource Use: The development and maintenance of the line ROWs will result in the permanent loss of some forest production and mining use areas as it will not be permissible to regrow trees or mine within these areas during the operational life of the transmission line.	• Claim and lease holders will be contacted and provided with information on the Project and to discuss potential issues and mitigation strategies. • Specific concerns regarding mine claims will be addressed and all reasonable efforts made to come to business-to-business agreements with all mining claim holders who have claims staked prior to notification, and this, prior to formal submission of Land Use Permit applications to the Ministry of Natural Resources. • Continued consultation with all claim-holders within the Project area will take place throughout the development, and construction stages of the Project with the objective to resolve any concerns of claim holders.
Disruption of Recreational Areas: The Lake Superior coastline is home to a number of recreational activities (hunting, fishing, hiking, camping, canoeing and snowmobiling). Conditions during the construction phase, such as increased human activity and noise, could impact game populations, although temporarily. There will be minor disturbances during the construction phase to resource use such as trapping, fishing and hunting.	• Temporary and construction areas will be rehabilitated and restored in the operational phase. • Since it is proposed that the majority of new transmission line parallels the existing transmission corridor (or highway), most of the aesthetic effects would be mitigated. • Additional mitigation measures such as notice of construction signs and public consultations will be undertaken to ensure there is reduced conflict between the construction of the transmission line and recreational activities.
Potential Impairment of Protected Areas: The Project will pass through a variety of Nature Reserves and Provincial and National Parks. The construction and operation activities may disrupt or impact the ecological integrity of these protected areas.	• NextBridge will undertake personal consultation with officials for the affected Parks to discuss concerns, incorporate input and mitigate anticipated impacts. • Lake Superior Shoreline Enhanced Management Area, local municipalities, as well as First Nation and Métis communities and resource stakeholders will play a major role in the future planning and management of this area. NextBridge will undertake consultation with the affected communities to discuss concerns, incorporate input and mitigate anticipated impacts. • Appropriate mitigation, consultation and monitoring procedures will be implemented to reduce impact to ecological integrity.

Issues	Mitigation Strategy
Human Health and Safety: The proposed transmission line would produce Alternating Current (AC) electromagnetic fields (EMF) that oscillate at 60 hertz (Hz). Numerous scientific and health agencies studies have concluded that there is no link between EMF and health, behaviour or productivity of humans or animals, and that there are no adverse effects on the growth or viability of plants and crops. Although Ontario has no maximum EMF level standard, policy or requirement, and EMF levels from proposed transmission lines have not historically been modeled or provided as part of environmental assessment studies, there may be community requests for such modeling.	• Routing of the transmission line will take into consideration neighbouring land use.

9.3 Proposed Route for East-West Tie Line

Route Description and Specifications

NextBridge will undertake its route determination process for the 230 kV EWT Line over three stages – conceptual, preliminary and final routing. The conceptual phase has been undertaken for the purpose of developing a realistic proposal for the Project. After being selected as the Designated Transmitter and through the development phase, NextBridge will take the necessary steps to transition the route specified in the conceptual stage to a preliminary stage involving public and regulatory consultation and review. The final routing stage will include obtaining land agreements for the ROW, conducting an environmental assessment, and acquiring permits and approvals to construct and operate the transmission line.

Conceptual Stage Analysis:

The conceptual stage for routing involved a preliminary review of the study area identified by the Reference Plan with the aim of analyzing the Reference Route and identifying viable route corridors or variants. This involved a comprehensive review of existing, readily available documents and data, site visits and preliminary agency meetings.

This effort provided information on different opportunities and constraints such as land use, environmental and wildlife constraints, First Nation Reserve lands, Municipalities, National Parks, Provincial Parks, Federal Lands and Provincial Crown Lands.

Our siting analysis was also supplemented with aerial imagery, forest management and mining plans, and governmental planning documents, to determine current and future projects in the area. Additional field verification, stakeholder meetings and outreach efforts will be conducted to improve accuracy of existing datasets and to review constructability of the Project.

Upon review of the Reference Route, three main issues were identified along the Reference Route as discussed in previous sections: the crossing of Plays Plat and Michipicoten First Nation Reserves and routing through Pukaskwa National Park. NextBridge conducted a comprehensive review of these areas to determine contingent variants to the Reference Route should it become necessary to circumvent either of the two First Nation Reserves and/or the National Park.

- **Reference Route:** The Reference Route starts at the Lakehead substation near Thunder Bay, Ontario. The transmission line exits the substation on the North side of the substation and heads due North on the West side of the existing Hydro One 230kV transmission ROW, crossing Highway 527 (Trans- Canada Highway) where it then parallels, on the North side, the same existing Hydro One transmission line ROW. The Reference Route continues NorthEast through rural forest areas and crosses the Nipigon River, South of Nipigon. The line continues to parallel the existing Hydro One 230kV line East through significant terrain and rural forest areas to the Marathon substation, passing through Pays Plat First Nation. After the Marathon substation, the route then heads southeast and continues to parallel the existing Hydro One 230 kV ROW through Pukaskwa National Park towards Wawa. The Reference Route has limited access points and significant terrain to cross in Pukaskwa National Park. The Reference Route travels through Michipicoten First Nation. The line then travels east through rural forests to Wawa Substation, southeast of the Township of Wawa.
- **Reference Route Variants:** Variants to the Reference Route have been identified as contingencies. If it is necessary to bypass Pukaskwa National Park, it is proposed that at Marathon, the route would depart from the Reference Route and head due East along a transmission line corridor just North of Highway 17 towards White Lake. Just before White Lake the revised route would head due south through areas of active timber harvesting with good logging road access where it could then

reconnect with the Reference Route. Although longer in distance, this variation would circumvent many environmentally sensitive areas and several major watercourse crossings. As discussed above, the first variant bypasses Pukaskwa National Park completely. The other two variants bypass the Pays Plat and Michipicoten First Nation Reserves. Such decisions would be made in discussion with each of the affected First Nations.

Additional detail on the Reference Route variants and preliminary corridor development metrics are in Appendix 20: EWT Line Route Statistics and Appendix 21: Preliminary Corridor Development Metrics, respectively. We provide maps of the Reference Route and the three contingent variants below.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

NIPIGON
RED ROCK
DORION
HIGHWAY 17
PAYS PLAT
TERRACE BAY
SCHREIBER
MARATHON
Marathon TS
HIGHWAY 521
HIGHWAY 527
SHUNIAH
Lakehead TS
HIGHWAY 17
Lake Superior
PUKASKWA NATIONAL PARK
WHITE RIVER
ALGOMA
HIGHWAY 631
HIGHWAY 17
HIGHWAY 519
DUBREUILVILLE
MICHIPICOTEN
HIGHWAY 101
Wawa TS

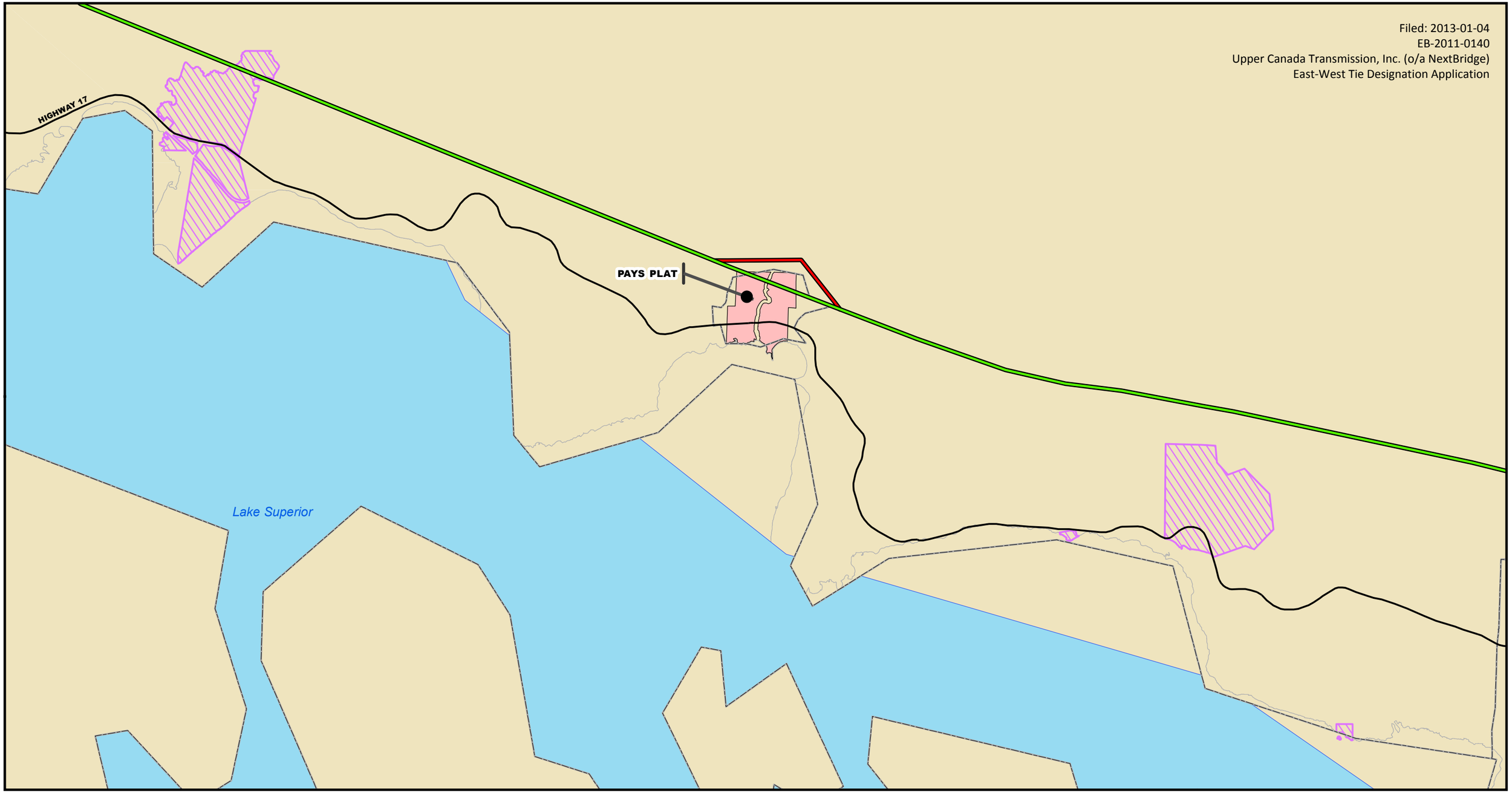
East West Tie Line Project
Route Overview
Figure 30: Reference Route Map with Variants

Albers Equal Area Conic 1:800,000
25 12.5 0 25 50 KM

File Name: East West Tie Line Project
Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nations
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality
- International Border

NEXTBRIDGE INFRASTRUCTURE



POLAR Geomatic Solutions

East West Tie Line Project

Figure 31: Pays Plat First Nation Reserve - Route Variant

Albers Equal Area Conic

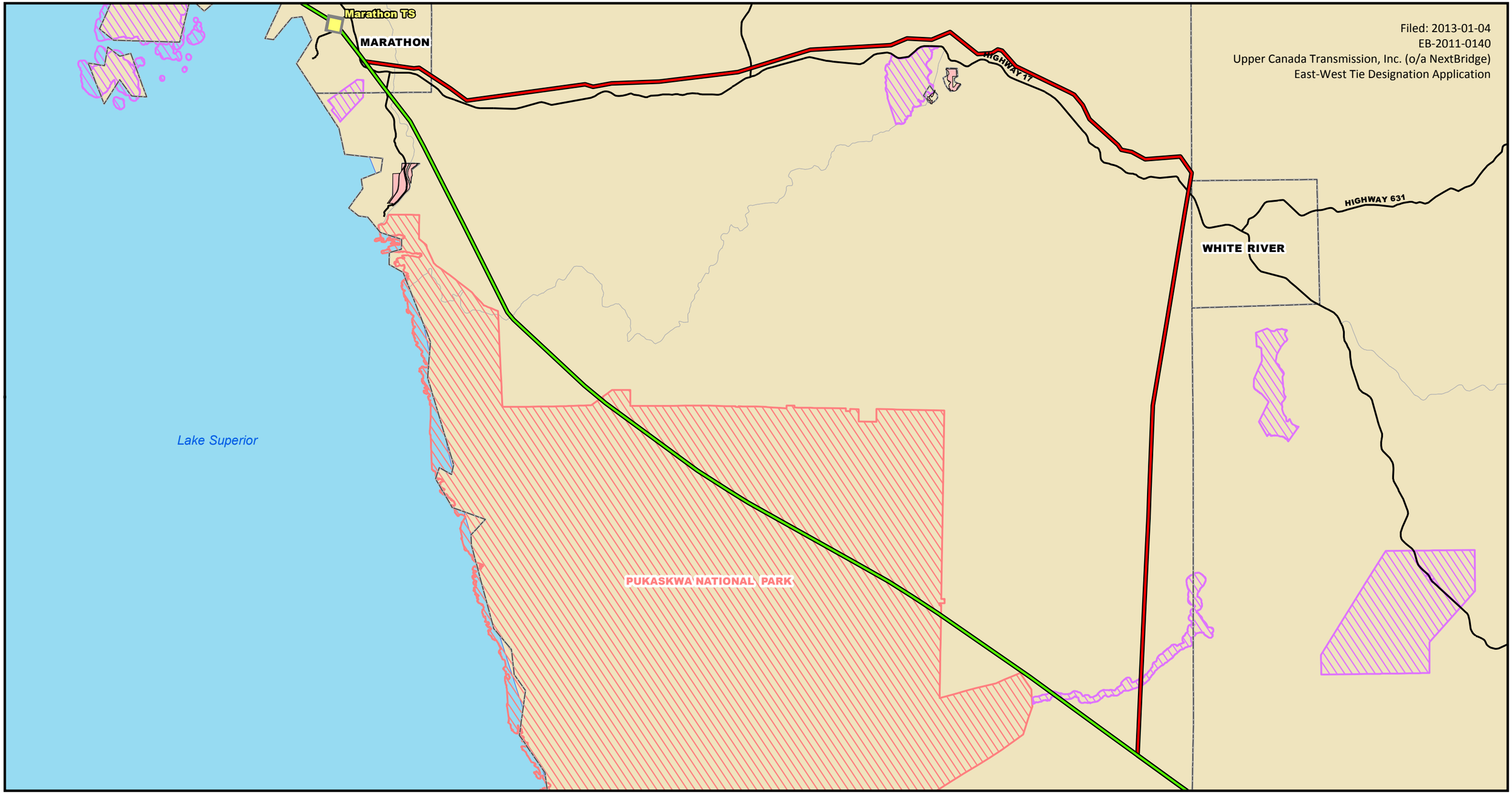
1:90,000

10 5 0 KM

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nation
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality

NEXTBRIDGE INFRASTRUCTURE



East West Tie Line Project

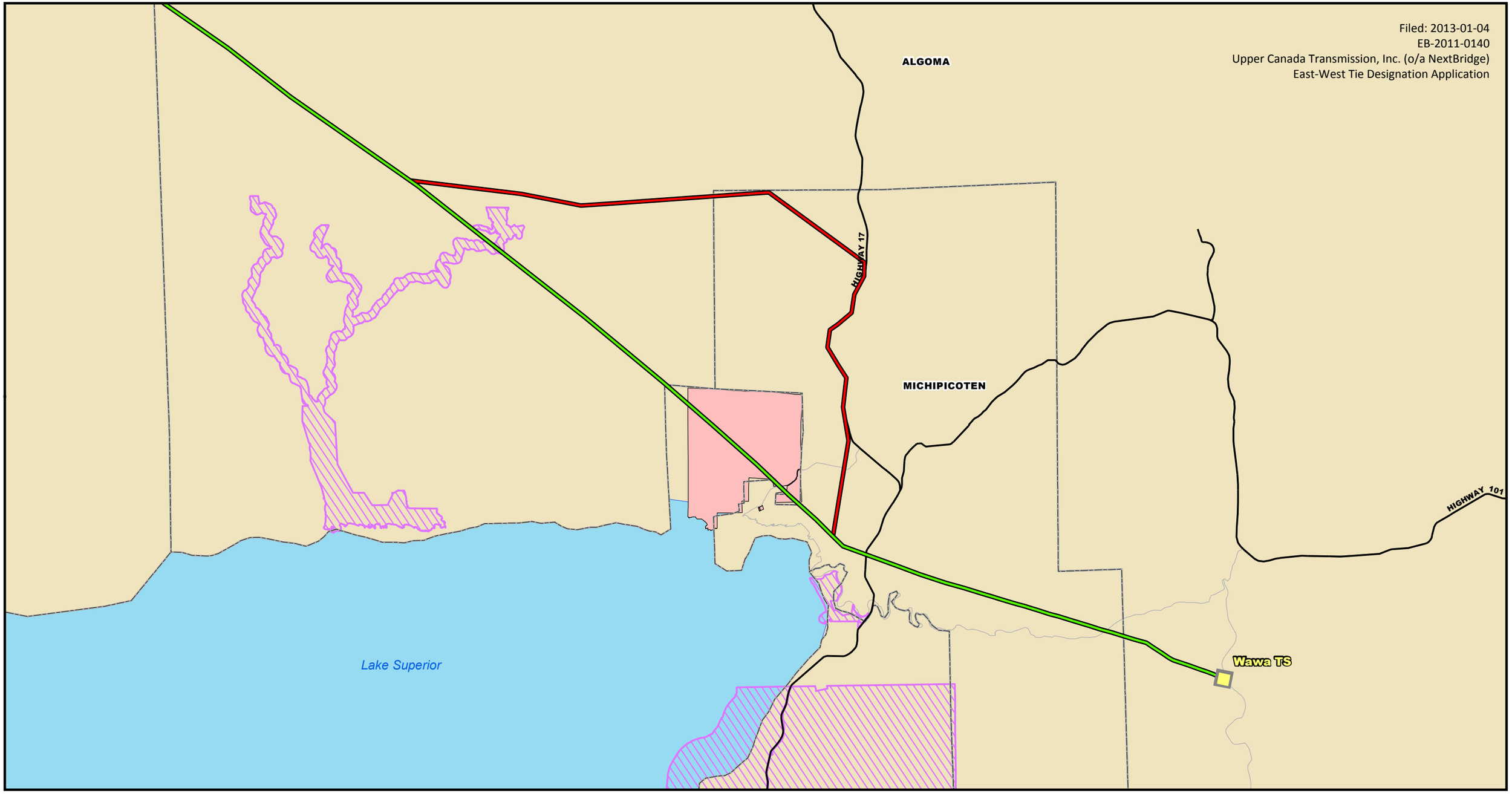
Figure 32: Pukaskwa National Park - Route Variant

Albers Equal Area Conic 1:300,000

10 5 0 10 20 Km

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nation
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality



POLAR Geomatic Solutions

East West Tie Line Project

Figure 33: Michipicoten First Nation Reserve - Route Variant

Albers Equal Area Conic 1:190,000

10 5 0 10 Km

Jan 03, 2013

- Substation
- Reference Route
- Reference Route Variant
- Major Highway
- Water Body
- First Nation
- Provincial Park
- National Park
- Wildlife Management Unit
- Municipality

NEXTBRIDGE INFRASTRUCTURE

Considerations for Using Reference Route Variants: As previously mentioned, a constraints-based analysis was conducted to identify the potential impacts of the Reference Route variants relative to the Reference Route itself. The findings of this analysis showed that the following considerations must be taken into account when assessing the necessity for using the route variants.

- **Bypassing Reserve Lands:** The Reference Route passes through Reserve lands that fall under Federal jurisdiction which may result in additional permitting requirements and environmental assessment requirements. This could impact both Project schedule and cost. While the contingent variations from the Reference Route would increase the cost of the Project, this cost would have to be weighed against any incremental land costs presented in these sensitive areas and any costs or other detriments associated with delays that might arise as a result of the negotiation and permitting issues associated with these areas. The decision to pass through or around First Nation Reserve lands will be made in full consultation with the affected communities in order to arrive at the best solution.
- **Minimizing Environmental Impact:** A key strategy in minimizing environmental impact is maximizing the length that the new transmission line will parallel existing disturbances. The Project footprint can then be minimized by utilizing existing cleared areas, sharing ROW where technically feasible, minimizing the requirement for new access roads and reducing fragmentation of the landscape. This siting design was discussed with the Ontario Ministry of Natural Resources in Thunder Bay.

  The Reference Route parallels existing disturbances for the entire length of the ROW. However, routing through Pukaskwa National Park will present several challenges from a permitting perspective. This route could require broader public discussion of the Project as well as additional environmental studies and mitigation, and could decrease the options available for construction, maintenance and operations of the EWT Line.
- **Access to the Corridors:** This is an important issue for construction, as well as operation and maintenance of the line. Although the Reference Route parallels existing disturbances, the section between Marathon and Wawa has very few access points and significant terrain challenges.

The Reference Route variants take advantage of a series of logging roads that bisect the corridor providing various opportunities for construction and maintenance operations to access the corridor, and utilize existing cleared areas. This will minimize the requirement to develop long stretches of new access roads and take advantage of existing watercourse crossings utilized on the logging roads. The Reference Route variants also minimize the area that traverses sensitive caribou habitat ranges. The coastal habitat area and connecting habitat corridors in the Pukaskwa National Park area are avoided by routing outside and away from the National Park. The importance of maintaining connectivity and minimizing fragmentation of the landscape in these areas is paramount – both in the management of the Woodland Caribou and deer wintering area populations.

- **Minimizing Number of Watercourse Crossings**: This is also a key component in effectively routing linear corridors. In developing the Reference Route variants, we aimed to minimize the number of watercourses and wetlands that the transmission line will cross – specifically 19 fewer major watercourses (> 200m) are crossed relative to the Reference Route. Additionally the watercourses affected are not within Pukaskwa National Park which is doubly advantageous.

Preliminary Stage – Refining the Corridor Option:

After being selected as the Designated Transmitter, NextBridge will refine the Reference Route corridors discussed above, based on stakeholder feedback, additional field studies and key agency consultation. To date, preliminary route discussions with key agencies within the study area have helped to identify potential obstacles that the Project may encounter. Further consultation with affected communities and key agencies will be undertaken at this stage to allow for the refinement of the corridor. This refinement will continue through to the final stages of routing taking into account stakeholder requests, environmentally sensitive areas, aesthetic concerns and regulatory requirements. In addition, technical route driven revisions will be identified and accounted for through geo-technical ground studies, as well as engineering and field visits. These revisions may require slight route alignment adjustments to account for industry standard setback requirements, crossing requirements, deflection angle and other such items which cannot be identified and addressed via engineering design alone.

Final Stage – Right-of-Way Width:

Based on the preliminary engineering specifications, the expected ROW width for the proposed Project is 50-56 metres. This value can change based on individually determined, site-specific constraints encountered during detailed engineering which will occur as part of the development phase, after selection as the Designated Transmitter. NextBridge will work with Hydro-One and other disposition holders and landowners to the extent possible, to utilize shared, existing, cleared areas to minimize the extent of disturbance associated with the development. This final stage will be complete prior to submitting our leave to construct application.

Description of the Environmental Challenges Posed by Proposed Route

NextBridge has already started to develop a framework for a preliminary Environmental Protection Plan (EPP) which it will further develop during the early stages of the Project. The EPP will outline the environmental commitments as well as industry best practices and standards, which will be used during the Project. NextBridge will ensure that environmental specialists will be available to monitor high risk activities or where additional mitigation plans may need to be developed. On the Project, all environmental commitments will be monitored and reported on by the Lead for the Environment and Permitting work stream. Environmental monitors will be employed throughout the construction phase of the Project to ensure that stated commitments are met, to address any issues that arise during construction, and to provide regular reporting on environmental activities.

NextBridge has identified a series of mitigation strategies to manage the environmental sensitivities during the development and construction phases of the Project. This is not an exhaustive, comprehensive or a final list, however it outlines high impact event mitigation strategies that may be employed. These strategies will be refined after consulting with Regional, Provincial and Federal authorities.

A Project specific Environmental Protection Plan will be developed to guide construction activities from an environmental perspective. Additionally, these mitigation strategies will be codified in an operations and maintenance manual in order to guide maintenance activities. Discussed below are the key environmental and associated permitting challenges in this Project, as well as mitigation plans for each challenge.

FIGURE 34: ENVIRONMENTAL CHALLENGES

Issues	Mitigation Strategy
Parks and Reserves: There are several parks and reserves to pass near or through including but not limited to: • A pass through the Northern boundary of Ruby Lake Provincial Park, Black Sturgeon River Provincial Park, and Pukaskwa Provincial Park; • A pass through the Gravel River Provincial Nature Reserve; • A pass through Nimoosh Provincial Park, and Pukaskwa National Park.	• Project impacts on these features will depend on the use and sensitivity of the feature. Consultation with Provincial and Federal agencies (e.g. Parks Ontario and Parks Canada) will be required to confirm their acceptance of the crossings, the need for re-routing, and expected facility design/mitigation commitments. • The crossing of Black Sturgeon River Provincial Park may also be problematic as the Park Management Plan indicates that new utility corridor crossings will not be permitted (despite there being existing power line and gas pipeline crossings of the Park). A route around Black Sturgeon River Provincial Park to the South appears to be possible but would add length to the Project.
Species at Risk (SAR): There are many SAR species in the Project area. In some cases permits are required and have specific data collection and monitoring requirements that could affect the Project approval and construction timelines.	• The potential for impacts on SAR species can only be confirmed through discussions with the MNR, and completion of wildlife surveys and the environmental impact assessment. • There may be a need for SAR permits for the Project. Early identification of any long lead data collection and monitoring requirements. • Develop watercourse and wetland specific crossing plans to minimize impacts on water quality and fish habitat.
Birds and Waterfowl: There are many birds and waterfowl species in the Project area, which must be considered during Project construction and operations.	• The potential for impacts on birds and waterfowl can only be confirmed through discussions with the MNR, and completion of wildlife surveys and the environmental impact assessment. • **Bird / Transmission Line Interactions:** Bird flight deterrents will be installed when paralleling or crossing major watercourses and wetlands. • Raptor perch inhibitors will be installed to minimize nest construction on structures and reduce predation in identified sensitive habitats (i.e. next to waterfowl staging areas). • **Waterfowl and Colonial Nesting Birds:** Avoid known colonial nesting habitat sites and conduct pre-construction surveys of the corridor to ensure additional sites do not exist. • Ensure clearing takes place outside of the restricted activity period for migratory birds if possible.
Woodland Caribou: Routing will pass through the coastal range and connecting corridor habitat of the woodland caribou. There will be concerns that the Project will add to further pressure on this species, in the form of construction disturbance, habitat fragmentation and access	• Minimize new access in Caribou Management zones, where new access is required construct only winter grade access (snow roads) and completely decommission roads by planting trees and spreading slash. • Install barriers to sight along the ROW to reduce increased predation. • Install breaks in snow banks along the ROW access to allow passage across the ROW by ungulates

Issues	Mitigation Strategy
(particularly in the Marathon area where northern habitat ranges connect with the coastal range). There may be demands for specific population/corridor movement studies by the MNR and Project specific mitigation requirements.	• Minimize ROW, access and workspace width in Caribou Management Zones where feasible. • Utilize an early in and early out construction strategy to minimize the impact to Caribou during wintering and calving seasons.
Tourism, Recreation and Aesthetic: The Project area is a significant tourism area for Ontario. The North shore of Lake Superior is one of Ontario's most valued and famous scenic landscapes. The lakes and rivers in the area provide numerous opportunities for tourism and recreation which the local economies rely on. Impacts on views along the coastline will be a key concern of stakeholders. The crossing of waterway parks may be a concern by the users of these features as a result of the potential for impact on the wilderness experience. This also has an impact on the crossing of the Reference Route through the Pukaskwa National Park.	• Utilize existing corridors wherever possible. • Perform an analysis of the aesthetic impact of the route during detailed design to identify measures to reduce the impact of the line in populated areas.
Access Road Effects: Access roads to facilitate the construction of the transmission facility can have as great, if not greater, environmental impact than the facility itself. For the Reference Route, lands between Marathon and Wawa are relatively remote and it is anticipated that a significant number of access roads would be needed for construction. This could include the improvement of existing forest access roads and/or the construction of new roads. Roads can also result in effects that transmission facilities themselves can typically avoid (e.g. fisheries effects from water crossings).	• **Access Roads:** Utilizing existing access and ROW access will be the predominant method of accessing the construction areas. • Winter access will be used whenever possible (limited grading and utilization of snow and ice as road base). • **Erosion Control:** Only grades necessary for construction will be graded and erosion control devices will be immediately installed. A cereal cover crop may be used to provide temporary vegetation cover when required.
Surface Water Effects: Related to the above, any works near water bodies including wetlands will receive	• **Wetland Crossings:** Avoid wetland habitat whenever possible and place a 100 metre buffer on wetlands to exclude structures from riparian zones where possible.

Issues	Mitigation Strategy
particular attention. There are a significant number of water bodies in the Project area that the Project would either be near and/or have to cross. How these crossings are accomplished will require specific consideration. Any impacts on Provincially Significant Wetlands (PSWs), or the Nipigon River, will be of particular concern, and will require detailed study and site specific mitigation.	• Minimize disturbance to riparian and wetland vegetation within the 100 metre buffer, this will include clearing only vegetation necessary for safe operation of the line and minimizing travel widths through these sensitive areas. • Aerial stringing and maintenance activities across all wetlands and watercourses. • Construction of work around access roads to minimize the requirement to construct wetland crossings where possible. • **Major Watercourse Crossings:** Implement a minimal disturbance buffer zone area of 30metre where limited activities are allowed to take place • Minimize disturbance to riparian and wetland vegetation within the 30 metre buffer, this will include clearing only vegetation necessary for safe operation of the line and minimizing travel widths through these sensitive areas • Install only watercourse crossings that are essential and minimize bank disturbance during installation of temporary bridges, utilize work-around where feasible.
Construction Timing Windows Due to Environmental Conditions: Project construction, including vegetation clearing, cannot be started until Project approvals have been received. The clearing of vegetation during bird breeding season (May-July) will be discouraged by the MNR.	• Develop the detailed project construction schedule to manage around environmental concerns and potential issues. • Any in-water works are typically preferred during the low water summer months or under frozen conditions. Winter construction has benefits when dealing with wetland areas as frozen water bodies provide better access to areas and winter construction tends have less impact on the natural environment. Appropriate construction windows will be confirmed with MNR as part of the Environmental Assessment for the Project.
Vegetation Management: NextBridge has reviewed the numerous Forest Management Plans for the region to determine an appropriate vegetation management plan for construction and operations.	• **Vegetation Management:** During construction, the Project will review appropriate vegetation clearing and disposal with landowners, agencies and other stakeholders. Once constructed, vegetation maintenance to ensure proper reliability and safety of the transmission ROW will be completed as appropriate. Mechanical maintenance procedures and the use of herbicides will be evaluated. Herbicide use may be restricted or limited by agencies or in deference to First Nation and Métis communities to protect sensitive environments and waterways. A vegetation management plan will be created once the final route is selected. • Manual and motor-manual brush control strategies will be employed in restricted zones. • Herbicide control in low impact areas - Vegetation will be managed seasonally to reduce impacts to sensitive wildlife populations and nesting disturbance.

Issues	Mitigation Strategy
Weed Species Management: During construction it is possible to spread weeds or transfer them from one location to another, which should be avoided.	• During initial environmental planning of the corridor a weed species study will be completed, identifying areas of concern for avoidance and future control. • Equipment will be cleaned before entering the ROW and when travel to or from infested areas is required.
Soil Management: Construction activities have the potential to damage soil conditions.	• A saturated soils contingency plan will be developed to direct construction activities in situations where soil damage may occur during construction. • All pole hole (structure foundation) topsoil will be conserved and re-spread on site to ensure adequate re-vegetation of the area. • All pole hole subsoil will be spread thinly on the right-of-way to allow re-vegetation of the site. • Native seed mixtures will be utilized to establish cover where natural vegetation establishment is delayed.

Estimate of Ownership by Category of Lands along the Reference Route

This information is summarized in Section 9.1.

9.4 If a proposed route for the line has not been identified

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10 First Nation and Métis Consultation

10.1 Proposed First Nation and Métis Consultation Plan

List of First Nation and Métis Communities with Interests Affected by East-West Tie Line Project

NextBridge will undertake consultation with the communities listed below. This list is consistent with the First Nation and Métis communities identified by the Ontario Ministry of Energy in its May 31, 2011 communication to the Ontario Power Authority (OPA).

FIGURE 35: CROWN IDENTIFIED FIRST NATION AND MÉTIS COMMUNITIES

Crown Identified First Nation
• Animbiigoo Zaagi'igan Anishinaabek First Nation (Lake Nipigon Ojibway) • Biinjitiwaabik Zaaging Anishinaabek First Nation (Rocky Bay) • Bingwi Neyaashi Anishinaabek (Sand Point First Nation) • Fort William First Nation • Ginoogaming First Nation • Long Lake No. 58 First Nation • Michipicoten First Nation • Missanabie Cree First Nation • Ojibways of Batchewana • Ojibways of Garden River • Ojibways of Pic River (Heron Bay First Nation) • Pays Plat First Nation • Pic Mobert First Nation • Red Rock Indian Band
Crown Identified Métis Organizations
• Greenstone Métis Council • Red Sky Independent Métis Nation • Superior North Shore Métis Council • Thunder Bay Métis Council

Should a First Nation or Métis community that has not been previously engaged identify itself as being affected by the Project, NextBridge will engage with that group. This engagement will be for the purpose of sharing information about the Project; hearing and addressing concerns of the newly identified group to the extent possible; and ensuring on-going dialogue about the Project, its potential implications and benefits.

An Approach for Engaging with Affected First Nation or Métis Communities and Related Rationale

We recognize that the Crown plans to delegate the procedural aspects of consultation to NextBridge, upon selection as the designated transmitter. We further understand that the Crown wishes to enter into a Memorandum of Understanding (MOU) with the designated transmitter as referenced in the December 11, 2012 letter from the OEB to the electricity transmitters registered in the East-West Tie Line designation proceeding EB-2011-0140. NextBridge is prepared to enter into such an MOU, provided that it does not delay our engagement efforts and can be pursued in parallel, as opposed to being a condition precedent to commencing consultation.

As the delegate with respect to the procedural aspects of consultation, we will undertake thorough and well-documented consultation efforts. Our objective during consultation is to develop strong relationships with the First Nation and Métis communities affected by the Project. Our approach for engaging these communities and entering into consultations is based on the following guiding principles:

- **Understanding the Communities:** NextBridge will collaborate with First Nation and Métis communities to better understand their asserted rights as well as their concerns for the people affected by our work in the areas where we will operate. Our approach adheres to key principles for relations with First Nation and Métis communities, including respect for traditional ways and land, heritage sites, the environment, and traditional knowledge. We believe that positive relationships with First Nation and Métis communities, based on shared respect, are of mutual benefit and importance.
- **Commitment to Effective Policies and Procedures:** Our consultation approach is based on upholding the highest common principles of engagement across the NextBridge partners. Our Consultation Plan is rooted in NextEra's First Nation and Métis Relationship Policy (Appendix 23: NextEra Energy First Nation and Métis Relationship Policy) and Enbridge's Aboriginal and Native American Policy (Appendix 22: Enbridge Aboriginal and Native American Policy) and adheres to regulatory and permitting requirements. In adhering to the principles set out in these policies, NextBridge will conduct all consultation in an open and transparent manner.

- **Meeting or Exceeding Regulations:** We take a 'good neighbour' approach and aim to meet or exceed regulatory requirements during the process of attaining Project approvals. Going to this length ensures that our Consultation Plan will be executed in a manner that is compliant with applicable government policy requirements, while respecting First Nation and Métis communities during consultation. First Nation and Métis engagement and consultation for the Project will also be guided by Federal and Provincial government consultation policies and requirements.
- **Communication and Transparency:** In our dealings with affected First Nation and Métis communities we form good working relationships through: open dialogue; communicating key Project information and updates; and being attentive to the communities' concerns about Project impacts or questions about Project benefits. Through a number of different forums ranging from informative materials, reports and web postings, to community open-houses and meetings, to initial and follow up community visits – we aim to become a trusted partner in the local communities and economies affected by the Project.

Based on these guiding principles, we have developed a sound, effective approach to First Nation and Métis engagement and consultation. Relying upon the expertise of our qualified and experienced in-house Aboriginal Affairs personnel, NextBridge will carry out all consultation activities with First Nation and Métis communities in an open and respectful fashion.

Throughout each phase of the Project, NextBridge will use a comprehensive web-based database program (named *Praxis* and used by Enbridge on its projects) to track our First Nation and Métis contacts and activities. These activities cover all points of contact throughout the regulatory and construction phases of the project, including phone calls, e-mail, mailings, face-to-face meetings and community open houses. The program also facilitates the development of documents for reporting purposes. This comprehensive database provides continuity in consultation tracking for the Project, and contributes to transparent and effective reporting to meet regulatory requirements.

The key activities and timelines comprising NextBridge's First Nation and Métis Consultation Plan, summarized below, will continue to evolve as we gather more information and feedback.

FIGURE 36: FIRST NATION AND MÉTIS CONSULTATION PLAN

First Nation and Métis Consultation Plan
Phase 1: Milestones Prior to Submission of the OEB Designation Application – Fourth Quarter, 2012
During the preparation of this proposal we are already working to establish the foundation of our Consultation Plan by undertaking a number of key activities: • NextBridge has contacted First Nation and Métis communities through introductory letters describing NextBridge, its three partner organizations and our intent to apply for designation to develop the Project. • We have formed the AAB – our Aboriginal Advisory Board that has been advising us on the development of our Consultation Plan. • We have initiated requests for self-defined consultation protocols from various First Nation and Métis communities and will continue to do so during subsequent phases of our Consultation Plan.
Phase 2: Submission of OEB Designation Application to Designation
Making use of the time prior to designation NextBridge will put itself in a position to begin the consultation process immediately following the conclusion of the designation process. To do this, we will: • Gather key statistical and demographic information; • Understand and measure the capacity for different First Nation and Métis communities to participate in direct or indirect activities resulting from the Project; • Obtain traditional mapping of different areas along the route; • Collect information on Traditional Land Use Studies where available; • Seek counsel from regional treaty organizations; and • Undertake an initial assessment of the scope of issues and concerns in the region(s) surrounding the EWT Line.
Phase 3: Designation to Approval of the Leave to Construct
This will be a crucial, intensive stage in our Consultation Plan, during which a number of key activities will occur: • **Consultation Process:** We will execute transparent consultation processes. We will start by collaborating with affected First Nation and Métis communities and organizations regarding an agreed upon consultation process, while ascertaining and respecting consultation protocols for each community and organization. An important part of this consultation process will be outlining our intentions and our proposed steps towards building a long-term relationship with potentially affected First Nation and Métis communities and organizations. • **Information Gathering and Sharing:** Key project information will be shared with First Nation and Métis communities – including a Project overview, route options, anticipated timelines, maps and transmission line operational information. In turn, key information will be collected from the communities, including statistical and demographic information, business listings, capacity to participate, and obtaining traditional mapping. • **Communication with First Nation and Métis Organizations:** Throughout this phase, NextBridge will engage with First Nation and Métis Organizations using a variety of communications methods which may include phone calls, mail-outs, face-to-face meetings and community open houses. • **Communication with Government Bodies:** We will communicate with the Crown about claims of impact to traditional rights and uses, with corresponding mitigation strategies. We will also continue to obtain and record any issues or concerns about the EWT Line project relayed from affected First Nation and Métis communities and organizations. These issues will be shared with relevant provincial or federal agencies. Active management of such issues and providing timely responses is a key feature of our plan. • **Determine First Nation and Métis Aboriginal Economic Participation:** Working closely with each individual

First Nation and Métis Consultation Plan
First Nation and Métis community, NextBridge will finalize First Nation and Métis participation in the Project. We have discussed alternatives for participation in greater detail in Section 3. • **Determine Project-specific impacts to rights:** We will work with individual First Nation and Métis communities to determine Project-specific impacts and develop strategies and actions to proactively address them.
Phase 4: Leave to Construct to Commercial Operation Date
Our consultation process will be ongoing throughout the Project. We will continue to: • Communicate Project milestones with First Nation and Métis communities; • Respond to issues or concerns that arise through the course of the Project; • Facilitate the relationships we seek to build with affected First Nation and Métis businesses and organizations that will work with our Project team and primary contractors.
Phase 5: Operations
Our communication and relationships will continue throughout the Project lifecycle. NextBridge will continue to: • Build and strengthen relationships between NextBridge and First Nation and Métis communities; • Maintain ongoing, two-way dialogue with First Nation and Métis communities to determine operational impacts, if any, and concerns and work to address them.

Description of First Nation or Métis Issues Anticipated in Consultation and Plan to Address Them

NextBridge is committed to working with First Nation and Métis communities to mitigate Project specific issues and concerns including impacts to traditional rights and practices as well as land access. NextBridge anticipates that we will learn more about the key issues outlined below during the consultation process and discuss our plan to address these issues should they arise. It will be important to us to seek the views of the First Nation and Métis communities as to these potential issues and mitigation strategies throughout the consultation process.

FIGURE 37: ISSUES RELATED TO CONSULTATION AND PLAN TO ADDRESS

Issue	Mitigation Strategy
Impact of Project on First Nation and Métis rights	• We will work with individual First Nation and Métis communities to determine Project-specific impacts and develop strategies and actions to proactively address them.
Employment/contracting opportunities e.g. right-of-way (ROW) clearing, transmission line construction, operation, etc.	• Work with local economic development officers to complete early identification of business/service capacity of First Nation and Métis Communities. • Initiate internal discussions with procurement experts in order to assist First Nation and Métis businesses in meeting regulatory and industry standards. • Hire First Nation and Métis construction liaisons to ensure contractors fulfill commitments to First Nation and Métis employment and training.

Issue	Mitigation Strategy
Routing - crossing of reserve lands, waterway crossings, width of the ROW	• Minimize impacts on reserve lands to the extent possible. • Width of ROW to remain as narrow as reasonably possible to minimize environmental footprint. • Waterway crossings – use methods which impact waterways the least, but ensure water flows and marine life continue during construction. Seek counsel from community elders and trappers in advance of construction.
Increased access to remote areas by non-area residents	• Inform affected communities of potential for increased access by non-area residents. • If appropriate, impose restrictions on activities such as hunting, fishing, etc. for non-area residents.
Decreased access to remote areas for First Nation and Métis community members	• Work with individual First Nation and Métis to understand access requirements and accommodate access during construction and post-construction.
Seasonal access for recreational vehicles	• Work with local communities to determine access issues for both First Nation and Métis, and the general public.
Timber cutting and slashing – whether it will lie fallow or be available for other use	• Work with local communities to determine potential residential and/or commercial use in advance of clearing activities.
Potential use of herbicides on vegetation	• Limit use of herbicides in sensitive areas and/or during specific seasons. Consult in advance of activities with First Nation and Métis to understand any regionally specific sensitivities.
Impact on migration routes of wildlife	• Cease activities as necessary to not interfere with rutting season/migration patterns as required by regulations. Consult with First Nation and Métis with regard to specific local interests beforehand.
Impact on water flows	• Consult with local elders to tap into traditional knowledge of multi-seasonal changes in water flow for consideration in clearing, construction and operations planning.
Potential for enhanced development of local resources (power; mining; forestry)	• Consult with and understand local communities' economic development proposals which could benefit from the development of this type of transmission line.
Effect of Electromagnetic Field (EMF) on habitat	• Have material ready to address EMF questions that may arise.

Overview of Expected Outcomes

NextBridge expects a number of positive outcomes from executing our Consultation Plan, including:

- An open communication channel between NextBridge and First Nation and Métis communities for identifying, assessing and resolving communities' concerns;
- Thorough understanding of the Project objectives, schedule, impact and participation opportunities among First Nation and Métis communities;

- Thorough understanding of the Project impacts on First Nation and Métis communities by NextBridge;
- Enhanced Project planning informed by community knowledge of Elders and trappers of relevant local environmental factors;
- Strong, long-standing relationships with First Nation and Métis individuals and organizations in the communities impacted by the Project through open dialogue and genuine cooperation; and
- Opportunity for First Nation and Métis communities to have active involvement and a strong voice in their own economic development.

10.2 Evidence of experience in undertaking procedural aspects of First Nation and Métis consultation

As described in Section 3, NextBridge is a partnership that draws on the contributions of each of its three partners in the area of Aboriginal Relations. The cumulative effect is a broad and deep knowledge base about First Nation and Métis concerns and interests. In the table at the end of this section, we highlight a number of key projects that outline our ability to successfully work with First Nation and Métis communities. Every project NextBridge and its constituent partners undertake gives us an opportunity to expand our knowledge and understanding, and we look forward to developing this Project. The NextBridge Aboriginal Relations team is composed of qualified and experienced in-house personnel who have continuous ongoing access to additional expertise being gained by the partner organizations.

As part of this Application, NextBridge has been asked to highlight any existing relationships with the First Nation and Métis communities to be engaged as part of the Project. We make note of our existing relationships with the Red Rock Indian Band and the Fort William First Nation, as well as the three Métis Councils and the Red Sky Independent Métis Nation, through Enbridge. During the Greenwich Wind Energy Project, internal Enbridge personnel who are currently engaged by NextBridge on this Project established a strong relationship with each of Red Rock Indian Band and Fort William First Nation, by accepting and fulfilling responsibilities under agreements that provide sustainable benefits flowing from that project to each of the First Nations. First Nation members provided nearly 7,500 hours of labour to the project during construction in 2011. Greenwich Wind also contracted with a First Nation owned company to provide road maintenance services to the

project in 2011-2012, and these services will be provided to Greenwich Wind on an ongoing basis by First Nation contractors.

We highlight below examples of First Nation and Métis community engagement success stories:

- **Greenwich Wind Project (Enbridge):** In November of 2011, Enbridge and its partner Renewable Energy Systems Canada (RES) completed construction of the 99MW Greenwich Wind Energy Project, on Crown lands near Thunder Bay, Ontario, and began commercial operation. In May 2012, Enbridge acquired the remaining RES interest and is now the 100% owner of the project.
  - Throughout the earlier regulatory process, two local First Nations, the Red Rock Indian Band and the Fort William First Nation, had been engaged, culminating in agreements that provide sustainable benefits flowing from the project to each of the First Nation.
  - The project hired community members during construction in 2011, and First Nation members provided almost 7,500 hours of labour to the project during that year.
  - As well, in 2011 Greenwich Wind contracted with a First Nation owned company to provide road maintenance services to the project in 2011-2012. These services will be provided to the project on an ongoing basis by First Nation contractors.
  - The Greenwich Limited Partnership had also concluded agreements with local Métis organizations in relation to the project. In 2011, the Project provided financial support to facilitate communication regarding the project between three local Métis Community Councils and their members, and to support Métis community development, as deemed appropriate by each of the Community Councils.
  - In addition, Greenwich LP agreed to completely restrict the use of chemical herbicide sprays in vegetation clearing activities during the operation of Project transmission line corridors, access roads, and turbine tower sites, in response to concerns expressed by the Métis Nation of Ontario.
- **Alberta Clipper Pipeline Project (Enbridge):** The Enbridge Alberta Clipper Pipeline Project, undertaken between the years 2008 and 2010, is notable for its success in both training and employment of Aboriginal people.

- Demonstrated our ability to be flexible in consultation and negotiation with affected Aboriginal groups using a variety of approaches and techniques, ultimately resulting in mutually beneficial outcomes.
- Improved and addressed issues and concerns raised and provided sustainable benefits to Aboriginal communities. We negotiated agreements, provided training and made sure contractors fulfilled commitments to maximizing Aboriginal participation.
- Provided $1 million worth of training for 100 Aboriginal people. Employed 645 Aboriginal people during construction, which accounted for 22% of the total construction workforce on the project and resulted in $24 million of wages paid to Aboriginal employees across Alberta, Saskatchewan and Manitoba (this was inclusive of both Enbridge's own employees and the prime contractors' local work force).
- In 2008, awarded the Aboriginal Relations-Best Practice Award of Distinction from INAC and the Aboriginal Workforce Participation Initiation for its achievements in this area.

- **Woodland Pipeline Project (Enbridge):** The Woodland Pipeline is a 140 km pipeline to transport blended bitumen between the Kearl oil sands project and Enbridge's existing Cheecham Terminal which connects with existing pipeline transportation systems. The Cheecham Terminal is approximately 70 km South of Fort McMurray, Alberta.
  - Between 2010 and 2011 the Woodland Pipeline team successfully executed over $15 million worth of business with Aboriginal companies. This level of engagement of Aboriginal goods and service providers was the direct result of Enbridge's pro-active efforts in the identification and pre-qualification of new First Nation and Métis businesses in the region.

- **Line 9 Reversal – Phase 1 (Enbridge):** In this Line 9 Reversal Phase 1 Project Enbridge will reverse a section of existing Line 9 between Sarnia and North Westover, Ontario. This change is being undertaken in order to meet a request from a customer, Imperial Oil Limited, for access to the Ontario market. This project received National Energy Board (NEB) approval in July 2012.

- One First Nation intervened in the project and was given the opportunity to file evidence with the NEB as part of the hearing process. Three other First Nation groups made their views known through letters of comment.
- Upon assessment of the concerns brought forward by these First Nation groups, the NEB decided to provide approval, noting that Enbridge had complied with the NEB's regulatory requirements and conditions.
- The NEB also acknowledged Enbridge's success in addressing community concerns and was satisfied that any potential project impacts on Aboriginal interests would be appropriately mitigated. Following this regulatory process, Enbridge continues efforts to address matters brought forward by those First Nation engaged on the Line 9 Reversal Phase 1 through construction and operation.

- **Ontario Feed-in-Tariff Wind Projects (NextEra):** NextEra is currently developing over 600 MW of renewable energy from wind under the FIT program in South Western Ontario.
  - NextEra is currently engaging with 14 First Nation and 3 Métis communities to support this project development.
  - NextEra staff is undertaking a well-defined engagement and consultation process attuned to the protocols and interests of each community.
  - NextEra has retained recognized Aboriginal professionals to monitor its archeological and environmental assessment program and has committed to a substantial twenty year post-secondary scholarship/bursary program for Aboriginal students.
- **Blythe Energy Project (NextEra Energy Resources):** The Blythe Energy Project in Riverside County, California involved the construction of a 108 km, 1,100 MW, 230 KV transmission line that became operational in 2010.
  - Blythe Energy, owned by NextEra Energy Resources, contacted tribes in 2008 regarding the project and received several letters, but none expressing concern regarding the project. Tribes and bands were invited to become involved in the programmatic agreement for treatment of cultural resources.

- Blythe Energy invited local tribes to consider participation in Native American monitoring during construction. The Torres-Martinez Desert Cahuilla Indians agreed to participate by providing monitors to cover some 110 km of the transmission line. Blythe Energy staff worked with monitors to ensure health and safety for tribal members sent to the project sire during construction in 2009. These monitors worked directly with Blythe Energy staff and contractors daily in the field. Blythe Energy staff also worked closely with Tribal office staff to develop and improve contracting and invoicing skills.
- The Blythe Energy project was a successful project for the Tribe—it built skills among monitors as well as in the tribal office. Most importantly, Native American monitors provided an every-day perspective during construction. Due to a change in business focus, NextEra Energy Resources sold its interest in the Blythe Energy Center in 2011.

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Section C: Other Factors

11 Other Factors

Consultation with Intervenors

NextBridge firmly believes that consultation with stakeholders will be very important to the success of this Project and is committed to two-way communications in all phases of the Project. In the preparation of this Application NextBridge reached out to as many of the intervenors as possible to accomplish three objectives: (i) introduce the NextBridge partnership; (ii) provide a status report on the Project; and (iii) better understand key areas of interest or concern for as many stakeholders as possible.

The following is a list of registered intervenors that we contacted while preparing our Application:

- Building Owners and Managers Association Toronto;
- Canadian Manufacturers and Exporters;
- City of Thunder Bay;
- Northwestern Ontario Associated Chambers of Commerce and Northwestern Ontario Municipal Association;
- Consumers Council of Canada;
- Energy Probe Research Foundation;
- Lake Superior Action-Research-Conservation;
- Bay Niche Conservancy;
- Municipality of Wawa and the Algoma Coalition;
- Northwatch;
- Power Workers' Union;
- School Energy Coalition; and
- Association of Major Power Consumers in Ontario (AMPCO was contacted, but indicated that it had withdrawn as an intervenor in this application)

The stakeholder consultation meetings were intentionally delayed until the six weeks prior to the filing date of the Application to ensure that we had our plans and options reasonably well formed to support a meaningful dialogue with the intervenors. Our initiative to meet with intervenors is a clear

indication of our determination to include stakeholders in the process, and commitment to continue stakeholder discussions after designation.

The meetings with these parties, whether in person or by telephone were positive, allowing us to convey our value proposition and obtain important and timely input from available intervenors. Some of the key takeaways from our meetings, which we have considered and will continue to incorporate into our planning for the Project include:

- Our plan should align with the Growth Plan for Northern Ontario that was developed in 2011 and approved by the Lieutenant Governor in Council;
- Involvement in the Project from municipalities will be important to moving the Project forward;
- Quality of power is an important consideration in ensuring that the significant development, particularly in the mining industry, planned for Northwestern Ontario is realized;
- Regional planning is very important to communities. The OEB's recently published document on the Renewed Regulatory Framework for Electricity places this responsibility with the transmitter and should be a consideration for this OEB process;
- There is significant concern about availability of power generally, and in particular, should natural resource development result in growing demand for power in Northwestern Ontario. Enabling lines are of interest to the communities so that they can connect renewable projects.
- Proven track record of performance relative to cost and schedule will be a critical factor in selecting the Designated Transmitter.

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Upper Canada Transmission, Inc. (o/a NextBridge)
East-West Tie Designation Application
Appendix 1

NextEra 2011 Annual Report

TAB A1a

NEXTera ENERGY

Annual Report 2011



Investing

Affordable and Reliable Energy

Workers inspect the exhaust end of a highly efficient combustion turbine being installed at the Cape Canaveral Next Generation Clean Energy Center.

Financial Highlights

Year End ($ in millions, except per share amounts)

FINANCIAL RESULTS	2011	2010	% change
Net Income	$ 1,923	$ 1,957	(1.7)
Adjustments, net of income taxes:			
Net unrealized mark-to-market gains associated with non-qualifying hedges	(190)	(175)	
Loss on sale of natural gas-fired generating assets	98	–	
Other than temporary impairment losses – net	6	(4)	
Adjusted Earnings	$ 1,837	$ 1,778	3.3
Earnings Per Share (assuming dilution)	$ 4.59	$ 4.74	(3.2)
Adjustments:			
Net unrealized mark-to-market gains associated with non-qualifying hedges	(0.45)	(0.43)	
Loss on sale of natural gas-fired generating assets	0.24	–	
Other than temporary impairment losses – net	0.01	(0.01)	
Adjusted Earnings Per Share (assuming dilution)	$ 4.39	$ 4.30	2.1
Operating Revenues	$ 15,341	$ 15,317	0.2
Operating Income	$ 3,378	$ 3,243	4.2
Cash Flows from Operating Activities	$ 4,074	$ 3,834	6.3
Total Assets	$ 57,188	$ 52,994	7.9
COMMON STOCK DATA			
Weighted-Average Shares Outstanding (assuming dilution – millions)	419	413	1.5
Dividends Per Share	$ 2.20	$ 2.00	10.0
Book Value Per Share	$ 35.91	$ 34.36	4.5
Market Price Per Share (high – low)	$ 61.20 - 49.00	$ 56.26 - 45.29	
OPERATING DATA			
Utility Energy Sales (kilowatt-hour – millions)	106,662	107,978	(1.2)
FPL Customer Accounts (year end – thousands)	4,554	4,527	0.6
Employees (year end)	15,048	14,977	0.5

FORWARD-LOOKING STATEMENTS: This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, strategies, future events or performance (often, but not always, through the use of words or phrases such as will, will likely result, are expected to, will continue, is anticipated, aim, believe, could, should, would, estimated, may, plan, potential, future, projection, goals, target, outlook, predict and intend or words of similar meaning) are not statements of historical facts and may be forward looking. Forward-looking statements involve estimates, assumptions and uncertainties. Accordingly, any such statements are qualified in their entirety by reference to important factors included in Part I, Item 1A. Risk Factors at pages 24-35 of the enclosed Form 10-K (in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements) that could have a significant impact on NextEra Energy's operations and financial results, and could cause NextEra Energy's actual results to differ materially from those contained or implied in forward-looking statements made by or on behalf of NextEra Energy in this report, in presentations, on its website, in response to questions or otherwise. Any forward-looking statement speaks only as of the date on which such statement is made, and NextEra Energy undertakes no obligation to update any forward-looking statement to reflect events or circumstances, including, but not limited to, unanticipated events, after the date on which such statement is made, unless otherwise required by law. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained or implied in any forward-looking statement.

NextEra Energy, Inc.

NextEra Energy, Inc. (NYSE: NEE) is a leading clean energy company with 2011 revenues of more than $15.3 billion, more than 41,000 megawatts of generating capacity, and approximately 15,000 employees in 24 states and Canada. Headquartered in Juno Beach, Fla., NextEra Energy's principal subsidiaries are Florida Power & Light Company, which serves approximately 4.6 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country, and NextEra Energy Resources, LLC, which together with its affiliated entities is the largest generator in the United States of renewable energy from the wind and sun. Through its subsidiaries, NextEra Energy operates the third largest number of commercial nuclear power units in the United States. For more information about NextEra Energy companies, visit these websites: www.NextEraEnergy.com, www.FPL.com, www.NextEraEnergyResources.com.

Cover photo by: Pedro Portal

Investing in Affordable and Reliable Energy

To our shareholders:

NextEra Energy generated solid results in 2011, and proved that we can deliver value despite the challenges and uncertainties of the current environment. Florida Power & Light Company (FPL) continued to deliver the lowest electricity bill in Florida and one of the best value propositions of any electric utility in the entire nation. NextEra Energy Resources, LLC (with its subsidiaries, "NextEra Energy Resources") remains the biggest generator of wind and solar power in the United States, and is now developing the largest backlog of renewable projects we have ever had.

Our scale and strength helped us set another all-time high for our company's adjusted earnings per share in 2011. Our 2011 growth in adjusted earnings per share, at 2.1 percent,[1] was roughly in line with what our peers have delivered on average over the past 10 years, which includes a long period when market conditions were much more favorable than they are today. Moreover, our profitability, as reflected in 2011 adjusted return on equity (ROE)[2], continues to be better than the long-term industry median.



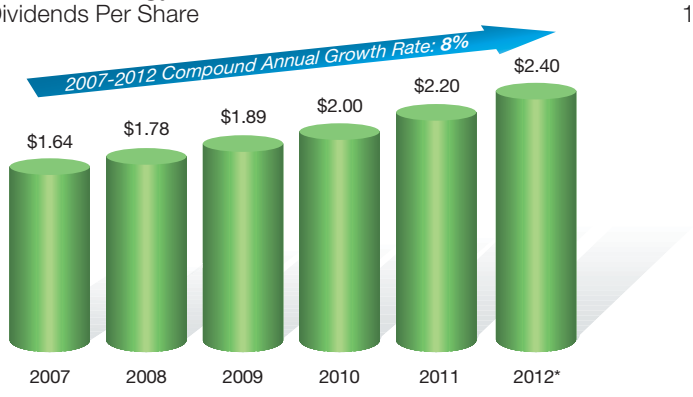
Lewis Hay, III
Chairman and
Chief Executive Officer

FPL has a clear strategy of investing in new, clean power generation to continue delivering benefits to our customers, and one of those projects is featured on the front cover of this report. The new Cape Canaveral Next Generation Clean Energy Center is a $1 billion investment. Because it will use 33 percent less fuel per megawatt-hour of power generated, this plant effectively pays for itself primarily due to fuel savings estimated at more than $1 billion over the 30-year operational life of the plant. At the same time, it will generate far fewer emissions and support our efforts to deliver exceptional system reliability.

NextEra Energy Resources faced several challenges in 2011, yet we reached key milestones as well. We signed nearly 2,200 megawatts (MW) of long-term wind and solar contracts in 2011, our most ever in a single year. On the solar front, the company has between 850 and 950 MW of already-contracted solar projects expected to enter service through 2016. Our wind business in 2011 generated nearly 25 million megawatt-hours of electricity, which is comparable to the retail output of such utilities as OGE Energy, Alliant Energy or Great Plains Energy.

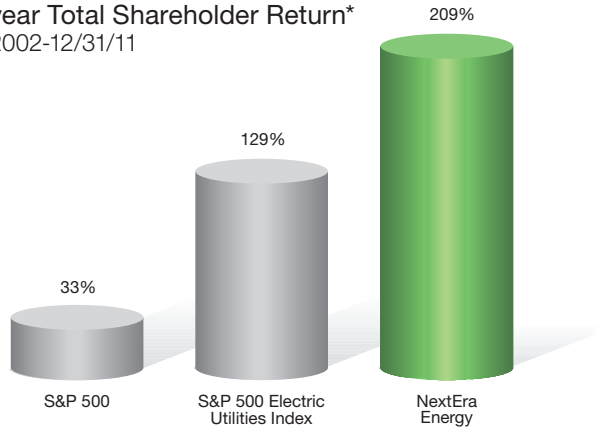
We believe that NextEra Energy is well positioned to continue to deliver outstanding value to our shareholders over the long term. For the 10 years ended Dec. 31, 2011, our adjusted earnings per share grew at a compound annual rate of 6.3 percent,[3] compared to the 2.2 percent compound annual growth rate of the S&P 500 Electric Utilities Index. Our dividends per share also grew at a

NextEra Energy
Dividends Per Share



* Projected based upon dividend of $0.60 declared on Feb. 17, 2012, for payment on March 15, 2012; dividend declarations are subject to the discretion of the Board of Directors of NextEra Energy.

10-year Total Shareholder Return*
1/1/2002-12/31/11



* With dividend reinvestment

Source: Bloomberg

[1] See inside front cover for reconciliations of adjusted amounts to GAAP.
[2] See page AR-6 for reconciliations of Adjusted Return on Equity (ROE) to GAAP ROE.
[3] See page AR-6 for reconciliations of adjusted amounts to GAAP.

compound annual rate of 7 percent for the 10 years ended Dec. 31, 2011, compared to a 4.9 percent rate for the S&P 500 Electric Utilities Index. Over the 10 years ended Dec. 31, 2011, our total shareholder return was 209 percent, compared to 129 percent for the S&P 500 Electric Utilities Index and 33 percent for the S&P 500 Index. In February 2012, we announced an increase in our quarterly dividend to 60 cents per share, which is consistent with the current expectation of the Board of Directors to target a payout ratio, expressed relative to adjusted earnings, of about 55 percent in 2014. We remain focused on building long-term value for our shareholders by investing in energy technologies that are designed to provide affordable and reliable power for our customers for years to come.

Florida Power & Light Company

For the full year 2011, FPL reported net income of $1.07 billion, or $2.55 per share, compared with $945 million, or $2.29 per share, in 2010. The main drivers of this earnings growth were our investments in clean and efficient power generation. These investments provide significant benefits for our customers, who have electric bills that are the lowest in Florida and 25 percent lower than the national average. Our customers enjoy reliability that ranks as the best in the state among investor-owned utilities as well as award-winning customer service. FPL customers also benefit from an emissions profile that is among the best in the industry.

During 2011, FPL deployed more than $3 billion in capital on projects providing significant customer benefits. In addition to Cape Canaveral, other major capital investments also moved forward last year. Unit 3 at our West County Energy Center in Palm Beach County came into service on time and under budget. Local officials and residents from Riviera Beach, also in Palm Beach County, enjoyed witnessing firsthand the demolition of the old Riviera plant, paving the way for another modernization. We began to pursue a third modernization project, Port Everglades in Broward County, which is also expected to save customers hundreds of millions of dollars over and above the cost of the plant.

Operationally, FPL's fossil fuel fleet set a new record for its fuel efficiency in 2011, bringing its systemwide heat rate – a key measure of power plant efficiency – down to 7,803 British thermal units (BTU) per kilowatt-hour. The average fossil heat rate for the electric utility industry was 10,045 BTUs per kilowatt-hour for 2010, the most recent year for which data is available. Since 2001, FPL's fossil heat rate has improved by 19 percent, and greater fuel efficiency has saved our customers more than $5.5 billion in fuel costs, including more than $650 million in 2011 alone. As fuel costs for our customers have averaged nearly $5 billion per year over the five years ended in 2011, FPL's fuel efficiency since 2001 has saved our customers the equivalent of approximately one year's supply of fuel.

FPL also had a very good year in keeping operations and maintenance (O&M) costs low, and reliability high. FPL's O&M expenses for all of 2011 were 1.64 cents per retail kilowatt-hour sales, compared with the latest available industry average of 2.28 cents per retail kilowatt-hour sales. FPL's service reliability, as measured by the System Average Interruption Duration Index (SAIDI), was the best among Florida investor-owned utilities during the five years ended in 2011.

We are proud of the affordable and reliable electric power FPL delivered to our 4.6 million customers in 2011, and we believe our investments will continue to benefit our customers going forward. Through 2013, we expect to invest an average of approximately $3 billion per year in generation and infrastructure projects that benefit our customers, including new, clean, efficient power generation.

In part to help pay for these investments and to maintain our superior performance for customers, FPL has filed with the Florida Public Service Commission a request for an increase, currently estimated at $6.97 per month, or about 23 cents per day, on the base portion of a typical residential bill beginning in 2013. We know there is never a good time to ask for a rate increase. Yet because of projected fuel savings resulting from investments in more efficient power generation, as well as lower fuel prices and

other adjustments, the net increase that a typical residential customer would pay is currently estimated at less than $2.50 per month, or about 8 cents per day. So even with the increase, we expect to continue to deliver the lowest typical residential bill in Florida.

NextEra Energy Resources

NextEra Energy Resources reported 2011 net income on a GAAP basis of $774 million, or $1.85 per share, compared with $980 million, or $2.37 per share, in 2010. On an adjusted basis, NextEra Energy Resources' 2011 earnings were $679 million, or $1.62 per share, compared with $800 million, or $1.93 per share, for the full year 2010.[4]

These results did not meet the expectations we set out for ourselves at the beginning of the year, for several reasons. We were overly optimistic about the market environment for our proprietary trading activities, and so we have reduced our expectations for these activities to reflect softer market conditions. We had unplanned and extended outages at our Seabrook nuclear facility, which led to less availability than we had anticipated. We were negatively impacted by the extreme heat in Texas in August, and since then we have made a number of operational changes to improve our responsiveness and resilience should such extreme conditions recur.

Finally, we had hoped to get a few more megawatts of new renewable projects in the ground by the end of 2011. Instead, two projects were pushed into the first quarter of this year. The long-term financial impact on these projects will be minimal, as the projects are still expected to qualify for relevant tax incentives.

Strong enterprises succeed despite their challenges, and that is what NextEra Energy Resources did in 2011. Our non-nuclear generating facilities performed exceptionally well, with one of our lowest forced-outage rates on record. We had a banner year for development of new renewable energy projects, which created the largest backlog of new renewable energy projects in our history. We believe we are positioned well to grow in the years ahead, and to extend our leadership as the largest generator in the United States of renewable energy from the wind and the sun.

We entered into long-term contracts for more than 1,600 MW of wind generation during 2011, with expected in-service dates through 2014. We added approximately 380 MW of wind generation during the year, and we remain on track to add approximately 1,400 to 2,000 MW of new wind assets to our portfolio during the two years ending on Dec. 31, 2012.

On the solar front, our company's backlog of 940 MW of contracted solar projects includes our 50 percent portion of the recently announced Desert Sunlight project and 100 percent of the recently announced McCoy photovoltaic project, both in California. Including all of the planned solar projects that are already under long-term contract, NextEra Energy Resources plans to invest between $2.1 billion and $2.3 billion from 2011 through 2012, and between $1.3 billion and $1.5 billion in 2013 and 2014 in solar development projects. The backlog of contracted solar opportunities is expected to begin contributing meaningfully to cash flow and earnings in 2013.

In 2012, NextEra Energy is urging policymakers to extend policy support for renewable energy, including through extension of the federal Production Tax Credit (PTC) for wind energy. This incentive is a good deal for U.S. taxpayers, as it has encouraged tens of billions of dollars of private investment in high-tech American manufacturing. Indeed, investment in new wind projects that would follow an extension of the PTC is projected to generate tax revenues for federal, state and local governments that are larger than the cost of the extension itself. Over the past three years, investment in wind technology has decreased the cost of wind energy by nearly one-third and increased its efficiency by more than 20 percent. We believe the PTC has proven its value, and we are hoping that the past bipartisan consensus to support it will re-emerge.

Recognition of Excellence

As NextEra Energy's leadership position in the electric power industry has grown, so has our reputation. In 2011,

[4] See page AR-6 for reconciliations of adjusted amounts to GAAP.

we were named to the prestigious Dow Jones Sustainability Index for the third year in a row. In 2012, we were named No. 1 in our sector on *Fortune* magazine's "World's Most Admired Companies" list for the sixth year in a row.

At FPL, we continued to deliver award-winning customer service. For an industry-record eighth consecutive year, FPL earned the ServiceOne Award for exceptional customer service, which is presented annually by PA Consulting Group. The worldwide consulting firm also honored FPL with ServiceOne Balanced Scorecard Achievement Awards for our customer care, billing, meter reading and field meters departments. FPL was also one of three utilities honored for Outstanding Customer Service by the 25 national chain customers that comprise the Customer Advisory Group of the Edison Electric Institute.

A Legacy of Leadership

We expect 2012 to be a year of new opportunities for NextEra Energy, but it is also a year for showing gratitude to a highly respected leader in the utility industry. After 40 years of dedicated and successful service to our company, FPL Chief Executive Officer Armando Olivera has announced that he will retire in May. He has led FPL with extraordinary success since June 2003 and leaves the business one of the strongest and best-performing utilities anywhere in the nation. In addition to managing the business, Armando has always focused on developing the next generation of leaders. We are confident that Eric Silagy, who was named President of FPL in December and who has worked closely with Armando for the last four years, will continue the culture of excellence Armando has developed. We thank Armando for his service, we congratulate him on his remarkable record, and we all wish him well.

We also thank J. Hyatt Brown, who is retiring from the NextEra Energy Board of Directors after more than 23 years of dedicated service. Hyatt has given wise counsel and steady leadership throughout his tenure, including his service as Lead Director in 2010-2011 and as the current chair of the Board's Governance & Nominating Committee.

Finally, 2012 will be a year of transition as I have announced my intention to retire at the end of 2013 as part of a planned leadership succession process. Jim Robo, currently our President and Chief Operating Officer, will succeed me as Chief Executive Officer effective July 1, 2012, and I will serve as Executive Chairman, a full-time role, from July 1 until my retirement.

I've been extremely blessed and privileged to have had the opportunity to lead NextEra Energy over the past 11 years. I have a deep passion for our company and enormous love and respect for our people. I'm extremely proud of what our team has accomplished during my tenure.

Jim Robo has been an invaluable partner and was instrumental in developing and executing on NextEra Energy's clean energy growth strategy over the past decade. He is an insightful strategist, experienced operator and proven developer of talent. Jim is fully qualified and clearly ready for his new role leading our company.

With that in mind, this is the perfect time for our company to start this transition. NextEra Energy is in great shape, both financially and operationally, and we have a great team and an outstanding successor in place who will undoubtedly take this company to even higher levels of performance.

We thank you for your continued support and interest in NextEra Energy.

Lewis Hay, III

Lewis Hay, III
Chairman and Chief Executive Officer
March 22, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2011**

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices and registrants' telephone number	IRS Employer Identification Number
1-8841	**NEXTERA ENERGY, INC.**	59-2449419
2-27612	**FLORIDA POWER & LIGHT COMPANY**	59-0247775

700 Universe Boulevard
Juno Beach, Florida 33408
(561) 694-4000

State or other jurisdiction of incorporation or organization: Florida

	Name of exchange on which registered
Securities registered pursuant to Section 12(b) of the Act:	
NextEra Energy, Inc.: Common Stock, $0.01 Par Value	New York Stock Exchange
Florida Power & Light Company: None	

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act of 1933.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

NextEra Energy, Inc. Yes ☐ No ☑ Florida Power & Light Company Yes ☐ No ☑

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrants are a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Securities Exchange Act of 1934.

NextEra Energy, Inc.	Large Accelerated Filer ☑	Accelerated Filer ☐	Non-Accelerated Filer ☐	Smaller Reporting Company ☐
Florida Power & Light Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-Accelerated Filer ☑	Smaller Reporting Company ☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity of NextEra Energy, Inc. held by non-affiliates as of June 30, 2011 (based on the closing market price on the Composite Tape on June 30, 2011) was $24,179,141,166.

There was no voting or non-voting common equity of Florida Power & Light Company held by non-affiliates as of June 30, 2011.

The number of shares outstanding of NextEra Energy, Inc. common stock, as of the latest practicable date: Common Stock, $0.01 par value, outstanding as of January 31, 2012: 416,208,761 shares.

As of January 31, 2012, there were issued and outstanding 1,000 shares of Florida Power & Light Company common stock, without par value, all of which were held, beneficially and of record, by NextEra Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of NextEra Energy, Inc.'s Proxy Statement for the 2012 Annual Meeting of Shareholders are incorporated by reference in Part III hereof.

This combined Form 10-K represents separate filings by NextEra Energy, Inc. and Florida Power & Light Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Florida Power & Light Company makes no representations as to the information relating to NextEra Energy, Inc.'s other operations.

Florida Power & Light Company meets the conditions set forth in General Instruction I.(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

DEFINITIONS

Acronyms and defined terms used in the text include the following:

Term	Meaning
AFUDC	allowance for funds used during construction
AFUDC - debt	debt component of allowance for funds used during construction
AFUDC - equity	equity component of allowance for funds used during construction
AOCI	accumulated other comprehensive income
capacity clause	capacity cost recovery clause, as established by the FPSC
CFTC	U.S. Commodity Futures Trading Commission
CO_2	carbon dioxide
DOE	U.S. Department of Energy
Duane Arnold	Duane Arnold Energy Center
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
FPL FiberNet	Fiber-optic telecommunications business
FPSC	Florida Public Service Commission
fuel clause	fuel and purchased power cost recovery clause, as established by the FPSC
GAAP	generally accepted accounting principles in the U.S.
GHG	greenhouse gas(es)
ISO	independent system operator
ITCs	investment tax credits
kw	kilowatt
kwh	kilowatt-hour(s)
Lone Star	Lone Star Transmission, LLC
Management's Discussion	Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
mortgage	mortgage and deed of trust dated as of January 1, 1944, from FPL to Deutsche Bank Trust Company Americas, as supplemented and amended
mw	megawatt(s)
mwh	megawatt-hour(s)
NEE	NextEra Energy, Inc.
NEECH	NextEra Energy Capital Holdings, Inc.
NEER	NextEra Energy Resources, LLC
NERC	North American Electric Reliability Corporation
Note __	Note __ to consolidated financial statements
NOx	nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
O&M expenses	other operations and maintenance expenses in the consolidated statements of income
OCI	other comprehensive income
OTC	over-the-counter
OTTI	other than temporary impairment
PJM	PJM Interconnection, L.L.C.
PMI	NextEra Energy Power Marketing, LLC
Point Beach	Point Beach Nuclear Power Plant
PTCs	production tax credits
PUCT	Public Utility Commission of Texas
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
PV	photovoltaic
RFP	request for proposal
ROE	return on common equity
regulatory ROE	return on common equity as determined for regulatory purposes
RPS	renewable portfolio standards
RTO	regional transmission organization
Seabrook	Seabrook Station
SEC	U.S. Securities and Exchange Commission
SO_2	sulfur dioxide
U.S.	United States of America
WCEC	FPL's West County Energy Center in western Palm Beach County, Florida

NEE, FPL, NEECH and NEER each has subsidiaries and affiliates with names that may include NextEra Energy, FPL, NextEra Energy Resources, FPL Group Capital, FPL Energy, FPLE and similar references. For convenience and simplicity, in this report the terms NEE, FPL, NEECH and NEER are sometimes used as abbreviated references to specific subsidiaries, affiliates or groups of subsidiaries or affiliates. The precise meaning depends on the context.

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FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, strategies, future events or performance (often, but not always, through the use of words or phrases such as will, will likely result, are expected to, will continue, is anticipated, aim, believe, could, should, would, estimated, may, plan, potential, future, projection, goals, target, outlook, predict and intend or words of similar meaning) are not statements of historical facts and may be forward-looking. Forward-looking statements involve estimates, assumptions and uncertainties. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, important factors included in Part I, Item 1A. Risk Factors (in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements) that could have a significant impact on NEE's and/or FPL's operations and financial results, and could cause NEE's and/or FPL's actual results to differ materially from those contained or implied in forward-looking statements made by or on behalf of NEE and/or FPL in this combined Form 10-K, in presentations, on their respective websites, in response to questions or otherwise.

Any forward-looking statement speaks only as of the date on which such statement is made, and NEE and FPL undertake no obligation to update any forward-looking statement to reflect events or circumstances, including, but not limited to, unanticipated events, after the date on which such statement is made, unless otherwise required by law. New factors emerge from time to time and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained or implied in any forward-looking statement.

PART I

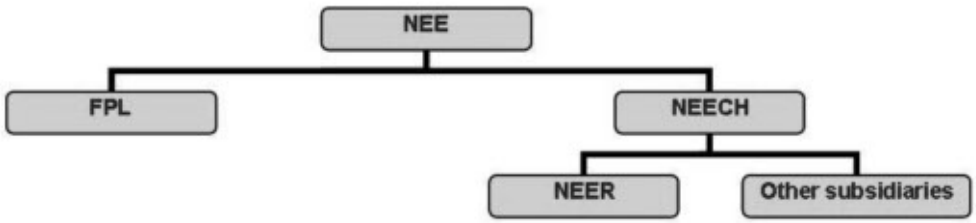
Item 1. Business

OVERVIEW

NextEra Energy, Inc. (hereafter, NEE) is one of the largest electric power companies in North America, with over 41,000 mw of generating capacity in 24 states in the U.S. and 3 provinces in Canada, and employing approximately 14,800 people as of December 31, 2011. NEE provides retail and wholesale electric services to more than 4 million customers and owns generation, transmission and distribution facilities to support its services. It also purchases electric power for resale to its customers and provides risk management services related to power and gas consumption for a limited number of customers. NEE is the largest generator in the U.S. of renewable energy from the wind and sun and owned approximately 18% of the installed base of U.S. wind power production capacity as of December 31, 2011. NEE also produces electricity from solar facilities, and owns and operates one of the largest fleets of nuclear power stations in the U.S., with eight reactors at five sites located in four states, representing approximately 6% of U.S. nuclear power electric generating capacity as of December 31, 2011. NEE's business strategy has emphasized the development, acquisition and operation of renewables, nuclear and natural gas-fired generation facilities in response to long-term federal policy trends supportive of zero and low air emissions sources of power. NEE's generation fleet has significantly lower rates of emissions of CO_2, SO_2 and NOx than the average rates of the U.S. electric power industry with approximately 93% of its 2011 generation, measured by mwh produced, coming from renewables, nuclear and natural gas-fired facilities. Certain environmental attributes of NEE's electric generating facilities, such as renewable energy credits, emissions reductions, offsets, allowances and the avoided emission of GHG pollutants, have been or likely will be sold or transferred to third parties, who are solely entitled to the reporting rights and ownership of the environmental attributes.

NEE was incorporated in 1984 under the laws of Florida and conducts its operations principally through two wholly-owned subsidiaries, Florida Power & Light Company (hereafter, FPL) and NextEra Energy Resources, LLC (hereafter, NEER). NextEra Energy Capital Holdings, Inc. (hereafter, NEECH), another wholly-owned subsidiary of NEE, owns and provides funding for NEER's and NEE's other operating subsidiaries, other than FPL and its subsidiaries. NEE's two principal businesses also constitute NEE's reportable segments for financial reporting purposes, as illustrated below:

NEE Organizational Chart



FPL is a rate-regulated electric utility engaged primarily in the generation, transmission, distribution and sale of electric energy in Florida. FPL is the largest electric utility in the state of Florida and one of the largest electric utilities in the U.S. based on generation. FPL is vertically integrated, with approximately 24,500 mw of generating capacity as of December 31, 2011. FPL's investments in its infrastructure since 2001, such as modernizing less efficient generating plants and upgrading its transmission and distribution systems, have allowed FPL to produce more energy with less fuel and fewer air emissions, and deliver service reliability that was among the best of the Florida investor-owned utilities, all while providing residential and commercial bills that were among the lowest in Florida and below the national average based on a rate per kwh as of July 2011. With 85% of its power generation coming from natural gas, nuclear and solar, FPL is also one of the cleanest electric utilities in the nation. Based on 2011 information, FPL's emissions rates for CO_2, SO_2 and NOx were 36%, 84% and 72% lower, respectively, than the average rates of the U.S. electric power industry.

NEER is one of the largest wholesale generators of electric power in the U.S., with approximately 16,600 mw of generating capacity across 22 states and 3 Canadian provinces as of December 31, 2011. NEER produces the majority of its electricity from clean and renewable sources, including wind, solar and hydro. NEER also provides full energy and capacity requirements services, owns a retail electricity provider serving customers in 13 states and the District of Columbia and engages in power and gas marketing and trading activities.

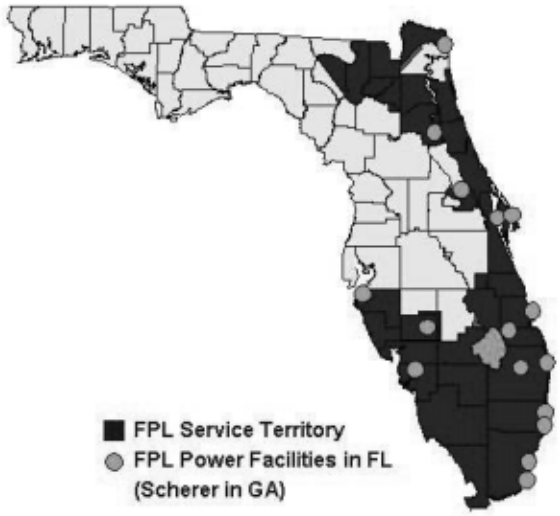
NEECH's other business activities are primarily conducted through FPL FiberNet and Lone Star. FPL FiberNet delivers wholesale and enterprise telecommunications services in Florida and certain areas of the South Central U.S. Lone Star, a rate-regulated transmission service provider in Texas, is constructing transmission lines and other associated facilities in Texas.

NEE seeks to create value in its two principal businesses by meeting its customers' needs more economically and more reliably than its competitors, as described in more detail in the following sections. NEE's strategy has resulted in profitable growth over sustained periods at both FPL and NEER. Management seeks to grow each business in a manner consistent with the varying opportunities open to it and does not maintain any specific goal as to the relative size of the two businesses. However, management believes that the diversification and balance represented by FPL and NEER is a valuable characteristic of the enterprise.

NEE'S OPERATING SUBSIDIARIES

I. FPL

FPL was incorporated under the laws of Florida in 1925, and is a wholly-owned subsidiary of NEE. FPL is a rate-regulated electric utility and is the largest electric utility in the state of Florida and one of the largest electric utilities in the U.S based on generation. FPL, with 24,460 mw of generating capacity at December 31, 2011, supplies electric service throughout most of the east and lower west coasts of Florida, serving nearly 8.9 million people through approximately 4.6 million customer accounts. At December 31, 2011, FPL's service territory and plant locations are as follows (see Item 2 - Generating Facilities):



FRANCHISE AGREEMENTS AND COMPETITION

FPL's service to its retail customers is provided primarily under franchise agreements negotiated with municipalities or counties. Municipalities and counties may form their own utility companies to provide service to their residents. In a few cases, the franchise agreement provides the municipality or county the right to buy the distribution assets serving local residents at the end of the agreement. However, during the term of a franchise agreement, which is typically 30-years, the municipality or county agrees not to form its own utility, and FPL has the right to offer electric service to residents. FPL currently holds 178 franchise agreements with various municipalities and counties in Florida with varying expiration dates through 2042. Four of these franchise agreements expire in 2013 and 174 expire during the period 2014 through 2042. These franchise agreements cover approximately 83% of FPL's retail customer base in Florida. Negotiations are ongoing to renew the franchise agreements that expire in 2013. FPL considers its franchises to be adequate for the conduct of its business. FPL also provides service to 11 other municipalities and to 22 unincorporated areas within its service area without franchise agreements pursuant to the general obligation to serve as a public utility, relying upon Florida law for access to public rights of way.

Because any retail customer may elect to provide his/her own services, FPL effectively must compete for an individual customer's business. As a practical matter, few customers provide their own service at the present time since FPL's cost of service is generally substantially lower than the cost of self-generation for the vast majority of customers. Changing technology and economic conditions could alter the favorable relative cost position that FPL currently enjoys; however, FPL seeks as a matter of strategy to ensure that it delivers superior value, in the form of high reliability, low bills and excellent customer service.

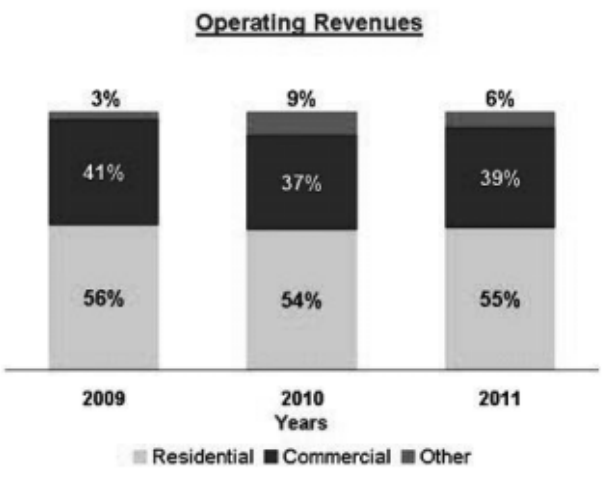
FPL also faces competition from other suppliers of electrical energy to wholesale customers and from alternative energy sources and self-generation for other customer groups, primarily industrial customers. In 2011, 2010 and 2009, operating revenues from wholesale and industrial customers combined represented approximately 3%, 3% and 4%, respectively, of FPL's total operating revenues.

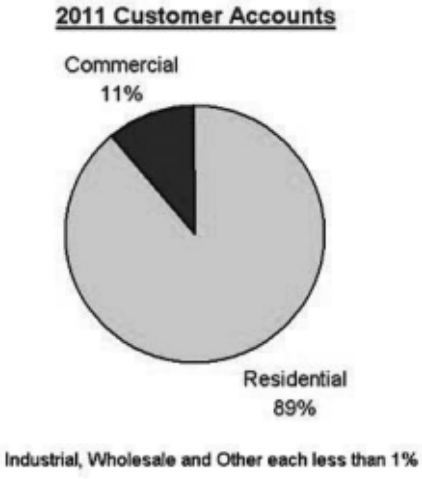
The FPSC promotes cost competitiveness in the building of new steam generating capacity by requiring investor-owned electric utilities, including FPL, to issue a request for proposal (RFP) except when the FPSC determines that an exception from the RFP process is in the public interest. The RFP process allows independent power producers and others to bid to supply the new generating capacity. If a bidder has the most cost-effective alternative, meets other criteria such as financial viability and

demonstrates adequate expertise and experience in building and/or operating generating capacity of the type proposed, the investor-owned electric utility would seek to negotiate a purchased power agreement with the selected bidder and request that the FPSC approve the terms of the purchased power agreement and, if appropriate, provide the required authorization for the construction of the bidder's generating capacity. New nuclear power plants are exempt from the RFP requirement. See FPL Sources of Generation - Nuclear Operations below regarding FPL's planned two additional nuclear units at Turkey Point.

CUSTOMERS AND REVENUE

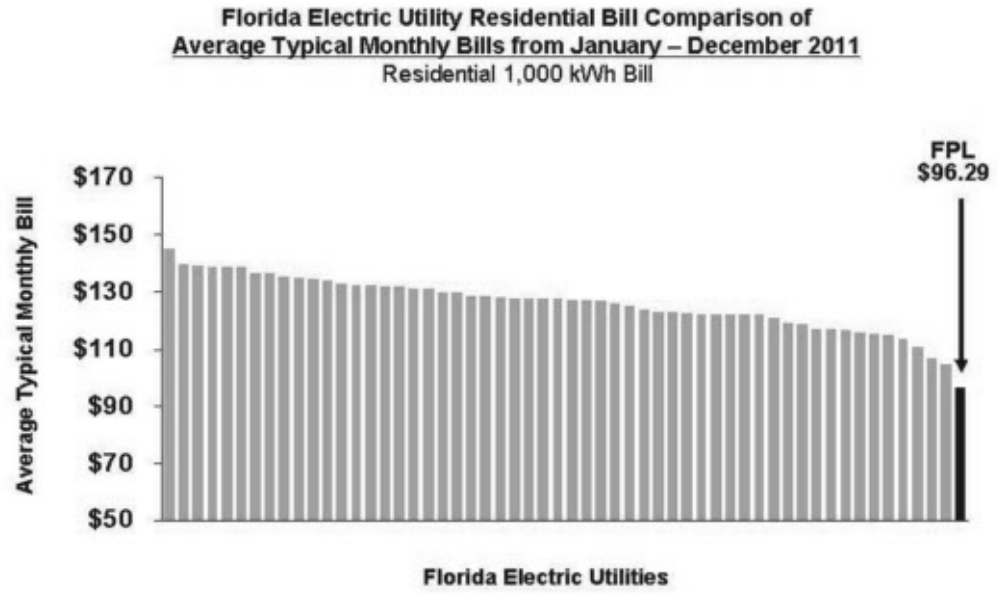
FPL's primary source of operating revenues is from its retail customer base; it also serves a limited number of wholesale customers within Florida. The percentage of FPL's operating revenues and customer accounts by customer class were as follows:





For both retail and wholesale customers, the prices (or rates) that FPL may charge are controlled by regulation, by the FPSC in the case of retail customers, and by the FERC in the case of wholesale customers. In general, under U.S. and Florida law, regulated rates are intended to cover the cost of providing service, including an appropriate rate of return on capital employed. However, the regulatory bodies have authority to determine the relevant cost of providing service and the appropriate rate of return on capital employed and there can be no guarantee that FPL will be able to earn any particular rate of return or recover all or any portion of its costs through regulated rates. See discussion of regulation at FPL Regulation - FPL Rate Regulation below.

As noted above, FPL seeks to maintain attractive rates for its customers. A common benchmark used in the electric power industry for comparing rates across companies is the cost per 1,000 kwh of consumption per month for a residential customer. FPL's 2011 average cost per 1,000 kwh of monthly residential usage was the lowest of the 55 electric utilities within Florida as indicated below:



TRANSMISSION AND DISTRIBUTION

FPL provides service to its customers through an integrated transmission and distribution system that links all its generation facilities to all its customers. FPL also maintains interconnection facilities with neighboring utilities and wholesale power providers, enabling it to buy and sell wholesale electricity outside its service territory and to enhance the reliability of its own network and support the reliability of neighboring networks. FPL's transmission system carries high voltage electricity from its generating facilities to substations where the electricity is stepped down to lower voltage levels and is sent through the distribution system to its customers.

A key element of FPL's strategy is to provide highly reliable service to its customers. The transmission and distribution system is susceptible to interruptions or outages from a wide variety of sources including weather, animal interference, traffic accidents, equipment failure and many others, and FPL seeks to reduce or eliminate outages where economically practical and to restore service rapidly in the event of an outage. A common benchmark for transmission and distribution system reliability is the system average interruption duration index (SAIDI), which represents the number of minutes the average customer is without power during a time period. During the five years ended 2010, FPL had the best average SAIDI of the Florida investor-owned utilities.

FPL SYSTEM CAPABILITY AND LOAD

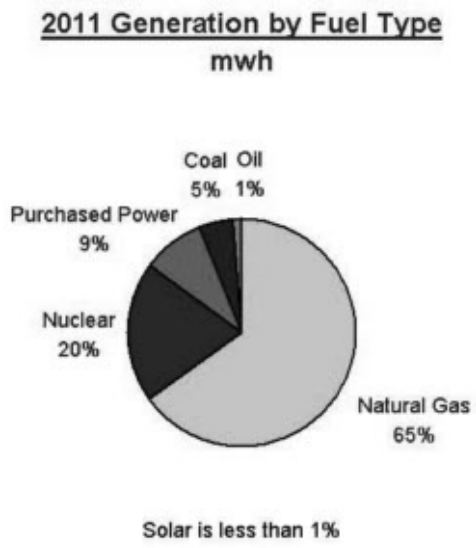
At December 31, 2011, FPL's resources for serving load consisted of 26,538 mw, of which 24,460 mw were from FPL-owned facilities (see Item 2 - Generating Facilities) and 2,078 mw were available through purchased power agreements (see FPL Sources of Generation - Purchased Power below). Occasionally, unusually cold temperatures during the winter months result in significant increases in electricity usage for short periods of time. However, customer usage and operating revenues are typically higher during the summer months, largely due to the prevalent use of air conditioning in FPL's service territory. The highest peak load FPL has served to date was 24,346 mw, which occurred on January 11, 2010. FPL had adequate resources available at the time of this peak to meet customer demand.

FPL's projected reserve margin for the summer of 2012 is approximately 28%. This reserve margin is expected to be achieved through the combination of available output from FPL's active generating units, purchased power agreements and the capability to reduce peak demand through the implementation of demand side management programs, including load management which was estimated at December 31, 2011 to be capable of reducing demand by 1,817 mw, and energy efficiency and conservation programs. See FPL Sources of Generation - Fossil Operations and Nuclear Operations below regarding generation projects currently under construction.

FPL SOURCES OF GENERATION

FPL relies upon a diverse mix of fuel sources for its generating facilities, along with purchased power, in order to maintain the flexibility to achieve a more economical fuel mix by responding to market and industry developments. See descriptions of fossil, nuclear and solar operations below and a listing of FPL's generating facilities in Item 2 - Generating Facilities.

FPL's 2011 fuel mix based on mwh produced, including purchased power, was as follows:



Fossil Operations (Natural Gas, Coal and Oil)

At December 31, 2011, FPL owned and operated 78 units that used fossil fuels such as natural gas and/or oil, and had a joint ownership interest in three coal units, which combined provided 21,455 mw of generating capacity for FPL. These fossil units are out of service from time to time for routine maintenance or on standby during periods of reduced electricity demand.

FPL's natural gas plants require natural gas transportation, supply and storage. FPL has firm transportation contracts in place with four different transportation suppliers with expiration dates ranging from 2015 to 2036 that together are expected to satisfy substantially all of the anticipated needs for natural gas transportation at existing units. To the extent desirable, FPL also purchases interruptible natural gas transportation service from these natural gas suppliers based on pipeline availability. FPL has several short- and medium-term natural gas supply contracts to provide a portion of FPL's anticipated needs for natural gas. The remainder of FPL's natural gas requirements is purchased in the spot market. FPL has an agreement for the storage of natural gas that expires in 2013. See Note 14 - Contracts. With respect to its oil plants, FPL obtains its fuel requirements in the spot market.

St. Johns River Power Park (SJRPP) Units Nos. 1 and 2, in which FPL has a joint ownership interest, has a coal supply and transportation contract for all of the 2012 fuel needs and a portion of the 2013 and 2014 fuel needs for those units. All of the transportation requirements and a portion of the coal supply needs for Scherer Unit No. 4, the other coal unit in which FPL has a joint ownership interest, are covered by a series of annual and long-term contracts. The remaining fuel requirements for these units will be obtained in the spot market. See Note 14 - Contracts.

Modernization Projects. FPL is in the process of modernizing its Cape Canaveral and Riviera Beach power plants to high-efficiency natural gas-fired units and expects the units to be placed in service by June 2013 and by 2014, respectively. Each modernized plant is expected to provide approximately 1,200 mw of capacity. In November 2011, FPL filed a need petition with the FPSC to modernize its Port Everglades power plant to a high-efficiency natural gas-fired unit. The modernized Port Everglades unit is expected to provide approximately 1,280 mw of capacity, be in service in 2016 and cost approximately $1.2 billion. The modernization of the Port Everglades plant is contingent upon, among other things, FPSC approval. An FPSC decision regarding the modernization of the Port Everglades plant is expected in late March 2012.

Nuclear Operations

At December 31, 2011, FPL owned, or had undivided interests in, and operated the following four nuclear units with a total net generating capacity of 2,970 mw.

Facility	mw	Operating License Expiration Dates
St. Lucie Unit No. 1	839	2036
St. Lucie Unit No. 2	745	2043
Turkey Point Unit No. 3	693	2032
Turkey Point Unit No. 4	693	2033

FPL has several contracts for the supply of uranium and the conversion, enrichment and fabrication of nuclear fuel with expiration dates ranging from March 2012 through 2022. See Note 14 - Contracts. NRC regulations require FPL to submit a plan for decontamination and decommissioning five years before the projected end of plant operation. FPL's current plans, under the applicable operating licenses, provide for prompt dismantlement of Turkey Point Units Nos. 3 and 4 with decommissioning activities commencing in 2032 and 2033, respectively. Current plans provide for St. Lucie Unit No. 1 to be mothballed beginning in 2036 with decommissioning activities to be integrated with the prompt dismantlement of St. Lucie Unit No. 2 commencing in 2043. See Management's Discussion - Critical Accounting Policies and Estimates - Nuclear Decommissioning and Fossil/Solar Dismantlement.

Projects to Add Additional Capacity. FPL is in the process of adding approximately 450 mw to 490 mw of capacity at its existing nuclear units at St. Lucie and Turkey Point, which is expected to result in significant fuel cost savings compared to other sources of generation over the lives of the units. The additional capacity is projected to be placed in service by 2013; approximately 31 mw were placed in service in May 2011 at St. Lucie Unit No. 2. As part of the conditions of certification by the FDEP for the Turkey Point project, FPL was required to implement a monitoring plan in and around the Turkey Point cooling canals due to concerns over potential saltwater intrusion beyond FPL's property. Monitoring under the plan includes collection of data prior to and after the additional capacity is placed in service. Data for the first year has been collected and provided to the FDEP. The ultimate results of the monitoring plan are uncertain, and the financial and operational impacts on FPL, if any, cannot be determined at this time. In 2008, the FPSC approved FPL's need petition for two additional nuclear units at its Turkey Point site. The two units combined are expected to add approximately 2,200 mw of capacity and have projected in-service dates between 2022 and 2023. Additional approvals from other regulatory agencies will be required later in the development process.

Nuclear Unit Scheduled Refueling Outages. FPL's nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, including inspections, repairs and certain other modifications. Scheduled nuclear refueling outages typically require the unit to be removed from service for variable lengths of time. The scheduled nuclear refueling outages

for 2012 are all expanded scope outages related to the addition of capacity at the existing nuclear units which are expected to require the unit to be removed from service for between 110 and 160 days. The following table summarizes each unit's current or next scheduled refueling outage:

Facility	Beginning of Current or Next Scheduled Refueling Outage
St. Lucie Unit No. 1	November 2011
St. Lucie Unit No. 2	August 2012
Turkey Point Unit No. 3	February 2012
Turkey Point Unit No. 4	November 2012

Disposition of Spent Nuclear Fuel. FPL's nuclear facilities use both on-site storage pools and dry storage casks to store spent nuclear fuel generated by these facilities, which are expected to allow FPL to store spent nuclear fuel at these facilities through license expiration.

Under the Nuclear Waste Policy Act of 1982, as amended (Nuclear Waste Policy Act), the DOE is responsible for the development of a repository for the disposal of spent nuclear fuel and high-level radioactive waste. As required by the Nuclear Waste Policy Act, FPL is a party to contracts with the DOE to provide for disposal of spent nuclear fuel from its nuclear units.

The DOE was required to construct permanent disposal facilities and take title to and provide transportation and disposal for spent nuclear fuel by January 31, 1998 for a specified fee based on current generation from nuclear power plants. The DOE did not meet its statutory obligation for disposal of spent nuclear fuel under the Nuclear Waste Policy Act. In 2009, FPL and certain nuclear plant joint owners entered into a settlement agreement (spent fuel settlement agreement) with the U.S. government agreeing to dismiss with prejudice lawsuits filed against the U.S. government seeking damages caused by the DOE's failure to dispose of spent nuclear fuel from FPL's nuclear plants. The spent fuel settlement agreement permits FPL to make annual filings to recover certain spent fuel storage costs incurred by FPL which are payable by the U.S. government on an annual basis. In a separate lawsuit filed in 2011, FPL joined the Nuclear Energy Institute and several other nuclear plant owners and operators in petitioning the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) to challenge the DOE's decision to continue to collect the nuclear waste fee, which petition is pending. FPL will continue to pay fees to the U.S. government's nuclear waste fund pending the D.C. Circuit's decision on the fee suspension petition.

In March 2010, the DOE filed a motion with the NRC to withdraw its license application for a nuclear waste repository at Yucca Mountain. The DOE's withdrawal motion has been challenged and is being litigated before the NRC and the D.C. Circuit. In light of the Obama Administration's decision not to proceed with the Yucca Mountain repository project, the DOE established a Blue Ribbon Commission on America's Nuclear Future (BRC) to conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle and to provide recommendations for developing a safe, long-term solution to managing spent nuclear fuel and high-level radioactive waste. In January 2012, the BRC issued its report and recommendations which include a consent-based approach, working with all affected units of government, to siting future nuclear waste management facilities, creation of a new organization, independent of the DOE, dedicated solely to assuring the safe storage and ultimate disposal of spent nuclear fuel and high-level radioactive waste, providing access to the U.S. government's nuclear waste fund for the purpose of nuclear waste storage and disposal and initiating prompt efforts to develop geologic disposal facilities, consolidated interim storage facilities and transportation to those facilities. The BRC's recommendations are not expected to result in any immediate change to the nuclear waste management and disposal situation.

Recent Nuclear Developments. As a result of the impact of the March 2011 earthquake and tsunami on nuclear facilities in Japan, the NRC established a task force to conduct a comprehensive review of processes and regulations relating to nuclear facilities in the U.S. to determine whether the NRC should make additional improvements to its regulatory system and to make recommendations to the NRC for its policy direction. In July 2011, the NRC task force released its recommendations to the NRC and, since then, the NRC staff presented certain conclusions based on their review of the task force recommendations, which conclusions have been approved by the NRC. The NRC staff's report concluded that none of the findings addressed by the task force recommendations rise to the level of an imminent hazard to public health and safety. However, since the recommendations can contribute to safety improvements, the NRC staff proposed the following actions: 1) issue orders within approximately six months to require each nuclear site to purchase portable equipment and revise procedures to address multi-unit events, provide reliable spent fuel pool instrumentation and enhance containment venting capabilities for boiling water reactors (FPL's nuclear units do not use boiling water reactors); 2) request each site to re-evaluate its seismic and flood protection designs in light of current requirements and identify any areas for improvement; and 3) issue new regulations requiring enhancements relating to extended periods of loss of alternating current power, emergency preparedness and spent fuel pool cooling capabilities. The NRC is reviewing the timeline for implementation of all of the actions, but has indicated that all actions should be completed by the end of 2016. FPL is currently reviewing the NRC's directions relating to the NRC staff's recommendations and assessing the potential financial and operational impacts on its nuclear units.

The lessons learned from the events in Japan and the results of the NRC's review of the NRC staff's recommendations may, among other things, result in changes in or new licensing and safety-related requirements for U.S. nuclear facilities. Changes in or new requirements could, among other things, impact the capacity additions (uprates) at FPL's existing nuclear units at St. Lucie and

Turkey Point, and future licensing and operations of U.S. nuclear facilities, including FPL's existing nuclear facilities and the NRC approval of two additional nuclear units at FPL's Turkey Point site, and could, among other things, result in increased cost and capital expenditures associated with the operation and maintenance of FPL's nuclear units. While the NRC continues its review, FPL continues to work with industry organizations to understand the events in Japan and apply lessons learned, which may result in FPL proactively making certain modifications to its nuclear facilities to, among other things, improve operational and safety systems prior to any potential requirements being imposed by the NRC. Any modifications could, among other things, result in increased cost and capital expenditures associated with the operation and maintenance of FPL's nuclear units. Third parties have requested that the NRC suspend the approval of nuclear uprates, nuclear license extensions and new licenses, including approval of licenses for two additional nuclear units at FPL's Turkey Point site. Another third party request was filed with the NRC seeking immediate suspension of the NRC operating licenses for all boiling water reactors that use a certain primary containment system pending completion of the NRC review. The NRC denied the request for immediate action related to the suspension of operating licenses for boiling water reactors, and, since the nuclear events in Japan, has continued to grant approvals for nuclear uprates and license extensions. However, it is uncertain at this time how and when the NRC will respond to the other items in these requests or other requests it may receive, or take action with regard to the timing for implementation of all of the NRC staff's recommendations.

Solar Operations

Solar generation can be provided primarily through two conventions, utility-owned and customer-owned. In utility-owned solar generation, the energy generated goes directly to the transmission grid, whereas, customer-owned solar generation goes directly to the location it is serving. There are two principal solar technologies used for utility-scale projects: photovoltaic and thermal. FPL placed its first utility-scale solar generating facility into service in 2009 and placed two additional solar generating facilities in service in 2010. FPL's three solar generating facilities consist of a 25 mw solar PV facility in DeSoto County, Florida, a 10 mw solar PV facility in Brevard County, Florida and a 75 mw solar thermal facility in Martin County, Florida.

Purchased Power

In addition to owning generation facilities, FPL also purchases electricity from other utilities to meet customer demand through long- and short-term purchased power agreements. As of December 31, 2011, FPL's long-term purchased power agreements provided for the purchase of approximately 2,190 mw of power with expiration dates ranging from May 2012 through 2034. See Note 14 - Contracts. FPL also procures short-term capacity for both economic and reliability purposes.

FPL ENERGY MARKETING AND TRADING

FPL's Energy Marketing & Trading division (EMT) buys and sells wholesale energy commodities, such as natural gas, oil and electricity. EMT procures natural gas and oil for FPL's use in power generation and sells excess natural gas, oil and electricity. EMT also uses derivative instruments (primarily swaps, options and forwards) to manage the commodity price risk inherent in the purchase and sale of fuel and electricity. Substantially all of the results of EMT's activities are passed through to customers in the fuel or capacity clauses. See FPL Regulation - FPL Rate Regulation below, Management's Discussion - Energy Marketing and Trading and Market Risk Sensitivity and Note 3.

FPL REGULATION

FPL's operations are subject to regulation by a number of federal, state and other organizations, including, but not limited to, the following:

- The FPSC, which has jurisdiction over retail rates, service territory, issuances of securities, planning, siting and construction of facilities, among other things.
- The FERC, which oversees the acquisition and disposition of facilities, transmission services and wholesale purchases and sales of electric energy, among other things.
- The NERC, which, through its regional entities, establishes and enforces mandatory reliability standards, subject to approval by the FERC, to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system blackouts.
- The NRC, which has jurisdiction over the operation of FPL's nuclear power plants through the issuance of operating licenses, rules, regulations and orders. See FPL Sources of Generation - Nuclear Operations above.
- The EPA, which has the responsibility to maintain and enforce national standards under a variety of environmental laws. The EPA also works with industries and all levels of government in a wide variety of voluntary pollution prevention programs and energy conservation efforts.

FPL Rate Regulation

The FPSC sets rates at a level that is intended to allow FPL the opportunity to collect from retail customers total revenues (revenue requirements) equal to FPL's cost of providing service, including a reasonable rate of return on invested capital. To accomplish this, the FPSC uses various ratemaking mechanisms, including, among other things, base rates and cost recovery clauses.

Base Rates. In general, the basic costs of providing electric service, other than fuel and certain other costs, are recovered through base rates, which are designed to recover the costs of constructing, operating and maintaining the utility system. These basic costs include O&M expenses, depreciation and taxes, as well as a return on FPL's investment in assets used and useful in providing electric service (rate base). At the time base rates are determined, the allowed rate of return on rate base approximates the FPSC's determination of FPL's estimated weighted-average cost of capital, which includes its costs for outstanding debt and an allowed ROE. The FPSC monitors FPL's actual regulatory ROE through a surveillance report that is filed monthly by FPL with the FPSC. The FPSC does not provide assurance that any ROE will be achieved. Base rates are determined in rate proceedings or through negotiated settlements of those proceedings, which occur at the initiative of FPL, the FPSC, the State of Florida Office of Public Counsel or a substantially affected party. Base rates remain in effect until new base rates are approved by the FPSC.

Effective March 1, 2010, pursuant to an FPSC final order (FPSC rate order) new retail base rates for FPL were established, resulting in an increase in retail base revenues of approximately $75 million on an annualized basis. The FPSC rate order also established a regulatory ROE of 10.0% with a range of plus or minus 100 basis points and an adjusted regulatory equity ratio of 59.1%. It also shifted certain costs from retail base rates to the capacity clause. (See Cost Recovery Clauses below for additional information regarding the capacity clause.) In addition, the FPSC rate order directed FPL to reduce depreciation expense (surplus depreciation credit) over the 2010 to 2013 period related to a depreciation reserve surplus. In February 2011, the FPSC issued a final order approving a stipulation and settlement agreement between FPL, the State of Florida Office of Public Counsel, the Florida Attorney General's Office and all other principal parties in FPL's 2009 rate case regarding FPL's base rates (2010 rate agreement), which enables FPL to earn a regulatory ROE of up to 11% per year over the term of the 2010 rate agreement. Key elements of the 2010 rate agreement, which is effective through December 31, 2012, are as follows:

- Subject to the provisions of the 2010 rate agreement, retail base rates are effectively frozen through the end of 2012.
- Incremental cost recovery through FPL's capacity clause for the new combined-cycle natural gas unit at WCEC (WCEC Unit No. 3), which was placed in service in May 2011, is permitted up to the amount of the projected annual fuel savings for customers during the term of the 2010 rate agreement.
- Future storm restoration costs would be recoverable on an accelerated basis beginning 60 days from the filing of a cost recovery petition, but capped at an amount that produces a surcharge of no more than $4 for every 1,000 kwh of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL may request an increase to the $4 surcharge to recover the amount above $800 million.
- If FPL's earned regulatory ROE falls below 9%, FPL may seek retail base rate relief. If FPL's earned regulatory ROE rises above 11%, any party to the 2010 rate agreement may seek a reduction in FPL's retail base rates. In determining the regulatory ROE for all purposes under the 2010 rate agreement, earnings will be calculated on an actual, non-weather-adjusted basis.
- FPL can vary the amount of surplus depreciation credit taken in any calendar year up to a cap in 2010 of $267 million, a cap in subsequent years of $267 million plus the amount of any unused portion from prior years, and a total cap of $776 million (surplus depreciation credit cap) over the course of the 2010 rate agreement, provided that in any year of the 2010 rate agreement FPL must use at least enough surplus depreciation credit to maintain a 9% earned regulatory ROE but may not use any amount of surplus depreciation credit that would result in an earned regulatory ROE in excess of 11%.

In January 2012, FPL notified the FPSC of its intent to initiate a base rate proceeding in 2012. See Recent Regulatory Developments below.

Cost Recovery Clauses. Cost recovery clauses, which are designed to permit full recovery of certain costs and provide a return on certain assets allowed to be recovered through the various clauses, include substantially all fuel, purchased power and interchange expenses, conservation and certain environmental-related expenses, certain revenue taxes and franchise fees. Beginning in 2009, pre-construction costs and carrying charges on construction costs for FPL's planned two additional nuclear units at Turkey Point and carrying charges on construction costs for FPL's approximately 450 mw to 490 mw of additional capacity at St. Lucie and Turkey Point are also recoverable through a cost recovery clause. Also beginning in 2009, costs incurred for FPL's three solar generating facilities are recoverable through a cost recovery clause. Cost recovery clause costs are recovered through levelized monthly charges per kwh or kw, depending on the customer's rate class. These cost recovery clause charges are calculated at least annually based on estimated costs and estimated customer usage for the following year, plus or minus a true-up adjustment to reflect the estimated over or under recovery of costs in the current year. An adjustment to the levelized charges may be approved during the course of a year to reflect revised estimates.

Fuel costs are recovered from customers through the fuel clause, the most significant of the cost recovery clauses. FPL uses a risk management fuel procurement program which has been approved by the FPSC. The FPSC reviews the program activities and results for prudence annually as part of its review of fuel costs. The program is intended to manage fuel price volatility by locking in fuel prices for a portion of FPL's fuel requirements. See FPL Energy Marketing and Trading above, Management's Discussion - FPL: Results of Operations, Note 1 - Regulation and Note 3.

Capacity payments to other utilities and generating companies for purchased power are recovered from customers through the capacity clause. In accordance with the FPSC's nuclear cost recovery rule, FPL also recovers pre-construction costs and carrying charges (equal to a pretax AFUDC rate) on construction costs for new nuclear capacity through the capacity clause. As property related to the new nuclear capacity goes into service, construction costs and a return on investment are recovered through base rate increases effective beginning the following January. See FPL Sources of Generation - Nuclear Operations above. In

accordance with the 2010 rate agreement, cost recovery for WCEC Unit No. 3, which was placed in service in May 2011, is permitted up to the amount of the projected annual fuel savings for customers during the term of the 2010 rate agreement through FPL's capacity clause and is reported as retail base revenues.

Costs associated with implementing energy conservation programs are recovered from customers through the energy conservation cost recovery clause. Certain costs of complying with federal, state and local environmental regulations enacted after April 1993 and costs associated with FPL's three solar facilities are recovered through the environmental compliance cost recovery clause (environmental clause).

The FPSC has the authority to disallow recovery of costs that it considers excessive or imprudently incurred. These costs may include, among others, fuel and O&M expenses, the cost of replacing power lost when fossil and nuclear units are unavailable, storm restoration costs and costs associated with the construction or acquisition of new facilities.

FERC

The Federal Power Act gives the FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, electric utilities must maintain tariffs and rate schedules on file with the FERC which govern the rates, terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. The Federal Power Act also gives the FERC authority to certify and oversee a national electric reliability organization with authority to develop mandatory reliability standards applicable to all users, owners and operators of bulk-power systems. The FERC also approves reliability standards and makes them enforceable. See NERC below. Electric utilities also are subject to accounting, record-keeping and reporting requirements administered by the FERC. The FERC also places certain limitations on transactions between electric utilities and their affiliates.

NERC

The NERC has been certified by the FERC as the national electric reliability organization. The NERC ensures the reliability and security of the North American bulk power system. The NERC's regional entities establish requirements, approved by the FERC, for reliable operation and maintenance of power generation facilities and transmission systems. FPL is subject to these reliability requirements and can incur significant penalties for failing to comply with them. Each NERC region reports seasonally and annually on the status of generation and transmission in each region.

FPL Environmental Regulation

FPL is subject to environmental laws and regulations, and is affected by some of the emerging issues, described in the NEE Environmental Matters section below. FPL expects to seek recovery through the environmental clause for compliance costs associated with any new environmental laws and regulations.

During 2011, FPL spent approximately $117 million on capital additions related to environmental matters, primarily to comply with existing environmental laws and regulations. FPL's capital expenditures related to environmental matters are estimated to total approximately $325 million for 2012 through 2014, including $118 million in 2012.

Recent Regulatory Developments

In January 2012, FPL filed a formal notification with the FPSC indicating its intent to initiate a base rate proceeding. The notification stated that, based on preliminary estimates, FPL expects to request a base rate increase of approximately $525 million effective January 2013 and an additional base rate increase of approximately $170 million annually commencing when the modernized Cape Canaveral plant becomes operational, which is expected to occur in June 2013. FPL expects to propose an allowed regulatory ROE of 11.25% with a 0.25% ROE adder, which is included in the base rate increase FPL expects to request, if FPL maintains the lowest typical residential customer bill among all the electric utilities in Florida. FPL expects to file its formal request to initiate a base rate proceeding before the end of the first quarter of 2012 with a final FPSC decision expected in the fourth quarter of 2012 in time for new rates to be effective January 1, 2013.

FPL EMPLOYEES

FPL had approximately 9,800 employees at December 31, 2011. Approximately 31% of the employees are represented by the International Brotherhood of Electrical Workers (IBEW) under a collective bargaining agreement with FPL that expires October 31, 2014.

II. NEER

NEER was formed in 1998 to aggregate NEE's competitive energy businesses. It is a limited liability company organized under the laws of Delaware and is a wholly-owned subsidiary of NEECH. Through its subsidiaries, NEER currently owns, develops, constructs, manages and operates electric generating facilities in wholesale energy markets primarily in the U.S., as well as in Canada and Spain. See Note 15. NEER is one of the largest wholesale generators of electric power in the U.S., with 16,607 mw of generating capacity across 22 states and 3 Canadian provinces as of December 31, 2011. NEER produces the majority of its electricity from clean and renewable sources as described more fully below. NEER is the largest owner of wind and solar energy projects in the U.S. and one of the largest owners and developers of wind projects in Canada. Since 2002, NEER has more than doubled its generating capacity, primarily through the development of new wind projects and acquisition of nuclear projects.

In addition, NEER provides full energy and capacity requirements services primarily to distribution utilities in certain markets, offers customized power and gas and related risk management services to wholesale customers and engages in power and gas marketing and trading activities. NEER also owns a retail electricity provider serving customers in 13 states and the District of Columbia and engages in limited development of natural gas reserves, as well as pipeline infrastructure, through non-operating ownership interests, hereafter referred to as the gas infrastructure business.

MARKETS AND COMPETITION

Electricity markets in the U.S. are regional and diverse in character. All are extensively regulated, and competition in these markets is shaped and constrained by regulation. The nature of the products offered varies based on the specifics of regulation in each region, and the degree of control participants have over pricing also varies. Generally, in addition to the natural constraints on pricing freedom presented by competition, NEER may also face specific constraints in the form of price caps, or maximum allowed prices, for certain products. NEER's ability to sell the output of its generation facilities is also constrained by available transmission capacity, which can vary from time to time and can have a significant impact on pricing.

The degree and nature of competition that NEER faces is different in wholesale markets and in retail markets. The majority of NEER's revenue, roughly 90%, is derived from wholesale markets.

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. NEER competes on the basis of the location of its plants and ownership of multiple plants in various regions, which increases the reliability of its energy supply. Wholesale power generation is a regional business that is currently highly fragmented relative to other commodity industries and diverse in terms of industry structure. As such, there is a wide variation in terms of the capabilities, resources, nature and identity of the companies NEER competes with depending on the market. In wholesale markets, customers' needs are met through a variety of means, including long-term bilateral contracts, standardized bilateral products such as full requirements service and customized supply and risk management services.

In general, U.S. electricity markets encompass three classes of product: energy, capacity and ancillary services. Energy services relate to the physical delivery of power; capacity services relate to the availability of mw capacity of a power generation asset; and ancillary services are other services related to power generation assets, for example, load-following services, which require the supplier of energy to vary the quantity delivered based on the load demand needs of the customer. The exact nature of these classes of product is defined in part by regulation. Not all regions have a capacity product class, and the specific definitions of ancillary services vary from region to region.

RTOs and ISOs exist in a number of regions within which NEER operates to coordinate generation and transmission across wide geographic areas. NEER also has operations that fall within the Western Electricity Coordinating Council reliability region that are not under the jurisdiction of an established RTO or ISO. Although each RTO and ISO may have differing objectives and structures, some benefits of these entities include regional planning, managing transmission congestion, developing larger wholesale markets for energy and capacity, maintaining reliability and facilitating competition among wholesale electricity providers. NEER has operations that fall within the following RTOs and ISOs:

- Alberta Electric System Operator
- California Independent System Operator
- ERCOT
- Independent Electricity System Operator
- ISO New England
- Midwest Independent Transmission System Operator (MISO)
- New York Independent System Operator (NYISO)
- PJM
- Southwest Power Pool

NEER competes in different regions to different degrees, but in general it seeks to enter into long-term bilateral contracts for the full output of its generating facilities, and approximately 55% of NEER's generating capacity is fully committed under long-term contracts. In some regions long-term contracts are not practical and NEER sells the output of its facilities into daily spot markets. In such cases, NEER will frequently enter into shorter term bilateral contracts, typically but not always of one to three years duration, to hedge the price risk associated with selling into a daily spot market. Such bilateral contracts, which may be hedges either for physical delivery or for financial (pricing) offset, may only protect a portion of the revenue that NEER expects to derive from the associated generation facility and may not qualify for hedge accounting under GAAP. Contracts that serve the economic purpose of hedging some portion of the expected revenue of a generation facility but are not recorded as hedges under GAAP are referred to as “non-qualifying hedges” for adjusted earnings purposes. See Management's Discussion - Overview.

While the majority of NEER's revenue is derived from the output of its generating facilities, NEER is also an active competitor in several regions in the wholesale full requirements business and in providing structured and customized power and gas products and services to a variety of customers. In the full requirements service, the supplier agrees to meet the customer's needs for a full range of products for every hour of the day for a fixed period of time, thereby assuming the risk of fluctuations in the customer's volume requirements.

The deregulated retail energy business is typically a highly competitive business. In general, competition in the retail energy business is on the basis of price, service, brand image, product offerings and market perceptions of creditworthiness. Electricity is sold pursuant to a variety of product types, including fixed, indexed and renewable products, and customers elect terms of service typically ranging from one month to five years. Retail energy rates are market-based, and not subject to traditional cost-of-service regulation by public service commissions. Non-affiliated transmission and distribution service companies provide, on a non-discriminatory basis, the wires and metering services necessary to access customers. Subsidiaries of NEER compete in certain states for retail customers, which can be divided into two principal segments: residential and commercial and industrial (C&I). Residential customers largely require only energy services, which may be purchased on a month-to-month basis or under a multi-year contract. Large C&I customers share many of the same characteristics as wholesale utility customers and may require similarly customized and structured products.

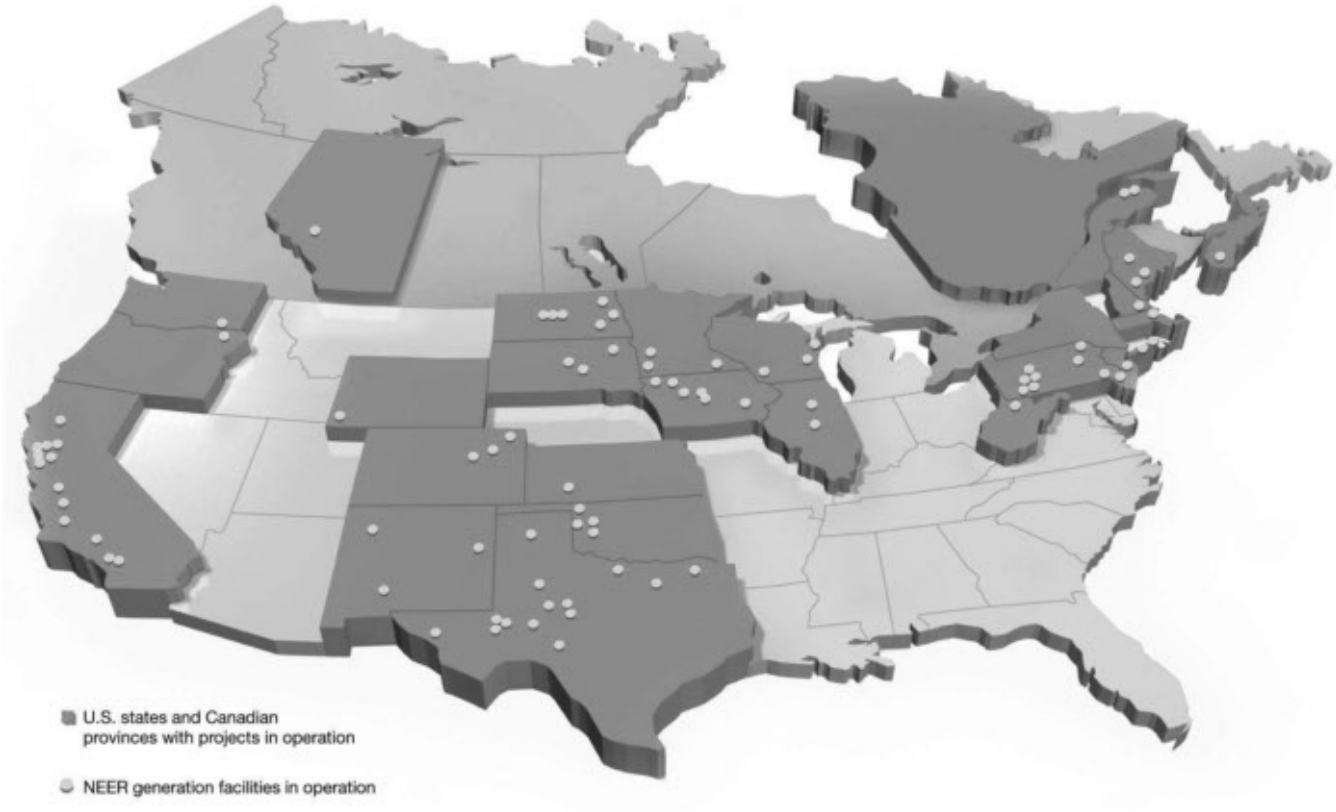
In general, competitive retail electric providers are exposed to both volume and price risk: customers' volumes will vary, and competitive retail providers are committed to supplying the customer's full needs at all times and are therefore responsible for purchases in wholesale markets to meet those needs; and wholesale prices will fluctuate in ways that do not necessarily match the retail prices committed to the customer.

Expanded competition in a frequently changing regulatory environment presents both opportunities and risks for NEER. Opportunities exist for the selective acquisition of generation assets and for the construction and operation of efficient facilities that can sell power in competitive markets. NEER seeks to reduce its market risk by having a diversified portfolio by fuel type and location, as well as by contracting for the future sale of a significant amount of the electricity output of its facilities.

GENERATION AND OTHER OPERATIONS

The vast majority of NEER's revenue is derived from selling the products (energy, capacity and ancillary services) produced by its own generating facilities. To a limited extent, NEER also meets its customers' needs through purchases of relevant products in wholesale markets and may combine purchases with sales from its own assets in order to meet particular customers' needs.

At December 31, 2011, the locations of NEER's generation facilities in North America are as follows:



At December 31, 2011, NEER managed or participated in the management of essentially all of its projects in which it has an ownership interest.

NEER categorizes its portfolio in a number of different ways for different business purposes. See a listing of NEER's generating facilities in Item 2 - Generating Facilities. The following combination of the presence/absence of long-term contracts, fuel/technology and region is a common presentation that NEE has used in communicating its business:

Contracted, Merchant and Other Operations

NEER's portfolio of operations based on the presence/absence of long-term contracts and other operations is described below.

Contracted Assets. Contracted assets are projects with long-term power sales agreements for substantially all of their output and certain wind assets where long-term power contracts are expected to be executed. At December 31, 2011, NEER had 9,647 mw of contracted assets, substantially all of which have long-term power contracts. Essentially all of the output of these contracted assets were under power sales agreements, with a weighted-average remaining contract life of approximately 16 years, and have firm fuel and transportation agreements with expiration dates ranging from March 2012 through 2022. See Note 14 - Contracts. Approximately 6,860 mw of this capacity is wind generation and 1,621 mw of this capacity is nuclear generation. The remaining 1,166 mw use a variety of fuels and technologies such as natural gas, oil and solar.

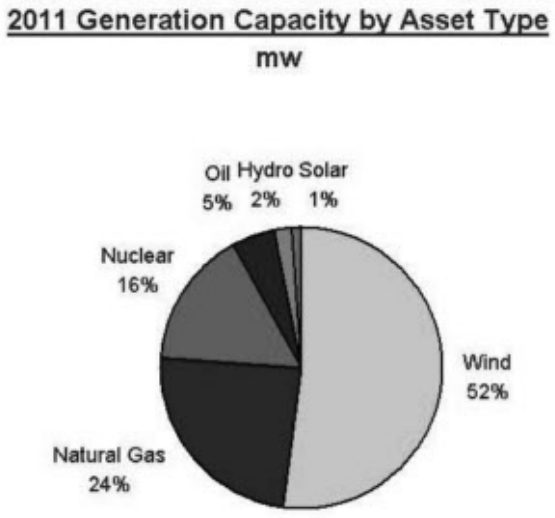
Merchant Assets. Merchant assets are projects that do not have long-term power sales agreements to sell their output, or, in the case of certain wind assets, are not expected to have long-term power contracts, and therefore require active marketing and hedging. At December 31, 2011, NEER's portfolio of merchant assets consists of 6,960 mw of owned wind, nuclear, natural gas, oil, solar and hydro generation facilities, including 846 mw of peak generating facilities. Approximately 60% (based on net mw capacity) of the natural gas-fueled merchant assets have natural gas transportation agreements to provide for fluctuating natural

gas requirements. See Note 14 - Contracts. Derivative instruments (primarily swaps, options, futures and forwards) are used to lock in pricing and manage the commodity price risk inherent in power sales and fuel purchases. Managing market risk through these instruments introduces other types of risk, primarily counterparty, credit and operational risks.

Other. NEER's operations also include the gas infrastructure and customer supply and proprietary power and gas trading businesses. See NEER Customer Supply and Proprietary Power and Gas Trading below.

NEER Fuel/Technology Mix

NEER's generating capacity is produced using a variety of fuel sources as further described below.



Wind Facilities

At December 31, 2011, NEER had ownership interests in wind generating facilities with a total capacity of 8,569 mw (net ownership). NEER operates substantially all of these wind facilities, which are located in 17 states and Canada. NEER added 379 mw of new wind generation in 2011, including 128 mw related to the repowering of two California wind facilities, and expects to add approximately 1,150 mw to 1,500 mw of new wind generation in 2012.

Natural Gas Facilities

At December 31, 2011, NEER had 3,991 mw of natural gas assets. NEER owns and operates 1,004 mw of natural gas-fired generation from contracted assets located throughout the Northeast. During 2011, subsidiaries of NEER sold their ownership interests in a portfolio of natural gas-fired generating assets totaling approximately 2,700 mw of capacity located in California, Virginia, Alabama, South Carolina and Rhode Island. See Management's Discussion - Overview and Note 4 - Nonrecurring Fair Value Measurements.

Nuclear Facilities

At December 31, 2011, NEER owned, or had undivided interests in, and operated the following four nuclear units with a total net generating capacity of 2,721 mw.

Facility	Location	mw	Portfolio Category	Operating License Expiration Dates
Seabrook	New Hampshire	1,100	Merchant	2030 [(a)]
Duane Arnold	Iowa	431	Contracted[(b)]	2034
Point Beach Unit No. 1	Wisconsin	595	Contracted[(c)]	2030
Point Beach Unit No. 2	Wisconsin	595	Contracted[(c)]	2033

(a) In 2010, NEER filed an application with the NRC to renew Seabrook's operating license for an additional 20 years.
(b) NEER sells substantially all of its share of the output of Duane Arnold under a long-term contract expiring in 2014.
(c) NEER sells all of the output of Point Beach Units Nos. 1 and 2 under long-term contracts through the current operating license terms.

NEER's nuclear facilities have several contracts for the supply of uranium and conversion, enrichment and fabrication of nuclear fuel with expiration dates ranging from March 2012 through 2022. See Note 14 - Contracts. NEER is responsible for all nuclear unit operations and the ultimate decommissioning of the nuclear units, the cost of which is shared on a pro-rata basis by the joint owners for the jointly owned units. NRC regulations require plant owners to submit a plan for decontamination and decommissioning five years before the projected end of plant operation. See estimated decommissioning cost data in Management's Discussion - Critical Accounting Policies and Estimates - Nuclear Decommissioning and Fossil/Solar Dismantlement.

Nuclear Unit Scheduled Refueling Outages. NEER's nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, including inspections, repairs and certain other modifications. Scheduled nuclear refueling outages typically require the unit to be removed from service for variable lengths of time. The duration is longer for expanded scope outages, one of which is scheduled at Duane Arnold in 2012 and is expected to last approximately 60 days. The following table summarizes the next scheduled refueling outages:

Facility	Next Scheduled Refueling Outage
Seabrook	October 2012
Duane Arnold	October 2012
Point Beach Unit No. 1	April 2013
Point Beach Unit No. 2	November 2012

Disposition of Spent Nuclear Fuel. NEER's nuclear facilities use both on-site storage pools and dry storage casks to store spent nuclear fuel generated by these facilities, which are expected to allow NEER to store spent nuclear fuel at these facilities through license expiration.

As owners and operators of nuclear facilities, certain subsidiaries of NEER are subject to the Nuclear Waste Policy Act and are parties to the spent fuel settlement agreement and legal actions described in I. FPL - Nuclear Operations. Similar to FPL, these subsidiaries will continue to pay fees to the U.S. government's nuclear waste fund pending the D.C. Circuit's decision on the fee suspension petition.

Recent Nuclear Developments. For discussion of current developments regarding the impact of the 2011 earthquake and tsunami in Japan as it relates to U.S. nuclear facilities, see I. FPL - Nuclear Operations. NEER's nuclear facilities are subject to the same potential NRC actions as described for FPL. Duane Arnold is NEER's only boiling water reactor unit. NEER is currently reviewing the NRC's directions relating to the NRC staff's recommendations and assessing the potential financial and operational impact on its nuclear units.

Solar Facilities

NEER is one of the largest owners of utility-scale solar energy projects in the U.S., principally through a 310 mw facility in California's Mojave Desert, of which 148 mw is owned by NEER as of December 31, 2011. NEER is in the process of constructing solar thermal facilities with generating capacity of 99.8 mw in Spain (Spain solar project) and 250 mw in California (Genesis solar project), which are expected to be completed in 2013 and 2014, respectively. In addition, a 550 mw solar PV project in California (Desert Sunlight solar project), in which NEER has a 50% equity investment, has commenced construction and commercial operation is expected to be phased in during 2013 through 2015. During 2011, NEER added approximately 5 mw of new solar generation.

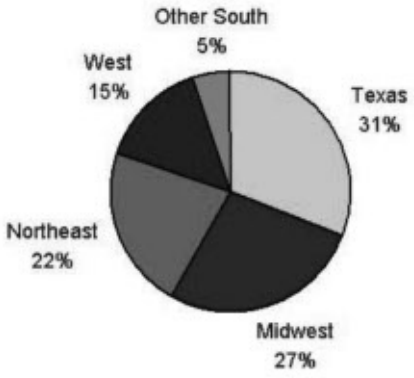
Other Assets

At December 31, 2011, NEER had 1,168 mw of generation assets from a variety of other fuel technologies, including oil and hydropower, with facilities located throughout the Northeast.

NEER Generation by Geographic Region

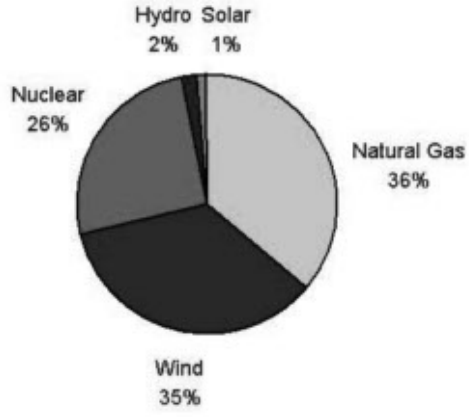
NEER's generating capacity spans various geographic regions in North America, thereby reducing overall volatility related to varying market conditions and seasonality on a portfolio basis. NEER's generating facilities at December 31, 2011 are categorized by geographic region (See Item 2 - Generating Facilities) in terms of mw of capacity as follows:

2011 Generation Capacity by Geographic Region
mw



NEER's power generation in terms of mwh produced for the year ended December 31, 2011 by fuel type is as follows:

2011 Generation by Fuel Type
mwh



NEER CUSTOMER SUPPLY AND PROPRIETARY POWER AND GAS TRADING

PMI, a subsidiary of NEER, buys and sells wholesale energy commodities, such as electricity, natural gas and oil. PMI sells the output from NEER's plants that has not been sold under long-term contracts and procures the non-nuclear fuel for use by NEER's generation fleet. Its primary role is to manage the commodity risk of NEER's portfolio. PMI uses derivative instruments such as swaps, options, futures and forwards to manage the risk associated with fluctuating commodity prices and to optimize the value of NEER's power generation assets.

PMI also provides a wide range of electricity and gas commodity products as well as marketing and trading services to electric and gas utilities, municipalities, cooperatives and other load-serving entities, as well as to owners of electric generation facilities. PMI's customer supply business includes providing full energy and capacity requirements and mid-marketing services that include sales and purchases of wholesale commodities-related products and the operations of a retail electricity provider, which during 2011, served approximately 2,200 mw of peak load to approximately 201,800 customers across the ERCOT, New England Power Pool (NEPOOL), PJM, NYISO and MISO markets.

The results of PMI's activities are included in NEER's operating results. See Management's Discussion - Energy Marketing and Trading and Market Risk Sensitivity, Note 1 - Energy Trading and Note 3.

NEER REGULATION

Each of the energy markets in which NEER operates is subject to domestic and foreign regulation, including local, state and federal regulation, and other specific rules.

At December 31, 2011, NEER had ownership interests in operating independent power projects located in the U.S. that have received exempt wholesale generator status as defined under the Public Utility Holding Company Act of 2005, which represent approximately 95% of NEER's net generating capacity. Exempt wholesale generators own or operate a facility exclusively to sell electricity to wholesale customers. They are barred from selling electricity directly to retail customers. NEER's exempt wholesale generators produce electricity from wind, hydro, fossil fuels and nuclear facilities. Essentially all of the remaining 5% of NEER's net generating capacity has qualifying facility status under PURPA. NEER's qualifying facilities generate electricity primarily from wind, solar and fossil fuels. Qualifying facility status exempts the projects from, among other things, many of the provisions of the Federal Power Act, as well as state laws and regulations relating to rates and financial or organizational regulation of electric utilities. While projects with qualifying facility and/or exempt wholesale generator status are exempt from various restrictions, each project must still comply with other federal, state and local laws, including, but not limited to, those regarding siting, construction, operation, licensing, pollution abatement and other environmental laws.

Additionally, NEER facilities located in the U.S. are subject to FERC regulations and market rules, the NERC's mandatory reliability standards and the EPA's environmental laws, and its nuclear facilities are also subject to the jurisdiction of the NRC. See FPL - FPL Regulation for additional discussion of FERC, NERC, NRC, and EPA regulations. With the exception of facilities located in ERCOT, the FERC has jurisdiction over various aspects of NEER's business, including the oversight and investigation of competitive wholesale energy markets, regulation of the transmission and sale of natural gas, regulation of hydro projects and oversight of environmental matters related to natural gas and hydro projects and major electricity policy initiatives. The PUCT has jurisdiction, including the regulation of rates and services, oversight of competitive markets, and enforcement of statutes and rules, over NEER facilities located in ERCOT.

NEER is subject to environmental laws and regulations, and is affected by some of the emerging issues related to renewable energy resources as described in the NEE Environmental Matters section below. In order to better anticipate these potential regulatory changes, NEER continues to actively evaluate and participate in regional market redesigns of existing operating rules for the integration of renewable energy resources and for the purchase and sale of energy commodities.

NEER EMPLOYEES

NEER and its subsidiaries had approximately 4,700 employees at December 31, 2011. Subsidiaries of NEER have collective bargaining agreements with various unions which are summarized in the table below.

Union	Location	Contract Expiration Date	% of NEER's Employees Covered
IBEW	Wisconsin	June 2012 - September 2013[(a)]	10%
Utility Workers Union of America	New Hampshire	December 2013	5
IBEW	Iowa	May 2012	3
Security Police and Fire Professionals of America	Iowa	July 2012	2
IBEW	Maine	February 2013	2
IBEW	California	March 2012	-[(b)]
Total			22%

(a) Various employees at Point Beach are represented by the IBEW under four separate contracts with different expiration dates.
(b) Less than 1% of NEER's employees.

In addition, the employees of an operating project in Illinois, constituting less than 1% of NEER's employees, are represented by the International Union of Operating Engineers, which is currently negotiating its first collective bargaining agreement.

III. OTHER NEE OPERATING SUBSIDIARIES

NEE's Corporate and Other segment represents other business activities, primarily FPL FiberNet and Lone Star, that are not separately reportable. See Note 15.

FPL FIBERNET

FPL FiberNet conducts its business through two separate wholly-owned subsidiaries of NEECH. One subsidiary was formed in 2000 to enhance the value of NEE's fiber-optic network assets that were originally built to support FPL operations and the other was formed in 2011 to hold fiber-optic network assets which were acquired. Both subsidiaries are limited liability companies organized under the laws of Delaware. FPL FiberNet leases fiber-optic network capacity and dark fiber to FPL and other customers,

primarily telephone, wireless, internet and other telecommunications companies. FPL FiberNet's networks cover most of the metropolitan areas in Florida and several in Texas. FPL FiberNet also has a long-haul network providing bandwidth at wholesale rates. The long-haul network connects major cities in Florida and Texas with additional connectivity to Atlanta, Georgia and the South Central U.S., including Arkansas, Louisiana and Oklahoma. At December 31, 2011, FPL FiberNet's network consisted of approximately 7,800 route miles. FPL FiberNet is subject to regulation by the Federal Communications Commission which has jurisdiction over wire and wireless communication networks and by the public utility commissions in the states in which it provides intrastate telecommunication services.

LONE STAR

Lone Star, an indirect wholly-owned subsidiary of NEECH, is constructing approximately 320 miles of 345 kv transmission lines and other associated facilities in Texas. Lone Star, a limited liability company organized under the laws of Delaware, is a rate-regulated transmission service provider in Texas. Two substations and associated facilities with a total capital investment of approximately $60 million are expected to be placed in service in 2012, with the remaining associated facilities and transmission lines expected to be placed in service in the first quarter of 2013, for a total capital investment of approximately $785 million. Lone Star's transmission lines are part of a transmission grid improvement program that will add approximately 2,300 miles of 345 kv lines to deliver power from the Competitive Renewable Energy Zones in west Texas and the Texas panhandle to the Dallas/Fort Worth area and other population centers in Texas. Lone Star will own the transmission lines and associated facilities and operate them after they are placed in service.

Lone Star is subject to regulation by a number of federal, state and other agencies, including, but not limited to, the PUCT, the ERCOT, the NERC and the EPA, as well as certain limited regulations of the FERC. See I. FPL - FPL Regulation for further discussion of FERC, NERC, and EPA regulations and NEE Environmental Matters. The PUCT has jurisdiction over a wide range of Lone Star's business activities, including, among others, rates charged to customers and certain aspects of siting, construction and operation of transmission systems. The PUCT sets rates at a level that allows Lone Star the opportunity to collect from customers total revenues (revenue requirements) equal to Lone Star's cost of providing service, including a reasonable rate of return on invested capital.

In January 2012, Lone Star filed a petition with the PUCT requesting, among other things, interim rates that would take effect when Lone Star's first substation is placed in service and final rates when the transmission lines are energized. The petition also proposes to limit cost recovery to Lone Star's actual capital costs by making a true-up filing within 120 days of energizing the transmission lines. If approved, based on the expected in-service dates, the requested rates would result in annual revenues of approximately $14 million in 2012 and $110 million in 2013. Lone Star's requested rates are based on a proposed regulatory ROE of 11% with a regulatory equity ratio of 52%. Hearings on this rate proceeding are expected during the second quarter of 2012 and a final decision is expected during the third quarter of 2012. The interim rates would be subject to refund pending the final decision on the rate proceeding. The PUCT has the authority to disallow recovery of costs that it considers excessive or imprudently incurred.

NEE ENVIRONMENTAL MATTERS

NEE and FPL are subject to domestic and foreign environmental laws and regulations, including extensive federal, state, and local environmental statutes, rules, and regulations. The U.S. Congress and certain states and regions continue to consider several legislative and regulatory proposals with respect to GHG emissions. The economic and operational impact of climate change legislation on NEE and FPL depends on a variety of factors, including, but not limited to, the allowed emissions, whether emission allowances will be allocated or auctioned, the cost to reduce emissions or buy allowances in the marketplace and the availability of offsets and mitigating factors to moderate the costs of compliance. Based on the most recent reference data available from government sources, NEE is among the lowest emitters, among electric generators, of GHG in the U.S. measured by its rate of emissions expressed as pounds of CO_2 per mwh of generation. However, the legislative and regulatory proposals have differing methods of implementation and the impact on FPL's and NEER's generating units and/or the financial impact (either positive or negative) to NEE and FPL could be material, depending on the eventual structure of any legislation enacted or specific implementation rules adopted.

I. Environmental Regulations

The following is a discussion of certain existing and emerging federal and state initiatives and rules, some of which could potentially have a material effect (either positive or negative) on NEE and its subsidiaries. FPL expects to seek recovery through the environmental clause for compliance costs associated with any new environmental laws and regulations.

- Mercury and Air Toxics Standards (MATS). In December 2011, the EPA issued a final MATS rule as required under the Clean Air Act which requires coal-fired and oil-fired generating units to reduce emissions of hazardous air pollutants. The MATS rule includes a limited use provision which excludes low-capacity generating units from the requirements to add pollution control equipment, under which three oil-fired units at FPL and four oil-fired units at NEER are expected to qualify. Based on the provisions of the rule, four oil-fired units and two coal-fired units at FPL are in the process of adding or could be required to add additional pollution control equipment to meet Maximum Achievable Control Technology standards. A third coal-fired unit at FPL is in the process of adding additional pollution control equipment to meet certain state compliance requirements which would also satisfy the Maximum Achievable Control Technology standards under the MATS rule. Units affected by the rule will

be required to comply by April 2015, with a possible one year extension for compliance if required to install pollution control equipment.

- Clean Air Interstate Rule (CAIR)/Cross-State Air Pollution Rule (CSAPR). The EPA's CAIR requires SO_2 and NOx emissions reductions from electric generating units in specified Eastern states and the District of Columbia, where the emissions from electric generating units are deemed to be transported to downwind states. NEER and FPL began complying with the CAIR on January 1, 2009. In July 2011, the EPA issued the CSAPR, a final rule which was to replace the CAIR beginning in January 2012. The CSAPR would limit emissions of SO_2 and NOx from power plants in 28 eastern states and provides an allocation methodology for emission allowances and reduction limits for SO_2 and NOx beginning in January 2012 and seasonal ozone requirements beginning in May 2012, with a second phase of reductions beginning in January 2014. FPL would only be affected by the seasonal ozone requirements of the rule while NEER would be affected by the annual SO_2 and NOx emissions requirements as well as the seasonal ozone requirements in several states. Several groups have petitioned the EPA to reconsider the CSAPR and in December 2011, the D.C. Circuit issued an order staying implementation of the CSAPR pending resolution of legal challenges to the rule and ordered that the CAIR remain in place while the CSAPR is stayed. The case is scheduled for oral argument in April 2012. The ultimate resolution of the issues surrounding the CSAPR is uncertain at this time.

- Clean Water Act Section 316(b). In March 2011, the EPA issued a proposed rule under Section 316(b) of the Clean Water Act to address the location, design, construction and capacity of intake structures at existing power plants with once-through cooling water systems, with a final rule not expected until the summer of 2012. The proposed rule is intended to require the Best Technology Available to reduce the impact on aquatic organisms from once-through cooling water intake systems. Under the proposed rule, potentially thirteen of FPL's facilities and five of NEER's facilities may be required to add additional controls or make operational changes to comply, the economic and operational impact of which cannot be determined at this time, but could be material. Prior to the passage of a new rule, states are continuing to utilize “Best Professional Judgment” in the application of Section 316(b) compliance requirements.

- Avian/Bat Regulations and Wind Turbine Siting Guidelines. NEER and FPL are subject to numerous environmental regulations and guidelines related to threatened and endangered species and their habitats, as well as avian and bat species, for the siting, construction and ongoing operations of their facilities. The facilities most significantly affected are wind facilities and transmission and distribution lines. The environmental laws include, among others, the Endangered Species Act, the Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act which provide for protection of migratory birds, eagles and endangered species of birds and bats and their habitats. Regulations have been adopted under some of these laws that contain provisions that allow the owner/operator of a facility to apply for a permit to undertake specific activities including those associated with certain siting decisions, construction activities and operations. In addition to regulations, voluntary wind turbine siting guidelines, which are expected to be finalized by the U.S. Fish and Wildlife Service by the end of the first quarter of 2012, will set forth siting, monitoring and coordination protocols that are designed to support wind development in the U.S. while also protecting both birds and bats and their habitats. These guidelines will include provisions for specific monitoring and study conditions which will need to be met in order for projects to be in adherence with these voluntary guidelines. Complying with these new environmental regulations and adhering to the provisions set forth in the voluntary wind turbine siting guidelines could result in additional costs at existing and new wind generating facilities and transmission and distribution facilities at NEER and FPL.

- Regulation of GHG Emissions. Pursuant to rules issued by the EPA under the Clean Air Act, new facilities emitting 100,000 tons per year (tpy) or more of GHG and modifications to existing facilities resulting in an increase of GHG emissions of 75,000 tpy or more have to perform a Best Available Control Technology review and, based on that review, may have to reduce emissions by adding additional emissions control equipment or implementing energy efficiency projects. Several petitioners have challenged the EPA's GHG regulations and the case is pending review by the D.C. Circuit, the timing and ultimate outcome of which is uncertain at this time. At FPL, the modernization of the Port Everglades facility, if approved by the FPSC, would be affected by this rule, the impact of which cannot be determined at this time.

II. Other GHG Emissions Reduction Initiatives

NEER's plants operate in certain states and regions that continue to consider and implement regulatory proposals to reduce GHG emissions. RPS, currently in place in approximately 30 states and the District of Columbia, require electricity providers in the state or district to meet a certain percentage of their retail sales with energy from renewable sources. These standards vary, but the majority include requirements to meet 10% to 25% of the electricity providers' retail sales with energy from renewable sources by 2025. NEER's plants operate in 18 states that have a RPS and NEER believes that these standards will create incremental demand for renewable energy in the future.

Other GHG reduction initiatives including, among others, the Regional Greenhouse Gas Initiative and the California Greenhouse Gas Regulation aim to reduce emissions through a variety of programs and under varying timelines. Based on its clean generating portfolio, NEER expects to continue experiencing a positive impact on earnings as a result of these GHG reduction initiatives. Additionally, these initiatives provide NEER opportunities with regards to wind and solar development as well as favorable energy pricing.

WEBSITE ACCESS TO SEC FILINGS

NEE and FPL make their SEC filings, including the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on NEE's internet website, www.nexteraenergy.com, as soon as reasonably practicable after those documents are electronically filed with or furnished to the SEC. The information and materials available on NEE's website (or any of its subsidiaries' websites) are not incorporated by reference into this combined annual report on Form 10-K. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding registrants that file electronically with the SEC at http://www.sec.gov.

EXECUTIVE OFFICERS OF NEE[a]

Name	Age	Position	Effective Date
Christopher A. Bennett	53	Executive Vice President & Chief Strategy, Policy & Business Process Improvement Officer of NEE	February 15, 2008[b]
Paul I. Cutler	52	Treasurer of NEE Treasurer of FPL Assistant Secretary of NEE and FPL	February 19, 2003 February 18, 2003 December 10, 1997
Moray P. Dewhurst	56	Vice Chairman and Chief Financial Officer, and Executive Vice President - Finance of NEE Executive Vice President, Finance and Chief Financial Officer of FPL	October 5, 2011
Shaun J. Francis	40	Executive Vice President, Human Resources of NEE Executive Vice President, Human Resources of FPL	August 16, 2010 January 31, 2011
Chris N. Froggatt	54	Vice President of NEE Controller and Chief Accounting Officer of NEE	October 19, 2009 February 27, 2010
Lewis Hay, III	56	Chief Executive Officer of NEE Chairman of NEE and FPL	June 11, 2001 January 1, 2002
Joseph T. Kelliher	51	Executive Vice President, Federal Regulatory Affairs of NEE	May 18, 2009
Robert L. McGrath	58	Executive Vice President, Engineering, Construction & Corporate Services of NEE and FPL	February 21, 2005[b]
Manoochehr K. Nazar	57	Executive Vice President, Nuclear Division and Chief Nuclear Officer of NEE Executive Vice President, Nuclear Division and Chief Nuclear Officer of FPL	January 1, 2010 January 15, 2010
Armando J. Olivera	62	Chief Executive Officer of FPL	July 17, 2008
Armando Pimentel, Jr.	49	President and Chief Executive Officer of NEER	October 5, 2011
James L. Robo	49	President and Chief Operating Officer of NEE	December 15, 2006
Antonio Rodriguez	69	Executive Vice President, Power Generation Division of NEE Executive Vice President, Power Generation Division of FPL	January 1, 2007[b] July 1, 1999[b]
Charles E. Sieving	39	Executive Vice President & General Counsel of NEE Executive Vice President of FPL	December 1, 2008 January 1, 2009

(a) Information is as of February 27, 2012. Executive officers are elected annually by, and serve at the pleasure of, their respective boards of directors. Except as noted below, each officer has held his present position for five years or more and his employment history is continuous. Mr. Bennett was vice president, business strategy & policy of NEE from July 2007 to February 2008. From September 1995 to June 2007, Mr. Bennett was vice president of Dean & Company, a management consulting and investment firm. Mr. Dewhurst has been vice chairman of NEE since August 2009 and was chief of staff of NEE from August 2009 to October 2011. From July 2001 to May 2008, Mr. Dewhurst was vice president, finance and chief financial officer of NEE and senior vice president, finance and chief financial officer of FPL. Mr. Francis was general manager of human resources for a division of General Electric Company, GE Transportation, a supplier to the railroad, marine, drilling, mining and wind power industries from February 2008 to August 2010. From February 2006 to February 2008, Mr. Francis served as general manager of human resources for a division of General Electric Company, GE Equipment Services, a leader in the transportation industry including rail cars, sea containers, tractor trailers, and truck leasing. Mr. Froggatt was the vice president and treasurer of Pinnacle West Capital Corporation, a public utility holding company, and its major subsidiary, Arizona Public Service Company (APS), a regulated electric utility, from December 2008 to October 2009. From October 2002 to December 2008, Mr. Froggatt was vice president, controller and chief accounting officer of APS. Mr. Hay was also chief executive officer of FPL from January 2002 to July 2008. Mr. Kelliher was chairman of the FERC from July 2005 to January 2009. Mr. Nazar was the chief nuclear officer of NEE from January 2009 to December 2009. Mr. Nazar was senior vice president and chief nuclear officer of FPL from November 2007 to January 2009. From October 2003 to November 2007, Mr. Nazar was senior vice president & chief nuclear officer of American Electric Power Company, Inc., a public utility holding company. Mr. Olivera was also president of FPL from June 2003 to December 2011. Mr. Olivera has announced that he will retire from FPL on May 2, 2012. Mr. Pimentel was chief financial officer of NEE and FPL from May 2008 to October 2011 and executive vice president, finance of NEE and FPL from February 2008 to October 2011. Prior to that, Mr. Pimentel was a partner of Deloitte & Touche LLP, an independent registered public accounting firm, from June 1998 to February 2008. Mr. Sieving was also assistant secretary of NEE from May 2010 to May 2011 and general counsel of FPL from January 2009 to May 2010. Mr. Sieving was executive vice president, general counsel and secretary of PAETEC Holding Corp., a communications services and solutions provider, from February 2007 to November 2008 and was primarily responsible for all legal and regulatory matters.

(b) NEE title changed from vice president to executive vice president effective May 23, 2008. Where applicable, FPL title changed from senior vice president to executive vice president effective July 17, 2008.

Item 1A. Risk Factors

Risks Relating to NEE's and FPL's Business

The business, financial condition, results of operations and prospects of NEE and FPL are subject to a variety of risks, many of which are beyond the control of NEE and FPL. The following is a description of important risks that may adversely affect the business, financial condition, results of operations and prospects of NEE and FPL and may cause actual results of NEE and FPL to differ substantially from those that NEE or FPL currently expects or seeks. In that event, the market price for the securities of NEE or FPL could decline. Accordingly, the risks described below should be carefully considered together with the other information set forth in this report and in future reports that NEE and FPL file with the SEC. The risks described below are not the only risks facing NEE and FPL. Additional risks and uncertainties may also materially adversely affect NEE's or FPL's business, financial condition, results of operations and prospects. Each of NEE and FPL has disclosed the material risks known to it to affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed to be material that may in the future adversely affect the performance or financial condition of NEE and FPL.

Regulatory, Legislative and Legal Risks

NEE's and FPL's business, financial condition, results of operations and prospects may be adversely affected by the extensive regulation of their business.

The operations of NEE and FPL are subject to complex and comprehensive federal, state and other regulation. This extensive regulatory framework, portions of which are more specifically identified in the following risk factors, regulates, among other things and to varying degrees, NEE's and FPL's industries, rates and cost structures, operation of nuclear power facilities, construction and operation of generation, transmission and distribution facilities and natural gas and oil production, transmission and fuel storage facilities, acquisition, disposal, depreciation and amortization of facilities and other assets, decommissioning costs and funding, service reliability, wholesale and retail competition, and commodities trading and derivatives transactions. In their business planning and in the management of their operations, NEE and FPL must address the effects of regulation on their business and any inability or failure to do so adequately could have a material adverse effect on their business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if they are unable to recover in a timely manner any significant amount of costs, a return on certain assets or an appropriate return on capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise.

FPL is a regulated entity subject to the jurisdiction of the FPSC over a wide range of business activities, including, among other items, the retail rates charged to its customers through base rates and cost recovery clauses, the terms and conditions of its services, procurement of electricity for its customers, issuance of securities, and aspects of the siting and operation of its generating plants and transmission and distribution systems for the sale of electric energy. The FPSC has the authority to disallow recovery by FPL of costs that it considers excessive or imprudently incurred and to determine the level of return that FPL is permitted to earn on its investments. The regulatory process, which may be adversely affected by the political, regulatory and economic environment in Florida and elsewhere, limits FPL's ability to increase earnings and does not provide any assurance as to achievement of authorized or other earnings levels. NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if any material amount of costs, a return on certain assets or an appropriate return on capital cannot be recovered through base rates, cost recovery clauses, other regulatory mechanisms or otherwise. Lone Star, an indirect wholly-owned subsidiary of NEE that is a regulated electric transmission utility subject to the jurisdiction of the PUCT, is subject to similar risks.

Regulatory decisions that are important to NEE and FPL may be materially adversely affected by political, regulatory and economic factors.

The local and national political, regulatory and economic environment has had, and may in the future have, an adverse effect on FPSC decisions with negative consequences for FPL. These decisions may require, for example, FPL to cancel or delay planned development activities, to reduce or delay other planned capital expenditures or to pay for investments or otherwise incur costs that it may not be able to recover through rates, each of which could have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL. Lone Star is subject to similar risks.

FPL's use of derivative instruments could be subject to prudence challenges and, if found imprudent, could result in disallowances of cost recovery for such use by the FPSC.

In the event that the FPSC engages in a prudence review of FPL's use of derivative instruments and finds such use to be imprudent, the FPSC could deny cost recovery for such use by FPL. Such an outcome could have a material adverse effect on FPL's business, financial condition, results of operations and prospects.

Any reduction or elimination of existing government support policies, including, but not limited to, tax incentives, RPS or feed-in tariffs, and ultimately any failure to renew or increase these existing support policies, could result in less demand for generation from NEER's renewable energy projects and could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

NEER depends heavily on government policies that support renewable energy and enhance the economic feasibility of developing and operating wind and solar energy projects in regions in which NEER operates or plans to develop and operate renewable energy facilities. The federal government, a majority of the 50 U.S. states and portions of Canada and Spain provide incentives, such as tax incentives, RPS or feed-in tariffs, that support the sale of energy from renewable energy facilities owned by NEER, such as wind and solar energy facilities. The applicable legislation often grants the relevant state public utility commission the ability to reduce electric supply companies' obligations to meet renewable energy requirements in specified circumstances. Any changes to, or the elimination of, governmental incentives that support renewable energy could result in less demand for generation from NEE's wind and solar energy projects and could have a material adverse effect on NEER's business, financial condition, results of operations and prospects.

NEER also depends heavily on investment cost recovery mechanisms currently available through the American Recovery and Reinvestment Act of 2009 (Recovery Act). The Recovery Act includes, among other things, provisions that allow companies building wind and solar energy facilities the option to choose between investment cost recovery mechanisms that make the development of such facilities economically attractive. Any changes to the Recovery Act that eliminate or reduce support for renewable generation projects could impede NEER's ability to economically develop wind and solar energy projects in the future and could have a material adverse effect on NEER's ability to develop renewable energy projects in the future.

If investments in renewable energy and associated projects are perceived less positively by legislators, regulators or the public, this could result in the non-renewal or elimination of beneficial tax policies, among other policies, that benefit NEER. Any such legislative changes could impede NEER's ability to economically develop wind and solar energy projects in the future and could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected as a result of new or revised laws, regulations or interpretations or other regulatory initiatives.

NEE's and FPL's business is influenced by various legislative and regulatory initiatives, including, but not limited to, initiatives regarding deregulation or restructuring of the energy industry, regulation of the commodities trading and derivatives markets, and environmental regulation, such as regulation of air emissions, regulation of water consumption and water discharges, and regulation of gas and oil infrastructure operations, as well as associated environmental permitting. Changes in the nature of the regulation of NEE's and FPL's business could have a material adverse effect on NEE's and FPL's results of operations. NEE and FPL are unable to predict future legislative or regulatory changes, initiatives or interpretations, although any such changes, initiatives or interpretations may increase costs and competitive pressures on NEE and FPL, which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

FPL has limited competition in the Florida market for retail electricity customers. Any changes in Florida law or regulation which introduce competition in the Florida retail electricity market could have a material adverse effect on FPL's business, financial condition, results of operations and prospects. There can be no assurance that FPL will be able to respond adequately to such regulatory changes, which could have a material adverse effect on FPL's business, financial condition, results of operations and prospects.

NEER is subject to FERC rules related to transmission that are designed to facilitate competition in the wholesale market on practically a nationwide basis by providing greater certainty, flexibility and more choices to wholesale power customers. NEE cannot predict the impact of changing FERC rules or the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond NEE's control. There can be no assurance that NEER will be able to respond adequately or sufficiently quickly to such rules and developments, or to any other changes that reverse or restrict the competitive restructuring of the energy industry in those jurisdictions in which such restructuring has occurred. Any of these events could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if the rules implementing the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) broaden the scope of its provisions regarding the regulation of OTC financial derivatives and make them applicable to NEE and FPL.

The Dodd-Frank Act, enacted into law in July 2010, among other things, provides for the regulation of the OTC derivatives market. The Dodd-Frank Act includes provisions that will require certain OTC derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. While the legislation is broad and detailed, substantial portions of the legislation require implementing rules to be adopted by federal governmental agencies including, but not limited to, the SEC and the CFTC.

NEE and FPL cannot predict the final rules that will be adopted to implement the OTC derivatives market provisions of the Dodd-

Frank Act. Those rules could negatively affect NEE's and FPL's ability to hedge their commodity and interest rate risks, which could have a material adverse effect on NEE's and FPL's results of operations. NEE or FPL may have portions of their business that may be required to register as swap dealers or major swap participants and submit to extensive regulation if they wish to continue certain aspects of their derivative activities. The rules could also cause NEER to restructure part of its energy marketing and trading operations or to discontinue certain portions of its business. In addition, if the rules require NEE and FPL to post significant amounts of cash collateral with respect to swap transactions, NEE's and FPL's liquidity could be materially adversely affected, and their ability to enter into OTC derivatives to hedge commodity and interest rate risks could be significantly limited. Reporting and compliance requirements of the rules also could significantly increase operating costs and expose NEE and FPL to penalties for non-compliance. The Dodd-Frank Act or other initiatives also could impede the efficient operation of the commodities trading and derivatives markets, which could also materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

NEE and FPL are subject to numerous environmental laws and regulations that require capital expenditures, increase their cost of operations and may expose them to liabilities.

NEE and FPL are subject to domestic and foreign environmental laws and regulations, including, but not limited to, extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, climate change, emissions of greenhouse gases, including, but not limited to, CO_2, waste management, hazardous wastes, marine, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health (including, but not limited to, electric and magnetic fields from power lines and substations), safety and RPS that could, among other things, prevent or delay the development of power generation, power or natural gas transmission, or other infrastructure projects, restrict the output of some existing facilities, limit the use of some fuels required for the production of electricity, require additional pollution control equipment, and otherwise increase costs, increase capital expenditures and limit or eliminate certain operations.

There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations, and those costs could be even more significant in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. For example, among other potential or pending changes, the use of hydraulic fracturing or similar technologies to drill for natural gas and related compounds used by NEE's gas infrastructure business is currently being debated for potential regulation at the state and federal levels.

Violations of current or future laws, rules and regulations could expose NEE and FPL to regulatory and legal proceedings, disputes with, and legal challenges by, third parties, and potentially significant civil fines, criminal penalties and other sanctions.

NEE's and FPL's business could be negatively affected by federal or state laws or regulations mandating new or additional limits on the production of greenhouse gas emissions.

Federal or state laws or regulations may be adopted that would impose new or additional limits on the emissions of greenhouse gases, including, but not limited to, CO2 and methane, from electric generating units using fossil fuels like coal and natural gas. The potential effects of such greenhouse gas emission limits on NEE's and FPL's electric generating units are subject to significant uncertainties based on, among other things, the timing of the implementation of any new requirements, the required levels of emission reductions, the nature of any market-based or tax-based mechanisms adopted to facilitate reductions, the relative availability of greenhouse gas emission reduction offsets, the development of cost-effective, commercial-scale carbon capture and storage technology and supporting regulations and liability mitigation measures, and the range of available compliance alternatives.

While NEE's and FPL's electric generating units emit greenhouse gases at a lower rate of emissions than most of the U.S. electric generation sector, the results of operations of NEE and FPL could be adversely affected to the extent that new federal or state legislation or regulators impose any new greenhouse gas emission limits. Any future limits on greenhouse gas emissions could:

- create substantial additional costs in the form of taxes or emission allowances;
- make some of NEE's and FPL's electric generating units uneconomical to operate in the long term;
- require significant capital investment in carbon capture and storage technology, fuel switching, or the replacement of high-emitting generation facilities with lower-emitting generation facilities; or
- affect the availability or cost of fossil fuels.

There can be no assurance that NEE or FPL would be able to completely recover any such costs or investments, which could have a material adverse effect on their business, financial condition, results of operations and prospects.

Extensive federal regulation of the operations of NEE and FPL exposes NEE and FPL to significant and increasing compliance costs and may also expose them to substantial monetary penalties and other sanctions for compliance failures.

NEE and FPL are subject to extensive federal regulation, which imposes significant and increasing compliance costs on their operations. Additionally, any actual or alleged compliance failures could result in significant costs and other potentially adverse effects of regulatory investigations, proceedings, settlements, decisions and claims, including, among other items, potentially significant monetary penalties. As an example, under the Energy Policy Act of 2005, NEE and FPL, as owners and operators of bulk power transmission systems and/or electric generation facilities, are subject to mandatory reliability standards. Compliance

with these mandatory reliability standards may subject NEE and FPL to higher operating costs and may result in increased capital expenditures. If FPL or NEE is found not to be in compliance with these standards, it may incur substantial monetary penalties and other sanctions. Both the costs of regulatory compliance and the costs that may be imposed as a result of any actual or alleged compliance failures could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, regulations and interpretations, the financial condition and results of operations of NEE and FPL, and the resolution of audit issues raised by taxing authorities. Ultimate resolution of income tax matters may result in material adjustments to tax-related assets and liabilities, which could negatively affect NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects may be materially adversely affected due to adverse results of litigation.

NEE's and FPL's business, financial condition, results of operations and prospects may be materially affected by adverse results of litigation. Unfavorable resolution of legal proceedings in which NEE is involved or other future legal proceedings, including, but not limited to, class action lawsuits, may have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL.

Operational Risks

NEE's and FPL's business, financial condition, results of operations and prospects could suffer if NEE and FPL do not proceed with projects under development or are unable to complete the construction of, or capital improvements to, electric generation, transmission and distribution facilities, gas infrastructure facilities or other facilities on schedule or within budget.

NEE's and FPL's ability to complete construction of, and capital improvement projects for, their electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities on schedule and within budget may be adversely affected by escalating costs for materials and labor and regulatory compliance, inability to obtain or renew necessary licenses, rights-of-way, permits or other approvals on acceptable terms or on schedule, disputes involving contractors, labor organizations, land owners, governmental entities, environmental groups, Native American and aboriginal groups, and other third parties, negative publicity, transmission interconnection issues and other factors. If any development project or construction or capital improvement project is not completed, is delayed or is subject to cost overruns, certain associated costs may not be approved for recovery or recoverable through regulatory mechanisms that may otherwise be available, and NEE and FPL could become obligated to make delay or termination payments or become obligated for other damages under contracts, could experience the loss of tax credits or tax incentives and could be required to write-off all or a portion of their investments in the project. Any of these events could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE and FPL may face risks related to project siting, financing, construction, permitting, governmental approvals and the negotiation of project development agreements that may impede their development and operating activities.

NEE and FPL own, develop, construct, manage and operate electric-generating and transmission facilities. A key component of NEE's and FPL's growth is their ability to construct and operate generation and transmission facilities to meet customer needs. As part of these operations, NEE and FPL must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. Should NEE or FPL be unsuccessful in obtaining necessary licenses or permits on acceptable terms, should there be a delay in obtaining or renewing necessary licenses or permits or should regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances on NEE or FPL, NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected. Any failure to negotiate successful project development agreements for new facilities with third parties could have similar results.

The operation and maintenance of NEE's and FPL's electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities are subject to many operational risks, the consequences of which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities are subject to many operational risks. Operational risks could result in, among other things, lost revenues due to prolonged outages, increased expenses due to monetary penalties or fines for compliance failures, liability to third parties for property and personal injury damage,

a failure to perform under applicable power sales agreements and associated loss of revenues from terminated agreements or liability for liquidated damages under continuing agreements, and replacement equipment costs or an obligation to purchase or generate replacement power at potentially higher prices.

Uncertainties and risks inherent in operating and maintaining NEE's and FPL's facilities include, but are not limited to:

- risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned;
- failures in the availability, acquisition or transportation of fuel or other necessary supplies;
- the impact of unusual or adverse weather conditions, including, but not limited to, natural disasters such as hurricanes, floods, earthquakes and droughts;
- performance below expected or contracted levels of output or efficiency;
- breakdown or failure, including, but not limited to, explosions, fires or other major events, of equipment, transmission and distribution lines or pipelines;
- availability of replacement equipment;
- risks of property damage or human injury from energized equipment, hazardous substances or explosions, fires or other events;
- availability of adequate water resources and ability to satisfy water intake and discharge requirements;
- inability to manage properly or mitigate known equipment defects in NEE's and FPL's facilities;
- use of new or unproven technology;
- risks associated with dependence on a specific fuel source, such as commodity price risk and lack of available alternative fuel sources;
- increased competition due to, among other factors, new facilities, excess supply and shifting demand; and
- insufficient insurance, warranties or performance guarantees to cover any or all lost revenues or increased expenses from the foregoing.

NEE's and FPL's business, financial condition, results of operations and prospects may be negatively affected by a lack of growth or slower growth in the number of customers or in customer usage.

Growth in customer accounts and growth of customer usage each directly influence the demand for electricity and the need for additional power generation and power delivery facilities. Customer growth and customer usage are affected by a number of factors outside the control of NEE and FPL, such as mandated energy efficiency measures, demand side management goals, and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. A lack of growth, or a decline, in the number of customers or in customer demand for electricity may cause NEE and FPL to fail to fully realize the anticipated benefits from significant investments and expenditures and could have a material adverse effect on NEE's and FPL's own growth, business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects can be materially adversely affected by weather conditions, including, but not limited to, the impact of severe weather.

Weather conditions directly influence the demand for electricity and natural gas and other fuels and affect the price of energy and energy-related commodities. In addition, severe weather, such as hurricanes, floods and earthquakes, can be destructive and cause power outages and property damage, reduce revenue, affect fuel supply, and require NEE and FPL to incur additional costs, for example, to restore service and repair damaged facilities, obtain replacement power and access available financing sources. Furthermore, NEE's and FPL's physical plant could be placed at greater risk of damage should changes in global climate produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, abnormal levels of precipitation and, particularly relevant to FPL, a change in sea level. FPL operates in the east and lower west coasts of Florida, an area that historically has been prone to severe weather events, such as hurricanes. A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, storage or distribution systems in the event of a hurricane, tornado or other severe weather event, or otherwise, could prevent NEE and FPL from operating their business in the normal course and could result in any of the adverse consequences described above. Any of the foregoing could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

At FPL and other businesses of NEE where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

Changes in weather can also affect the production of electricity at power generating facilities, including, but not limited to, NEER's wind, solar and hydro-powered facilities. For example, the level of wind resource affects the revenue produced by wind generating facilities. Because the levels of wind, solar and hydro resources are variable and difficult to predict, NEER's results of operations for individual wind, solar and hydro facilities specifically, and NEE's results of operations generally, may vary significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected.

Threats of terrorism and catastrophic events that could result from terrorism, cyber attacks, or individuals and/or groups attempting to disrupt NEE's and FPL's business, or the businesses of third parties, may materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

NEE and FPL are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. NEE's and FPL's generation, transmission and distribution facilities, fuel storage facilities, information technology systems and other infrastructure facilities and systems could be direct targets of, or be indirectly affected by, such activities.

Terrorist acts or other similar events affecting NEE's and FPL's systems and facilities, or those of third parties on which NEE and FPL rely, could harm NEE's and FPL's business, for example, by limiting their ability to generate, purchase or transmit power, by limiting their ability to bill customers and collect and process payments, and by delaying their development and construction of new generating facilities or capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues, significant additional costs (for example, to repair assets, implement additional security requirements or maintain or acquire insurance), and reputational damage, could adversely affect NEE's and FPL's operations (for example, by contributing to disruption of supplies and markets for natural gas, oil and other fuels), and could impair NEE's and FPL's ability to raise capital (for example, by contributing to financial instability and lower economic activity).

The ability of NEE and FPL to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. NEE's and FPL's insurance coverage does not provide protection against all significant losses.

Insurance coverage may not continue to be available or may not be available at rates or on terms similar to those presently available to NEE and FPL. The ability of NEE and FPL to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. If insurance coverage is not available or obtainable on acceptable terms, NEE or FPL may be required to pay costs associated with adverse future events. NEE and FPL generally are not fully insured against all significant losses. For example, FPL is not fully insured against hurricane-related losses, but would instead seek recovery of such uninsured losses from customers subject to approval by the FPSC, to the extent losses exceed restricted funds set aside to cover the cost of storm damage. A loss for which NEE or FPL is not fully insured could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

If supply costs necessary to provide NEER's full energy and capacity requirement services are not favorable, operating costs could increase and adversely affect NEE's business, financial condition, results of operations and prospects.

NEER provides full energy and capacity requirements services primarily to distribution utilities, which include load-following services and various ancillary services to satisfy all or a portion of such utilities' power supply obligations to their customers. The supply costs for these transactions may be affected by a number of factors, including, but not limited to, events that may occur after such utilities have committed to supply power, such as weather conditions, fluctuating prices for energy and ancillary services, and the ability of the distribution utilities' customers to elect to receive service from competing suppliers. NEER may not be able to recover all of its increased supply costs, which could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

Due to the potential for significant volatility in market prices for fuel, electricity and renewable and other energy commodities, NEER's inability or failure to hedge effectively its assets or positions against changes in commodity prices, volumes, interest rates, counterparty credit risk or other risk measures could significantly impair NEE's results of operations.

There can be significant volatility in market prices for fuel, electricity and renewable and other energy commodities. NEE's inability to manage properly or hedge the commodity risks within its portfolios, based on factors both from within or wholly or partially outside of NEE's control, may materially adversely affect NEE's business, financial condition, results of operations and prospects.

Sales of power on the spot market or on a short-term contractual basis may cause NEE's results of operations to be volatile.

A portion of NEER's power generation facilities operate wholly or partially without long-term power purchase agreements. Power from these facilities is sold on the spot market or on a short-term contractual basis. Spot market sales are subject to market volatility, and the revenue generated from these sales is subject to fluctuation that may cause NEE's results of operations to be volatile. NEER and NEE may not be able to manage volatility adequately, which could then have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

Reductions in the liquidity of energy markets may restrict the ability of NEE to manage its operational risks, which, in turn, could negatively affect NEE's results of operations.

NEE is an active participant in energy markets. The liquidity of regional energy markets is an important factor in the company's ability to manage risks in these operations. Over the past several years, other market participants have ceased or significantly reduced their activities in energy markets as a result of several factors, including, but not limited to, government investigations, changes in market design and deteriorating credit quality. Liquidity in the energy markets can be adversely affected by price volatility, restrictions on the availability of credit and other factors, and any reduction in the liquidity of energy markets could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

If price movements significantly or persistently deviate from historical behavior, NEE's and FPL's hedging and trading procedures and associated risk management tools may not protect against significant losses.

NEE and FPL have hedging and trading procedures and associated risk management tools, such as separate but complementary financial, credit, operational, compliance and legal reporting systems, internal controls, management review processes and other mechanisms. NEE and FPL are unable to assure that such procedures and tools will be effective against all potential risks. Additionally, risk management tools and metrics such as daily value at risk, earnings at risk, stop loss limits and liquidity guidelines are based on historical price movements. Due to the inherent uncertainty involved in price movements and potential deviation from historical pricing behavior, NEE and FPL are unable to assure that their risk management tools and metrics will be effective to protect against adverse effects on their business, financial condition, results of operations and prospects. Such adverse effects could be material.

If power transmission or natural gas, nuclear fuel or other commodity transportation facilities are unavailable or disrupted, FPL's and NEER's ability to sell and deliver power or natural gas may be limited.

FPL and NEER depend upon power transmission and natural gas, nuclear fuel and other commodity transportation facilities, many of which they do not own. Occurrences affecting the operation of these facilities that may or may not be beyond FPL's and NEER's control (such as severe weather or a generator or transmission facility outage, pipeline rupture, or sudden and significant increase or decrease in wind generation) may limit or halt the ability of FPL and NEER to sell and deliver power and natural gas, or to purchase necessary fuels and other commodities, which could materially adversely impact NEE's and FPL's business, financial condition, results of operations and prospects.

NEE and FPL are subject to credit and performance risk from customers, hedging counterparties and vendors.

NEE and FPL are exposed to risks associated with the creditworthiness and performance of their customers, hedging counterparties and vendors under contracts for the supply of equipment, materials, fuel and other goods and services required for their business operations and for the construction and operation of, and for capital improvements to, their facilities. Adverse conditions in the energy industry or the general economy, as well as circumstances of individual customers, hedging counterparties and vendors, may affect the ability of some customers, hedging counterparties and vendors to perform as required under their contracts with NEE and FPL.

If any hedging, vending or other counterparty fails to fulfill its contractual obligations, NEE and FPL may need to make arrangements with other counterparties or vendors, which could result in financial losses, higher costs, untimely completion of power generation facilities and other projects, and/or a disruption of their operations. If a defaulting counterparty is in poor financial condition, NEE and FPL may not be able to recover damages for any contract breach.

NEE and FPL could recognize financial losses or a reduction in operating cash flows if a counterparty fails to perform or make payments in accordance with the terms of derivative contracts or if NEE or FPL is required to post margin cash collateral under derivative contracts.

NEE and FPL use derivative instruments, such as swaps, options, futures and forwards, some of which are traded in the OTC markets or on exchanges, to manage their commodity and financial market risks, and for NEE to engage in trading and marketing activities. Any failures by their counterparties to perform or make payments in accordance with the terms of those transactions could have a material adverse effect on NEE's or FPL's business, financial condition, results of operations and prospects. Similarly, any requirement for FPL or NEE to post margin cash collateral under its derivative contracts could have a material adverse effect on its business, financial condition, results of operations and prospects.

NEE and FPL are highly dependent on sensitive and complex information technology systems, and any failure or breach of those systems could have a material adverse effect on their business, financial condition, results of operations and prospects.

NEE and FPL operate in a highly regulated industry that requires the continuous functioning of sophisticated information technology systems and network infrastructure. Despite NEE's and FPL's implementation of security measures, all of their technology systems are vulnerable to disability, failures or unauthorized access due to such activities. If NEE's or FPL's information technology systems were to fail or be breached, and NEE or FPL was unable to recover in a timely way, NEE and FPL would be unable to fulfill critical business functions, and sensitive confidential and other data could be compromised.

NEE's and FPL's business is highly dependent on their ability to process and monitor, on a daily basis, a very large number of

transactions, many of which are highly complex and cross numerous and diverse markets. Due to the size, scope and geographical reach of NEE's and FPL's business, and due to the complexity of the process of power generation, transmission and distribution, the development and maintenance of information technology systems to keep track of and process this information is both critical and extremely challenging. NEE's and FPL's operating systems and facilities may fail to operate properly or become disabled as a result of events that are either within, or wholly or partially outside, their control, such as operator error, severe weather or terrorist activities. Any such failure or disabling event could adversely affect NEE's and FPL's ability to process transactions and provide services, and their financial results and liquidity.

NEE and FPL add, modify and replace information systems on a regular basis. Modifying existing information systems or implementing new or replacement information systems is costly and involves risks, including, but not limited to, integrating the modified, new or replacement system with existing systems and processes, implementing associated changes in accounting procedures and controls, and ensuring that data conversion is accurate and consistent. Any disruptions or deficiencies in existing information systems, or disruptions, delays or deficiencies in the modification or implementation of new information systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively impact the effectiveness of the companies' control environment, and/or the companies' ability to timely file required regulatory reports.

NEE and FPL also face the risks of operational failure or capacity constraints of third parties, including, but not limited to, those who provide power transmission and natural gas transportation services.

NEE's and FPL's retail businesses are subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to their reputation and/or the results of operations of the retail business.

NEE's and FPL's retail businesses require access to sensitive customer data in the ordinary course of business. NEE's and FPL's retail businesses may also need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center services, to the retail businesses. If a significant breach occurred, the reputation of NEE and FPL could be adversely affected, customer confidence could be diminished, or customer information could be subject to identity theft. NEE and FPL would be subject to costs associated with the breach and/or NEE and FPL could be subject to fines and legal claims, any of which may have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL.

NEE and FPL could recognize financial losses as a result of volatility in the market values of derivative instruments and limited liquidity in OTC markets.

NEE and FPL execute transactions in derivative instruments on either recognized exchanges or via the OTC markets, depending on management's assessment of the most favorable credit and market execution factors. Transactions executed in OTC markets have the potential for greater volatility and less liquidity than transactions on recognized exchanges. As a result, NEE and FPL may not be able to execute desired OTC transactions due to such heightened volatility and limited liquidity.

In the absence of actively quoted market prices and pricing information from external sources, the valuation of derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these derivative instruments and have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE and FPL may be adversely affected by negative publicity.

From time to time, political and public sentiment may result in a significant amount of adverse press coverage and other adverse public statements affecting NEE and FPL. Adverse press coverage and other adverse statements, whether or not driven by political or public sentiment, may also result in investigations by regulators, legislators and law enforcement officials or in legal claims. Responding to these investigations and lawsuits, regardless of the ultimate outcome of the proceeding, can divert the time and effort of senior management from NEE's and FPL's business.

Addressing any adverse publicity, governmental scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of NEE and FPL, on the morale and performance of their employees and on their relationships with their respective regulators. It may also have a negative impact on their ability to take timely advantage of various business and market opportunities. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects may be materially adversely affected if FPL is unable to maintain, negotiate or renegotiate franchise agreements on acceptable terms with municipalities and counties in Florida.

FPL must negotiate franchise agreements with municipalities and counties in Florida to provide electric services within such municipalities and counties, and electricity sales generated pursuant to these agreements represent a very substantial portion of

FPL's revenues. If FPL is unable to maintain, negotiate or renegotiate such franchise agreements on acceptable terms, it could contribute to lower earnings and FPL may not fully realize the anticipated benefits from significant investments and expenditures, which could materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

Increasing costs associated with health care plans may materially adversely affect NEE's and FPL's results of operations.

The costs of providing health care benefits to employees and retirees have increased substantially in recent years. NEE and FPL anticipate that their employee benefit costs, including, but not limited to, costs related to health care plans for employees and former employees, will continue to rise. The increasing costs and funding requirements associated with NEE's and FPL's health care plans may materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects could be negatively affected by the lack of a qualified workforce or the loss or retirement of key employees.

NEE and FPL may not be able to service customers, grow their business or generally meet their other business plan goals effectively and profitably if they do not attract and retain a qualified workforce. Additionally, the loss or retirement of key executives and other employees may materially adversely affect service and productivity and contribute to higher training and safety costs.

Over the next several years, a significant portion of NEE's and FPL's workforce, including, but not limited to, many workers with specialized skills maintaining and servicing the nuclear generation facilities and electrical infrastructure, will be eligible to retire. Such highly skilled individuals may not be able to be replaced quickly due to the technically complex work they perform. If a significant amount of such workers retire and are not replaced, the subsequent loss in productivity and increased recruiting and training costs could result in a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected by work strikes or stoppages and increasing personnel costs.

Employee strikes or work stoppages could disrupt operations and lead to a loss of revenue and customers. Personnel costs may also increase due to inflationary or competitive pressures on payroll and benefits costs and revised terms of collective bargaining agreements with union employees. These consequences could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's ability to successfully identify, complete and integrate acquisitions is subject to significant risks, including, but not limited to, the effect of increased competition for acquisitions resulting from the consolidation of the power industry.

NEE is likely to encounter significant competition for acquisition opportunities that may become available as a result of the consolidation of the power industry in general. In addition, NEE may be unable to identify attractive acquisition opportunities at favorable prices and to complete and integrate them successfully and in a timely manner.

Nuclear Generation Risks

The construction, operation and maintenance of NEE's and FPL's nuclear generation facilities involve environmental, health and financial risks that could result in fines or the closure of the facilities and in increased costs and capital expenditures.

NEE's and FPL's nuclear generation facilities are subject to environmental, health and financial risks, including, but not limited to, those relating to site storage of spent nuclear fuel, the disposition of spent nuclear fuel, leakage and emissions of tritium and other radioactive elements in the event of a nuclear accident or otherwise, the threat of a terrorist attack and other potential liabilities arising out of the ownership or operation of the facilities. NEE and FPL maintain decommissioning funds and external insurance coverage which are intended to reduce the financial exposure to some of these risks; however, the cost of decommissioning nuclear generation facilities could exceed the amount available in NEE's and FPL's decommissioning funds, and the exposure to liability and property damages could exceed the amount of insurance coverage. If NEE or FPL is unable to recover the additional costs incurred through insurance or, in the case of FPL, through regulatory mechanisms, their business, financial condition, results of operations and prospects could be materially adversely affected.

In the event of an incident at any nuclear generation facility in the U.S. or at certain nuclear generation facilities in Europe, NEE and FPL could be assessed significant retrospective assessments and/or retrospective insurance premiums as a result of their participation in a secondary financial protection system and nuclear insurance mutual companies.

Liability for accidents at nuclear power plants is governed by the Price-Anderson Act, which limits the liability of nuclear reactor owners to the amount of insurance available from both private sources and an industry retrospective payment plan. In accordance with this Act, NEE maintains $375 million of private liability insurance per site, which is the maximum obtainable, and participates in a secondary financial protection system, which provides up to $12.2 billion of liability insurance coverage per incident at any nuclear reactor in the U.S. Under the secondary financial protection system, NEE is subject to retrospective assessments and/or retrospective insurance premiums of up to $940 million ($470 million for FPL), plus any applicable taxes, per incident at any nuclear

reactor in the U.S. or at certain nuclear generation facilities in Europe, regardless of fault or proximity to the incident, payable at a rate not to exceed $140 million ($70 million for FPL) per incident per year. Such assessments, if levied, could materially adversely affect NEE's and FPL's business, financial condition, results of operations and prospects.

NRC orders or new regulations related to increased security measures and any future safety requirements promulgated by the NRC could require NEE and FPL to incur substantial operating and capital expenditures at their nuclear generation facilities.

The NRC has broad authority to impose licensing and safety-related requirements for the operation and maintenance of nuclear generation facilities, the addition of capacity at existing nuclear generation facilities and the construction of nuclear generation facilities, and these requirements are subject to change. In the event of non-compliance, the NRC has the authority to impose fines or shut down a nuclear generation facility, or to take both of these actions, depending upon its assessment of the severity of the situation, until compliance is achieved. Any of the foregoing events could require NEE and FPL to incur increased costs and capital expenditures, and could reduce revenues.

Any serious nuclear incident occurring at a NEE or FPL plant could result in substantial remediation costs and other expenses. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear generation facility. An incident at a nuclear facility anywhere in the world also could cause the NRC to impose additional conditions or other requirements on the industry, which could increase costs, reduce revenues and result in additional capital expenditures.

The inability to operate any of NEER's or FPL's nuclear generation units through the end of their respective operating licenses could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

The operating licenses for NEE's and FPL's nuclear generation facilities extend through at least 2030. If the facilities cannot be operated for any reason through the life of those operating licenses, NEE or FPL may be required to increase depreciation rates, incur impairment charges and accelerate future decommissioning expenditures, any of which could materially adversely affect their business, financial condition, results of operations and prospects.

Various hazards posed to nuclear generation facilities, along with increased public attention to and awareness of such hazards, could result in increased nuclear licensing or compliance costs which are difficult or impossible to predict and could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

The threat of terrorist activity, as well as recent international events implicating the safety of nuclear facilities, could result in more stringent or complex measures to keep facilities safe from a variety of hazards, including, but not limited to, natural disasters such as earthquakes and tsunamis, as well as terrorist or other criminal threats. This increased focus on safety could result in higher compliance costs which, at present, cannot be assessed with any measure of certainty and which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, and for other purposes. If planned outages last longer than anticipated or if there are unplanned outages, NEE's and FPL's results of operations and financial condition could be materially adversely affected.

NEE's and FPL's nuclear units are periodically removed from service to accommodate normal refueling and maintenance outages, including, but not limited to, inspections, repairs and certain other modifications. In addition, outages may be scheduled, often in connection with a refueling outage, to replace equipment, to increase the generation capacity at a particular nuclear unit, or for other purposes, and those planned activities increase the time the unit is not in operation. In the event that a scheduled outage lasts longer than anticipated or in the event of an unplanned outage due to, for example, equipment failure, such outages could materially adversely affect NEE's or FPL's business, financial condition, results of operations and prospects.

Liquidity, Capital Requirements and Common Stock Risks

Disruptions, uncertainty or volatility in the credit and capital markets may negatively affect NEE's and FPL's ability to fund their liquidity and capital needs and to meet their growth objectives, and can also adversely affect the results of operations and financial condition of NEE and FPL.

NEE and FPL rely on access to capital and credit markets as significant sources of liquidity for capital requirements and other operations requirements that are not satisfied by operating cash flows. Disruptions, uncertainty or volatility in those capital and credit markets, including, but not limited to, the conditions of the most recent financial crises in the U.S. and abroad, could increase NEE's and FPL's cost of capital. If NEE or FPL is unable to access regularly the capital and credit markets on terms that are reasonable, it may have to delay raising capital, issue shorter-term securities and incur an unfavorable cost of capital, which, in turn, could adversely affect its ability to grow its business, could contribute to lower earnings and reduced financial flexibility, and could have a material adverse effect on its business, financial condition, results of operations and prospects.

Although NEE's competitive energy subsidiaries have used non-recourse or limited-recourse, project-specific financing in the past, market conditions and other factors could adversely affect the future availability of such financing. The inability of NEE's subsidiaries to access the capital and credit markets to provide project-specific financing for electric-generating and other energy facilities on favorable terms, whether because of disruptions or volatility in those markets or otherwise, could necessitate additional capital raising or borrowings by NEE and/or NEECH in the future.

The inability of subsidiaries that have existing project-specific financing arrangements to meet the requirements of various agreements relating to those financings could give rise to a project-specific financing default which, if not cured or waived, might result in the specific project, and potentially in some limited instances its parent companies, being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have rights to foreclose against the project assets and related collateral. Such an occurrence also could result in NEE expending additional funds or incurring additional obligations over the shorter term to ensure continuing compliance with project-specific financing arrangements based upon the expectation of improvement in the project's performance or financial returns over the longer term. Any of these actions could materially adversely affect NEE's business, financial condition, results of operations and prospects, as well as the availability or terms of future financings for NEE or its subsidiaries.

NEE's, NEECH's and FPL's inability to maintain their current credit ratings may adversely affect NEE's and FPL's liquidity and results of operations, limit the ability of NEE and FPL to grow their business, and increase interest costs.

The inability of NEE, NEECH and FPL to maintain their current credit ratings could adversely affect their ability to raise capital or obtain credit on favorable terms, which, in turn, could impact NEE's and FPL's ability to grow their business and service indebtedness and repay borrowings, and would likely increase their interest costs. Some of the factors that can affect credit ratings are cash flows, liquidity, the amount of debt as a component of total capitalization, and political, legislative and regulatory actions. There can be no assurance that one or more of the ratings of NEE, NEECH and FPL will not be lowered or withdrawn entirely by a rating agency.

NEE's and FPL's liquidity may be impaired if their creditors are unable to fund their credit commitments to the companies or to maintain their current credit ratings.

The inability of NEE's, NEECH's and FPL's credit providers to fund their credit commitments or to maintain their current credit ratings could require NEE, NEECH or FPL, among other things, to renegotiate requirements in agreements, find an alternative credit provider with acceptable credit ratings to meet funding requirements, or post cash collateral and could have a material adverse effect on NEE's and FPL's liquidity.

Poor market performance and other economic factors could affect NEE's and FPL's defined benefit pension plan's funded status, which may materially adversely affect NEE's and FPL's liquidity and results of operations.

NEE sponsors a qualified noncontributory defined benefit pension plan for substantially all employees of NEE and its subsidiaries. A decline in the market value of the assets held in the defined benefit pension plan due to poor investment performance or other factors may increase the funding requirements for this obligation.

NEE's and FPL's defined benefit pension plan is sensitive to changes in interest rates, since, as interest rates decrease the funding liabilities increase, potentially increasing benefits costs and funding requirements. Any increase in benefits costs or funding requirements may have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

Poor market performance and other economic factors could adversely affect the asset values of NEE's and FPL's nuclear decommissioning funds, which may materially adversely affect NEE's and FPL's liquidity and results of operations.

NEE and FPL are required to maintain decommissioning funds to satisfy their future obligations to decommission their nuclear power plants. A decline in the market value of the assets held in the decommissioning funds due to poor investment performance or other factors may increase the funding requirements for these obligations. Any increase in funding requirements may have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

Certain of NEE's investments are subject to changes in market value and other risks, which may adversely affect NEE's liquidity and financial results.

NEE holds other investments where changes in the fair value affect NEE's financial results. In some cases there may be no observable market values for these investments, requiring fair value estimates to be based on other valuation techniques. This type of analysis requires significant judgment and the actual values realized in a sale of these investments could differ materially from those estimated. A sale of an investment below previously estimated value, or other decline in the fair value of an investment, could result in losses or the write-off of such investment, and may have an material adverse effect on NEE's financial condition and results of operations.

NEE may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to NEE.

NEE is a holding company and, as such, has no material operations of its own. Substantially all of NEE's consolidated assets are held by its subsidiaries. NEE's ability to meet its financial obligations, including, but not limited to, its guarantees, and to pay dividends on its common stock are primarily dependent on its subsidiaries' net income and cash flows, which are subject to the risks of their respective businesses, and their ability to pay upstream dividends or to repay funds to NEE.

NEE's subsidiaries are separate legal entities and have no independent obligation to provide NEE with funds for its payment obligations. The subsidiaries have financial obligations, including, but not limited to, payment of debt service, which they must satisfy before they can fund NEE. In addition, in the event of a subsidiary's liquidation or reorganization, NEE's right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors.

The dividend-paying ability of some of the subsidiaries is limited by contractual restrictions which are contained in outstanding financing agreements and which may be included in future financing agreements. The future enactment of laws or regulations also may prohibit or restrict the ability of NEE's subsidiaries to pay upstream dividends or to repay funds.

NEE may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if NEE is required to perform under guarantees of obligations of its subsidiaries.

NEE guarantees many of the obligations of its consolidated subsidiaries, other than FPL, through guarantee agreements with NEECH. These guarantees may require NEE to provide substantial funds to its subsidiaries or their creditors or counterparties at a time when NEE is in need of liquidity to meet its own financial obligations. Funding such guarantees may materially adversely affect NEE's ability to pay dividends.

Disruptions, uncertainty or volatility in the credit and capital markets may exert downward pressure on the market price of NEE's common stock.

The market price and trading volume of NEE's common stock are subject to fluctuations as a result of, among other factors, general credit and capital market conditions and changes in market sentiment regarding the operations, business and financing strategies of NEE and its subsidiaries. As a result, disruptions, uncertainty or volatility in the credit and capital markets may, for example, have a material adverse effect on the market price of NEE's common stock.

The factors described above, as well as other information set forth in this report, which could materially adversely affect NEE's and FPL's businesses, financial condition, future financial results and/or liquidity should be carefully considered. The risks described above are not the only risks facing NEE and FPL. Additional risks and uncertainties not currently known to NEE or FPL, or that are currently deemed to be immaterial, also may materially adversely affect NEE's or FPL's business, financial condition, results of operations and prospects.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

NEE and its subsidiaries maintain properties which are adequate for their operations. The principal properties of FPL and NEER are described below.

Generating Facilities

FPL

At December 31, 2011, the electric generating, transmission, distribution and general facilities of FPL represented approximately 48%, 12%, 36% and 4%, respectively, of FPL's gross investment in electric utility plant in service. At December 31, 2011, FPL had the following generating facilities:

FPL Facilities	Location	No. of Units	Fuel	Net Capability (mw)[a]	
Fossil					
Combined-cycle					
Fort Myers	Fort Myers, FL	1	Gas	1,432	
Lauderdale	Dania, FL	2	Gas/Oil	884	
Manatee	Parrish, FL	1	Gas	1,111	
Martin	Indiantown, FL	1	Gas/Oil/Solar Thermal	1,132	[b]
Martin	Indiantown, FL	2	Gas	938	
Putnam	Palatka, FL	2	Gas/Oil	498	
Sanford	Lake Monroe, FL	2	Gas	1,912	
Turkey Point	Florida City, FL	1	Gas/Oil	1,148	
West County	West Palm Beach, FL	3	Gas/Oil	3,657	
Steam turbines					
Cutler	Miami, FL	2	Gas	205	
Manatee	Parrish, FL	2	Oil/Gas	1,624	
Martin	Indiantown, FL	2	Oil/Gas	1,652	
Port Everglades	Port Everglades, FL	4	Oil/Gas	1,187	
St. Johns River Power Park	Jacksonville, FL	2	Coal/Petroleum Coke	254	[c]
Sanford	Lake Monroe, FL	1	Oil/Gas	138	
Scherer	Monroe County, GA	1	Coal	672	[d]
Turkey Point	Florida City, FL	2	Oil/Gas	788	
Simple-cycle combustion turbines					
Fort Myers	Fort Myers, FL	2	Gas/Oil	315	
Gas turbines					
Fort Myers	Fort Myers, FL	12	Oil	648	
Lauderdale	Dania, FL	24	Oil/Gas	840	
Port Everglades	Port Everglades, FL	12	Oil/Gas	420	
Nuclear					
St. Lucie	Hutchinson Island, FL	2	Nuclear	1,584	[e]
Turkey Point	Florida City, FL	2	Nuclear	1,386	
Solar PV					
DeSoto	Arcadia, FL	1	Solar PV	25	
Space Coast	Cocoa, FL	1	Solar PV	10	
TOTAL				24,460	[f]

(a) Represents FPL's net ownership interest in plant capability.
(b) The megawatts generated by the 75 mw solar thermal facility replace steam produced by this unit and therefore are not incremental.
(c) Represents FPL's 20% ownership interest in each of SJRPP Units Nos. 1 and 2, which are jointly owned with JEA.
(d) Represents FPL's approximately 76% ownership of Scherer Unit No. 4, which is jointly owned with JEA.
(e) Excludes Orlando Utilities Commission's and the Florida Municipal Power Agency's combined share of approximately 15% of St. Lucie Unit No. 2.
(f) Substantially all of FPL's properties are subject to the lien of FPL's mortgage.

NEER

At December 31, 2011, NEER had the following generating facilities:

NEER Facilities	Location	Geographic Region	No. of Units	Fuel	Net Capability (mw)[a]
Wind					
Ashtabula Wind[b][c]	Barnes County, ND	Midwest	99	Wind	148
Ashtabula Wind II[c]	Griggs & Steele Counties, ND	Midwest	80	Wind	120
Ashtabula Wind III	Barnes County, ND	Midwest	39	Wind	62
Baldwin Wind[b]	Burleigh County, ND	Midwest	64	Wind	102
Butler Ridge Wind[b][c]	Dodge County, WI	Midwest	36	Wind	54
Cabazon[b]	Riverside County, CA	West	53	Wind	40
Callahan Divide[b]	Taylor County, TX	ERCOT	76	Wind	114
Capricorn Ridge	Sterling & Coke Counties, TX	ERCOT	208	Wind	364
Capricorn Ridge Expansion	Sterling & Coke Counties, TX	ERCOT	199	Wind	298
Cerro Gordo[b]	Cerro Gordo County, IA	Midwest	55	Wind	41
Crystal Lake I[b][c]	Hancock County, IA	Midwest	100	Wind	150
Crystal Lake II	Winnebago County, IA	Midwest	80	Wind	200
Crystal Lake III	Winnebago County, IA	Midwest	44	Wind	66
Day County Wind[b]	Day County, SD	Midwest	66	Wind	99
Delaware Mountain	Culberson County, TX	ERCOT	38	Wind	28
Diablo Wind[b]	Alameda County, CA	West	31	Wind	21
Elk City Wind[b]	Roger Mills & Beckham Counties, OK	Other South	43	Wind	99
Elk City Wind II	Roger Mills & Beckham Counties, OK	Other South	66	Wind	101
Endeavor Wind	Osceola County, IA	Midwest	40	Wind	100
Endeavor Wind II	Osceola County, IA	Midwest	20	Wind	50
Ghost Pine Wind	Trochu, Alberta, Canada	West	51	Wind	82
Gray County	Gray County, KS	Other South	170	Wind	112
Green Mountain[b]	Somerset County, PA	Northeast	8	Wind	10
Green Power	Riverside County, CA	West	22	Wind	17
Green Ridge Power	Alameda & Contra Costa Counties, CA	West	803	Wind	87
Hancock County[b]	Hancock County, IA	Midwest	148	Wind	98
High Winds[b]	Solano County, CA	West	90	Wind	162
Horse Hollow Wind[b]	Taylor County, TX	ERCOT	142	Wind	213
Horse Hollow Wind II[b]	Taylor & Nolan Counties, TX	ERCOT	130	Wind	299
Horse Hollow Wind III[b]	Nolan County, TX	ERCOT	149	Wind	224
Indian Mesa	Pecos County, TX	ERCOT	125	Wind	83
King Mountain[b]	Upton County, TX	ERCOT	214	Wind	278
Lake Benton II[b]	Pipestone County, MN	Midwest	137	Wind	103
Langdon Wind[b][c]	Cavalier County, ND	Midwest	79	Wind	118
Langdon Wind II[b][c]	Cavalier County, ND	Midwest	27	Wind	41
Lee / DeKalb Wind	Lee & DeKalb Counties, IL	Midwest	145	Wind	217
Logan Wind[c]	Logan County, CO	West	134	Wind	201
Majestic Wind[b][c]	Carson County, TX	Other South	53	Wind	80
Meyersdale[b]	Somerset County, PA	Northeast	20	Wind	30
Mill Run[b]	Fayette County, PA	Northeast	10	Wind	15
Minco Wind[b]	Grady County, OK	Other South	62	Wind	99
Minco Wind II[b]	Grady & Caddo Counties, OK	Other South	63	Wind	101
Montezuma Wind[b]	Solano County, CA	West	16	Wind	37
Montfort[b]	Iowa County, WI	Midwest	20	Wind	30
Mount Copper[b]	Murdochville, Quebec, Canada	Midwest	30	Wind	54
Mount Miller[b]	Murdochville, Quebec, Canada	Midwest	30	Wind	54
Mountaineer[b]	Preston & Tucker Counties, WV	Northeast	44	Wind	66
Mower County Wind[c]	Mower County, MN	Midwest	43	Wind	99
New Mexico Wind[b]	Quay & Debaca Counties, NM	West	136	Wind	204
North Dakota Wind[b]	LaMoure County, ND	Midwest	41	Wind	62
Northern Colorado[b]	Logan County, CO	West	81	Wind	174
Oklahoma / Sooner Wind[b]	Harper & Woodward Counties, OK	Other South	68	Wind	102
Oliver County Wind I[c]	Oliver County, ND	Midwest	22	Wind	51
Oliver County Wind II[c]	Oliver County, ND	Midwest	32	Wind	48
Peetz Table Wind[c]	Logan County, CO	West	133	Wind	199
Pubnico Point[b]	Yarmouth, Nova Scotia, Canada	Midwest	17	Wind	31
Red Canyon Wind Energy[b]	Borden, Garza & Scurry Counties, TX	ERCOT	56	Wind	84

NEER Facilities	Location	Geographic Region	No. of Units	Fuel	Net Capability (mw)[a]	
Red Mesa Wind	Cibola County, NM	West	64	Wind	102	
Sky River[b]	Kern County, CA	West	342	Wind	77	
Somerset Wind Power[b]	Somerset County, PA	Northeast	6	Wind	9	
South Dakota Wind[b]	Hyde County, SD	Midwest	27	Wind	41	
Southwest Mesa[b]	Upton & Crockett Counties, TX	ERCOT	106	Wind	74	
Stateline[b]	Umatilla County, OR and Walla Walla County, WA	West	454	Wind	300	
Story County Wind[b][c]	Story County, IA	Midwest	100	Wind	150	
Story County Wind II[b]	Story & Hardin Counties, IA	Midwest	100	Wind	150	
Vansycle[b]	Umatilla County, OR	West	38	Wind	25	
Vansycle II	Umatilla County, OR	West	43	Wind	99	
Vasco Winds[c]	Contra Costa County, CA	West	33	Wind	78	
Victory Garden[b]	Kern County, CA	West	96	Wind	22	
Waymart[b]	Wayne County, PA	Northeast	43	Wind	65	
Weatherford Wind[b]	Custer & Washita Counties, OK	Other South	98	Wind	147	
Wessington Springs Wind[b][c]	Jerauld County, SD	Midwest	34	Wind	51	
White Oak[c]	McLean County, IL	Midwest	100	Wind	150	
Wilton Wind[b]	Burleigh County, ND	Midwest	33	Wind	49	
Wilton Wind II[c]	Burleigh County, ND	Midwest	33	Wind	50	
Windpower Partners 1990	Alameda & Contra Costa Counties, CA	West	141	Wind	14	
Windpower Partners 1991	Alameda & Contra Costa Counties, CA	West	162	Wind	16	
Windpower Partners 1991-92	Alameda & Contra Costa Counties, CA	West	223	Wind	22	
Windpower Partners 1992	Alameda & Contra Costa Counties, CA	West	300	Wind	30	
Windpower Partners 1993[c]	Riverside County, CA	West	33	Wind	50	
Windpower Partners 1993	Lincoln County, MN	Midwest	73	Wind	26	
Windpower Partners 1994	Culberson County, TX	ERCOT	107	Wind	39	
Wolf Ridge Wind	Cooke County, TX	ERCOT	75	Wind	112	
Woodward Mountain	Upton & Pecos Counties, TX	ERCOT	242	Wind	160	
Wyoming Wind[b]	Uinta County, WY	West	80	Wind	144	
Investments in joint ventures[d]	Various	West	643	Wind	95	
Total Wind					8,569	
Contracted						
Bayswater[b]	Far Rockaway, NY	Northeast	2	Gas	56	
Duane Arnold	Palo, IA	Midwest	1	Nuclear	431	[e]
Hatch Solar	Hatch, NM	West	1	CPV Solar	5	
Jamaica Bay[b]	Far Rockaway, NY	Northeast	2	Gas/Oil	54	
Marcus Hook 750[b]	Marcus Hook, PA	Northeast	4	Gas	744	
Point Beach	Two Rivers, WI	Midwest	2	Nuclear	1,190	
Investments in joint ventures:						
SEGS III-IX[b]	Kramer Junction & Harper Lake, CA	West	7	Solar	148	
Other	Various	Northeast	4	[f]	158	
Total Contracted					2,786	
Merchant						
Forney	Forney, TX	ERCOT	8	Gas	1,792	
Lamar Power Partners	Paris, TX	ERCOT	6	Gas	1,000	
Maine - Cape, Wyman	Various - ME	Northeast	6	Oil	796	[g]
Maine[b]	Various - ME	Northeast	81	Hydro	359	
Marcus Hook 50	Marcus Hook, PA	Northeast	1	Gas	50	
Paradise Solar	West Deptford, NJ	Northeast	1	Solar PV	5	
Seabrook	Seabrook, NH	Northeast	1	Nuclear	1,100	[h]
Investment in joint ventures	Various	Northeast	4	[f]	150	
Total Merchant					5,252	
TOTAL					16,607	

(a) Represents NEER's net ownership interest in plant capacity.
(b) These generating facilities are encumbered by liens against their assets securing various financings.
(c) NEER owns these wind facilities together with third-party investors with differential membership interests. See Note 1 - Sale of Differential Membership Interests.
(d) Represents plants with no more than 50% ownership using wind technology. Certain facilities, totaling 57 mw, are encumbered by liens against their assets securing a financing.
(e) Excludes Central Iowa Power Cooperative and Cornbelt Power Cooperative's combined share of 30%.
(f) Represents plants with no more than 50% ownership using fuels such as natural gas and waste coal.
(g) Excludes six other energy-related partners' combined share of 16%.
(h) Excludes Massachusetts Municipal Wholesale Electric Company's, Taunton Municipal Lighting Plant's and Hudson Light & Power Department's combined share of 11.77%.

Transmission and Distribution

At December 31, 2011, FPL owned and operated 587 substations and the following electric transmission and distribution lines:

Nominal Voltage	Overhead Lines Pole Miles	Trench and Submarine Cables Miles
500 kv	1,106 [(a)]	—
230 kv	3,038	25
138 kv	1,575	53
115 kv	746	1
69 kv	164	14
Less than 69 kv	42,334	25,111
Total	48,963	25,204

(a) Includes approximately 75 miles owned jointly with JEA.

Character of Ownership

Substantially all of FPL's properties are subject to the lien of FPL's mortgage, which secures most debt securities issued by FPL. The majority of FPL's real property is held in fee and is free from other encumbrances, subject to minor exceptions which are not of a nature as to substantially impair the usefulness to FPL of such properties. Some of FPL's electric lines are located on parcels of land which are not owned in fee by FPL but are covered by necessary consents of governmental authorities or rights obtained from owners of private property. The majority of NEER's generating facilities are owned by NEER subsidiaries and a number of those facilities are encumbered by liens securing various financings. Additionally, certain of NEER's generating facilities are located on land leased from owners of private property. See Generating Facilities and Note 1 - Electric Plant, Depreciation and Amortization.

Item 3. Legal Proceedings

NEE and FPL are parties to various legal and regulatory proceedings in the ordinary course of their respective businesses. For information regarding legal proceedings that could have a material effect on NEE or FPL, see Note 14 - Legal Proceedings. Such descriptions are incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable

PART II

Item 5. Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock Data. All of FPL's common stock is owned by NEE. NEE's common stock is traded on the New York Stock Exchange under the symbol "NEE." The high and low sales prices for the common stock of NEE as reported in the consolidated transaction reporting system of the New York Stock Exchange and the cash dividends per share declared for each quarter during the past two years are as follows:

	2011			2010		
Quarter	High	Low	Cash Dividends	High	Low	Cash Dividends
First	$ 55.86	$ 51.54	$ 0.55	$ 53.75	$ 45.29	$ 0.50
Second	$ 58.98	$ 54.16	$ 0.55	$ 53.50	$ 47.96	$ 0.50
Third	$ 58.25	$ 49.00	$ 0.55	$ 55.98	$ 48.44	$ 0.50
Fourth	$ 61.20	$ 51.33	$ 0.55	$ 56.26	$ 50.00	$ 0.50

The amount and timing of dividends payable on NEE's common stock are within the sole discretion of NEE's Board of Directors. The Board of Directors reviews the dividend rate at least annually (generally in February) to determine its appropriateness in light of NEE's financial position and results of operations, legislative and regulatory developments affecting the electric utility industry in general and FPL in particular, competitive conditions, change in business mix and any other factors the Board of Directors deems relevant. The ability of NEE to pay dividends on its common stock is dependent upon, among other things, dividends paid to it by its subsidiaries. There are no restrictions in effect that currently limit FPL's ability to pay dividends to NEE. In February 2012, NEE announced that it would increase its quarterly dividend on its common stock from $0.55 to $0.60 per share. See Management's Discussion - Liquidity and Capital Resources - Covenants with respect to dividend restrictions and Note 11 - Common Stock Dividend Restrictions regarding dividends paid by FPL to NEE.

As of the close of business on January 31, 2012, there were 25,588 holders of record of NEE's common stock.

Issuer Purchases of Equity Securities. Information regarding purchases made by NEE of its common stock during the three months ended December 31, 2011 is as follows:

Period	Total Number of Shares Purchased		Average Price Paid Per Share	Total Number of Shares Purchased as Part of a Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program[(a)]
10/1/2011 - 10/31/11	848	(b)	$ 54.82	—	20,000,000
11/1/2011 - 11/30/11	5,093	(b)	$ 55.65	—	20,000,000
12/1/2011 - 12/31/11	6,725,809	(c)	$ 55.76	6,725,252	13,274,748
Total	6,731,750		$ 55.76	6,725,252	

(a) In February 2005, NEE's Board of Directors authorized a common stock repurchase plan of up to 20 million shares of common stock over an unspecified period, which authorization was most recently reaffirmed and ratified by the Board of Directors in July 2011.

(b) Includes shares of common stock withheld from employees to pay certain withholding taxes upon the vesting of stock awards granted to such employees under the NextEra Energy, Inc. Amended and Restated Long-Term Incentive Plan (former LTIP).

(c) Includes: (1) 557 shares of common stock purchased as a reinvestment of dividends by the trustee of a grantor trust in connection with NEE's obligation under a February 2006 grant under the former LTIP of deferred retirement share awards to an executive officer; and (2) 6,725,252 shares of common stock purchased under an Accelerated Share Repurchase (ASR) agreement (see Note 11 - ASR of NEE Common Stock).

Item 6. Selected Financial Data

	Years Ended December 31,				
	2011	2010	2009	2008	2007
SELECTED DATA OF NEE (millions, except per share amounts):					
Operating revenues	$ 15,341	$ 15,317	$ 15,643	$ 16,410	$ 15,263
Net income[(a)]	$ 1,923	$ 1,957	$ 1,615	$ 1,639	$ 1,312
Earnings per share of common stock - basic	$ 4.62	$ 4.77	$ 3.99	$ 4.10	$ 3.30
Earnings per share of common stock - assuming dilution	$ 4.59	$ 4.74	$ 3.97	$ 4.07	$ 3.27
Dividends paid per share of common stock	$ 2.20	$ 2.00	$ 1.89	$ 1.78	$ 1.64
Total assets	$ 57,188	$ 52,994	$ 48,458	$ 44,821	$ 40,123
Long-term debt, excluding current maturities	$ 20,810	$ 18,013	$ 16,300	$ 13,833	$ 11,280
SELECTED DATA OF FPL (millions):					
Operating revenues	$ 10,613	$ 10,485	$ 11,491	$ 11,649	$ 11,622
Net income	$ 1,068	$ 945	$ 831	$ 789	$ 836
Total assets	$ 31,816	$ 28,698	$ 26,812	$ 26,175	$ 24,044
Long-term debt, excluding current maturities	$ 7,483	$ 6,682	$ 5,794	$ 5,311	$ 4,976
Energy sales (kwh)	106,662	107,978	105,414	105,406	108,636
Energy sales:					
Residential	51.2%	52.2%	51.2%	50.5%	50.8%
Commercial	42.2	41.3	42.7	43.2	42.3
Industrial	2.9	2.9	3.1	3.4	3.5
Interchange power sales	0.9	0.8	1.4	1.6	1.8
Other[(b)]	2.8	2.8	1.6	1.3	1.6
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Approximate 60-minute peak load (mw):[(c)]					
Summer season	21,619	22,256	22,351	21,060	21,962
Winter season	17,934	21,153	24,346	20,031	18,055
Average number of customer accounts (thousands):					
Residential	4,027	4,004	3,984	3,992	3,981
Commercial	508	504	501	501	493
Industrial	9	9	10	13	19
Other	3	3	4	4	4
Total	4,547	4,520	4,499	4,510	4,497
Average price billed to customers (cents per kwh)	9.83	9.34	11.19	10.96	10.63

(a) Includes net unrealized mark-to-market after-tax (gains) losses associated with non-qualifying hedges of $(190) million, $(175) million, $20 million, $(170) million and $86 million and OTTI after-tax losses, net of OTTI reversals of $6 million, $(4) million, $13 million, $76 million and $6 million for the years ended December 31, 2011, 2010, 2009, 2008 and 2007, respectively. Also, 2011 includes a loss on the sale of natural gas-fired generating assets of approximately $98 million. See Note 4 - Nonrecurring Fair Value Measurements.

(b) Includes the net change in unbilled sales.

(c) Winter season includes November and December of the current year and January to March of the following year (for 2011, through February 27, 2012).

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

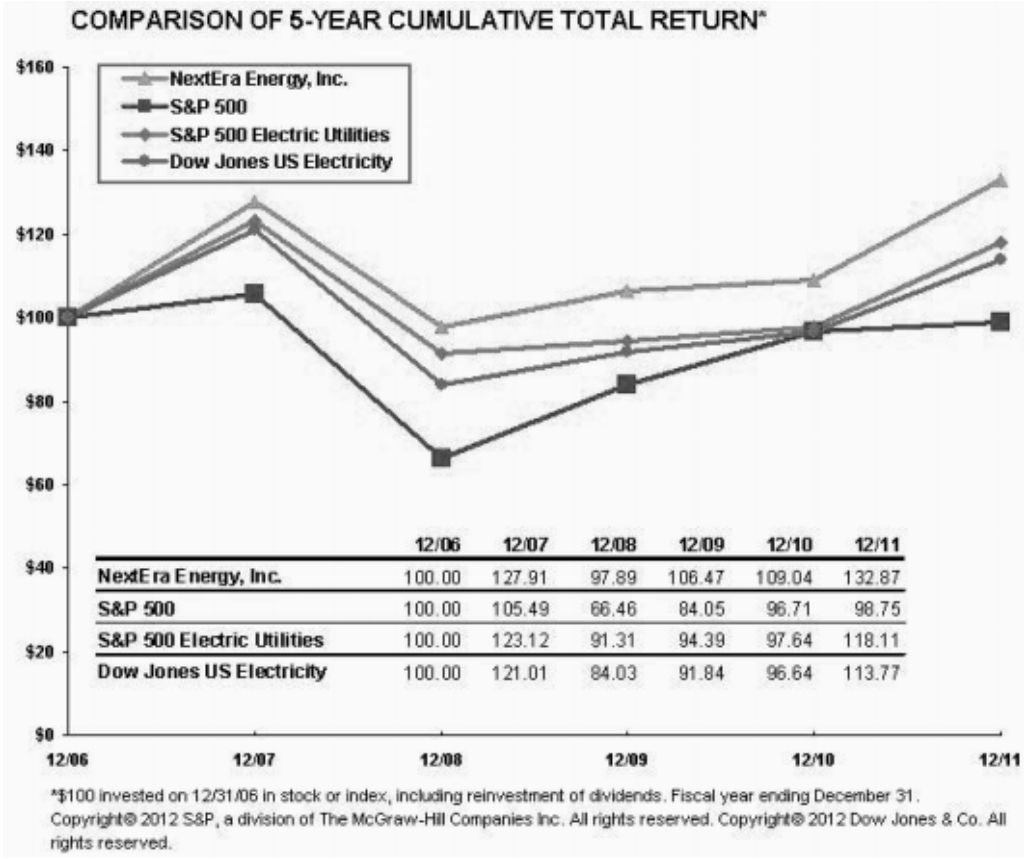
NEE's operating performance is driven primarily by the operations of its two principal subsidiaries, FPL, which serves approximately 4.6 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the U.S., and NEER, which together with its affiliated entities is the largest generator in the U.S. of renewable energy from the wind and sun. The table below presents NEE's net income and earnings per share by reportable segment - FPL, NEER and Corporate and Other, which is primarily comprised of interest expense, the operating results of FPL FiberNet, Lone Star and other business activities, as well as other income and expense items, including income taxes and eliminating entries (see Note 15 for additional segment information). The

discussion that follows should be read in conjunction with the Notes to the Consolidated Financial Statements contained herein. In the discussion below and in Results of Operations, all comparisons are with the corresponding items in the prior year.

	Net Income			Earnings Per Share, assuming dilution		
	Years Ended December 31,			Years Ended December 31,		
	2011	2010	2009	2011	2010	2009
	(millions)					
FPL	$ 1,068	$ 945	$ 831	$ 2.55	$ 2.29	$ 2.04
NEER[(a)]	774	980	759	1.85	2.37	1.86
Corporate and Other	81	32	25	0.19	0.08	0.07
NEE	$ 1,923	$ 1,957	$ 1,615	$ 4.59	$ 4.74	$ 3.97

(a) NEER's results reflect an allocation of interest expense from NEECH to NEER based on a deemed capital structure of 70% debt and allocated shared service costs.

For the five years ended December 31, 2011, NEE delivered a total shareholder return of approximately 33%, significantly outpacing the S&P 500's 1% decline, the Dow Jones US Electricity's 14% return and the S&P 500 Electric Utilities' 18% return. The historical stock performance of NEE's common stock shown in the performance graph below is not necessarily indicative of future stock price performance.



	12/06	12/07	12/08	12/09	12/10	12/11
NextEra Energy, Inc.	100.00	127.91	97.89	106.47	109.04	132.87
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
S&P 500 Electric Utilities	100.00	123.12	91.31	94.39	97.64	118.11
Dow Jones US Electricity	100.00	121.01	84.03	91.84	96.64	113.77

Adjusted Earnings

NEE prepares its financial statements in accordance with GAAP. However, management uses earnings excluding certain items (adjusted earnings), a non-GAAP financial measure, internally for financial planning, for analysis of performance, for reporting of results to the Board of Directors and as an input in determining whether performance goals are met for performance-based compensation under NEE's employee incentive compensation plans. NEE also uses adjusted earnings when communicating its financial results and earnings outlook to investors. NEE's management believes adjusted earnings provides a more meaningful representation of the company's fundamental earnings power. Although the excluded amounts are properly included in the determination of net income in accordance with GAAP, management believes that the amount and/or nature of such items make period to period comparisons of operations difficult and potentially confusing. Adjusted earnings do not represent a substitute for net income, as prepared in accordance with GAAP.

Adjusted earnings exclude the unrealized mark-to-market effect of non-qualifying hedges (as described below), OTTI losses on securities held in NEER's nuclear decommissioning funds, net of the reversal of previously recognized OTTI losses on securities sold and losses on securities where price recovery was deemed unlikely (collectively, OTTI reversals) and, in 2011, the after-tax loss on the sale of natural gas-fired generating assets. OTTI reversals are reported in other - net in NEE's consolidated statements of income.

NEE and NEER segregate into two categories unrealized mark-to-market gains and losses on energy derivative transactions which are used to manage commodity price risk. The first category, referred to as trading activities, represents the net unrealized effect of actively traded positions entered into to take advantage of market price movements and, in 2011 and 2010, the impact related to exiting hedged positions on future gas drilling opportunities. The second category, referred to as non-qualifying hedges, represents certain hedging transactions entered into as economic hedges but the transactions do not meet the requirements for hedge accounting or hedge accounting treatment is not elected. Changes in the fair value of those transactions are marked to market and reported in the consolidated statements of income, resulting in earnings volatility because the economic offset to the positions which are required to be marked to market (such as the physical assets from which power is generated) are not marked to market. As a consequence, net income reflects only the movement in one part of economically-linked transactions. For this reason, NEE's management views results expressed excluding the unrealized mark-to-market impact of the non-qualifying hedges as a meaningful measure of current period performance. At FPL, substantially all changes in the fair value of energy derivative transactions are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel clause or the capacity clause. See Note 4 - Nonrecurring Fair Value Measurements.

In 2011, subsidiaries of NEER completed the sales of their ownership interest in five natural gas-fired generating plants with a total generating capacity of approximately 2,700 mw located in California, Virginia, Alabama, South Carolina and Rhode Island. In connection with these sales, a loss of approximately $151 million ($98 million total after-tax with $92 million of this loss recorded by NEER) was recorded in NEE's consolidated statements of income, which due to its nature and significance, was excluded from adjusted earnings. See Note 3.

The following table provides details of the net unrealized after-tax gains and losses from non-qualifying hedges, after-tax OTTI losses, net of reversals and the after-tax loss on the sale of the natural gas-fired generating assets.

	Years Ended December 31,		
	2011	2010	2009
	(millions)		
Net unrealized mark-to-market after-tax gains (losses) from non-qualifying hedge activity[a]	$ 190	$ 175	$ (20)
OTTI after-tax losses on securities held in nuclear decommissioning funds, net of OTTI reversals	$ (6)	$ 4	$ (13)
After-tax loss on sale of natural gas-fired assets[b]	$ (98)	$ —	$ —

(a) $193 million, $176 million and $(20) million, respectively, is included in NEER's net income; the balance, if any, is included in Corporate and Other.
(b) $92 million is included in NEER's net income; the balance is included in Corporate and Other.

The change in unrealized mark-to-market activity from non-qualifying hedges is primarily attributable to changes in forward power and natural gas prices, as well as the reversal of previously recognized unrealized mark-to-market gains or losses as the underlying transactions were realized. As a general rule, a gain (loss) in the non-qualifying hedge category is offset by decreases (increases) in the fair value of related physical asset positions in the portfolio or contracts, which are not marked to market under GAAP.

2011 Summary

FPL's earned regulatory ROE was 11% in both 2010 and 2011 and FPL expects to earn an 11% regulatory ROE in 2012. FPL's increase in net income in 2011 was primarily driven by investments in plant in service and FPL's ability to use the surplus depreciation credit, as permitted under the 2010 rate agreement, to earn up to FPL's allowed 11% regulatory ROE on its retail rate base, as well as higher cost recovery clause results. The 2010 rate agreement results in retail base rates that remain effectively frozen until the end of 2012. Additionally, cost recovery for FPL's WCEC Unit No. 3 is permitted during the term of the agreement and FPL can vary the amount of surplus depreciation amortized in any one year subject to certain caps, provided its retail regulatory return on equity remains within the allowed range of 9% to 11%.

NEER's earnings declined in 2011 reflecting the loss on sale of natural gas-fired generating assets, lower results from the customer supply and proprietary power and gas trading businesses, extended and unplanned outages at Seabrook and lower deferred tax benefits associated with cash grants (convertible ITCs), partly offset by a higher wind resource and higher gas infrastructure results. In 2011, NEER added 379 mw of wind capacity and secured approximately 1,600 mw of long-term wind power sales agreements. Additionally, in 2011 construction began on the 250 mw Genesis solar project in California and the 550 mw Desert Sunlight solar project in California, in which NEER has a 50% equity investment.

Corporate and Other's earnings in 2011 increased primarily due to state deferred income tax benefits related to state tax law changes and an income tax benefit related to the dissolution of a subsidiary.

NEE and its subsidiaries, including FPL, require funds to support and grow their businesses. These funds are primarily provided by cash flow from operations and short- and long-term borrowings and, from time to time, issuance of equity securities. As of February 9, 2012, NEE's total net available liquidity was approximately $5.1 billion, of which FPL's portion was approximately $2.8 billion.

Outlook

NEE's strategy at both of its major businesses seeks to meet customer needs more economically and reliably than competitors. Meeting customer needs frequently requires the commitment of large capital expenditures to projects that have long lives and such commitments are difficult to reverse once made. At the end of 2011, both FPL and NEER had made commitments to a variety of major capital projects that are expected to be completed over the next several years. While NEE management believes that these projects individually and collectively are attractive investments with the potential to create value for shareholders, there can be no guarantee that all or any of these projects will be successful. Because of their importance, management focuses particular attention on these large projects.

In 2012, NEE expects to focus efforts in particular on the following initiatives:

At FPL:

- Sustaining FPL's customer value proposition. The combination of low bills, good reliability and excellent customer service that FPL currently provides its customers is both an objective of FPL's strategy and an important contributor to its long-term business success. FPL seeks to, at minimum, maintain and ideally improve its overall customer value proposition.
- Major Capital Projects: FPL is currently in a large capital expansion program and its objective is to bring these projects in on schedule and within budget. This program includes:
    - modernizing its Cape Canaveral and Riviera Beach power plants to high-efficiency natural gas-fired 1,200 mw units to be placed in service by 2013 and 2014, respectively,
    - adding a total of approximately 450 mw to 490 mw of capacity at its existing nuclear units at St. Lucie and Turkey Point, to be placed in service by 2013, and
    - petitioning the FPSC in November 2011 to modernize its Port Everglades power plant to a high-efficiency natural gas-fired 1,280 mw unit which, if approved, is expected to be in service in 2016 and cost approximately $1.2 billion.
- Rate Case: In January 2012, FPL filed a formal notification with the FPSC indicating its intent to initiate a base rate proceeding. The notification stated that, based on preliminary estimates, FPL expects to request a base rate increase of approximately $525 million effective January 2013 and an additional base rate increase of approximately $170 million annually commencing when the modernized Cape Canaveral plant becomes operational, which is expected to occur in June 2013.

At NEER:

- Maintaining excellence in day-to-day operations. NEER has developed a track record of generally running its facilities reliably and cost-effectively. The company seeks to, at minimum, maintain and ideally improve its operating performance.
- Wind: Add approximately 1,150 mw to 1,500 mw of new U.S. wind generation in 2012 and 600 mw of new Canadian wind generation between 2012 and 2015, and
- Solar: Add approximately 935 mw of new solar generation during the period 2012 through 2016, including the 250 mw Genesis solar project in California, the 99.8 mw Spain solar project, the 550 mw Desert Sunlight solar project in California, in which NEER has a 50% equity investment, and the 250 mw McCoy solar PV project located in the Mojave Desert near the Genesis and Desert Sunlight solar projects.

At Lone Star, which is in the process of constructing approximately 320 miles of transmission lines and other associated facilities in Texas:

- Construction: Achieve commercial operations by the end of the first quarter of 2013.
- Rate Case: In January 2012, Lone Star filed a petition with the PUCT requesting, among other things, interim rates which would take effect when Lone Star's first substation is placed in service, currently projected to be in 2012, and final rates when the transmission lines are energized. If approved, based on the expected in-service dates, the requested rates would result in annual revenues of approximately $14 million in 2012 and $110 million in 2013.

In addition, NEE and FPL devote effort to numerous other initiatives designed to support their long-term growth and development. There can be no guarantees that NEE or FPL will be successful in attaining their goals with respect to any of these initiatives.

For additional information on certain of the above matters, see Item 1. Business.

RESULTS OF OPERATIONS

NEE's net income for 2011 was $1.92 billion, compared to $1.96 billion in 2010 and $1.61 billion in 2009. The decrease in NEE's 2011 net income was primarily driven by lower earnings at NEER, partly offset by improved results at FPL and income tax benefits at Corporate and Other. The increase in NEE's 2010 net income was primarily driven by improved results at FPL and by net unrealized mark-to-market after-tax gains from non-qualifying hedges at NEER.

NEE's effective income tax rate for all periods presented reflects PTCs for wind projects at NEER and deferred tax benefits associated with convertible ITCs under the Recovery Act. PTCs and deferred tax benefits associated with convertible ITCs can significantly affect NEE's effective income tax rate depending on the amount of pretax income. PTCs can be significantly affected by wind generation and by the expiration of PTCs after ten years of production. See Note 1 - Income Taxes and - Sale of Differential Membership Interests and Note 6.

FPL: Results of Operations

FPL's net income for 2011, 2010 and 2009 was $1,068 million, $945 million and $831 million, respectively, representing an increase in 2011 of $123 million and an increase in 2010 of $114 million. FPL obtains its operating revenues primarily from the sale of electricity to retail customers at rates established by the FPSC through base rates and cost recovery clause mechanisms.

In 2011 and 2010, FPL earned a regulatory ROE of 11%, as permitted by the 2010 rate agreement, and expects to earn an 11% regulatory ROE in 2012. In 2011 and in 2010, growth in earnings for FPL was driven by:

- investment in plant in service and FPL's ability to use the surplus depreciation credit, and
- higher cost recovery clause results,

partly offset for 2010 by,

- lower AFUDC - equity.

FPL's operating revenues consisted of the following:

	Years Ended December 31,		
	2011	2010	2009
	(millions)		
Retail base	$ 4,217	$ 4,190	$ 3,828
Fuel cost recovery	4,416	4,090	5,982
Net deferral of retail fuel revenues	—	—	(356)
Net repayment of previously deferred retail fuel revenues	—	356	—
Other cost recovery clauses and pass-through costs, net of any deferrals	1,751	1,638	1,840
Other, primarily pole attachment rentals, transmission and wholesale sales and customer-related fees	229	211	197
Total	$ 10,613	$ 10,485	$ 11,491

Retail Base

As permitted by the 2010 rate agreement, FPL collected approximately $101 million in retail base revenues through the capacity clause related to the placement in service of WCEC Unit No. 3 in May 2011. In addition, a base rate increase pursuant to an FPSC order which became effective March 1, 2010, increased retail base revenues by approximately $8 million and $68 million in 2011 and 2010, respectively, and retail base revenues increased in 2010 by $196 million resulting from WCEC Unit Nos. 1 and 2 placed in service in 2009.

FPSC Rate Order

Effective March 1, 2010, pursuant to the FPSC rate order, new retail base rates for FPL were established, resulting in an increase in retail base revenues of approximately $75 million on an annualized basis. The FPSC rate order also established a regulatory ROE of 10.0% with a range of plus or minus 100 basis points and an adjusted regulatory equity ratio of 59.1%. It also shifted certain costs from retail base rates to the capacity clause. In addition, the FPSC rate order directed FPL to reduce depreciation expense (surplus depreciation credit) over the 2010 to 2013 period related to a depreciation reserve surplus. Subsequently, the principal parties in FPL's 2009 rate case signed the 2010 rate agreement and, in February 2011, the FPSC issued a final order approving the 2010 rate agreement. Key elements of that rate agreement, which is effective through December 31, 2012, are as follows:

- Subject to the provisions of the 2010 rate agreement, retail base rates are effectively frozen through the end of 2012.
- Incremental cost recovery through FPL's capacity clause for the new combined-cycle natural gas unit at WCEC Unit No. 3, which was placed in service in May 2011, is permitted up to the amount of the projected annual fuel savings for customers during the term of the 2010 rate agreement.
- Future storm restoration costs would be recoverable on an accelerated basis beginning 60 days from the filing of a cost recovery

petition, but capped at an amount that produces a surcharge of no more than $4 for every 1,000 kwh of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL may request an increase to the $4 surcharge to recover the amount above $800 million.

- If FPL's earned regulatory ROE falls below 9%, FPL may seek retail base rate relief. If FPL's earned regulatory ROE rises above 11%, any party to the 2010 rate agreement may seek a reduction in FPL's retail base rates. In determining the regulatory ROE for all purposes under the 2010 rate agreement, earnings will be calculated on an actual, non-weather-adjusted basis.
- FPL can vary the amount of surplus depreciation credit taken in any calendar year up to a cap in 2010 of $267 million, a cap in subsequent years of $267 million plus the amount of any unused portion from prior years, and a total cap of $776 million (surplus depreciation credit cap) over the course of the 2010 rate agreement, provided that in any year of the 2010 rate agreement, FPL must use at least enough surplus depreciation credit to maintain a 9% earned regulatory ROE but may not use any amount of surplus depreciation credit that would result in an earned regulatory ROE in excess of 11%. In 2010 and 2011, FPL used a total of $191 million of surplus depreciation credit; $585 million of the surplus depreciation credit cap remains available for use in 2012.

Under the terms of the 2005 rate agreement, which was in effect from January 1, 2006 through February 28, 2010, retail base rates did not increase except to allow recovery of the revenue requirements of FPL's three power plants that achieved commercial operation during the term of the 2005 rate agreement: Turkey Point Unit No. 5 in 2007 and WCEC Units Nos. 1 and 2 in 2009. Under the terms of the 2005 rate agreement, FPL's electric property depreciation rates were based upon the comprehensive depreciation studies it filed with the FPSC in March 2005; however, FPL reduced depreciation on its plant in service by $125 million each year as allowed by the 2005 rate agreement. The 2005 rate agreement also provided for a revenue sharing mechanism, whereby revenues from retail base operations in excess of certain thresholds would be shared with customers. During the term of the 2005 rate agreement, FPL's revenues did not exceed the thresholds.

Retail Customer Usage and Growth

For the year ended December 31, 2011, FPL experienced a 2% decrease in average usage per retail customer, reflecting weather and other factors, which decreased retail base revenues by approximately $107 million. For the year ended December 31, 2010, FPL experienced a 1.7% increase in usage per retail customer, reflecting weather and other factors, which increased retail base revenues by approximately $79 million. The usage per retail customer data for the year ended December 31, 2011 includes three extra days of sales after adjusting for a change from a fiscal month to a calendar month. At December 31, 2011, inactive accounts (accounts with installed meters without corresponding customer names) and low-usage customers (customers using less than 200 kwh per month), both measures of empty homes, were approximately 5.8% and 1.6% less, respectively, than they had been at December 31, 2010. Non-weather related usage per retail customer began to decline in the mid-2000s and this decline intensified in the 2007 to 2009 period. The rate of decline in non-weather related usage per retail customer moderated in 2010 and 2011.

For the year ended December 31, 2011, FPL experienced a 0.6% increase in the average number of customer accounts, increasing retail base revenues by approximately $25 million, compared to a 0.5% increase in customer accounts in 2010, which increased 2010 retail base revenues by $19 million. Positive customer account growth is projected to continue in 2012, although the rate of growth is projected to be below FPL's average rate of 1.5% over the last 10 years.

FPL believes that the economic slowdown and the downturn in the housing market that have affected the country and the state of Florida have contributed to the slowdown in customer growth and to the decline in non-weather related usage per retail customer. The unemployment rate in Florida was 9.9% and 12.0% in December 2011 and 2010, respectively; the December 2011 rate is the lowest since April 2009. A portion of the decline in non-weather related usage per retail customer may also be related to federal and state energy efficiency standards. FPL is unable to predict whether or when growth in customers and non-weather related customer usage might return to previous trends.

Cost Recovery Clauses

In 2011, 2010 and 2009, cost recovery clauses contributed $108 million, $75 million, $41 million, respectively, to FPL's net income. The increase in 2011 and 2010 cost recovery clause results is primarily due to a return related to additional solar, environmental and nuclear capacity expenditures. In 2012, it is expected that cost recovery clauses will contribute higher earnings for FPL as a result of additional nuclear capacity expenditures. Fluctuations in fuel cost recovery revenues are primarily driven by changes in fuel and energy charges which are included in fuel, purchased power and interchange expense in the consolidated statements of income, as well as by changes in energy sales. Fluctuations in revenues from other cost recovery clauses and pass-through costs are primarily driven by changes in storm-related surcharges, capacity charges, franchise fee costs, the impact of changes in O&M and depreciation expenses on the underlying cost recovery clause, investment in solar and environmental projects, investment in nuclear capacity until such capacity goes into service, pre-construction costs associated with the development of two additional nuclear units at the Turkey Point site and changes in energy sales. Capacity charges and franchise fee costs are included in fuel, purchased power and interchange and taxes other than income taxes and other, respectively, in the consolidated statements of income.

Risk Management Fuel Procurement Program
FPL uses a risk management fuel procurement program which was approved by the FPSC. The FPSC reviews the program activities and results for prudence on an annual basis as part of its annual review of fuel costs. The program is intended to manage fuel price volatility by locking in fuel prices for a portion of FPL's fuel requirements. The current regulatory asset for the change in fair value of derivative instruments used in the fuel procurement program amounted to approximately $502 million and $236 million at December 31, 2011 and 2010, respectively.

In 2010, pursuant to an FPSC order, FPL was required to refund in the form of a one-time credit to retail customers' bills the 2009 year-end estimated fuel overrecovery; during the first quarter of 2010, approximately $404 million was refunded to retail customers. At December 31, 2009, approximately $356 million of retail fuel revenues were overrecovered, the reversal of which is reflected in the net repayment of previously deferred retail fuel revenues caption included in the table above. The difference between the refund and the December 31, 2009 overrecovery was collected from retail customers in 2011. The increase in fuel revenues in 2011 reflects the absence of the $404 million refund partly offset by approximately $41 million related to lower energy sales and $37 million related to a lower average fuel factor. The decrease in fuel revenues in 2010 reflects the $404 million refund and approximately $1,573 million related to a lower average fuel factor, partly offset by $85 million attributable to higher energy sales. The decrease from December 31, 2010 to December 31, 2011 in deferred clause and franchise expenses and in deferred clause and franchise revenues was approximately $181 million and positively affected NEE's and FPL's cash flows from operating activities for the year ended December 31, 2011.

Other
The decrease in revenues from other cost recovery clauses and pass-through costs in 2010 is primarily due to lower revenues associated with the FPSC's nuclear cost recovery rule and lower revenues related to franchise and revenue taxes, partly offset by higher environmental clause revenues. The decline in 2010 in revenues associated with the nuclear cost recovery rule is primarily due to lower spending related to the development of the two additional nuclear units at the Turkey Point site. The decline in 2010 revenues related to franchise and revenue taxes reflects the decline in fuel revenues. The nuclear cost recovery rule provides for the recovery of prudently incurred pre-construction costs and carrying charges (equal to a pretax AFUDC rate) on construction costs for new nuclear capacity through levelized charges under the capacity clause. The same rule provides for the recovery of construction costs, once property related to the new nuclear capacity goes into service, through a base rate increase effective beginning the following January.

Other Items Impacting FPL Results

Fuel, Purchased Power and Interchange
The major components of FPL's fuel, purchased power and interchange expense are as follows:

	Years Ended December 31,		
	2011	2010	2009
		(millions)	
Fuel and energy charges during the period	$ 4,237	$ 4,714	$ 5,425
Net collection of previously deferred retail fuel costs	159	—	256
Net deferral of retail fuel costs	—	(276)	—
Other, primarily capacity charges, net of any capacity deferral	581	544	539
Total	$ 4,977	$ 4,982	$ 6,220

The decrease in fuel and energy charges in 2011 reflects lower fuel and energy prices of $415 million and lower energy sales of $62 million. The decrease in fuel and energy charges in 2010 reflects lower fuel and energy prices of approximately $822 million, partly offset by approximately $111 million attributable to higher energy sales.

O&M Expenses
FPL's O&M expenses increased $79 million in 2011 primarily due to higher cost recovery clause costs which did not significantly affect net income.

FPL's O&M expenses increased $124 million in 2010 reflecting an approximately $20 million charge for workforce reductions and higher nuclear and fossil generation, distribution, transmission and nuclear insurance costs of $34 million, $29 million, $16 million, $8 million and $12 million, respectively, partly offset by lower customer service costs, primarily due to lower uncollectible accounts, of $13 million. The increase in nuclear generation costs is primarily due to higher maintenance costs and reflects a reimbursement in 2009 of prior years' costs of approximately $10 million related to a spent nuclear fuel litigation settlement agreement with the U.S. Government. The increase in fossil generation costs is primarily related to WCEC Units Nos. 1 and 2, which units were placed in service in the second half of 2009, and higher plant overhaul costs. The increase in distribution and transmission costs reflects higher restoration and tree trimming costs. Other changes in O&M expenses were primarily driven by pass-through costs which did not significantly affect net income.

Depreciation and Amortization Expense
The major components of FPL's depreciation and amortization expense are as follows:

	Years Ended December 31,		
	2011	2010	2009
		(millions)	
$125 million annual reduction under the 2005 rate agreement	$ —	$ —	$ (125)
Surplus depreciation credit recorded under the 2010 rate agreement	(187)	(4)	—
Other depreciation and amortization recovered under base rates	944	891	942
Depreciation and amortization recovered under cost recovery clauses and securitized storm-recovery cost amortization	41	121	280
Total	$ 798	$ 1,008	$ 1,097

From 2002 through 2009, FPL recorded the $125 million annual reduction in depreciation and amortization expense that was approved by the FPSC in previous rate orders. Under the terms of the 2010 rate agreement, FPL can vary the amount of surplus depreciation credit taken in any calendar year up to a cap in 2010 of $267 million, a cap in subsequent years of $267 million plus the amount of any unused portion from prior years, and a cap of $776 million (surplus depreciation credit cap) over the 2010 to 2012 period. In any year of the 2010 rate agreement FPL must use at least enough surplus depreciation credit to maintain a 9% earned regulatory ROE but may not use any amount of surplus depreciation credit that would result in an earned regulatory ROE in excess of 11%. As of December 31, 2011, approximately $585 million of the surplus depreciation credit cap remains available for use in 2012. The increase in other depreciation and amortization expense recovered under base rates in 2011 is primarily due to higher plant in service balances. The decline in other depreciation and amortization expense recovered under base rates in 2010 is primarily due to lower depreciation rates as a result of the FPSC rate order, partly offset by higher plant in service balances related to WCEC Units Nos. 1 and 2, which were placed in service in 2009. The decrease in depreciation and amortization recovered under cost recovery clauses and securitized storm-recovery cost amortization in 2011 and 2010 is primarily due to lower depreciation and amortization under the FPSC's nuclear cost recovery rule. See Note 1 - Electric Plant, Depreciation and Amortization.

Taxes Other Than Income Taxes and Other
Taxes other than income taxes and other increased $37 million in 2011 primarily due to higher franchise fees and revenue taxes, both of which are pass-through costs and reflect the increase in revenues from fuel and other cost recovery clauses and pass-through costs. Taxes other than income taxes and other decreased by $71 million in 2010 primarily due to changes in franchise fees and revenue taxes. In addition, taxes other than income taxes and other in 2011 and 2010 reflect higher property taxes of $5 million and $34 million, respectively, primarily due to growth in plant in service balances and, in 2010, a higher average property tax rate, partly offset in 2011 by a lower average property tax rate.

Interest Expense
The increase in interest expense in 2011 is primarily due to higher average interest rates and higher average debt balances. The increase in interest expense in 2010 is primarily due to higher average debt balances, as well as lower AFUDC - debt. Interest expense on storm-recovery bonds, as well as certain other interest expense (collectively, clause interest), are essentially pass-through amounts and do not significantly affect net income, as the clause interest is recovered either under cost recovery clause mechanisms or through a storm-recovery bond surcharge. Clause interest for 2011, 2010 and 2009 amounted to approximately $65 million, $56 million, and $45 million, respectively. The increase in clause interest in 2011 and 2010 is primarily due to higher interest associated with solar, environmental and nuclear capacity expenditures.

AFUDC - Equity
The decrease in AFUDC - equity in 2010 is primarily attributable to WCEC Units Nos. 1 and 2, which units commenced commercial operation in 2009, partly offset by additional AFUDC - equity on WCEC Unit No. 3. The decrease in AFUDC - equity in 2010 also reflects a decline, effective April 1, 2010, in the AFUDC rate from 7.41% to 6.41%, as approved by the FPSC.

NEER: Results of Operations

NEER's net income for 2011, 2010 and 2009 was $774 million, $980 million and $759 million, respectively, resulting in a decrease in 2011 of $206 million and an increase in 2010 of $221 million. The primary drivers, on an after-tax basis, of these changes were as follows:

	Increase (Decrease) From Prior Period	
	Years Ended December 31,	
	2011	2010
	(millions)	
New investments[(a)]	$ (26)	$ 45
Existing assets[(a)]	26	54
Gas infrastructure[(b)]	23	23
Customer supply and proprietary power and gas trading businesses[(b)]	(92)	(25)
Asset sales	(18)	7
Impairment charges	(20)	(11)
Interest expense, differential membership costs and other	(14)	(85)
Change in unrealized mark-to-market non-qualifying hedge activity[(c)(d)]	17	196
Loss on sale of natural gas-fired generating assets[(e)]	(92)	—
Change in OTTI losses on securities held in nuclear decommissioning funds, net of OTTI reversals[(d)]	(10)	17
Net income increase (decrease)	$ (206)	$ 221

(a) Includes PTCs and state ITCs on wind projects and, for new investments, deferred income tax and other benefits associated with convertible ITCs (see Note 1 - Electric Plant, Depreciation and Amortization, Note 1 - Income Taxes, Note 1 - Sale of Differential Membership Interests and Note 6) but does not include allocation of interest expense or corporate general and administrative expenses. Results from new projects are included in new investments during the first twelve months of operation. A project's results are included in existing assets beginning with the thirteenth month of operation.
(b) Does not include allocation of interest expense or corporate general and administrative expenses.
(c) See Note 3 and Overview related to derivative instruments.
(d) See table in Overview for additional detail.
(e) See Note 4 - Nonrecurring Fair Value Measurements and Overview for additional information.

New Investments

Results from new investments for the years ended December 31, 2011, 2010 and 2009 include approximately $1 million, $66 million and $87 million, respectively, of deferred tax benefits associated with convertible ITCs. In addition, an after-tax benefit associated with convertible ITCs of approximately $34 million was recorded in 2011 from the sale of membership interests where the investors elected to receive the convertible ITCs related to the underlying wind projects; the pretax amount of such benefit was recorded in taxes other than income taxes and other in NEE's consolidated statements of income for the year ended December 31, 2011. Results from new investments in 2011 also reflect lower state ITCs partly offset by the addition of approximately 1,130 mw of wind and 5 mw of solar generation during or after 2010. NEER's 2010 results from new investments also reflect the addition of over 2,100 mw of wind generation during or after 2009 and a benefit related to state ITCs.

Existing Assets

In 2011, results from NEER's existing asset portfolio increased $26 million primarily due to:

- lower after-tax depreciation and amortization expense of $44 million due to a change in estimate of the useful lives of certain equipment across the wind portfolio (see Note 1 - Electric Plant, Depreciation and Amortization),
- higher wind results of approximately $35 million due to a higher wind resource partly offset by lower prices,
- a $30 million income tax benefit related to a valuation allowance reversal for certain state ITCs reflecting state tax planning initiatives,
- higher results of $23 million from a natural gas-fired project in California, which was sold in the fourth quarter of 2011, reflecting higher prices under a new long-term contract,

partly offset by,

- lower results at Seabrook of $91 million primarily due to extended and unplanned outages in 2011 and lower priced hedges, and
- the expiration of PTCs ($15 million) on certain projects after ten years of production.

In 2010, results from NEER's existing asset portfolio increased $54 million primarily due to:

- favorable results at Seabrook of approximately $62 million resulting primarily from the absence of an extended outage in 2010,
- favorable generation due to lower curtailments and a higher wind resource across the wind portfolio totaling $46 million,

partly offset by,

- unfavorable market conditions in the ERCOT market affecting NEER's merchant gas assets totaling $30 million, and
- the absence of a tax benefit of $15 million recorded in 2009 related to a change in state tax law that extended the carry forward period of ITCs on certain wind projects.

Gas Infrastructure

The increase in gas infrastructure results in 2011 and 2010 is primarily due to exiting the hedged positions on a number of future gas drilling opportunities.

Customer Supply and Proprietary Power and Gas Trading

Results from the customer supply and proprietary power and gas trading businesses decreased in 2011 by $92 million primarily due to lower full requirements results, lower power and gas trading results, lower results from the retail electricity provider reflecting the adverse effects of purchasing power at high prices during a period of hot weather in Texas in August 2011 and the absence of a gain on the sale of a power supply contract realized in 2010. In 2010, results from the customer supply and proprietary power and gas trading businesses decreased by $25 million, primarily due to lower power and gas trading results, partly offset by the gain from the sale of the power supply contract.

Asset Sales

Asset sales in 2011 include an after-tax loss of $92 million realized on the sale of natural gas-fired generating assets, which due to its nature and significance was excluded from adjusted earnings (see Overview). Asset sales in 2010 include an after-tax gain of approximately $6 million on the sale of a coal-fired project and an after-tax gain on a waste-to-energy project of approximately $12 million recorded in 2010 after the expiration of an option for the buyer to sell the project back to NEER. Asset sales in 2009 include after-tax gains of $3 million for the sale of wind development rights, $6 million for the sale of a 50 mw wind project and $2 million for the sale of an interest in the waste-to-energy project.

Impairment Charges

In 2011, NEER recorded impairment charges primarily to write down the value of certain wind and oil-fired generation assets deemed to be unrecoverable. As a result of a fair value analysis, long-lived assets held and used with a carrying amount of approximately $79 million were written down to their fair value of $28 million, resulting in an impairment charge of $51 million or $31 million after-tax. See Note 4 - Nonrecurring Fair Value Measurements. In 2010, NEER recorded impairment charges of $19 million or $11 million after-tax to write down the value of certain assets associated with the plans to repower two California wind facilities. These impairment charges are reported as a separate line item in NEE's consolidated statements of income.

Interest Expense, Differential Membership Costs and Other

In both 2011 and 2010, interest expense, differential membership costs and other reflects higher interest and other costs due to growth of the business and, for 2010, also reflects the absence of an $18 million income tax benefit recorded in 2009 due to a reduction of previously deferred income taxes resulting from an additional equity investment in Canadian operations.

Other Factors

In addition to the primary drivers of the changes in net income discussed above, the discussion below describes changes in certain line items set forth in NEE's consolidated statements of income as they relate to NEER.

Operating Revenues

Operating revenues for the year ended December 31, 2011 decreased $134 million primarily due to:

- lower revenues at PMI, reflecting lower trading and full requirements activity, and the existing asset portfolio, primarily due to the extended and unplanned outages at Seabrook and unfavorable market conditions in the NEPOOL and ERCOT regions (collectively, approximately $763 million),

partly offset by,

- unrealized mark-to-market gains of $414 million from non-qualifying hedges compared to $75 million of losses on such hedges in 2010, and
- higher revenues from project additions of $132 million.

Operating revenues for the year ended December 31, 2010 increased $639 million primarily due to:

- higher revenues at PMI and NEER's retail electricity provider (collectively, approximately $242 million),
- higher revenues in the existing asset portfolio of $206 million primarily due to the absence of an extended outage in 2010 at Seabrook,
- higher revenues from project additions of $143 million,

- higher gas infrastructure revenues of $31 million,
- favorable generation due to lower curtailments and a higher wind resource across the wind portfolio, and
- losses of $75 million on unrealized mark-to-market non-qualifying hedge activity compared to $88 million of such losses in 2009.

Operating Expenses
Operating expenses for the year ended December 31, 2011 decreased $53 million primarily due to:

- lower fuel costs of approximately $445 million, and
- higher benefits associated with differential membership interests of $102 million,

partly offset by,

- $95 million of unrealized mark-to-market losses from non-qualifying hedges compared to $364 million of gains on such hedges in 2010, and
- higher impairment charges of $32 million.

Operating expenses for the year ended December 31, 2010 increased $262 million primarily due to:

- higher fuel costs of approximately $366 million,
- higher other operating expenses of $130 million due to higher maintenance activities, impairment charges associated with the plans to repower two California wind facilities and additional wells in gas infrastructure,
- higher costs for project additions of approximately $85 million,

partly offset by,

- $364 million of unrealized mark-to-market gains from non-qualifying hedges compared to $60 million of such gains in 2009.

Interest Expense
NEER's interest expense for the years ended December 31, 2011 and 2010 increased $15 million and $55 million, respectively, primarily due to increased borrowings to support the growth of the business, partly offset by lower average interest rates and, in 2011, higher interest capitalized on construction projects.

Gains on Disposal of Assets - net
Gains on disposal of assets - net in NEE's consolidated statements of income for the year ended December 31, 2011, 2010 and 2009 primarily reflect gains on sales of securities held in NEER's nuclear decommissioning funds and, in 2010, also reflect a pretax gain of $18 million on the sale of the waste-to-energy project.

Tax Credits and Benefits
PTCs from NEER's wind projects are reflected in NEER's earnings. PTCs are recognized as wind energy is generated and sold based on a per kwh rate prescribed in applicable federal and state statutes, and were approximately $271 million, $307 million and $255 million for the years ended December 31, 2011, 2010 and 2009, respectively. In addition, NEE's effective income tax rate for the years ended December 31, 2011, 2010 and 2009 was affected by deferred tax benefits associated with convertible ITCs of $2 million, $68 million and $88 million, respectively. See Note 6.

Corporate and Other: Results of Operations

Corporate and Other is primarily comprised of interest expense, the operating results of FPL FiberNet, Lone Star and other business activities, as well as corporate interest income and expenses. Corporate and Other allocates non-utility interest expense and shared service costs to NEER. Interest expense is allocated based on a deemed capital structure of 70% debt and, for purposes of allocating non-utility interest expense, the deferred credit associated with differential membership interests sold by NEER's subsidiaries is included with debt. Each subsidiary's income taxes are calculated based on the "separate return method," except that tax benefits that could not be used on a separate return basis, but are used on the consolidated tax return, are recorded by the subsidiary that generated the tax benefits. Any remaining consolidated income tax benefits or expenses are recorded at Corporate and Other. The major components of Corporate and Other's results, on an after-tax basis, are as follows:

	Years Ended December 31,		
	2011	2010	2009
	(millions)		
Interest expense, net of allocations to NEER	$ (72)	$ (63)	$ (43)
Interest income	32	43	34
Federal and state income tax benefits	91	35	—
Other	30	17	34
Net income	$ 81	$ 32	$ 25

The increase in interest expense in 2011 and 2010 reflects additional debt outstanding, partly offset by lower average interest rates and, in 2010, a higher allocation of interest costs to NEER. The decline in interest income in 2011 is primarily due to lower interest recorded on unrecognized tax benefits, reflecting the settlement with the Internal Revenue Service in 2011. See Note 6 - Unrecognized Tax Benefits. The increase in interest income in 2010 is primarily due to earnings on an energy-related loan made to a third party by a NEECH subsidiary. The federal and state income tax benefits reflect consolidating income tax adjustments and include the following the items:

- in 2011, a state deferred income tax benefit of approximately $64 million, net of federal income taxes, related to state tax law changes,
- in 2011, an income tax benefit of $41 million related to the dissolution of a subsidiary,
- in 2011, a $6 million expense associated with the loss on sale of natural gas-fired generating assets, and
- in 2010, an income tax benefit of $24 million related to employee benefits.

Other includes all other corporate income and expenses, as well as other business activities. The decline in other in 2010 is primarily due to an $11 million after-tax loss on the sale of assets held under leveraged leases; the pretax amount ($17 million) of such loss is reflected in other - net in NEE's consolidated statements of income.

LIQUIDITY AND CAPITAL RESOURCES

NEE and its subsidiaries, including FPL, require funds to support and grow their businesses. These funds are used for, among other things, working capital, capital expenditures, investments in or acquisitions of assets and businesses, payment of maturing debt obligations and, from time to time, redemption or repurchase of outstanding debt or equity securities. It is anticipated that these requirements will be satisfied through a combination of cash flow from operations, short- and long-term borrowings, and the issuance, from time to time, of short- and long-term debt and equity securities, consistent with NEE's and FPL's objective of maintaining, on a long-term basis, a capital structure that will support a strong investment grade credit rating. NEE, FPL and NEECH rely on access to credit and capital markets as significant sources of liquidity for capital requirements and other operations that are not satisfied by operating cash flows. The inability of NEE, FPL and NEECH to maintain their current credit ratings could affect their ability to raise short- and long-term capital, their cost of capital and the execution of their respective financing strategies, and could require the posting of additional collateral under certain agreements.

Cash Flows

Sources and uses of NEE's and FPL's cash for the years ended December 31, 2011, 2010 and 2009 were as follows:

	NEE			FPL		
	Years Ended December 31,			Years Ended December 31,		
	2011	2010	2009	2011	2010	2009
	(millions)					
Sources of cash:						
Cash flows from operating activities	$ 4,074	$ 3,834	$ 4,463	$ 2,245	$ 1,934	$ 2,871
Long-term borrowings, net of loan proceeds restricted for construction	3,375	3,724	3,220	840	924	516
Proceeds from the sale of differential membership interests, net of payments to investors	366	261	—	—	—	—
Sale of natural gas-fired generating assets	1,204	—	—	—	—	—
Capital contribution from NEE	—	—	—	410	660	—
Cash grants under the Recovery Act	624	588	100	218	161	—
Issuances of common stock - net	48	308	198	—	—	—
Net increase in short-term debt	460	—	154	229	—	45
Other sources	205	76	102	89	65	76
Total sources of cash	10,356	8,791	8,237	4,031	3,744	3,508
Uses of cash:						
Capital expenditures and independent power and other investments and nuclear fuel purchases	(6,628)	(5,846)	(6,006)	(3,502)	(2,706)	(2,717)
Retirements of long-term debt	(2,121)	(769)	(1,635)	(45)	(42)	(263)
Net decrease in short-term debt	—	(1,130)	—	—	(717)	—
Dividends	(920)	(823)	(766)	(400)	(250)	(485)
Repurchases of common stock	(375)	—	—	—	—	—
Other uses	(237)	(159)	(127)	(68)	(92)	(80)
Total uses of cash	(10,281)	(8,727)	(8,534)	(4,015)	(3,807)	(3,545)
Net increase (decrease) in cash and cash equivalents	$ 75	$ 64	$ (297)	$ 16	$ (63)	$ (37)

NEE's primary capital requirements are for expanding and enhancing FPL's electric system and generating facilities to continue to provide reliable service to meet customer electricity demands and for NEER's investments in independent power and other projects. The following table provides a summary of the major capital investments for the years ended December 31, 2011, 2010 and 2009.

	Years Ended December 31,		
	2011	2010	2009
	(millions)		
FPL:			
Generation:			
New	$ 1,424	$ 1,112	$ 1,185
Existing	907	636	734
Transmission and distribution	880	606	633
Nuclear fuel	365	101	195
General and other	213	101	102
Other, primarily the exclusion of AFUDC - equity and change in accrued property additions	(287)	150	(132)
Total	$ 3,502	$ 2,706	$ 2,717
NEER:			
Wind	953	1,950	2,625
Solar	594	185	40
Nuclear, including nuclear fuel	727	510	455
Other	500	427	115
Total	2,774	3,072	3,235
Corporate and Other	352	68	54
Total capital expenditures and independent power and other investments and nuclear fuel purchases	$ 6,628	$ 5,846	$ 6,006

In February 2012, an indirect wholly-owned subsidiary of NEER issued Class B membership interests to two third-party investors for approximately $225 million. The NEER subsidiary has ownership interests in a wind generation facility with generating capacity totaling approximately 662 mw located in Texas.

Liquidity

On February 9, 2012, FPL and NEECH refinanced a portion of their bank revolving line of credit facilities. The table below provides the components of FPL's and NEECH's estimated total net available liquidity as of that date.

				Maturity Date	
	FPL	NEECH	Total	FPL	NEECH
	(millions)				
Bank revolving line of credit facilities[(a)]	$ 3,018	$ 4,579	$ 7,597	(b)	(b)
Less letters of credit[(c)]	(80)	(1,484)	(1,564)		
	2,938	3,095	6,033		
Revolving credit facility	235	—	235	2014	
Less borrowings	—	—	—		
	235	—	235		
Subtotal	3,173	3,095	6,268		
Cash and cash equivalents[(c)]	26	400	426		
Less commercial paper[(c)]	(412)	(1,188)	(1,600)		
Net available liquidity	$ 2,787	$ 2,307	$ 5,094		

(a) Provide for the funding of loans up to $7,597 million ($3,018 million for FPL) and the issuance of letters of credit up to $4,097 million ($1,568 million for FPL). The entire amount of the credit facilities is available for general corporate purposes, including to provide back-up liquidity for FPL's and NEECH's commercial paper programs and other short-term borrowings and to provide additional liquidity in the event of a loss to the companies' or their subsidiaries' operating facilities (including, in the case of FPL, a transmission and distribution property loss). FPL's bank revolving line of credit facilities are also available to support the purchase of $633 million of pollution control, solid waste disposal and industrial development revenue bonds (tax exempt bonds) in the event they are tendered by individual bond holders and not remarketed prior to maturity.

(b) Approximately $4 million and $1,114 million of FPL's bank revolving line of credit facilities expire in 2012 and 2013, respectively. Approximately $10 million and $1,469 million of NEECH's bank revolving line of credit facilities expire in 2012 and 2013, respectively. The remaining portion of bank revolving line of credit facilities for FPL and NEECH expires in 2017.

(c) As of January 31, 2012.

As of February 27, 2012, 62 banks participate in FPL's and NEECH's bank revolving line of credit facilities and FPL's revolving credit facility, with no one bank providing more than 5% of the combined bank revolving line of credit facilities and FPL's revolving credit facility. European banks provide approximately 35% of the combined bank revolving line of credit facilities and FPL's revolving credit facility. Pursuant to a 1998 guarantee agreement, NEE guarantees the payment of NEECH's debt obligations under the bank revolving line of credit facilities. In order for FPL or NEECH to borrow or to have letters of credit issued under the terms of their respective bank revolving line of credit facilities and FPL's revolving credit facility, FPL, in the case of FPL, and NEE, in the case of the NEECH, are required, among other things, to maintain a ratio of funded debt to total capitalization that does not exceed a stated ratio. The FPL and NEECH bank revolving line of credit facilities and FPL revolving credit facility also contain default and related acceleration provisions relating to, among other things, failure of FPL and NEE, as the case may be, to maintain the respective ratio of funded debt to total capitalization at or below the specified ratio. At December 31, 2011, each of NEE and FPL was in compliance with its required ratio.

Additionally, at December 31, 2011, certain subsidiaries of NEE had credit or loan facilities with available liquidity as follows:

	Original Amount	Amount Remaining Available at December 31, 2011	Rate	Maturity Date	Related Project Use
		(millions)			
NEECH and NEER:					
Canadian bank revolving credit agreements[(a)]	C$300	$121	Variable	2013	Canadian renewable generating assets
Revolving loan agreement[(a)]	€170	$175	Variable	2014	Construction of Spain solar project
NEER:					
Senior secured limited-recourse loan agreement[(b)(c)]	€589	$485	Variable	2030	Construction of Spain solar project
Term loan facility[(b)(c)]	$150	$150	Variable	2019	Construction of Genesis solar project
Lone Star:					
Senior secured limited-recourse loan agreement[(b)(d)]	$387	$279	Variable	2016	Construction of Lone Star transmission line and substations

(a) Includes as a precondition to borrowing or issuing letters of credit as well as default and related acceleration provisions that require NEE's ratio of funded debt to total capitalization to not exceed a stated ratio. Payment obligations are guaranteed by NEE pursuant to the 1998 guarantee agreement with NEECH.

(b) Includes default and related acceleration provisions for, among other things, failure to comply with certain covenants, including requirements that construction of the project must be completed by a certain date.

(c) Borrowings are preconditioned on equity being contributed by the project's parent, and are drawn on a pro-rata basis with those equity contributions. The total equity funding commitment and, until certain conditions or obligations related to the project are met, certain obligations, including all or a portion of the debt payment obligations, are guaranteed by NEECH, which guarantee obligations are in turn guaranteed by NEE. The related NEECH guarantee contains default and acceleration provisions relating to, among other things, NEE's ratio of funded debt to total capitalization exceeding a specified ratio.

(d) Borrowings are preconditioned on equity being contributed by Lone Star's parent, and are drawn on a pro-rata basis with those equity contributions. The total equity funding commitment has been guaranteed by NEECH, which guarantee obligations are in turn guaranteed by NEE. The related NEECH guarantee contains default provisions and related provisions for acceleration of the unfunded equity commitment relating to, among other things, NEE's ratio of funded debt to total capitalization exceeding a specified ratio.

Storm Restoration Costs

At December 31, 2011, FPL had the capacity to absorb up to approximately $202 million in future prudently incurred storm restoration costs without seeking recovery through a rate adjustment from the FPSC or filing a petition with the FPSC. See Note 1 – Revenue and Rates.

Dodd-Frank Act

The Dodd-Frank Act, enacted into law in July 2010, among other things, provides for the regulation of the OTC derivatives market. The Dodd-Frank Act includes provisions that will require certain OTC derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. While the legislation is broad and detailed, substantial portions of the legislation require implementing rules to be adopted by federal governmental agencies including, but not limited to, the SEC and the CFTC. While some provisions of the statute related to OTC derivatives are currently in effect or have been finalized, the majority of the rules are expected to be finalized and implemented in 2012. NEE and FPL cannot predict the impact of the final rules that will be adopted to implement the OTC derivative-related provisions of the Dodd-Frank Act. Those rules could negatively affect NEE's and FPL's ability to hedge their commodity and interest rate risks, which could have a material effect on NEE's and FPL's risk exposure and financial results. The rules also could cause NEER to decide to restructure part of its energy marketing and trading operations or to discontinue certain portions of that business. In addition, if the rules require NEE and FPL to post significant amounts of cash collateral with respect to swap transactions, NEE's and FPL's liquidity could be materially affected, and their ability to enter into OTC derivatives

to hedge commodity and interest rate risks could be significantly limited. Reporting and compliance requirements of the rules also could significantly increase operating costs and expose NEE and FPL to penalties for any failure to comply with the new requirements. The financial and operational impact of the final rules cannot be determined at this time, but could be material.

Capital Support

Letters of Credit, Surety Bonds and Guarantees
NEE and FPL obtain letters of credit and surety bonds, and issue guarantees to facilitate commercial transactions with third parties and financings. Letters of credit, surety bonds and guarantees support, among other things, the buying and selling of wholesale energy commodities, debt and related reserves, nuclear activities, capital expenditures for wind and solar development and other contractual agreements.

In addition, as part of contract negotiations in the normal course of business, NEE and FPL may agree to make payments to compensate or indemnify other parties for possible future unfavorable financial consequences resulting from specified events. The specified events may include, but are not limited to, an adverse judgment in a lawsuit, the imposition of additional taxes due to a change in tax law or interpretations of the tax law or the non-receipt of renewable tax credits or proceeds from cash grants under the Recovery Act. NEE and FPL are unable to develop an estimate of the maximum potential amount of future payments under some of these contracts because events that would obligate them have not yet occurred or, if any such event has occurred, they have not been notified of its occurrence.

In addition, NEE has guaranteed certain payment obligations of NEECH, including most of its debt and all of its debentures and commercial paper issuances, as well as most of its payment guarantees and indemnifications, and NEECH has guaranteed certain debt and other obligations of NEER and its subsidiaries. See Note 14 - Commitments.

At December 31, 2011, NEE had approximately $1.4 billion of standby letters of credit ($40 million for FPL), approximately $160 million of surety bonds ($56 million for FPL) and approximately $14.5 billion notional amount of guarantees and indemnifications ($25 million for FPL), of which approximately $9.2 billion ($45 million for FPL) letters of credit, guarantees and indemnifications have expiration dates within the next five years. An aggregate of approximately $1.3 billion ($34 million for FPL) of the standby letters of credit at December 31, 2011 were issued under FPL's and NEECH's credit facilities.

Each of NEE and FPL believe it is unlikely that it would incur any liabilities associated with these letters of credit, surety bonds, guarantees and indemnifications. Accordingly, at December 31, 2011, NEE and FPL did not have any liabilities recorded for these letters of credit, surety bonds, guarantees and indemnifications.

Shelf Registration
In August 2009, NEE, NEECH, FPL and certain affiliated trusts filed a shelf registration statement with the SEC for an unspecified amount of securities which became effective upon filing. The amount of securities issuable by the companies is established from time to time by their respective boards of directors. As of February 27, 2012, securities that may be issued under the registration statement include, depending on the registrant, senior debt securities, subordinated debt securities, junior subordinated debentures, first mortgage bonds, preferred trust securities, common stock, preferred stock, stock purchase contracts, stock purchase units, warrants and guarantees related to certain of those securities. As of February 27, 2012, NEE and NEECH had approximately $2.3 billion (issuable by either or both of them up to such aggregate amount) of board-authorized available capacity, and FPL had $750 million of board-authorized available capacity.

Contractual Obligations and Estimated Planned Capital Expenditures

NEE's and FPL's commitments at December 31, 2011 were as follows:

	2012	2013	2014	2015	2016	Thereafter	Total
				(millions)			
Long-term debt, including interest:[a]							
FPL	$ 428	$ 818	$ 409	$ 410	$ 411	$ 13,476 [b]	$ 15,952
NEER	729	958	986	707	677	4,317	8,374
Corporate and Other	739	1,697	1,531	1,610	405	12,580	18,562
Purchase obligations:							
FPL[c]	5,985	3,810	2,900	2,545	2,295	9,415	26,950
NEER[d]	1,970	475	140	110	100	520	3,315
Corporate and Other[e]	250	15	—	—	—	—	265
Asset retirement activities:[f]							
FPL[g]	—	—	—	—	—	7,106	7,106
NEER[h]	2	—	—	—	—	11,564	11,566
Other Commitments:							
NEER[i]	142	76	78	103	115	557	1,071
Total	$ 10,245	$ 7,849	$ 6,044	$ 5,485	$ 4,003	$ 59,535	$ 93,161

(a) Includes principal, interest and interest rate swaps. Variable rate interest was computed using December 31, 2011 rates.
(b) Includes $633 million of tax exempt bonds that permit individual bond holders to tender the bonds for purchase at any time prior to maturity. In the event bonds are tendered for purchase, they would be remarketed by a designated remarketing agent in accordance with the related indenture. If the remarketing is unsuccessful, FPL would be required to purchase the tax exempt bonds. As of December 31, 2011, all tax exempt bonds tendered for purchase have been successfully remarketed. FPL's bank revolving line of credit facilities are available to support the purchase of tax exempt bonds.
(c) Represents required capacity and minimum charges under long-term purchased power and fuel contracts (see Note 14 - Contracts), and projected capital expenditures through 2016 (see Note 14 - Commitments).
(d) Represents firm commitments primarily in connection with construction activities and fuel-related contracts. See Note 14 - Commitments and Contracts.
(e) Represents firm commitments primarily for development and construction activities relating to Lone Star's transmission line and other associated facilities.
(f) Represents expected cash payments adjusted for inflation for estimated costs to perform asset retirement activities.
(g) At December 31, 2011, FPL had approximately $2,612 million in restricted funds for the payment of future expenditures to decommission FPL's nuclear units, which are included in NEE's and FPL's special use funds. See Note 13.
(h) At December 31, 2011, NEER's 88.23% portion of Seabrook's and 70% portion of Duane Arnold's and its Point Beach's restricted funds for the payment of future expenditures to decommission its nuclear units totaled approximately $1,130 million and are included in NEE's special use funds. See Note 13.
(i) Represents estimated cash distributions related to membership interests and payments related to the acquisition of certain development rights. For further discussion of membership interests, see Note 1 - Sale of Differential Membership Interests.

Credit Ratings

NEE's and FPL's liquidity, ability to access credit and capital markets, cost of borrowings and collateral posting requirements under certain agreements are dependent on their credit ratings. At February 27, 2012, Moody's Investors Service, Inc. (Moody's), Standard & Poor's Ratings Services (S&P) and Fitch Ratings (Fitch) had assigned the following credit ratings to NEE, FPL and NEECH:

	Moody's[a]	S&P[a]	Fitch[a]
NEE:[b]			
Corporate credit rating	Baa1	A-	A-
FPL:[b]			
Corporate credit rating	A2	A-	A
First mortgage bonds	Aa3	A	AA-
Pollution control, solid waste disposal and industrial development revenue bonds	VMIG-1	A	A+
Commercial paper	P-1	A-2	F1
NEECH:[b]			
Corporate credit rating	Baa1	A-	A-
Debentures	Baa1	BBB+	A-
Junior subordinated debentures	Baa2	BBB	BBB
Commercial paper	P-2	A-2	F1

(a) A security rating is not a recommendation to buy, sell or hold securities and should be evaluated independently of any other rating. The rating is subject to revision or withdrawal at any time by the assigning rating organization.
(b) The outlook indicated by each of Moody's, S&P and Fitch is stable.

NEE and its subsidiaries, including FPL, have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt. A change in ratings is not an event of default under applicable debt instruments, and while there are conditions to drawing on the credit facilities noted above, with the exception of the Spain senior secured limited-recourse loan facility, the maintenance of a specific minimum credit rating is not a condition to drawing on these credit facilities.

Commitment fees and interest rates on loans under these credit facilities' agreements are tied to credit ratings. A ratings downgrade also could reduce the accessibility and increase the cost of commercial paper and other short-term debt issuances and additional or replacement credit facilities. In addition, a ratings downgrade could result in the requirement that NEE subsidiaries, including FPL, post collateral under certain agreements, including those related to fuel procurement, power sales and purchases, nuclear decommissioning funding, debt-related reserves and trading activities. FPL's and NEECH's credit facilities are available to support these potential requirements.

Covenants

NEE's charter does not limit the dividends that may be paid on its common stock. As a practical matter, the ability of NEE to pay dividends on its common stock is dependent upon, among other things, dividends paid to it by its subsidiaries. For example, FPL pays dividends to NEE in a manner consistent with FPL's long-term targeted capital structure. However, the mortgage securing FPL's first mortgage bonds contains provisions which, under certain conditions, restrict the payment of dividends to NEE and the issuance of additional first mortgage bonds. Additionally, in some circumstances, the mortgage restricts the amount of retained earnings that FPL can use to pay cash dividends on its common stock. The restricted amount may change based on factors set out in the mortgage. Other than this restriction on the payment of common stock dividends, the mortgage does not restrict FPL's use of retained earnings. As of December 31, 2011, no retained earnings were restricted by these provisions of the mortgage and in light of FPL's current financial condition and level of earnings, management does not expect that planned financing activities or dividends would be affected by these limitations.

FPL may issue first mortgage bonds under its mortgage subject to its meeting an adjusted net earnings test set forth in the mortgage, which generally requires adjusted net earnings to be at least twice the annual interest requirements on, or at least 10% of the aggregate principal amount of, FPL's first mortgage bonds including those to be issued and any other non-junior FPL indebtedness. As of December 31, 2011, coverage for the 12 months ended December 31, 2011 would have been approximately 6.5 times the annual interest requirements and approximately 3.6 times the aggregate principal requirements. New first mortgage bonds are also limited to an amount equal to the sum of 60% of unfunded property additions after adjustments to offset property retirements, the amount of retired first mortgage bonds or qualified lien bonds and the amount of cash on deposit with the mortgage trustee. As of December 31, 2011, FPL could have issued in excess of $8.9 billion of additional first mortgage bonds based on the unfunded property additions and in excess of $5.8 billion based on retired first mortgage bonds. As of December 31, 2011, no cash was deposited with the mortgage trustee for these purposes.

In September 2006, NEE and NEECH executed a Replacement Capital Covenant (September 2006 RCC) in connection with NEECH's offering of $350 million principal amount of Series A Enhanced Junior Subordinated Debentures due 2066 and $350 million principal amount of Series B Enhanced Junior Subordinated Debentures due 2066 (collectively, Series A and Series B junior subordinated debentures). The September 2006 RCC is for the benefit of persons that buy, hold or sell a specified series of long-term indebtedness (covered debt) of NEECH (other than the Series A and Series B junior subordinated debentures) or, in certain cases, of NEE. FPL Group Capital Trust I's 5 7/8% Preferred Trust Securities have been initially designated as the covered debt under the September 2006 RCC. The September 2006 RCC provides that NEECH may redeem, and NEE or NEECH may purchase, any Series A and Series B junior subordinated debentures on or before October 1, 2036, only to the extent that the redemption or purchase price does not exceed a specified amount of proceeds from the sale of qualifying securities, subject to certain limitations described in the September 2006 RCC. Qualifying securities are securities that have equity-like characteristics that are the same as, or more equity-like than, the Series A and Series B junior subordinated debentures at the time of redemption or purchase, which are sold within 180 days prior to the date of the redemption or repurchase of the Series A and Series B junior subordinated debentures.

In June 2007, NEE and NEECH executed a Replacement Capital Covenant (June 2007 RCC) in connection with NEECH's offering of $400 million principal amount of its Series C Junior Subordinated Debentures due 2067 (Series C junior subordinated debentures). The June 2007 RCC is for the benefit of persons that buy, hold or sell a specified series of covered debt of NEECH (other than the Series C junior subordinated debentures) or, in certain cases, of NEE. FPL Group Capital Trust I's 5 7/8% Preferred Trust Securities have been initially designated as the covered debt under the June 2007 RCC. The June 2007 RCC provides that NEECH may redeem or purchase, or satisfy, discharge or defease (collectively, defease), and NEE and any majority-owned subsidiary of NEE or NEECH may purchase, any Series C junior subordinated debentures on or before June 15, 2037, only to the extent that the principal amount defeased or the applicable redemption or purchase price does not exceed a specified amount raised from the issuance, during the 180 days prior to the date of that redemption, purchase or defeasance, of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Series C junior subordinated debentures at the time of redemption, purchase or defeasance, subject to certain limitations described in the June 2007 RCC.

In September 2007, NEE and NEECH executed a Replacement Capital Covenant (September 2007 RCC) in connection with NEECH's offering of $250 million principal amount of its Series D Junior Subordinated Debentures due 2067 and $350 million principal amount of Series E Junior Subordinated Debentures due 2067 (collectively, Series D and Series E junior subordinated debentures). The September 2007 RCC is for the benefit of persons that buy, hold or sell a specified series of covered debt of NEECH (other than the

Series D and Series E junior subordinated debentures) or, in certain cases, of NEE. FPL Group Capital Trust I's 5 7/8% Preferred Trust Securities have been initially designated as the covered debt under the September 2007 RCC. The September 2007 RCC provides that NEECH may redeem, purchase, or defease, and NEE and any majority-owned subsidiary of NEE or NEECH may purchase, any Series D and Series E junior subordinated debentures on or before September 1, 2037, only to the extent that the principal amount defeased or the applicable redemption or purchase price does not exceed a specified amount raised from the issuance, during the 180 days prior to the date of that redemption, purchase or defeasance, of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Series D and Series E junior subordinated debentures at the time of redemption, purchase or defeasance, subject to certain limitations described in the September 2007 RCC.

In March 2009, NEE and NEECH executed a Replacement Capital Covenant (March 2009 RCC) in connection with NEECH's offering of $375 million principal amount of its Series F Junior Subordinated Debentures due 2069. The March 2009 RCC is for the benefit of persons that buy, hold or sell a specified series of covered debt of NEECH (other than the Series F junior subordinated debentures) or, in certain cases, of NEE. FPL Group Capital Trust I's 5 7/8% Preferred Trust Securities have been initially designated as the covered debt under the March 2009 RCC. The March 2009 RCC provides that NEECH may redeem, purchase, or defease, and NEE and any majority-owned subsidiary of NEE or NEECH may purchase, any Series F junior subordinated debentures on or before March 1, 2039, only to the extent that the principal amount defeased or the applicable redemption or purchase price does not exceed a specified amount raised from the issuance, during the 180 days prior to the date of that redemption, purchase or defeasance, of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Series F junior subordinated debentures at the time of redemption, purchase or defeasance, subject to certain limitations described in the March 2009 RCC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

NEE's and FPL's significant accounting policies are described in Note 1 to the consolidated financial statements, which were prepared in accordance with GAAP. Critical accounting policies are those that NEE and FPL believe are both most important to the portrayal of their financial condition and results of operations, and require complex, subjective judgments, often as a result of the need to make estimates and assumptions about the effect of matters that are inherently uncertain. Judgments and uncertainties affecting the application of those policies may result in materially different amounts being reported under different conditions or using different assumptions.

NEE and FPL consider the following policies to be the most critical in understanding the judgments that are involved in preparing their consolidated financial statements:

Accounting for Derivatives and Hedging Activities

NEE and FPL use derivative instruments (primarily swaps, options, futures and forwards) to manage the commodity price risk inherent in the purchase and sale of fuel and electricity, as well as interest rate and foreign currency exchange rate risk associated with outstanding and forecasted debt issuances. In addition, NEE, through NEER, uses derivatives to optimize the value of power generation assets and engages in power and gas marketing and trading activities to take advantage of expected future favorable price movements.

Nature of Accounting Estimates

Accounting pronouncements require the use of fair value accounting if certain conditions are met, which requires significant judgment to measure the fair value of assets and liabilities. This applies not only to traditional financial derivative instruments, but to any contract having the accounting characteristics of a derivative. Much of the existing accounting guidance related to derivatives focuses on when certain contracts for the purchase and sale of power and certain fuel supply contracts can be excluded from derivative accounting rules, however the guidance does not address all contract issues. As a result, significant judgment must be used in applying derivatives accounting guidance to contracts. In the event changes in interpretation occur, it is possible that contracts that currently are excluded from derivatives accounting rules would have to be recorded on the balance sheet at fair value, with changes in the fair value recorded in the statement of income.

Assumptions and Accounting Approach

NEE's and FPL's derivative instruments, when required to be marked to market, are recorded on the balance sheet at fair value. Fair values for some of the longer-term contracts where liquid markets are not available are derived through internally developed models which estimate the fair value of a contract by calculating the present value of the difference between the contract price and the forward prices. Forward prices represent the price at which a buyer or seller could contract today to purchase or sell a commodity at a future date. The near-term forward market for electricity is generally liquid and therefore the prices in the early years of the forward curves reflect observable market quotes. However, in the later years, the market is much less liquid and forward price curves must be developed using factors including the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of power plants in converting fuel to electricity) in the region where the purchase or sale takes place, and a fundamental forecast of expected spot prices based on modeled supply and demand in the region. NEE estimates the fair value of interest rate and foreign currency derivatives using a discounted cash flows valuation

technique based on the net amount of estimated future cash inflows and outflows related to the derivative agreements. The assumptions in these models are critical since any changes therein could have a significant impact on the fair value of the derivative.

At FPL, substantially all changes in the fair value of energy derivative transactions are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel clause or the capacity clause. See Note 3.

In NEE's non-rate regulated operations, predominantly NEER, all changes in the derivatives' fair value for power purchases and sales and trading activities are recognized on a net basis in operating revenues; fuel purchases and sales are recognized on a net basis in fuel, purchased power and interchange expense; and the equity method investees' related activity is recognized in equity in earnings of equity method investees in NEE's consolidated statements of income, unless the criteria for hedge accounting are met and the company elects to account for the derivative as a hedge.

For those transactions accounted for as cash flow hedges, much of the effects of changes in fair value are reflected in OCI, a component of common shareholders' equity, rather than being recognized in current earnings. For those transactions accounted for as fair value hedges, the effects of changes in fair value are reflected in current earnings offset by changes in the fair value of the item being hedged.

Certain hedging transactions at NEER are entered into as economic hedges but the transactions do not meet the requirements for hedge accounting or hedge accounting treatment is not elected. Changes in the fair value of those transactions are marked to market and reported in the consolidated statements of income, resulting in earnings volatility. These changes in fair value are captured in the non-qualifying hedge category in computing adjusted earnings. This could be significant to NEER's results because the economic offset to the positions which are required to be marked to market (such as the physical assets from which power is generated) are not marked to market. As a consequence, net income reflects only the movement in one part of economically-linked transactions. For this reason, NEE's management views results expressed excluding the unrealized mark-to-market impact of the non-qualifying hedges as a meaningful measure of current period performance. For additional information regarding derivative instruments, see Note 3, Overview and Energy Marketing and Trading and Market Risk Sensitivity.

Accounting for Pensions and Other Postretirement Benefits

NEE sponsors a qualified noncontributory defined benefit pension plan for substantially all employees of NEE and its subsidiaries. NEE also has a supplemental executive retirement plan (SERP) which includes a non-qualified supplemental defined benefit pension component that provides benefits to a select group of management and highly compensated employees. The impact of the SERP component is included within the pension plan as discussed below. Management believes that, based on actuarial assumptions and the well-funded status of the pension plan, NEE will not be required to make any cash contributions to the qualified pension plan in the near future.

In addition to pension benefits, NEE sponsors a contributory postretirement plan for health care and life insurance benefits (other benefits plan) for retirees of NEE and its subsidiaries meeting certain eligibility requirements. The qualified pension plan has a fully funded trust dedicated to providing the benefits under the plan. The other benefits plan has a partially funded trust dedicated to providing benefits related to life insurance. NEE allocates net periodic benefit income or cost associated with the pension and other benefits plans to its subsidiaries annually using specific criteria.

Nature of Accounting Estimates

For the pension plan, the benefit obligation is the actuarial present value as of the December 31 measurement date, of all benefits attributed by the pension benefit formula to employee service rendered to that date. The amount of benefit to be paid depends on a number of future events incorporated into the pension benefit formula, including estimates of the average life of employees/survivors and average years of service rendered. The projected benefit obligation is measured based on assumptions concerning future interest rates and future employee compensation levels. For the other benefits plan, the benefit obligation is the actuarial present value as of the December 31 measurement date of all future benefits attributed under the terms of the other benefits plan to employee service rendered to that date. NEE derives pension income and the cost of the other benefits plan from actuarial calculations based on each plan's provisions and management's assumptions regarding discount rate, rate of increase in compensation levels and expected long-term rate of return on plan assets and, in the case of the other benefits plan, health care cost trend rates.

Assumptions and Accounting Approach

NEE's regulatory assets and liabilities are established in association with accounting guidance which requires recognition of the funded status of benefit plans in the balance sheet, with changes in the funded status recognized in comprehensive income within shareholders' equity in the year in which the changes occur. Since NEE is the plan sponsor, and its subsidiaries do not have separate rights to the plan assets or direct obligations to their employees, this accounting guidance is reflected at NEE and not allocated to the subsidiaries. The portion of previously unrecognized actuarial gains and losses, prior service costs or credits and transition obligations that are estimated to be allocable to FPL as net periodic benefit (income) cost in future periods and that otherwise would be recorded in AOCI are classified as regulatory assets and liabilities at NEE in accordance with regulatory

treatment.

Pension income and the cost of the other benefits plan are included in O&M expenses, and are calculated using a number of actuarial assumptions. Those assumptions include:

- an expected long-term rate of return on qualified plan assets of 7.75% for all years for the pension plan and 8.00% for all years for the other benefits plan,
- assumed increases in salary of 4.00% for all years,
- weighted-average discount rates of 5.00%, 5.50%, and 6.90% for the pension plan and 5.25%, 5.50%, and 6.90% for the other benefits plan for the years ended December 31, 2011, 2010 and 2009, respectively, and
- health care cost trend rates (as related to other benefits) for those under age 65 of 7.60% for medical and 8.20% for prescription drug benefits and for those age 65 and over of 7.25% for medical and 7.75% for prescription drug benefits. These rates are assumed to decrease over the next 7 years for medical benefits and 9 years for prescription drug benefits to the ultimate trend rate of 5.50% and remain at that level thereafter. The ultimate trend rate is assumed to be reached in 2018 for medical benefits and 2020 for prescription drug benefits.

In developing these assumptions, NEE evaluated input from its actuaries and consultants, as well as information available in the marketplace. For the expected long-term rate of return on fund assets, NEE considered different models, capital market return assumptions and historical returns for a portfolio with an equity/bond asset mix similar to its funds, as well as its funds' historical compounded returns. NEE also considered input, including other qualitative and quantitative factors, from its actuaries and consultants as well as information available in the marketplace. NEE believes that 7.75% and 8.00% are reasonable long-term rates of return on its pension plan and other benefits plan assets, respectively. NEE will continue to evaluate all of its actuarial assumptions, including its expected rate of return, at least annually, and will adjust them as necessary.

NEE bases its determination of pension and other benefits plan expense or income on a market-related valuation of assets, as prescribed by accounting guidance. This market-related valuation reduces year-to-year volatility and recognizes investment gains or losses over a five-year period following the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return realized on those assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be affected as previously deferred gains or losses are recognized. Such gains and losses together with other differences between actual results and the estimates used in the actuarial valuations are deferred and recognized in determining pension income and other benefits plan expense only to the extent they exceed 10% of the greater of projected benefit obligations or the market-related value of assets.

The following table illustrates the effect on net periodic benefit income of changing the critical actuarial assumptions discussed above, while holding all other assumptions constant:

		Increase (Decrease) in 2011 Net Periodic Benefit Income	
	Change in Assumption	NEE	FPL
Expected long-term rate of return	(0.5)%	$ (16)	$ (11)
Discount rate	(0.5)%	$ 2	$ 1
Salary increase	0.5 %	$ (2)	$ (1)
Health care cost trend rate[(a)]	1.0 %	$ —	$ —

(a) Assumed health care cost trend rates can have a significant effect on the amounts reported for postretirement plans providing health care benefits. However, this effect is somewhat mitigated by the retiree cost sharing structure incorporated in NEE's other benefits plan.

See Note 2.

Carrying Value of Long-Lived Assets

NEE evaluates on an ongoing basis the recoverability of its assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

Nature of Accounting Estimates

The amount of future net cash flows, the timing of the cash flows and the determination of an appropriate interest rate all involve estimates and judgments about future events. In particular, the aggregate amount of cash flows determines whether an impairment exists, and the timing of the cash flows is critical in determining fair value. Because each assessment is based on the facts and circumstances associated with each long-lived asset, the effects of changes in assumptions cannot be generalized.

Assumptions and Accounting Approach

An impairment loss is required to be recognized if the carrying value of the asset exceeds the undiscounted future net cash flows associated with that asset. The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset's fair value. In most instances, the fair value is determined by discounting estimated future cash flows using an appropriate interest rate. See Note 4 - Nonrecurring Fair Value Measurements.

Nuclear Decommissioning and Fossil/Solar Dismantlement

The components of NEE's and FPL's decommissioning of nuclear plants, dismantlement of plants and other accrued asset removal costs are as follows:

	FPL									
	Nuclear Decommissioning		Fossil/Solar Dismantlement		Interim Removal Costs and Other		NEER		NEE	
	December 31,		December 31,		December 31,		December 31,		December 31,	
	2011	2010	2011	2010	2011	2010	2011	2010	2011	2010
					(millions)					
AROs	$ 1,114	$ 1,057	$ 27	$ 23	$ 3	$ 3	$ 467	$ 556	$ 1,611	$ 1,639
Less capitalized ARO asset net of accumulated depreciation	—	—	7	4	—	—	—	—	7	4
Accrued asset removal costs[a]	216	207	337	336	1,644	1,701	—	—	2,197	2,244
Asset retirement obligation regulatory expense difference[a]	1,618	1,571	23	22	(1)	(1)	—	—	1,640	1,592
Accrued decommissioning, dismantlement and other accrued asset removal costs	$ 2,948 [b]	$ 2,835 [b]	$ 380 [b]	$ 377 [b]	$ 1,646 [b]	$ 1,703 [b]	$ 467	$ 556	$ 5,441	$ 5,471

(a) Regulatory liability on NEE's and FPL's consolidated balance sheets.
(b) Represents total amount accrued for ratemaking purposes.

Nature of Accounting Estimates

The calculation of the future cost of retiring long-lived assets, including nuclear decommissioning and fossil and solar dismantlement costs, involves estimating the amount and timing of future expenditures and making judgments concerning whether or not such costs are considered a legal obligation. Estimating the amount and timing of future expenditures includes, among other things, making projections of when assets will be retired and ultimately decommissioned and how costs will escalate with inflation. In addition, NEE and FPL also make interest rate and rate of return projections on their investments in determining recommended funding requirements for nuclear decommissioning costs. Periodically, NEE and FPL are required to update these estimates and projections which can affect the annual expense amounts recognized, the liabilities recorded and the annual funding requirements for nuclear decommissioning costs. For example, an increase of 0.25% in the assumed escalation rates would increase NEE's and FPL's asset retirement obligations and conditional asset retirement obligations (collectively, AROs) as of December 31, 2011 by $126 million and $87 million, respectively.

Assumptions and Accounting Approach

NEE and FPL each account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as part of the carrying amount of the long-lived assets.

FPL - For ratemaking purposes, FPL accrues and funds for nuclear plant decommissioning costs over the expected service life of each unit based on studies that are filed with the FPSC at least every five years. The studies reflect, among other things, the expiration dates of the operating licenses for FPL's nuclear units. The most recent studies, filed in 2010, indicate that FPL's portion of the future cost of decommissioning its four nuclear units, including spent fuel storage above what is expected to be refunded by the DOE under the spent fuel settlement agreement, is approximately $6.2 billion, or $2.3 billion expressed in 2011 dollars.

FPL accrues the cost of dismantling its fossil and solar plants over the expected service life of each unit based on studies filed with the FPSC. Unlike nuclear decommissioning, dismantlement costs are not funded. The most recent studies became effective January 1, 2010. At December 31, 2011, FPL's portion of the ultimate cost to dismantle its fossil and solar units is approximately $860 million, or $421 million expressed in 2011 dollars. The majority of the dismantlement costs are not considered AROs. FPL accrues for interim removal costs over the life of the related assets based on depreciation studies approved by the FPSC. Any differences between the ARO amount recorded and the amount recorded for ratemaking purposes are reported as a regulatory liability in accordance with regulatory accounting.

NEER - NEER records a liability for the present value of its expected decommissioning costs which is determined using various internal and external data and applying a probability percentage to a variety of scenarios regarding the life of the plant and timing of decommissioning. The liability is being accreted using the interest method through the date decommissioning activities are expected to be complete. At December 31, 2011, the ARO for nuclear decommissioning of NEER's nuclear plants totaled approximately $383 million. NEER's portion of the ultimate cost of decommissioning its nuclear plants, including costs associated with spent fuel storage above what is expected to be refunded by the DOE under the spent fuel settlement agreement, is estimated to be approximately $11.4 billion, or $1.9 billion expressed in 2011 dollars.

See Note 1 - Asset Retirement Obligations, Note 1 - Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs and Note 13.

Regulatory Accounting

NEE's and FPL's regulatory assets and liabilities are as follows:

	NEE		FPL	
	December 31,		December 31,	
	2011	2010	2011	2010
Regulatory assets:	(millions)			
Current:				
Deferred clause and franchise expenses	$ 112	$ 368	$ 112	$ 368
Derivatives	$ 502	$ 236	$ 502	$ 236
Other	$ 84	$ 82	$ 80	$ 76
Noncurrent:				
Securitized storm-recovery costs	$ 517	$ 581	$ 517	$ 581
Other	$ 621	$ 329	$ 395	$ 293
Regulatory liabilities:				
Current, included in other current liabilities	$ 21	$ 52	$ 24	$ 47
Noncurrent:				
Accrued asset removal costs	$ 2,197	$ 2,244	$ 2,197	$ 2,244
Asset retirement obligation regulatory expense difference	$ 1,640	$ 1,592	$ 1,640	$ 1,592
Other	$ 419	$ 423	$ 416	$ 377

Nature of Accounting Estimates

Regulatory assets and liabilities represent probable future revenues that will be recovered from or refunded to customers through the ratemaking process. All regulatory assets and liabilities are included in rate base or otherwise earn (pay) a return on investment during the recovery period.

Assumptions and Accounting Approach

Accounting guidance allows regulators to create assets and impose liabilities that would not be recorded by non-rate regulated entities. If FPL were no longer subject to cost-based rate regulation, the existing regulatory assets and liabilities would be written off unless regulators specify an alternative means of recovery or refund. In addition, the FPSC has the authority to disallow recovery of costs that it considers excessive or imprudently incurred. Such costs may include, among others, fuel and O&M expenses, the cost of replacing power lost when fossil and nuclear units are unavailable, storm restoration costs and costs associated with the construction or acquisition of new facilities. The continued applicability of regulatory accounting is assessed at each reporting period. See Note 1 for a discussion of NEE's and FPL's other significant accounting policies.

Energy Marketing and Trading and Market Risk Sensitivity

NEE and FPL are exposed to risks associated with adverse changes in commodity prices, interest rates, equity prices and currency exchange rates. Financial instruments and positions affecting the financial statements of NEE and FPL described below are held primarily for purposes other than trading. Market risk is measured as the potential loss in fair value resulting from hypothetical reasonably possible changes in commodity prices, interest rates, equity prices or currency exchange rates over the next year. Management has established risk management policies to monitor and manage such market risks, as well as credit risks.

Commodity Price Risk

NEE and FPL use derivative instruments (primarily swaps, options, futures and forwards) to manage the commodity price risk inherent in the purchase and sale of fuel and electricity. In addition, NEE, through NEER, uses derivatives to optimize the value of power generation assets and engages in power and gas marketing and trading activities to take advantage of expected future favorable price movements. See Critical Accounting Policies and Estimates and Note 3.

During 2010 and 2011, the changes in the fair value of NEE's consolidated subsidiaries' energy contract derivative instruments were as follows:

		Hedges on Owned Assets			
	Trading	Non-Qualifying	OCI	FPL Cost Recovery Clauses	NEE Total
			(millions)		
Fair value of contracts outstanding at December 31, 2009	$ 39	$ 126	$ 131	$ (64)	$ 232
Reclassification to realized at settlement of contracts	(98)	(126)	(102)	492	166
Inception value of new contracts	108	(45)	-	-	63
Effective portion of changes in fair value recorded in OCI	-	-	20	-	20
Ineffective portion of changes in fair value recorded in earnings	-	1	-	-	1
Changes in fair value excluding reclassification to realized	76	457	-	(664)	(131)
Fair value of contracts outstanding at December 31, 2010	125	413	49	(236)	351
Reclassification to realized at settlement of contracts	2	(96)	(41)	381	246
Inception value of new contracts and contracts sold	11	(11)	—	—	—
Changes in fair value excluding reclassification to realized	72	403	—	(646)	(171)
Fair value of contracts outstanding at December 31, 2011	210	709	8	(501)	426
Net option premium payments (receipts)	(195)	11	—	—	(184)
Net margin cash collateral paid (received)					(24)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2011	$ 15	$ 720	$ 8	$ (501)	$ 218

NEE's total energy contract net assets (liabilities) at December 31, 2011 shown above are included on the consolidated balance sheets as follows:

	December 31, 2011
	(millions)
Current derivative assets	$ 589
Noncurrent derivative assets	931
Current derivative liabilities	(1,024)
Noncurrent derivative liabilities	(278)
NEE's total mark-to-market energy contract net assets	$ 218

The sources of fair value estimates and maturity of energy contract derivative instruments at December 31, 2011 were as follows:

	Maturity						
	2012	2013	2014	2015	2016	Thereafter	Total
	(millions)						
Trading:							
Quoted prices in active markets for identical assets	$ (49)	$ (73)	$ 4	$ —	$ —	$ —	$ (118)
Significant other observable inputs	(150)	19	4	10	—	33	(84)
Significant unobservable inputs	129	55	9	11	2	11	217
Total	(70)	1	17	21	2	44	15
Owned Assets - Non-Qualifying:							
Quoted prices in active markets for identical assets	(24)	(6)	(3)	(4)	—	—	(37)
Significant other observable inputs	160	82	93	85	—	72	492
Significant unobservable inputs	(14)	25	38	40	—	176	265
Total	122	101	128	121	—	248	720
Owned Assets - OCI:							
Quoted prices in active markets for identical assets	15	—	—	—	—	—	15
Significant other observable inputs	(7)	—	—	—	—	—	(7)
Significant unobservable inputs	—	—	—	—	—	—	—
Total	8	—	—	—	—	—	8
Owned Assets - FPL Cost Recovery Clauses:							
Quoted prices in active markets for identical assets	—	—	—	—	—	—	—
Significant other observable inputs	(505)	—	—	—	—	—	(505)
Significant unobservable inputs	3	1	—	—	—	—	4
Total	(502)	1	—	—	—	—	(501)
Total sources of fair value	$ (442)	$ 103	$ 145	$ 142	$ 2	$ 292	$ 242

With respect to commodities, NEE's Exposure Management Committee (EMC), which is comprised of certain members of senior management, and NEE's chief executive officer are responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels. The EMC and NEE's chief executive officer receive periodic updates on market positions and related exposures, credit exposures and overall risk management activities.

NEE uses a value-at-risk (VaR) model to measure commodity price market risk in its trading and mark-to-market portfolios. The VaR is the estimated nominal loss of market value based on a one-day holding period at a 95% confidence level using historical simulation methodology. As of December 31, 2011 and 2010, the VaR figures are as follows:

	Trading			Non-Qualifying Hedges and Hedges in OCI and FPL Cost Recovery Clauses[(a)]			Total		
	FPL	NEER	NEE	FPL	NEER	NEE	FPL	NEER	NEE
	(millions)								
December 31, 2010	$ —	$ 3	$ 3	$ 51	$ 21	$ 35	$ 51	$ 23	$ 36
December 31, 2011	$ —	$ 2	$ 2	$ 38	$ 50	$ 25	$ 38	$ 50	$ 26
Average for the period ended December 31, 2011	$ —	$ 3	$ 3	$ 46	$ 43	$ 37	$ 46	$ 43	$ 37

(a) Non-qualifying hedges are employed to reduce the market risk exposure to physical assets or contracts which are not marked to market. The VaR figures for the non-qualifying hedges and hedges in OCI and FPL cost recovery clauses category do not represent the economic exposure to commodity price movements.

Interest Rate Risk

NEE and FPL are exposed to risk resulting from changes in interest rates as a result of their respective issuances of debt, investments in special use funds and other investments. NEE and FPL manage their respective interest rate exposure by monitoring current interest rates, entering into interest rate swaps and using a combination of fixed rate and variable rate debt. Interest rate swaps are used to mitigate and adjust interest rate exposure when deemed appropriate based upon market conditions or when required by financing agreements.

The following are estimates of the fair value of NEE's and FPL's financial instruments:

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(millions)			
NEE:				
Fixed income securities:				
Special use funds	$ 1,897	$ 1,897 [(a)]	$ 1,701	$ 1,701 [(a)]
Other investments:				
Debt securities	$ 89	$ 89 [(a)]	$ 114	$ 114 [(a)]
Notes receivable	$ 503	$ 535 [(b)]	$ 525	$ 583 [(b)]
Long-term debt, including current maturities	$ 21,614	$ 23,699 [(c)]	$ 19,929	$ 20,756 [(c)]
Interest rate swaps - net unrealized losses	$ (283)	$ (283) [(d)]	$ (16)	$ (16) [(d)]
FPL:				
Fixed income securities - special use funds	$ 1,499	$ 1,499 [(a)]	$ 1,375	$ 1,375 [(a)]
Long-term debt, including current maturities	$ 7,533	$ 9,078 [(c)]	$ 6,727	$ 7,236 [(c)]

(a) Based on quoted market prices for these or similar issues.
(b) Based on market prices provided by external sources.
(c) Provided by external sources based on market prices indicative of market conditions.
(d) Modeled internally based on market values using discounted cash flow analysis and credit valuation adjustment.

The special use funds of NEE and FPL consist of restricted funds set aside to cover the cost of storm damage for FPL and for the decommissioning of NEE's and FPL's nuclear power plants. A portion of these funds is invested in fixed income debt securities primarily carried at estimated fair value. At FPL, changes in fair value, including any OTTI losses, result in a corresponding adjustment to the related liability accounts based on current regulatory treatment. The changes in fair value of NEE's non-rate regulated operations result in a corresponding adjustment to OCI, except for impairments deemed to be other than temporary, including any credit losses, which are reported in current period earnings. Because the funds set aside by FPL for storm damage could be needed at any time, the related investments are generally more liquid and, therefore, are less sensitive to changes in interest rates. The nuclear decommissioning funds, in contrast, are generally invested in longer-term securities, as decommissioning activities are not scheduled to begin until at least 2030 (2032 at FPL).

At December 31, 2011, the estimated fair value for NEE's interest rate swaps was as follows:

Notional Amount	Effective Date	Maturity Date	Rate Paid	Rate Received	Estimated Fair Value
(millions)					(millions)
Fair value hedges - NEECH:					
$250	May 2010	November 2013	Variable [a]	2.55%	$ 6
$400	August 2010	September 2015	Variable [b]	2.60%	11
$250	August 2011	June 2013	Variable [c]	5.35%	(1)
$500	August 2011	December 2015	Variable [d]	7.875%	(2)
$500	August 2011	March 2019	Variable [e]	6.00%	6
$400	August 2011	June 2021	Variable [f]	4.50%	12
Total fair value hedges					32
Cash flow hedges:					
NEER:					
$32	December 2003	December 2017	4.245%	Variable [g]	(3)
$10	April 2004	December 2017	3.845%	Variable [g]	(1)
$130	December 2005	November 2019	4.905%	Variable [g]	(14)
$336	January 2007	January 2022	5.390%	Variable [h]	(40)
$292	January 2009	December 2016	2.680%	Variable [g]	(17)
$124	January 2009[i]	December 2023	3.725%	Variable [g]	(3)
$78	January 2009	December 2023	2.578%	Variable [j]	(3)
$17	March 2009	December 2016	2.655%	Variable [g]	(1)
$7	March 2009[i]	December 2023	3.960%	Variable [g]	—
$282	May 2009	May 2017	3.015%	Variable [g]	(20)
$106	May 2009[i]	May 2024	4.663%	Variable [g]	(4)
$239	April 2010	January 2027	4.040%	Variable [h]	(37)
$275	October 2010	September 2028	2.822%	Variable [g]	(18)
$255	April 2011	December 2013	2.733%	Variable [k]	(18)
$764	April 2011[i]	June 2018	4.042%	Variable [l]	(54)
$632	April 2011[i]	December 2030	4.694%	Variable [l]	(53)
$70	August 2011	January 2016	(m)	Variable [g]	—
$216	December 2011	December 2029	2.275%	Variable [g]	(5)
NEECH:					
$250	October 2010[i]	June 2023	3.479%	Variable [g]	(24)
Total cash flow hedges					(315)
Total interest rate swaps					$ (283)

(a) Three-month London InterBank Offered Rate (LIBOR) plus 0.4726%.
(b) Three-month LIBOR plus 0.7980%.
(c) Three-month LIBOR plus 4.8275%.
(d) Three-month LIBOR plus 6.675%.
(e) Three-month LIBOR plus 3.945%.
(f) Three-month LIBOR plus 2.05%.
(g) Three-month LIBOR.
(h) Six-month LIBOR.
(i) Exchange of payments does not begin until December 2016, December 2016, May 2017, December 2013, June 2018 and June 2013, respectively.
(j) Three-month Banker's Acceptance Rate.
(k) One-month Euro Interbank Offered Rate (Euribor).
(l) Six-month Euribor.
(m) Rate varies over time from 0.4914% to 3.0048%.

Based upon a hypothetical 10% decrease in interest rates, which is a reasonable near-term market change, the net fair value of NEE's net liabilities would increase by approximately $1,012 million ($421 million for FPL) at December 31, 2011.

Equity Price Risk

NEE and FPL are exposed to risk resulting from changes in prices for equity securities. For example, NEE's nuclear decommissioning reserve funds include marketable equity securities primarily carried at their market value of approximately $1,970 million and $2,041 million ($1,238 million and $1,262 million for FPL) at December 31, 2011 and 2010, respectively. At December 31, 2011, a hypothetical 10% decrease in the prices quoted by stock exchanges, which is a reasonable near-term market change, would result in a $183 million ($116 million for FPL) reduction in fair value. For FPL, a corresponding adjustment would be made to the related liability accounts based on current regulatory treatment, and for NEE's non-rate regulated operations, a corresponding adjustment would be made to OCI to the extent the market value of the securities exceeded amortized cost and to OTTI loss to the extent the market value is below amortized cost.

Currency Exchange Rate Risk

At December 31, 2011, with respect to certain debt issuances and borrowings, NEECH has two cross currency swaps to hedge against currency movements with respect to both interest and principal payments. At December 31, 2011 and 2010, the fair value of cross currency swaps was approximately $18 million and $44 million, respectively.

Credit Risk

NEE and its subsidiaries are also exposed to credit risk through their energy marketing and trading operations. Credit risk is the risk that a financial loss will be incurred if a counterparty to a transaction does not fulfill its financial obligation. NEE manages counterparty credit risk for its subsidiaries with energy marketing and trading operations through established policies, including counterparty credit limits, and in some cases credit enhancements, such as cash prepayments, letters of credit, cash and other collateral and guarantees.

Credit risk is also managed through the use of master netting agreements. NEE's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis. For all derivative and contractual transactions, NEE's energy marketing and trading operations, which includes FPL's energy marketing and trading division, are exposed to losses in the event of nonperformance by counterparties to these transactions. Some relevant considerations when assessing NEE's energy marketing and trading operations' credit risk exposure include the following:

- Operations are primarily concentrated in the energy industry.
- Trade receivables and other financial instruments are predominately with energy, utility and financial services related companies, as well as municipalities, cooperatives and other trading companies in the U.S.
- Overall credit risk is managed through established credit policies and is overseen by the EMC.
- Prospective and existing customers are reviewed for creditworthiness based upon established standards, with customers not meeting minimum standards providing various credit enhancements or secured payment terms, such as letters of credit or the posting of margin cash collateral.
- Master netting agreements are used to offset cash and non-cash gains and losses arising from derivative instruments with the same counterparty. NEE's policy is to have master netting agreements in place with significant counterparties.

Based on NEE's policies and risk exposures related to credit, NEE and FPL do not anticipate a material adverse effect on their financial statements as a result of counterparty nonperformance. As of December 31, 2011, approximately 97% of NEE's and 100% of FPL's energy marketing and trading counterparty credit risk exposure is associated with companies that have investment grade credit ratings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See Management's Discussion – Energy Marketing and Trading and Market Risk Sensitivity.

Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

NextEra Energy, Inc.'s (NEE) and Florida Power & Light Company's (FPL) management are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The consolidated financial statements, which in part are based on informed judgments and estimates made by management, have been prepared in conformity with generally accepted accounting principles applied on a consistent basis.

To aid in carrying out this responsibility, we, along with all other members of management, maintain a system of internal accounting control which is established after weighing the cost of such controls against the benefits derived. In the opinion of management, the overall system of internal accounting control provides reasonable assurance that the assets of NEE and FPL and their subsidiaries are safeguarded and that transactions are executed in accordance with management's authorization and are properly recorded for the preparation of financial statements. In addition, management believes the overall system of internal accounting control provides reasonable assurance that material errors or irregularities would be prevented or detected on a timely basis by employees in the normal course of their duties. Any system of internal accounting control, no matter how well designed, has inherent limitations, including the possibility that controls can be circumvented or overridden and misstatements due to error or fraud may occur and not be detected. Also, because of changes in conditions, internal control effectiveness may vary over time. Accordingly, even an effective system of internal control will provide only reasonable assurance with respect to financial statement preparation and reporting.

The system of internal accounting control is supported by written policies and guidelines, the selection and training of qualified employees, an organizational structure that provides an appropriate division of responsibility and a program of internal auditing. NEE's written policies include a Code of Business Conduct & Ethics that states management's policy on conflicts of interest and ethical conduct. Compliance with the Code of Business Conduct & Ethics is confirmed annually by key personnel.

The Board of Directors pursues its oversight responsibility for financial reporting and accounting through its Audit Committee. This Committee, which is comprised entirely of independent directors, meets regularly with management, the internal auditors and the independent auditors to make inquiries as to the manner in which the responsibilities of each are being discharged. The independent auditors and the internal audit staff have free access to the Committee without management's presence to discuss auditing, internal accounting control and financial reporting matters.

Management assessed the effectiveness of NEE's and FPL's internal control over financial reporting as of December 31, 2011, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the Internal Control - Integrated Framework. Based on this assessment, management believes that NEE's and FPL's internal control over financial reporting was effective as of December 31, 2011.

NEE's and FPL's independent registered public accounting firm, Deloitte & Touche LLP, is engaged to express an opinion on NEE's and FPL's consolidated financial statements and an opinion on NEE's and FPL's internal control over financial reporting. Their reports are based on procedures believed by them to provide a reasonable basis to support such opinions. These reports appear on the following pages.

LEWIS HAY, III

Lewis Hay, III
Chairman and Chief Executive Officer of NEE and
Chairman of the Board of FPL

MORAY P. DEWHURST

Moray P. Dewhurst
Vice Chairman and Chief Financial Officer,
and Executive Vice President - Finance of NEE and
FPL

ARMANDO J. OLIVERA

Armando J. Olivera
Chief Executive Officer of FPL

CHRIS N. FROGGATT

Chris N. Froggatt
Vice President, Controller and Chief Accounting Officer
of NEE

KIMBERLY OUSDAHL

Kimberly Ousdahl
Vice President, Controller and Chief Accounting Officer
of FPL

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
NextEra Energy, Inc. and Florida Power & Light Company:

We have audited the internal control over financial reporting of NextEra Energy, Inc. and subsidiaries (NextEra Energy) and Florida Power & Light Company and subsidiaries (FPL) as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. NextEra Energy's and FPL's management are responsible for maintaining effective internal control over financial reporting and for their assessments of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on NextEra Energy's and FPL's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, NextEra Energy and FPL maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of NextEra Energy and FPL and our report dated February 27, 2012 expressed an unqualified opinion on those financial statements.

DELOITTE & TOUCHE LLP
Certified Public Accountants

Miami, Florida
February 27, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
NextEra Energy, Inc. and Florida Power & Light Company:

We have audited the accompanying consolidated balance sheets of NextEra Energy, Inc. and subsidiaries (NextEra Energy) and the separate consolidated balance sheets of Florida Power & Light Company and subsidiaries (FPL) as of December 31, 2011 and 2010, and the related consolidated statements of income, NextEra Energy's common shareholders' equity, FPL's common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of NextEra Energy's and FPL's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of NextEra Energy and FPL at December 31, 2011 and 2010, and the respective results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), NextEra Energy's and FPL's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2012 expressed an unqualified opinion on NextEra Energy's and FPL's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Certified Public Accountants

Miami, Florida
February 27, 2012

NEXTERA ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(millions, except per share amounts)

	Years Ended December 31,		
	2011	2010	2009
OPERATING REVENUES	$ 15,341	$ 15,317	$ 15,643
OPERATING EXPENSES			
Fuel, purchased power and interchange	6,256	6,242	7,405
Other operations and maintenance	3,002	2,877	2,649
Impairment charges	51	19	—
Depreciation and amortization	1,567	1,788	1,765
Taxes other than income taxes and other	1,087	1,148	1,230
Total operating expenses	11,963	12,074	13,049
OPERATING INCOME	3,378	3,243	2,594
OTHER INCOME (DEDUCTIONS)			
Interest expense	(1,035)	(979)	(849)
Loss on sale of natural gas-fired generating assets	(151)	—	—
Equity in earnings of equity method investees	55	58	52
Allowance for equity funds used during construction	39	37	53
Interest income	79	91	78
Gains on disposal of assets - net	85	67	60
Other than temporary impairment losses on securities held in nuclear decommissioning funds	(36)	(16)	(58)
Other - net	38	(12)	12
Total other deductions - net	(926)	(754)	(652)
INCOME BEFORE INCOME TAXES	2,452	2,489	1,942
INCOME TAXES	529	532	327
NET INCOME	$ 1,923	$ 1,957	$ 1,615
Earnings per share of common stock:			
Basic	$ 4.62	$ 4.77	$ 3.99
Assuming dilution	$ 4.59	$ 4.74	$ 3.97
Dividends per share of common stock	$ 2.20	$ 2.00	$ 1.89
Weighted-average number of common shares outstanding:			
Basic	416.6	410.3	404.4
Assuming dilution	419.0	413.0	407.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NEXTERA ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(millions, except par value)

	December 31,	
	2011	2010
PROPERTY, PLANT AND EQUIPMENT		
Electric utility plant in service and other property	$ 50,768	$ 48,841
Nuclear fuel	1,795	1,539
Construction work in progress	4,989	3,841
Less accumulated depreciation and amortization	(15,062)	(15,146)
Total property, plant and equipment - net ($3,063 and $2,398 related to VIEs, respectively)	42,490	39,075
CURRENT ASSETS		
Cash and cash equivalents	377	302
Customer receivables, net of allowances of $11 and $20, respectively	1,372	1,509
Other receivables	430	1,073
Materials, supplies and fossil fuel inventory	1,074	857
Regulatory assets:		
Deferred clause and franchise expenses	112	368
Derivatives	502	236
Other	84	82
Derivatives	611	506
Other	310	325
Total current assets	4,872	5,258
OTHER ASSETS		
Special use funds	3,867	3,742
Other investments	907	971
Prepaid benefit costs	1,021	1,259
Regulatory assets:		
Securitized storm-recovery costs ($317 and $356 related to a VIE, respectively)	517	581
Other	621	329
Derivatives	973	589
Other	1,920	1,190
Total other assets	9,826	8,661
TOTAL ASSETS	$ 57,188	$ 52,994
CAPITALIZATION		
Common stock ($0.01 par value, authorized shares - 800; outstanding shares - 416 and 421, respectively)	$ 4	$ 4
Additional paid-in capital	5,217	5,418
Retained earnings	9,876	8,873
Accumulated other comprehensive (loss) income	(154)	166
Total common shareholders' equity	14,943	14,461
Long-term debt ($1,364 and $1,338 related to VIEs, respectively)	20,810	18,013
Total capitalization	35,753	32,474
CURRENT LIABILITIES		
Commercial paper	1,349	889
Current maturities of long-term debt	808	1,920
Accounts payable	1,191	1,124
Customer deposits	547	634
Accrued interest and taxes	464	462
Derivatives	1,090	536
Accrued construction-related expenditures	518	371
Other	752	968
Total current liabilities	6,719	6,904
OTHER LIABILITIES AND DEFERRED CREDITS		
Asset retirement obligations	1,611	1,639
Accumulated deferred income taxes	5,681	5,109
Regulatory liabilities:		
Accrued asset removal costs	2,197	2,244
Asset retirement obligation regulatory expense difference	1,640	1,592
Other	419	423
Derivatives	541	243
Deferral related to differential membership interests - VIEs	1,203	949
Other	1,424	1,417
Total other liabilities and deferred credits	14,716	13,616
COMMITMENTS AND CONTINGENCIES		
TOTAL CAPITALIZATION AND LIABILITIES	$ 57,188	$ 52,994

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NEXTERA ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions)

	Years Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,923	$ 1,957	$ 1,615
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	1,567	1,788	1,765
Nuclear fuel amortization	277	285	239
Loss on sale of natural gas-fired generating assets	151	—	—
Impairment charges	51	19	—
Unrealized (gains) losses on marked to market energy contracts	(271)	(386)	59
Deferred income taxes	553	511	273
Cost recovery clauses and franchise fees	181	(629)	624
Changes in prepaid option premiums and derivative settlements	(11)	86	(11)
Equity in earnings of equity method investees	(55)	(58)	(52)
Distributions of earnings from equity method investees	95	74	69
Allowance for equity funds used during construction	(39)	(37)	(53)
Gains on disposal of assets - net	(85)	(67)	(60)
Other than temporary impairment losses on securities held in nuclear decommissioning funds	36	16	58
Other - net	203	38	119
Changes in operating assets and liabilities:			
Customer receivables	93	(73)	18
Other receivables	56	(29)	(13)
Materials, supplies and fossil fuel inventory	(308)	22	85
Other current assets	(22)	(52)	9
Other assets	(103)	42	(103)
Accounts payable	(97)	179	(86)
Customer deposits	(87)	21	38
Margin cash collateral	81	61	(110)
Income taxes	62	56	8
Interest and other taxes	12	(3)	22
Other current liabilities	3	76	(45)
Other liabilities	(192)	(63)	(5)
Net cash provided by operating activities	4,074	3,834	4,463
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures of FPL	(3,137)	(2,605)	(2,522)
Independent power and other investments of NEER	(2,601)	(2,899)	(3,068)
Cash grants under the American Recovery and Reinvestment Act of 2009	624	588	100
Funds received from a spent fuel settlement	73	44	86
Nuclear fuel purchases	(538)	(274)	(362)
Other capital expenditures	(352)	(68)	(54)
Sale of natural gas-fired generating assets	1,204	—	—
Loan proceeds restricted for construction	(565)	—	—
Proceeds from sale or maturity of securities in special use funds	4,348	6,726	4,592
Purchases of securities in special use funds	(4,440)	(6,835)	(4,710)
Proceeds from sale or maturity of other securities	488	721	773
Purchases of other securities	(515)	(714)	(782)
Other - net	132	32	12
Net cash used in investing activities	(5,279)	(5,284)	(5,935)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuances of long-term debt	3,940	3,724	3,220
Retirements of long-term debt	(2,121)	(769)	(1,635)
Proceeds from sale of differential membership interests	466	261	—
Payments to differential membership investors	(100)	—	—
Net change in short-term debt	460	(1,130)	154
Issuances of common stock - net	48	308	198
Repurchases of common stock	(375)	—	—
Dividends on common stock	(920)	(823)	(766)
Other - net	(118)	(57)	4
Net cash provided by financing activities	1,280	1,514	1,175
Net increase (decrease) in cash and cash equivalents	75	64	(297)
Cash and cash equivalents at beginning of year	302	238	535
Cash and cash equivalents at end of year	$ 377	$ 302	$ 238
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
Cash paid for interest (net of amount capitalized)	$ 978	$ 916	$ 805
Cash (received) paid for income taxes - net	$ (95)	$ 20	$ 61
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES			
Assumption of debt in connection with the purchase of independent power projects	$ —	$ 35	$ —
Accrued property additions	$ 909	$ 545	$ 683
Sale of natural gas-fired generating assets through assumption of debt by buyer	$ 158	$ —	$ —

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NEXTERA ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY
(millions)

	Common Stock		Additional Paid-In Capital	Unearned ESOP Compensation	Accumulated Other Comprehensive Income (Loss)[a]	Retained Earnings	Common Shareholders' Equity
	Shares	Aggregate Par Value					
Balances, December 31, 2008	409	$ 4	$ 4,905	$ (100)	$ (13)	$ 6,885	$ 11,681
Net income	—	—	—	—	—	1,615	
Issuances of common stock, net of issuance cost of approximately $2	4	—	204	4	—	—	
Exercise of stock options and other incentive plan activity	1	—	56	—	—	—	
Dividends on common stock	—	—	—	—	—	(766)	
Earned compensation under ESOP	—	—	30	11	—	—	
Other comprehensive income	—	—	—	—	165	—	
Defined benefit pension and other benefits plans	—	—	—	—	22	—	
Premium on publicly-traded equity units known as Corporate Units	—	—	(47)	—	—	—	
Issuance costs on publicly-traded equity units known as Corporate Units	—	—	(8)	—	—	—	
Implementation of new accounting rules	—	—	—	—	(5)	5	
Balances, December 31, 2009	414 [b]	4	5,140	(85)	169	7,739	$ 12,967
Net income	—	—	—	—	—	1,957	
Issuances of common stock, net of issuance cost of approximately $2	6	—	279	5	—	—	
Exercise of stock options and other incentive plan activity	1	—	107	—	—	—	
Dividends on common stock	—	—	—	—	—	(823)	
Earned compensation under ESOP	—	—	26	11	—	—	
Other comprehensive loss	—	—	—	—	(5)	—	
Defined benefit pension and other benefits plans	—	—	—	—	2	—	
Premium on publicly-traded equity units known as Corporate Units	—	—	(59)	—	—	—	
Issuance costs on publicly-traded equity units known as Corporate Units	—	—	(6)	—	—	—	
Balances, December 31, 2010	421 [b]	4	5,487	(69)	166	8,873	$ 14,461
Net income	—	—	—	—	—	1,923	
Issuances of common stock, net of issuance cost of less than $1	1	—	59	5	—	—	
Repurchases of common stock	(7)	—	(375)	—	—	—	
Exercise of stock options and other incentive plan activity	1	—	68	—	—	—	
Dividends on common stock	—	—	—	—	—	(920)	
Earned compensation under ESOP	—	—	31	11	—	—	
Other comprehensive loss	—	—	—	—	(275)	—	
Defined benefit pension and other benefits plans	—	—	—	—	(45)	—	
Balances, December 31, 2011	416 [b]	$ 4	$ 5,270	$ (53)	$ (154)	$ 9,876	$ 14,943

(a) Comprehensive income, which includes net income and other comprehensive income (loss), totaled approximately $1,603 million, $1,954 million and $1,802 million for 2011, 2010 and 2009, respectively.

(b) Outstanding and unallocated shares held by the Employee Stock Ownership Plan (ESOP) Trust totaled approximately 4 million, 5 million and 6 million at December 31, 2011, 2010 and 2009, respectively; the original number of shares purchased and held by the ESOP Trust was approximately 25 million shares.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

FLORIDA POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(millions)

	Years Ended December 31,		
	2011	2010	2009
OPERATING REVENUES	$ 10,613	$ 10,485	$ 11,491
OPERATING EXPENSES			
Fuel, purchased power and interchange	4,977	4,982	6,220
Other operations and maintenance	1,699	1,620	1,496
Depreciation and amortization	798	1,008	1,097
Taxes other than income taxes and other	1,063	1,026	1,097
Total operating expenses	8,537	8,636	9,910
OPERATING INCOME	2,076	1,849	1,581
OTHER INCOME (DEDUCTIONS)			
Interest expense	(387)	(361)	(318)
Allowance for equity funds used during construction	35	36	53
Other - net	(2)	1	(12)
Total other deductions - net	(354)	(324)	(277)
INCOME BEFORE INCOME TAXES	1,722	1,525	1,304
INCOME TAXES	654	580	473
NET INCOME	$ 1,068	$ 945	$ 831

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

FLORIDA POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS
(millions, except share amount)

	December 31,	
	2011	2010
ELECTRIC UTILITY PLANT		
Plant in service	$ 31,564	$ 29,519
Nuclear fuel	1,005	729
Construction work in progress	2,601	2,175
Less accumulated depreciation and amortization	(10,916)	(10,871)
Electric utility plant - net	24,254	21,552
CURRENT ASSETS		
Cash and cash equivalents	36	20
Customer receivables, net of allowances of $8 and $17, respectively	682	710
Other receivables	312	395
Materials, supplies and fossil fuel inventory	759	505
Regulatory assets:		
Deferred clause and franchise expenses	112	368
Derivatives	502	236
Other	80	76
Other	166	145
Total current assets	2,649	2,455
OTHER ASSETS		
Special use funds	2,737	2,637
Prepaid benefit costs	1,088	1,035
Regulatory assets:		
Securitized storm-recovery costs ($317 and $356 related to a VIE, respectively)	517	581
Other	395	293
Other	176	145
Total other assets	4,913	4,691
TOTAL ASSETS	$ 31,816	$ 28,698
CAPITALIZATION		
Common stock (no par value, 1,000 shares authorized, issued and outstanding)	$ 1,373	$ 1,373
Additional paid-in capital	5,464	5,054
Retained earnings	4,013	3,364
Total common shareholder's equity	10,850	9,791
Long-term debt ($437 and $486 related to a VIE, respectively)	7,483	6,682
Total capitalization	18,333	16,473
CURRENT LIABILITIES		
Commercial paper	330	101
Current maturities of long-term debt	50	45
Accounts payable	678	554
Customer deposits	541	628
Accrued interest and taxes	221	311
Derivatives	512	245
Accrued construction-related expenditures	261	183
Other	373	441
Total current liabilities	2,966	2,508
OTHER LIABILITIES AND DEFERRED CREDITS		
Asset retirement obligations	1,144	1,083
Accumulated deferred income taxes	4,593	3,835
Regulatory liabilities:		
Accrued asset removal costs	2,197	2,244
Asset retirement obligation regulatory expense difference	1,640	1,592
Other	416	377
Other	527	586
Total other liabilities and deferred credits	10,517	9,717
COMMITMENTS AND CONTINGENCIES		
TOTAL CAPITALIZATION AND LIABILITIES	$ 31,816	$ 28,698

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

FLORIDA POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(millions)

	Years Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,068	$ 945	$ 831
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	798	1,008	1,097
Nuclear fuel amortization	147	137	127
Deferred income taxes	675	419	391
Cost recovery clauses and franchise fees	181	(629)	624
Allowance for equity funds used during construction	(35)	(36)	(53)
Other - net	73	16	75
Changes in operating assets and liabilities:			
Customer receivables	28	127	(42)
Other receivables	37	(43)	42
Materials, supplies and fossil fuel inventory	(254)	23	34
Other current assets	(20)	(25)	6
Other assets	(52)	40	(62)
Accounts payable	(49)	51	(91)
Customer deposits	(88)	22	37
Income taxes	(215)	(129)	(132)
Interest and other taxes	(21)	7	10
Other current liabilities	32	22	(33)
Other liabilities	(60)	(21)	10
Net cash provided by operating activities	2,245	1,934	2,871
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(3,137)	(2,605)	(2,522)
Cash grants under the American Recovery and Reinvestment Act of 2009	218	161	—
Funds received from a spent fuel settlement	57	32	71
Nuclear fuel purchases	(365)	(101)	(195)
Proceeds from sale or maturity of securities in special use funds	2,988	5,079	3,270
Purchases of securities in special use funds	(3,052)	(5,160)	(3,349)
Other - net	32	33	(1)
Net cash used in investing activities	(3,259)	(2,561)	(2,726)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuances of long-term debt	840	924	516
Retirements of long-term debt	(45)	(42)	(263)
Net change in short-term debt	229	(717)	45
Capital contribution from NEE	410	660	—
Dividends to NEE	(400)	(250)	(485)
Other - net	(4)	(11)	5
Net cash provided by (used in) financing activities	1,030	564	(182)
Net increase (decrease) in cash and cash equivalents	16	(63)	(37)
Cash and cash equivalents at beginning of year	20	83	120
Cash and cash equivalents at end of year	$ 36	$ 20	$ 83
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
Cash paid for interest (net of amount capitalized)	$ 389	$ 321	$ 305
Cash paid for income taxes - net	$ 194	$ 291	$ 232
SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES			
Accrued property additions	$ 526	$ 275	$ 418

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

FLORIDA POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY[(a)]
(millions)

	Common Stock	Additional Paid-In Capital	Retained Earnings	Common Shareholder's Equity
Balances, December 31, 2008	$ 1,373	$ 4,393	$ 2,323	$ 8,089
Net income	—	—	831	
Dividends to NEE	—	—	(485)	
Other	—	—	1	
Balances, December 31, 2009	1,373	4,393	2,670	$ 8,436
Net income	—	—	945	
Capital contributions from NEE	—	660	—	
Dividends to NEE	—	—	(250)	
Other	—	1	(1)	
Balances, December 31, 2010	1,373	5,054	3,364	$ 9,791
Net income	—	—	1,068	
Capital contributions from NEE	—	410	—	
Dividends to NEE	—	—	(419)	
Balances, December 31, 2011	$ 1,373	$ 5,464	$ 4,013	$ 10,850

(a) FPL's comprehensive income is the same as reported net income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Summary of Significant Accounting and Reporting Policies

Basis of Presentation - The operations of NextEra Energy, Inc. (NEE) are conducted primarily through its wholly-owned subsidiary Florida Power & Light Company (FPL) and its wholly-owned indirect subsidiary NextEra Energy Resources, LLC (NEER). FPL, a rate-regulated electric utility, supplies electric service to approximately 4.6 million customer accounts throughout most of the east and lower west coasts of Florida. NEER invests in independent power projects through both controlled and consolidated entities and non-controlling ownership interests in joint ventures essentially all of which are accounted for under the equity method.

The consolidated financial statements of NEE and FPL include the accounts of their respective majority-owned and controlled subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts included in prior years' consolidated financial statements have been reclassified to conform to the current year's presentation. The preparation of financial statements requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Regulation - FPL is subject to regulation by the Florida Public Service Commission (FPSC) and the Federal Energy Regulatory Commission (FERC). Its rates are designed to recover the cost of providing electric service to its customers including a reasonable rate of return on invested capital. As a result of this cost-based regulation, FPL follows the accounting guidance that allows regulators to create assets and impose liabilities that would not be recorded by non-rate regulated entities. Regulatory assets and liabilities represent probable future revenues that will be recovered from or refunded to customers through the ratemaking process.

Cost recovery clauses, which are designed to permit full recovery of certain costs and provide a return on certain assets allowed to be recovered through the various clauses, include substantially all fuel, purchased power and interchange expenses, conservation and certain environmental-related expenses, certain revenue taxes and franchise fees. Beginning in 2009, pre-construction costs and carrying charges on construction costs for FPL's planned two additional nuclear units at Turkey Point and carrying charges on construction costs for FPL's approximately 450 megawatt (mw) to 490 mw of additional capacity at St. Lucie and Turkey Point are also recoverable through a cost recovery clause. Also beginning in 2009, costs incurred for FPL's three solar generating facilities are recoverable through a cost recovery clause. In accordance with the 2010 rate agreement, cost recovery for FPL's West County Energy Center (WCEC) Unit No. 3, which was placed in service in May 2011, is permitted up to the amount of the projected annual fuel savings for customers during the term of the 2010 rate agreement through a cost recovery clause and is reported as retail base revenues. See Revenues and Rates below. Revenues from cost recovery clauses are recorded when billed; FPL achieves matching of costs and related revenues by deferring the net underrecovery or overrecovery. Any underrecovered costs or overrecovered revenues are collected from or returned to customers in subsequent periods.

If FPL were no longer subject to cost-based rate regulation, the existing regulatory assets and liabilities would be written off unless regulators specify an alternative means of recovery or refund. In addition, the FPSC has the authority to disallow recovery of costs that it considers excessive or imprudently incurred. The continued applicability of regulatory accounting is assessed at each reporting period.

Revenues and Rates - FPL's retail and wholesale utility rate schedules are approved by the FPSC and the FERC, respectively. FPL records unbilled base revenues for the estimated amount of energy delivered to customers but not yet billed. Unbilled base revenues are included in customer receivables on NEE's and FPL's consolidated balance sheets and amounted to approximately $160 million and $148 million at December 31, 2011 and 2010, respectively. FPL's operating revenues also include amounts resulting from cost recovery clauses (see Regulation above), franchise fees, gross receipts taxes and surcharges related to storm-recovery bonds (see Note 9 - FPL). Franchise fees and gross receipts taxes are imposed on FPL; however, the FPSC allows FPL to include in the amounts charged to customers the amount of the gross receipts tax for all customers and the franchise amount for those customers located in the jurisdiction that imposes the fee. Accordingly, franchise fees and gross receipts taxes are reported gross in operating revenues and taxes other than income taxes and other in NEE's and FPL's consolidated statements of income and were approximately $716 million, $687 million and $791 million in 2011, 2010 and 2009, respectively. The revenues from the surcharges related to storm-recovery bonds included in operating revenues in NEE's and FPL's consolidated statements of income were approximately $100 million, $101 million and $91 million in 2011, 2010 and 2009, respectively. FPL also collects municipal utility taxes which are reported gross in customer receivables and accounts payable on NEE's and FPL's consolidated balance sheets.

Effective March 1, 2010, pursuant to an FPSC final order (FPSC rate order) new retail base rates for FPL were established, resulting in an increase in retail base revenues of approximately $75 million on an annualized basis. The FPSC rate order also established a regulatory return on common equity (ROE) of 10.0% with a range of plus or minus 100 basis points and an adjusted regulatory equity ratio of 59.1%. It also shifted certain costs from retail base rates to the capacity cost recovery clause (capacity clause). In addition, the FPSC rate order directed FPL to reduce depreciation expense (surplus depreciation credit) over the 2010 to 2013 period related to a depreciation reserve surplus of approximately $895 million. In February 2011, the FPSC issued a final order approving a stipulation and settlement agreement between FPL and principal parties in FPL's 2009 rate case regarding FPL's base rates (2010 rate agreement), which enables FPL to earn a regulatory ROE of up to 11% per year over the term of the 2010 rate

agreement. Key elements of the 2010 rate agreement, which is effective through December 31, 2012, are as follows:

- Subject to the provisions of the 2010 rate agreement, retail base rates are effectively frozen through the end of 2012.
- Incremental cost recovery through FPL's capacity clause for WCEC Unit No. 3, which was placed in service in May 2011, is permitted up to the amount of the projected annual fuel savings for customers during the term of the 2010 rate agreement.
- Future storm restoration costs would be recoverable on an accelerated basis beginning 60 days from the filing of a cost recovery petition, but capped at an amount that produces a surcharge of no more than $4 for every 1,000 kilowatt-hours (kwh) of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL may request an increase to the $4 surcharge to recover the amount above $800 million.
- If FPL's earned regulatory ROE falls below 9%, FPL may seek retail base rate relief. If FPL's earned regulatory ROE rises above 11%, any party to the 2010 rate agreement may seek a reduction in FPL's retail base rates. In determining the regulatory ROE for all purposes under the 2010 rate agreement, earnings will be calculated on an actual, non-weather-adjusted basis.
- FPL can vary the amount of surplus depreciation credit taken in any calendar year up to a cap in 2010 of $267 million, a cap in subsequent years of $267 million plus the amount of any unused portion from prior years, and a total cap of $776 million (surplus depreciation credit cap) over the course of the 2010 rate agreement, provided that in any year of the 2010 rate agreement FPL must use at least enough surplus depreciation credit to maintain a 9% earned regulatory ROE but may not use any amount of surplus depreciation credit that would result in an earned regulatory ROE in excess of 11%.

Under the terms of a rate agreement approved in 2005 (2005 rate agreement), which was in effect from January 1, 2006 through February 28, 2010, retail base rates did not increase except to allow recovery of the revenue requirements of FPL's three power plants that achieved commercial operation during the term of the 2005 rate agreement: Turkey Point Unit No. 5 in 2007 and WCEC Units Nos. 1 and 2 in 2009. Under the terms of the 2005 rate agreement, FPL's electric property depreciation rates were based upon the comprehensive depreciation studies it filed with the FPSC in March 2005; however, FPL reduced depreciation on its plant in service by $125 million each year as allowed by the 2005 rate agreement. The 2005 rate agreement also provided for a revenue sharing mechanism, whereby revenues from retail base operations in excess of certain thresholds would be shared with customers. During the term of the 2005 rate agreement, FPL's revenues did not exceed the thresholds.

In January 2012, FPL filed a formal notification with the FPSC indicating its intent to initiate a base rate proceeding. The notification stated that, based on preliminary estimates, FPL expects to request a base rate increase of approximately $525 million effective January 2013 and an additional base rate increase of approximately $170 million annually commencing when the modernized Cape Canaveral plant becomes operational, which is expected to occur in June 2013. FPL expects to propose an allowed regulatory ROE of 11.25% with a 0.25% ROE adder, which is included in the base rate increase FPL expects to request, if FPL maintains the lowest typical residential customer bill among all the electric utilities in Florida. FPL expects to file its formal request to initiate a base rate proceeding before the end of the first quarter of 2012. A final FPSC decision regarding FPL's base rates is expected in the fourth quarter of 2012 in time for new rates to be effective January 1, 2013.

NEER's revenue is recorded on the basis of commodities delivered, contracts settled or services rendered, and includes estimated amounts yet to be billed to customers. Certain commodity contracts for the purchase and sale of power that meet the definition of a derivative are recorded at fair value with subsequent changes in fair value recognized as revenue, unless hedge accounting is applied. See Energy Trading and Note 3.

Electric Plant, Depreciation and Amortization - The cost of additions to units of property of FPL and NEER is added to electric utility plant. In accordance with regulatory accounting, the cost of FPL's units of utility property retired, less estimated net salvage value, is charged to accumulated depreciation. Maintenance and repairs of property as well as replacements and renewals of items determined to be less than units of utility property are charged to other operations and maintenance (O&M) expenses. At December 31, 2011, the electric generating, transmission, distribution and general facilities of FPL represented approximately 48%, 12%, 36% and 4%, respectively, of FPL's gross investment in electric utility plant in service. Substantially all of FPL's properties are subject to the lien of FPL's mortgage, which secures most debt securities issued by FPL. A number of NEER's generating facilities are encumbered by liens securing various financings. The net book value of NEER's assets serving as collateral was approximately $8 billion at December 31, 2011. The American Recovery and Reinvestment Act of 2009, as amended (Recovery Act), provided for an option to elect a cash grant (convertible investment tax credits (ITCs)) for certain renewable energy property (renewable property). Convertible ITCs are recorded as a reduction in property, plant and equipment on NEE's and FPL's consolidated balance sheets and were approximately $1.2 billion ($186 million at FPL) and $1.0 billion ($186 million at FPL) at December 31, 2011 and 2010, respectively, and are amortized as a reduction to depreciation and amortization expense over the estimated life of the related property. At December 31, 2011 and 2010, approximately $95 million (none at FPL) and $429 million ($124 million at FPL), respectively, of such convertible ITCs are included in other receivables on NEE's and FPL's consolidated balance sheets.

Depreciation of FPL's electric property is primarily provided on a straight-line average remaining life basis. FPL includes in depreciation expense a provision for fossil plant dismantlement, interim asset removal costs, accretion related to asset retirement obligations (see Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs), storm recovery amortization and amortization of pre-construction costs associated with planned nuclear units recovered through a cost

recovery clause. For substantially all of FPL's property, depreciation studies are performed and filed with the FPSC at least every four years. As part of the FPSC rate order, the FPSC approved new depreciation rates which became effective January 1, 2010. In addition, in accordance with the 2010 rate agreement, FPL can vary the amount of surplus depreciation credit taken in any calendar year up to a maximum of $267 million (with any unused portion of the maximum rolling over to and available in subsequent years), provided its regulatory ROE remains within the range of 9% to 11%; FPL may use up to a maximum of $776 million in surplus depreciation credit over the course of the 2010 rate agreement. FPL recognized approximately $187 million and $4 million of the surplus depreciation credit cap in 2011 and 2010, respectively. Under the terms of the 2005 rate agreement, FPL's electric property depreciation rates were based upon the comprehensive depreciation studies it filed with the FPSC in March 2005; however FPL reduced depreciation by $125 million annually as was allowed by the 2005 rate agreement. The weighted annual composite depreciation rate for FPL's electric plant in service, including capitalized software, but excluding the effects of decommissioning, dismantlement and the depreciation adjustments discussed above, was approximately 3.2%, 3.2% and 3.6% for 2011, 2010 and 2009, respectively.

NEER's electric plants in service less salvage value, if any, are depreciated primarily using the straight-line method over their estimated useful lives. NEER's effective depreciation rates, excluding decommissioning, were 4.0%, 4.4% and 4.2% for 2011, 2010 and 2009, respectively. NEER reviews the estimated useful lives of its fixed assets on an ongoing basis. In 2011, this review indicated that the actual lives of certain equipment at NEER's wind plants are expected to be longer than the previously estimated useful lives used for depreciation purposes. As a result, effective January 1, 2011, NEER changed the estimates of the useful lives of certain equipment to better reflect the estimated periods during which these assets are expected to remain in service. The useful lives of substantially all of the wind plants' equipment that were previously estimated to be 25 years were increased to 30 years. The effect of this change in estimate was to reduce depreciation and amortization expense by approximately $75 million, increase net income by $44 million and increase basic and diluted earnings per share by approximately $0.11 for the year ended December 31, 2011.

Nuclear Fuel - FPL and NEER have several contracts for the supply of uranium, conversion, enrichment and fabrication of nuclear fuel. See Note 14 - Contracts. FPL's and NEER's nuclear fuel costs are charged to fuel expense on a unit of production method.

Construction Activity - Allowance for funds used during construction (AFUDC) is a non-cash item which represents the allowed cost of capital, including an ROE, used to finance FPL construction projects. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense and the remainder is recorded as other income. FPSC rules limit the recording of AFUDC to projects that have an estimated cost in excess of 0.5% of a utility's plant in service balance and require more than one year to complete. FPSC rules allow construction projects below the 0.5% threshold as a component of rate base. During 2011, AFUDC was capitalized at a rate of 6.41% and amounted to approximately $50 million. During the period January 2010 through March 2010 and during April 2010 through December 2010, AFUDC was capitalized at a rate of 7.41% and 6.41%, respectively, and amounted to approximately $50 million for the year. During 2009, AFUDC was capitalized at a rate of 7.41%, and amounted to approximately $74 million. See Note 14 - Commitments.

FPL's construction work in progress includes construction materials, progress payments on major equipment contracts, third-party engineering costs, AFUDC and other costs directly associated with the construction of various projects. Upon completion of the projects, these costs are transferred to electric utility plant in service. Capitalized costs associated with construction activities are charged to O&M expenses when recoverability is no longer probable. See Regulation above for information on recovery of costs associated with new nuclear capacity and solar generating facilities.

NEER capitalizes project development costs once it is probable that such costs will be realized through the ultimate construction of a power plant or sale of development rights. At December 31, 2011 and 2010, NEER's capitalized development costs totaled approximately $89 million and $99 million, respectively, which are included in other assets on NEE's consolidated balance sheets. These costs include land rights and other third-party costs directly associated with the development of a new project. Upon commencement of construction, these costs either are transferred to construction work in progress or remain in other assets, depending upon the nature of the cost. Capitalized development costs are charged to O&M expenses when it is probable that these costs are not realizable.

NEER's construction work in progress includes construction materials, prepayments on turbine generators and other equipment, third-party engineering costs, capitalized interest and other costs directly associated with the construction and development of various projects. Interest capitalized on construction projects amounted to approximately $104 million, $71 million and $85 million during 2011, 2010 and 2009, respectively. Interest expense allocated from NextEra Energy Capital Holdings, Inc. (NEECH) to NEER is based on a deemed capital structure of 70% debt. Upon commencement of plant operation, costs associated with construction work in progress are transferred to electric utility plant in service and other property.

Asset Retirement Obligations - NEE and FPL each account for asset retirement obligations and conditional asset retirement obligations (collectively, AROs) under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as part of the carrying amount of the long-lived assets. The asset retirement cost is subsequently allocated to expense using a systematic and rational method over the asset's estimated useful life. Changes in the ARO resulting from the passage of time are

recognized as an increase in the carrying amount of the liability and as accretion expense, which is included in depreciation and amortization expense in the consolidated statements of income. Changes resulting from revisions to the timing or amount of the original estimate of cash flows are recognized as an increase or a decrease in the asset retirement cost, or income when asset retirement cost is depleted, in the case of NEE's non-rate regulated operations, and ARO and regulatory liability, in the case of FPL. See Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs below and Note 13.

Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs - For ratemaking purposes, FPL accrues for the cost of end of life retirement and disposal of its nuclear, fossil and solar plants over the expected service life of each unit based on nuclear decommissioning and fossil and solar dismantlement studies periodically filed with the FPSC. In addition, FPL accrues for interim removal costs over the life of the related assets based on depreciation studies approved by the FPSC. As approved by the FPSC, FPL previously suspended its annual decommissioning accrual. For financial reporting purposes, FPL recognizes decommissioning and dismantlement liabilities in accordance with accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred. Any differences between expense recognized for financial reporting purposes and the amount recoverable through rates are reported as a regulatory liability in accordance with regulatory accounting. See Electric Plant, Depreciation and Amortization, Asset Retirement Obligations and Note 13.

Nuclear decommissioning studies are performed at least every five years and are submitted to the FPSC for approval. FPL filed updated nuclear decommissioning studies with the FPSC in December 2010. These studies reflect FPL's current plans, under the operating licenses, for prompt dismantlement of Turkey Point Units Nos. 3 and 4 following the end of plant operation with decommissioning activities commencing in 2032 and 2033, respectively, and provide for St. Lucie Unit No. 1 to be mothballed beginning in 2036 with decommissioning activities to be integrated with the prompt dismantlement of St. Lucie Unit No. 2 in 2043. These studies also assume that FPL will be storing spent fuel on site pending removal to a U.S. government facility. The studies indicate FPL's portion of the ultimate costs of decommissioning its four nuclear units, including costs associated with spent fuel storage above what is expected to be refunded by the U.S. Department of Energy (DOE) under a spent fuel settlement agreement, to be approximately $6.2 billion. FPL's portion of the ultimate cost of decommissioning its four units, expressed in 2011 dollars, is estimated by the studies to aggregate $2.3 billion.

Restricted funds for the payment of future expenditures to decommission FPL's nuclear units are included in nuclear decommissioning reserve funds, which are included in special use funds on NEE's and FPL's consolidated balance sheets. Marketable securities held in the decommissioning funds are primarily classified as available for sale and carried at fair value with market adjustments, including any other than temporary impairment losses, resulting in a corresponding adjustment to the related regulatory liability accounts consistent with regulatory treatment. See Note 5. Contributions to the funds have been suspended since 2005. Fund earnings, net of taxes, are reinvested in the funds. Earnings are recognized as income/loss and then recorded to reflect a corresponding increase/decrease in the related regulatory liability accounts. As a result, there is no effect on net income. During 2011, 2010 and 2009, fund earnings on decommissioning funds were approximately $66 million, $76 million and $81 million, respectively. The tax effects of amounts not yet recognized for tax purposes are included in accumulated deferred income taxes.

Fossil and solar plant dismantlement studies are performed at least every four years and are submitted to the FPSC for approval. FPL's latest fossil and solar plant dismantlement studies became effective January 1, 2010 and resulted in an increase in the annual expense from $15 million to $18 million which is recorded in depreciation and amortization expense in NEE's and FPL's consolidated statements of income. At December 31, 2011, FPL's portion of the ultimate cost to dismantle its fossil and solar units is approximately $860 million, or $421 million expressed in 2011 dollars.

NEER records nuclear decommissioning liabilities for Seabrook Station (Seabrook), Duane Arnold Energy Center (Duane Arnold) and Point Beach Nuclear Power Plant (Point Beach) in accordance with accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred. The liability is being accreted using the interest method through the date decommissioning activities are expected to be complete. See Note 13. At December 31, 2011 and 2010, NEER's ARO related to nuclear decommissioning totaled approximately $383 million and $478 million, respectively, and was determined using various internal and external data and applying a probability percentage to a variety of scenarios regarding the life of the plant and timing of decommissioning. NEER's portion of the ultimate cost of decommissioning its nuclear plants, including costs associated with spent fuel storage above what is expected to be refunded by the DOE under a spent fuel settlement agreement, is estimated to be approximately $11.4 billion, or $1.9 billion expressed in 2011 dollars.

Seabrook files a comprehensive nuclear decommissioning study with the New Hampshire Nuclear Decommissioning Financing Committee (NDFC) every four years; the most recent study was filed in 2011 and the final order on the proposed decommissioning funding plan is pending NDFC approval. Seabrook's decommissioning funding plan is also subject to annual review by the NDFC, and in January 2012, the NDFC issued an interim order suspending Seabrook's decommissioning funding requirements pending the NDFC's final order. Currently, there are no ongoing decommissioning funding requirements for Duane Arnold and Point Beach, however, the U.S. Nuclear Regulatory Commission (NRC) has the authority to require additional funding in the future. NEER's portion of Seabrook's, Duane Arnold's and Point Beach's restricted funds for the payment of future expenditures to decommission these plants is included in nuclear decommissioning reserve funds, which are included in special use funds on NEE's consolidated

balance sheets. Marketable securities held in the decommissioning funds are primarily classified as available for sale and carried at fair value. Market adjustments result in a corresponding adjustment to other comprehensive income (OCI), except for unrealized losses associated with marketable securities considered to be other than temporary, including any credit losses, which are recognized as other than temporary impairment losses on securities held in nuclear decommissioning funds in NEE's consolidated statements of income. Fund earnings are recognized in income and are reinvested in the funds either on a pretax or after-tax basis. See Note 5. The tax effects of amounts not yet recognized for tax purposes are included in accumulated deferred income taxes.

Major Maintenance Costs - FPL uses the accrue-in-advance method for recognizing costs associated with planned major nuclear maintenance, in accordance with regulatory treatment, and records the related accrual as a regulatory liability. FPL expenses costs associated with planned fossil maintenance as incurred. FPL's estimated nuclear maintenance costs for each nuclear unit's next planned outage are accrued over the period from the end of the last outage to the end of the next planned outage. Any difference between the estimated and actual costs is included in O&M expenses when known. The accrued liability for nuclear maintenance costs at December 31, 2011 and 2010 totaled approximately $49 million and $58 million, respectively, and is included in regulatory liabilities - other. For the years ended December 31, 2011, 2010 and 2009, FPL recognized approximately $97 million, $100 million and $84 million, respectively, in nuclear maintenance costs which are included in O&M expenses in NEE's and FPL's consolidated statements of income.

NEER uses the deferral method to account for certain planned major maintenance costs. NEER's major maintenance costs for its nuclear generating units and combustion turbines are capitalized and amortized on a unit of production method over the period from the end of the last outage to the beginning of the next planned outage. NEER's capitalized major maintenance costs, net of accumulated amortization, totaled approximately $133 million and $95 million at December 31, 2011 and 2010, respectively, and are included in other assets. For the years ended December 31, 2011, 2010 and 2009, NEER recognized approximately $77 million, $88 million and $73 million in major maintenance costs which are included in O&M expenses in NEE's consolidated statements of income.

Cash Equivalents - Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Restricted Cash - At December 31, 2011 and 2010, NEE had approximately $88 million ($37 million for FPL) and $111 million ($39 million for FPL), respectively, of restricted cash included in other current assets on NEE's and FPL's consolidated balance sheets, which was restricted primarily for margin cash collateral and debt service payments. Where offsetting positions exist, restricted cash related to margin cash collateral is netted against derivative instruments. See Note 3. In addition, NEE had approximately $565 million of noncurrent restricted cash at December 31, 2011 related to loan proceeds held for construction at NEER, which was included in other assets on NEE's consolidated balance sheets.

Allowance for Doubtful Accounts - FPL maintains an accumulated provision for uncollectible customer accounts receivable that is estimated using a percentage, derived from historical revenue and write-off trends, of the previous five months of revenue. Additional amounts are included in the provision to address specific items that are not considered in the calculation described above. NEER regularly reviews collectibility of its receivables and establishes a provision for losses estimated as a percentage of accounts receivable based on the historical bad debt write-off trends for its retail electricity provider operations and, when necessary, using the specific identification method for all other receivables.

Inventory - FPL values materials, supplies and fossil fuel inventory using a weighted-average cost method. NEER's materials, supplies and fossil fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business.

Energy Trading - NEE provides full energy and capacity requirements services primarily to distribution utilities, which include load-following services and various ancillary services, in certain markets and engages in power and gas marketing and trading activities to optimize the value of electricity and fuel contracts and generating facilities, as well as to take advantage of expected favorable commodity price movements. Trading contracts that meet the definition of a derivative are accounted for at fair value and realized gains and losses from all trading contracts, including those where physical delivery is required, are recorded net for all periods presented. See Note 3.

Securitized Storm-Recovery Costs, Storm Fund and Storm Reserve - In connection with the 2007 storm-recovery bond financing (see Note 9 - FPL), the net proceeds to FPL from the sale of the storm-recovery property were used primarily to reimburse FPL for its estimated net of tax deficiency in its storm and property insurance reserve (storm reserve) and provide for a storm and property insurance reserve fund (storm fund). Upon the issuance of the storm-recovery bonds, the storm reserve deficiency was reclassified to securitized storm-recovery costs and is recorded as a regulatory asset on NEE's and FPL's consolidated balance sheets. As storm-recovery charges are billed to customers, the securitized storm-recovery costs are amortized and included in depreciation and amortization in NEE's and FPL's consolidated statements of income. Marketable securities held in the storm fund are classified as available for sale and are carried at fair value with market adjustments, including any other than temporary impairment losses, resulting in a corresponding adjustment to the storm reserve. Fund earnings, net of taxes, are reinvested in the fund. The tax effects of amounts not yet recognized for tax purposes are included in accumulated deferred income taxes. The storm fund is

included in special use funds on NEE's and FPL's consolidated balance sheets and was approximately $125 million at both December 31, 2011 and 2010. See Note 5.

The storm reserve that was reestablished in an FPSC financing order related to the issuance of the storm-recovery bonds is not reflected on NEE's and FPL's consolidated balance sheets as of December 31, 2011 or 2010 because the associated regulatory asset does not meet the specific recognition criteria under the accounting guidance for certain regulated entities. As a result, the storm reserve will be recognized as a regulatory liability as the storm-recovery charges are billed to customers and charged to depreciation and amortization in NEE's and FPL's consolidated statements of income. Although NEE's and FPL's consolidated balance sheets as of December 31, 2011 reflect a storm reserve of approximately $54 million (included in regulatory liabilities - other on NEE's and FPL's consolidated balance sheets), FPL had the capacity to absorb up to approximately $202 million in future prudently incurred storm restoration costs without seeking recovery through a rate adjustment from the FPSC or filing a petition with the FPSC.

Impairment of Long-Lived Assets - NEE evaluates on an ongoing basis the recoverability of its assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is required to be recognized if the carrying value of the asset exceeds the undiscounted future net cash flows associated with that asset. The impairment loss to be recognized is the amount by which the carrying value of the long-lived asset exceeds the asset's fair value. In most instances, the fair value is determined by discounting estimated future cash flows using an appropriate interest rate. See Note 4 - Nonrecurring Fair Value Measurements.

Goodwill and Other Intangible Assets - NEE's goodwill and other intangible assets are as follows:

	Weighted-Average Useful Lives	December 31,	
		2011	2010
	(years)	(millions)	
Goodwill:			
Merchant reporting unit		$ 72	$ 72
Wind reporting unit		50	45
Fiber-optic telecommunications reporting unit		25	—
Total goodwill		$ 147	$ 117
Other intangible assets:			
Purchased power agreements	19	$ 70	$ 87
Customer lists	7	45	34
Other, primarily land and transmission rights, permits and licenses	29	231	249
Total		346	370
Less accumulated amortization		88	93
Total other intangible assets - net		$ 258	$ 277

NEE's goodwill relates to various acquisitions which were accounted for using the purchase method of accounting. Other intangible assets are amortized, primarily on a straight-line basis, over their estimated useful lives. For the years ended December 31, 2011, 2010 and 2009, amortization expense was approximately $14 million, $18 million and $14 million, respectively, and is expected to be approximately $12 million, $9 million, $8 million, $7 million and $5 million for 2012, 2013, 2014, 2015 and 2016, respectively.

Goodwill and other intangible assets are included in other assets on NEE's consolidated balance sheets. Goodwill is assessed for impairment at least annually by applying a fair value-based analysis. Other intangible assets are periodically reviewed when impairment indicators are present to assess recoverability from future operations using undiscounted future cash flows.

Pension and Other Postretirement Plans - NEE allocates net periodic pension benefit income to its subsidiaries based on the pensionable earnings of the subsidiaries' employees; net periodic supplemental executive retirement plan (SERP) benefit costs to its subsidiaries based upon actuarial calculations by participant; and postretirement health care and life insurance benefits (other benefits) net periodic benefit costs to its subsidiaries based upon the number of eligible employees at each subsidiary.

NEE's regulatory assets and liabilities are established in association with accounting guidance which requires recognition of the funded status of benefit plans in the balance sheet, with changes in the funded status recognized in comprehensive income within shareholders' equity in the year in which the changes occur. Since NEE is the plan sponsor, and its subsidiaries do not have separate rights to the plan assets or direct obligations to their employees, this accounting guidance is reflected at NEE and not allocated to the subsidiaries. The portion of previously unrecognized actuarial gains and losses, prior service costs or credits and

transition obligations that are estimated to be allocable to FPL as net periodic benefit (income) cost in future periods and that otherwise would be recorded in accumulated other comprehensive income (AOCI) are classified as regulatory assets and liabilities at NEE in accordance with regulatory treatment.

Stock-Based Compensation - NEE accounts for stock-based payment transactions based on grant-date fair value. Compensation costs for awards with graded vesting are recognized on a straight-line basis over the requisite service period for the entire award. See Note 11 - Stock-Based Compensation.

Retirement of Long-Term Debt - Gains and losses that result from differences in FPL's reacquisition cost and the book value of long-term debt which is retired are deferred as a regulatory asset or liability and amortized to interest expense ratably over the remaining life of the original issue, which is consistent with its treatment in the ratemaking process. NEECH and NEER recognize such differences as other income (deductions) at the time of retirement.

Income Taxes - Deferred income taxes are provided on all significant temporary differences between the financial statement and tax bases of assets and liabilities. In connection with the tax sharing agreement between NEE and its subsidiaries, the income tax provision at each subsidiary reflects the use of the "separate return method," except that tax benefits that could not be used on a separate return basis, but are used on the consolidated tax return, are recorded by the subsidiary that generated the tax benefits. Any remaining consolidated income tax benefits or expenses are recorded at the corporate level. Included in other regulatory assets and other regulatory liabilities on NEE's and FPL's consolidated balance sheets is the revenue equivalent of the difference in accumulated deferred income taxes computed under accounting rules, as compared to regulatory accounting rules. The net regulatory asset totaled $171 million and $151 million at December 31, 2011 and 2010, respectively, and is being amortized in accordance with the regulatory treatment over the estimated lives of the assets or liabilities for which the deferred tax amount was initially recognized.

NEER recognizes ITCs as a reduction to income tax expense when the related energy property is placed into service. Production tax credits (PTCs) are recognized as wind energy is generated and sold based on a per kwh rate prescribed in applicable federal and state statutes and are recorded as a reduction of current income taxes payable, unless limited by tax law in which instance they are recorded as deferred tax assets. NEE and FPL record a deferred income tax benefit created by the convertible ITCs on the difference between the financial statement and tax bases of renewable property. For NEER, this deferred income tax benefit is recorded in income tax expense in the year that the renewable property is placed in service. For FPL, this deferred income tax benefit is offset by a regulatory liability, which is amortized as a reduction of depreciation expense over the approximate lives of the related renewable property in accordance with the regulatory treatment. At December 31, 2011 and 2010, the net deferred income tax benefits associated with the convertible ITCs were approximately $56 million and $58 million, respectively, and are included in other regulatory assets and regulatory liabilities on NEE's and FPL's consolidated balance sheets.

A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets when it is more likely than not that such assets will not be realized. NEE recognizes interest income (expense) related to unrecognized tax benefits (liabilities) in interest income and interest expense, respectively, net of the amount deferred at FPL. At FPL, the offset to accrued interest receivable (payable) on income taxes is classified as a regulatory liability (regulatory asset) which will be amortized to income (expense) over a five-year period upon settlement in accordance with regulatory treatment. All tax positions taken by NEE in its income tax returns that are recognized in the financial statements must satisfy a more-likely-than-not threshold. See Note 6.

Sale of Differential Membership Interests - Certain indirect wholly-owned subsidiaries of NEER sold their Class B membership interest in entities that have ownership interests in wind facilities, with generating capacity totaling approximately 1,916 mw at December 31, 2011, to third-party investors. In exchange for the cash received, the holders of the Class B membership interests will receive a portion of the economic attributes of the facilities, including tax attributes, for a variable period. The transactions are not treated as a sale under the accounting rules and the proceeds received are deferred and recorded in deferral related to differential membership interests on NEE's consolidated balance sheets. The deferred amount is being recognized as an adjustment to taxes other than income taxes and other in NEE's consolidated statements of income as the Class B members receive their portion of the economic attributes. NEE continues to operate and manage the wind facilities, and consolidates the entities that own the wind facilities.

Guarantees - NEE's and FPL's payment guarantees and related contracts provided to unconsolidated entities entered into after December 31, 2002, for which it or a subsidiary is the guarantor, are recorded at fair value. See Note 14 - Commitments.

Variable Interest Entities (VIEs) - An entity is considered to be a VIE when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. A reporting company is required to consolidate a VIE as its primary beneficiary when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. NEE and FPL evaluate whether an entity is a VIE whenever reconsideration events as defined by the accounting guidance occur. See Note 9.

2. Employee Retirement Benefits

Employee Benefit Plans and Other Postretirement Plan - NEE sponsors a qualified noncontributory defined benefit pension plan for substantially all employees of NEE and its subsidiaries. NEE also has a SERP, which includes a non-qualified supplemental defined benefit pension component that provides benefits to a select group of management and highly compensated employees. The impact of this SERP component is included within pension benefits in the following tables, and was not material to NEE's financial statements for the years ended December 31, 2011, 2010 and 2009. In addition to pension benefits, NEE sponsors a contributory postretirement plan for other benefits for retirees of NEE and its subsidiaries meeting certain eligibility requirements.

Plan Assets, Benefit Obligations and Funded Status - The changes in assets and benefit obligations of the plans and the plans' funded status are as follows:

	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(millions)			
Change in plan assets:				
Fair value of plan assets at January 1	$ 3,233	$ 3,028	$ 32	$ 32
Actual return on plan assets	(3)	380	(2)	2
Employer contributions[(a)]	1	3	29	28
Transfers[(b)]	—	(29)	—	—
Participant contributions	—	—	8	9
Benefit payments[(a)]	(109)	(149)	(39)	(39)
Fair value of plan assets at December 31	$ 3,122	$ 3,233	$ 28	$ 32
Change in benefit obligation:				
Obligation at January 1	$ 1,994	$ 1,866	$ 417	$ 430
Service cost	64	59	6	6
Interest cost	98	102	21	23
Participant contributions	—	—	8	9
Plan amendments	22	1	17	—
Special termination benefits	—	13	—	—
Actuarial losses (gains) - net	54	102	(3)	(12)
Benefit payments[(a)]	(109)	(149)	(39)	(39)
Obligation at December 31[(c)]	$ 2,123	$ 1,994	$ 427	$ 417
Funded status:				
Prepaid (accrued) benefit cost at NEE at December 31	$ 999	$ 1,239	$ (399)	$ (385)
Prepaid (accrued) benefit cost at FPL at December 31	$ 1,080	$ 1,027	$ (273)	$ (279)

(a) Employer contributions and benefit payments include only those amounts contributed directly to, or paid directly from, plan assets. FPL's portion of contributions related to SERP benefits was $1 million for 2011 and for 2010. FPL's portion of contributions related to other benefits was $27 million and $26 million for 2011 and 2010, respectively.

(b) Represents amounts that were transferred from the qualified pension plan as reimbursement for eligible retiree medical expenses paid by NEE pursuant to the provisions of the Internal Revenue Code.

(c) NEE's accumulated pension benefit obligation, which includes no assumption about future salary levels, for its pension plans at December 31, 2011 and 2010 was $2,068 million and $1,935 million, respectively.

NEE's and FPL's prepaid (accrued) benefit cost shown above are included on the consolidated balance sheets as follows:

	NEE				FPL			
	Pension Benefits		Other Benefits		Pension Benefits		Other Benefits	
	2011	2010	2011	2010	2011	2010	2011	2010
	(millions)							
Prepaid benefit costs	$ 1,021	$ 1,259	$ —	$ —	$ 1,088	$ 1,035	$ —	$ —
Accrued benefit cost included in other current liabilities	(4)	(3)	(26)	(27)	(2)	(2)	(22)	(23)
Accrued benefit cost included in other liabilities	(18)	(17)	(373)	(358)	(6)	(6)	(251)	(256)
Prepaid (accrued) benefit cost at December 31	$ 999	$ 1,239	$ (399)	$ (385)	$ 1,080	$ 1,027	$ (273)	$ (279)

NEE's unrecognized amounts included in accumulated other comprehensive income (loss) yet to be recognized as components of prepaid (accrued) benefit cost are as follows:

	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(millions)			
Components of AOCI:				
Unrecognized prior service benefit (cost) (net of $3, $2 and $2 tax benefits, respectively)	$ (5)	$ (4)	$ (3)	$ —
Unrecognized transition obligation (net of $1 tax benefit)	—	—	—	(1)
Unrecognized gain (loss) (net of $24 tax benefit, $5 tax expense, $3 tax benefit and $5 tax benefit, respectively)	(37)	8	(1)	(4)
Total	$ (42)	$ 4	$ (4)	$ (5)

NEE's unrecognized amounts included in regulatory assets (liabilities) yet to be recognized as components of net prepaid (accrued) benefit cost are as follows:

	Regulatory Assets (Liabilities) (Pension)		Regulatory Assets (SERP and Other)	
	2011	2010	2011	2010
	(millions)			
Unrecognized prior service cost	$ 16	$ 13	$ 13	$ 1
Unrecognized transition obligation	—	—	2	4
Unrecognized (gain) loss	153	(64)	44	37
Total	$ 169	$ (51)	$ 59	$ 42

The following table provides the weighted-average assumptions used to determine benefit obligations for the plans. These rates are used in determining net periodic benefit cost in the following year.

	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
Discount rate	4.65%	5.00%	4.75%	5.25%
Salary increase	4.00%	4.00%	4.00%	4.00%

The projected 2012 trend assumption used to measure the expected cost of health care benefits covered by the plans for those under age 65 is 7.30% for medical and 7.90% for prescription drug benefits and for those age 65 and over is 7.00% for medical and 7.50% for prescription drug benefits. These rates are assumed to decrease over the next 6 years for medical benefits and 8 years for prescription drug benefits to the ultimate trend rate of 5.50% and remain at that level thereafter. The ultimate trend rate is assumed to be reached in 2018 for medical benefits and 2020 for prescription drug benefits. Assumed health care cost trend rates have an effect on the amounts reported for postretirement plans providing health care benefits. An increase or decrease of one percentage point in assumed health care cost trend rates would have a corresponding effect on the other benefits accumulated obligation of approximately $2 million at December 31, 2011.

NEE's investment policy for the pension plan recognizes the benefit of protecting the plan's funded status, thereby avoiding the necessity of future employer contributions. Its broad objectives are to achieve a high rate of total return with a prudent level of risk taking while maintaining sufficient liquidity and diversification to avoid large losses and preserve capital over the long term.

The NEE pension plan fund's current asset allocation is a mix of 43.5% equity investments, 43.5% fixed income investments, 10% convertible securities and 3% alternative investments. The fund's investment strategy emphasizes traditional investments, broadly diversified across the global equity and fixed income markets, using a combination of different investment styles and vehicles. The pension fund's equity allocation includes direct equity holdings and assets classified as equity commingled vehicles. Similarly, its fixed income allocation includes direct debt security holdings and assets classified as debt security commingled vehicles. These equity and debt security commingled vehicles include common and collective trusts, pooled separate accounts, registered investment companies or other forms of pooled investment arrangements. The pension fund's convertible security allocation is principally direct holdings of convertible securities and includes a convertible security oriented limited partnership. The pension fund's alternative investments allocation consists of absolute return oriented limited partnerships that use a broad range of investment strategies on a global basis.

With regard to its other benefits plan, NEE's policy is to fund claims as incurred during the year through NEE contributions, participant contributions and plan assets. The other benefits plan's assets are invested with a focus on assuring the availability of funds to pay benefits while maintaining sufficient diversification to avoid large losses and preserve capital. The other benefits plan's fund has a strategic asset allocation that targets a mix of 60% equity investments and 40% fixed income investments. The fund's investment strategy consists of traditional investments, diversified across the global equity and fixed income markets. The fund's equity investments are comprised of assets classified as equity commingled vehicles. Similarly, its fixed income investments are comprised of assets classified as debt security commingled vehicles. These equity and debt commingled vehicles include common and collective trusts, pooled separate accounts, registered investment companies or other forms of pooled investment arrangements.

The fair value measurements of NEE's pension plan assets by fair value hierarchy level are as follows:

	December 31, 2011[a]			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions)			
Equity securities[b]	$ 750	$ 5	$ 1	$ 756
Equity commingled vehicles[c]	—	568	—	568
U.S. Government and municipal bonds	84	51	—	135
Corporate debt securities[d]	—	325	—	325
Asset-backed securities	—	318	—	318
Debt security commingled vehicles[e]	—	586	—	586
Convertible securities	—	265	—	265
Limited partnerships[f]	—	63	106	169
Total	$ 834	$ 2,181	$ 107	$ 3,122

(a) See Note 4 for discussion of fair value measurement techniques.
(b) Includes foreign investments of $258 million.
(c) Includes foreign investments of $185 million.
(d) Includes foreign investments of $58 million.
(e) Includes foreign investments of $61 million and $85 million of short-term commingled vehicles.
(f) Includes alternative investments of $94 million, of which $31 million were foreign investments. Fair values have been estimated using net asset value per share of the investments. These investments primarily have a one- to three-year lockup and are redeemable on either a quarterly or annual basis with a 30 to 90 day redemption notification requirement and have unfunded commitments of $24 million.

	December 31, 2010[a]			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions)			
Equity securities[b]	$ 800	$ 6	$ —	$ 806
Equity commingled vehicles[c]	—	669	11	680
U.S. Government and municipal bonds	60	35	—	95
Corporate debt securities[d]	—	335	—	335
Asset-backed securities	—	263	—	263
Debt security commingled vehicles[e]	—	744	—	744
Convertible securities	—	310	—	310
Total	$ 860	$ 2,362	$ 11	$ 3,233

(a) See Note 4 for discussion of fair value measurement techniques.
(b) Includes foreign investments of $293 million.
(c) Includes foreign investments of $219 million.
(d) Includes foreign investments of $47 million.
(e) Includes foreign investments of $56 million and $206 million of short-term commingled vehicles.

The fair value measurements, all of which were Level 2, of NEE's other benefits plan assets at December 31, 2011 and 2010 were approximately $17 million and $20 million of equity commingled vehicles (of which $4 million and $5 million were foreign investments) and $11 million and $12 million of debt security commingled vehicles, respectively.

Expected Cash Flows - NEE anticipates paying approximately $26 million for eligible retiree medical expenses on behalf of the other benefits plan during 2012.

The following table provides information about benefit payments expected to be paid by the plans, net of government drug subsidy, for each of the following calendar years:

	Pension Benefits	Other Benefits
	(millions)	
2012	$ 162	$ 33
2013	$ 162	$ 36
2014	$ 162	$ 36
2015	$ 162	$ 30
2016	$ 167	$ 30
2017 - 2021	$ 850	$ 144

Net Periodic Cost - The components of net periodic benefit (income) cost for the plans are as follows:

	Pension Benefits			Other Benefits		
	2011	2010	2009	2011	2010	2009
	(millions)					
Service cost	$ 64	$ 59	$ 51	$ 6	$ 6	$ 5
Interest cost	98	102	109	21	23	24
Expected return on plan assets	(238)	(241)	(239)	(2)	(2)	(3)
Amortization of transition obligation	—	—	—	3	3	4
Amortization of prior service benefit	(3)	(3)	(3)	—	—	—
Amortization of gains	—	1	(23)	—	—	—
SERP settlements	—	1	—	—	—	—
Special termination benefits	—	13	—	—	—	—
Net periodic benefit (income) cost at NEE	$ (79)	$ (68)	$ (105)	$ 28	$ 30	$ 30
Net periodic benefit (income) cost at FPL	$ (51)	$ (42)	$ (73)	$ 21	$ 23	$ 23

Other Comprehensive Income - The components of net periodic benefit income (cost) recognized in OCI for the plans are as follows:

	Pension Benefits		Other Benefits	
	2011	2010	2011	2010
	(millions)			
Prior service cost (net of $2 tax benefit)	$ —	$ —	$ (3)	$ —
Net gains (losses) (net of $32 tax benefit, none, $2 tax expense and $1 tax expense, respectively)	(45)	1	3	2
Amortization of prior service benefit	(1)	(1)	—	—
Amortization of transition obligation	—	—	1	—
Total	$ (46)	$ —	$ 1	$ 2

Regulatory Assets (Liabilities) - The components of net periodic benefit (income) cost recognized during the year in regulatory assets (liabilities) for the plans are as follows:

	Regulatory Assets (Liabilities) (Pension)		Regulatory Assets (SERP and Other)	
	2011	2010	2011	2010
	(millions)			
Prior service cost	$ 1	$ 1	$ 12	$ —
Unrecognized (gains) losses	217	(35)	7	(9)
Amortization of prior service benefit	2	2	—	—
Amortization of transition obligation	—	—	(2)	(2)
Total	$ 220	$ (32)	$ 17	$ (11)

The weighted-average assumptions used to determine net periodic benefit (income) cost for the plans are as follows:

	Pension Benefits			Other Benefits		
	2011	2010	2009	2011	2010	2009
Discount rate	5.00%	5.50%	6.90%	5.25%	5.50%	6.90%
Salary increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected long-term rate of return[(a)]	7.75%	7.75%	7.75%	8.00%	8.00%	8.00%

(a) In developing the expected long-term rate of return on assets assumption for its plans, NEE evaluated input, including other qualitative and quantitative factors, from its actuaries and consultants, as well as information available in the marketplace. NEE considered different models, capital market return assumptions and historical returns for a portfolio with an equity/bond asset mix similar to its funds. NEE also considered its funds' historical compounded returns.

Assumed health care cost trend rates have an effect on the amounts reported for postretirement plans providing health care benefits. An increase or decrease of one percentage point in assumed health care cost trend rates would have a corresponding effect on the total service and interest cost recognized at December 31, 2011 by less than $1 million.

Employee Contribution Plans - NEE offers employee retirement savings plans which allow eligible participants to contribute a percentage of qualified compensation through payroll deductions. NEE makes matching contributions to participants' accounts. Defined contribution expense pursuant to these plans was approximately $42 million, $34 million and $38 million for NEE ($28 million, $26 million and $28 million for FPL) for the years ended December 31, 2011, 2010 and 2009, respectively. See Note 11 - Employee Stock Ownership Plan.

3. Derivative Instruments

NEE and FPL use derivative instruments (primarily swaps, options, futures and forwards) to manage the commodity price risk inherent in the purchase and sale of fuel and electricity, as well as interest rate and foreign currency exchange rate risk associated with outstanding and forecasted debt issuances, and to optimize the value of NEER's power generation assets.

With respect to commodities related to NEE's competitive energy business, NEER employs risk management procedures to conduct its activities related to optimizing the value of its power generation assets, providing full energy and capacity requirements services primarily to distribution utilities, and engaging in power and gas marketing and trading activities to take advantage of expected future favorable price movements and changes in the expected volatility of prices in the energy markets. These risk management activities involve the use of derivative instruments executed within prescribed limits to manage the risk associated with fluctuating commodity prices. Transactions in derivative instruments are executed on recognized exchanges or via the over-the-counter markets, depending on the most favorable credit terms and market execution factors. For NEER's power generation assets, derivative instruments are used to hedge the commodity price risk associated with the fuel requirements of the assets, where applicable, as well as to hedge all or a portion of the expected energy output of these assets. These hedges protect NEER against adverse changes in the wholesale forward commodity markets associated with its generation assets. With regard to full energy and capacity requirements services, NEER is required to vary the quantity of energy and related services based on the load demands of the customer served by the distribution utility. For this type of transaction, derivative instruments are used to hedge the anticipated electricity quantities required to serve these customers and protect against unfavorable changes in the forward energy markets. Additionally, NEER takes positions in the energy markets based on differences between actual forward market levels and management's view of fundamental market conditions. NEER uses derivative instruments to realize value from these market dislocations, subject to strict risk management limits around market, operational and credit exposure.

Derivative instruments, when required to be marked to market, are recorded on NEE's and FPL's consolidated balance sheets as either an asset or liability measured at fair value. At FPL, substantially all changes in the derivatives' fair value are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel and purchased power cost recovery clause (fuel clause) or the capacity clause. For NEE's non-rate regulated operations, predominantly NEER, unless hedge accounting is applied, essentially all changes in the derivatives' fair value for power purchases and sales and trading activities are recognized on a net basis in operating revenues; fuel purchases and sales are recognized on a net basis in fuel, purchased power and interchange expense; and the equity method investees' related activity is recognized in equity in earnings of equity method investees in NEE's consolidated statements of income. Settlement gains and losses are included within the line items in the consolidated statements of income to which they relate. For commodity derivatives, NEE believes that, where offsetting positions exist at the same location for the same time, the transactions are considered to have been netted and therefore physical delivery has been deemed not to have occurred for financial reporting purposes. Transactions for which physical delivery is deemed not to have occurred are presented on a net basis in the consolidated statements of income. Settlements related to derivative instruments are primarily recognized in net cash provided by operating activities in NEE's and FPL's consolidated statements of cash flows.

While most of NEE's derivatives are entered into for the purpose of managing commodity price risk, reducing the impact of volatility in interest rates on outstanding and forecasted debt issuances and managing foreign currency risk, hedge accounting is only applied where specific criteria are met and it is practicable to do so. In order to apply hedge accounting, the transaction must be designated as a hedge and it must be highly effective in offsetting the hedged risk. Additionally, for hedges of forecasted transactions, the forecasted transactions must be probable. For interest rate swaps and foreign currency derivative instruments, generally NEE assesses a hedging instrument's effectiveness by using nonstatistical methods including dollar value comparisons of the change in the fair value of the derivative to the change in the fair value or cash flows of the hedged item. Hedge effectiveness is tested at the inception of the hedge and on at least a quarterly basis throughout its life. The effective portion of the gain or loss on a derivative instrument designated as a cash flow hedge is reported as a component of OCI and is reclassified into earnings in the period(s) during which the transaction being hedged affects earnings or when it becomes probable that a forecasted transaction being hedged would not occur. See Note 7. The ineffective portion of net unrealized gains (losses) on these hedges is reported in earnings in the current period. At December 31, 2011, NEE's AOCI included amounts related to discontinued commodity cash flow hedges with expiration dates through December 2012; interest rate cash flow hedges with expiration dates through December 2030; and foreign currency cash flow hedges with expiration dates through September 2030.

In 2011, subsidiaries of NEER sold their ownership interest in five natural gas-fired generating plants. See Note 4 - Nonrecurring Fair Value Measurements. Certain of the plants had hedged their exposure to interest rate and commodity price fluctuations by entering into derivative contracts. Because the plants were sold to a third party, it became no longer probable that the future hedged transactions would occur. Therefore, NEE was required to reclassify any gains or losses in AOCI related to those hedges to earnings. During the year ended December 31, 2011, NEE reclassified approximately $21 million of net losses to earnings, with $30 million of losses recorded in loss on sale of natural gas-fired generating assets and $9 million of gains recorded in other - net.

The net fair values of NEE's and FPL's mark-to-market derivative instrument assets (liabilities) are included on the consolidated balance sheets as follows:

	NEE		FPL	
	December 31,		December 31,	
	2011	2010	2011	2010
	(millions)			
Current derivative assets[a]	$ 611	$ 506	$ 10 [b]	$ 8 [b]
Noncurrent derivative assets[c]	973	589	2 [d]	1 [d]
Current derivative liabilities[e]	(1,090)	(536)	(512)	(245)
Noncurrent derivative liabilities[f]	(541)	(243)	(1) [g]	—
Total mark-to-market derivative instrument assets (liabilities)	$ (47)	$ 316	$ (501)	$ (236)

(a) At December 31, 2011 and 2010, NEE's balances reflect the netting of approximately $106 million and $23 million (none at FPL), respectively, in margin cash collateral received from counterparties.
(b) Included in current other assets on FPL's consolidated balance sheets.
(c) At December 31, 2011 and 2010, NEE's balances reflect the netting of approximately $109 million and $43 million (none at FPL), respectively, in margin cash collateral received from counterparties.
(d) Included in noncurrent other assets on FPL's consolidated balance sheets.
(e) At December 31, 2011 and 2010, NEE's balances reflect the netting of approximately $112 million and $23 million (none at FPL), respectively, in margin cash collateral provided to counterparties.
(f) At December 31, 2011 and 2010, NEE's balances reflect the netting of approximately $79 million and $72 million (none at FPL) in margin cash collateral provided to counterparties.
(g) Included in noncurrent other liabilities on FPL's consolidated balance sheets.

At December 31, 2011 and December 31, 2010, NEE had approximately $22 million and $7 million (none at FPL), respectively, in margin cash collateral received from counterparties that was not offset against derivative assets. These amounts are included in current other liabilities on NEE's consolidated balance sheets. Additionally, at December 31, 2011 and December 31, 2010, NEE had approximately $50 million and $58 million (none at FPL), respectively, in margin cash collateral provided to counterparties that was not offset against derivative liabilities. These amounts are included in current other assets on NEE's consolidated balance sheets.

As discussed above, NEE uses derivative instruments to, among other things, manage its commodity price risk, interest rate risk and foreign currency exchange rate risk. The table above presents NEE's and FPL's net derivative positions at December 31, 2011 and December 31, 2010, which reflect the offsetting of positions of certain transactions within the portfolio, the contractual ability to settle contracts under master netting arrangements and the netting of margin cash collateral. However, disclosure rules require that the following tables be presented on a gross basis.

The fair values of NEE's derivatives designated as hedging instruments for accounting purposes (none at FPL) are presented below as gross asset and liability values, as required by disclosure rules.

	December 31, 2011		December 31, 2010	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
	(millions)			
Interest rate swaps:				
Current derivative assets	$ 22	$ —	$ 16	$ —
Current derivative liabilities	—	60	—	64
Noncurrent derivative assets	15	—	91	—
Noncurrent derivative liabilities	—	260	—	59
Foreign currency swaps:				
Current derivative assets	—	—	24	—
Current derivative liabilities	—	3	—	4
Noncurrent derivative assets	—	—	11	—
Noncurrent derivative liabilities	—	3	—	—
Total	$ 37	$ 326	$ 142	$ 127

Gains (losses) related to NEE's cash flow hedges are recorded on NEE's consolidated financial statements (none at FPL) as follows:

	Year Ended December 31, 2011				Year Ended December 31, 2010				Year Ended December 31, 2009			
	Commodity Contracts	Interest Rate Swaps	Foreign Currency Swaps	Total	Commodity Contracts	Interest Rate Swaps	Foreign Currency Swaps	Total	Commodity Contracts	Interest Rate Swaps	Foreign Currency Swap	Total
	(millions)											
Gains (losses) recognized in OCI	$ —	$ (383)	$ (17)	$(400)	$ 20	$ (52)	$ 24	$ (8)	$ 197	$ 28	$ 3	$228
Gains (losses) reclassified from AOCI to net income[a]	$ 41	$ (76)	$ 1 [b]	$ (34)	$ 118	$ (65)	$ 20 [b]	$ 73	$ 164	$ (39)	$ 4 [c]	$129
Gains (losses) recognized in income[d]	$ —	$ —	$ —	$ —	$ 1	$ —	$ —	$ 1	$ 29	$ —	$ —	$ 29

(a) Included in operating revenues for commodity contracts and interest expense for interest rate swaps. In 2011, excludes approximately $21 million of net losses related to the discontinuance of certain cash flow hedges. See further discussion above.
(b) Loss of approximately $4 million is included in interest expense and the balance is included in other - net.
(c) Loss of approximately $1 million is included in interest expense and the balance is included in other - net.
(d) Represents the ineffective portion of the hedging instrument included in operating revenues.

For the year ended December 31, 2011, NEE recorded a gain of approximately $28 million on six fair value hedges which resulted in a corresponding increase in the related debt. For the year ended December 31, 2010, NEE recorded a gain of approximately $11 million on three fair value hedges which resulted in a corresponding increase in the related debt. For the year ended December 31, 2009, NEE recorded a loss of $6 million on a fair value hedge which resulted in a corresponding reduction in the related debt.

The fair values of NEE's and FPL's derivatives not designated as hedging instruments for accounting purposes are presented below as gross asset and liability values, as required by disclosure rules. However, the majority of the underlying contracts are subject to master netting arrangements and would not be contractually settled on a gross basis.

	December 31, 2011				December 31, 2010			
	NEE		FPL		NEE		FPL	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
	(millions)							
Commodity contracts:								
Current derivative assets	$ 1,127	$ 432	$ 11 [a]	$ 1 [a]	$ 754	$ 278	$ 9 [a]	$ 1 [a]
Current derivative liabilities	3,358	4,494	1	513	1,848	2,339	12	257
Noncurrent derivative assets	1,290	250	2 [b]	—	687	157	1 [b]	—
Noncurrent derivative liabilities	1,222	1,579	—	1 [c]	828	1,084	—	—
Foreign currency swap:								
Current derivative assets	—	—	—	—	13	—	—	—
Current derivative liabilities	—	3	—	—	—	—	—	—
Noncurrent derivative assets	27	—	—	—	—	—	—	—
Total	$ 7,024	$ 6,758	$ 14	$ 515	$ 4,130	$ 3,858	$ 22	$ 258

(a) Included in current other assets on FPL's consolidated balance sheets.
(b) Included in noncurrent other assets on FPL's consolidated balance sheets.
(c) Included in noncurrent other liabilities on FPL's consolidated balance sheets.

Gains (losses) related to NEE's derivatives not designated as hedging instruments are recorded in NEE's consolidated statements of income (none at FPL) as follows:

	Years Ended December 31,		
	2011	2010	2009
	(millions)		
Commodity contracts:			
Operating revenues	$ 473 [a]	$ 531 [a]	279 [a]
Fuel, purchased power and interchange	—	1	28
Foreign currency swap - other - net	22	18	(3)
Interest rate contracts - other - net	(11)	—	—
Total	$ 484	$ 550	$ 304

(a) In addition, for the years ended December 31, 2011, 2010 and 2009, FPL recorded approximately $646 million, $665 million and $688 million of losses, respectively, related to commodity contracts as regulatory assets on its consolidated balance sheets.

The following table represents net notional volumes associated with derivative instruments that are required to be reported at fair value in NEE's and FPL's consolidated financial statements. The table includes significant volumes of transactions that have minimal exposure to commodity price changes because they are variably priced agreements. The table does not present a complete picture of NEE's and FPL's overall net economic exposure because NEE and FPL do not use derivative instruments to hedge all of their commodity exposures. At December 31, 2011, NEE and FPL had derivative commodity contracts for the following net notional volumes:

Commodity Type	NEE		FPL	
	(millions)			
Power	(121)	mwh [a]	—	
Natural gas	1,132	mmbtu [b]	775	mmbtu [b]
Oil	(3)	barrels	—	

(a) Megawatt-hours
(b) One million British thermal units

At December 31, 2011, NEE had interest rate contracts with a notional amount totaling approximately $6.5 billion and foreign currency swaps with a notional amount totaling approximately $544 million.

Certain of NEE's and FPL's derivative instruments contain credit-risk-related contingent features including, among other things, the requirement to maintain an investment grade credit rating from specified credit rating agencies and certain financial ratios, as well as credit-related cross-default and material adverse change triggers. At December 31, 2011, the aggregate fair value of NEE's derivative instruments with credit-risk-related contingent features that were in a liability position was approximately $3.2 billion ($0.5 billion for FPL).

If the credit-risk-related contingent features underlying these agreements and other commodity-related contracts were triggered, NEE or FPL could be required to post collateral or settle contracts according to contractual terms which generally allow netting of contracts in offsetting positions. Certain contracts contain multiple types of credit-related triggers. To the extent these contracts contain a credit ratings downgrade trigger, the maximum exposure is included in the following credit ratings collateral posting requirements. If FPL's and NEECH's credit ratings were downgraded to BBB/Baa2 (a two level downgrade for FPL and a one level downgrade for NEECH from the current lowest applicable rating), NEE would be required to post collateral such that the total posted collateral would be approximately $800 million ($250 million at FPL). If FPL's and NEECH's credit ratings were downgraded to below investment grade, NEE would be required to post additional collateral such that the total posted collateral would be approximately $2.8 billion ($0.9 billion at FPL). Some contracts at NEE, including some FPL contracts, do not contain credit ratings downgrade triggers, but do contain provisions that require certain financial measures be maintained and/or have credit-related cross-default triggers. In the event these provisions were triggered, NEE could be required to post additional collateral of up to approximately $600 million ($100 million at FPL).

Collateral may be posted in the form of cash or credit support. At December 31, 2011, NEE had posted approximately $400 million ($30 million at FPL) in the form of letters of credit, related to derivatives, in the normal course of business which could be applied toward the collateral requirements described above. FPL and NEECH have bank revolving line of credit facilities in excess of the collateral requirements described above that would be available to support, among other things, derivative activities. Under the terms of the bank revolving line of credit facilities, maintenance of a specific credit rating is not a condition to drawing on these credit facilities, although there are other conditions to drawing on these credit facilities.

Additionally, some contracts contain certain adequate assurance provisions where a counterparty may demand additional collateral based on subjective events and/or conditions. Due to the subjective nature of these provisions, NEE and FPL are unable to determine an exact value for these items and they are not included in any of the quantitative disclosures above.

4. Fair Value Measurements

NEE and FPL use several different valuation techniques to measure the fair value of assets and liabilities, relying primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities for those assets and liabilities that are measured at fair value on a recurring basis. NEE's and FPL's assessment of the significance of any particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels. Non-performance risk, including the consideration of a credit valuation adjustment, is also considered in the determination of fair value for all assets and liabilities measured at fair value.

Cash Equivalents - Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. NEE and FPL primarily hold investments in money market funds. The fair value of these funds is calculated using current market prices.

Special Use Funds and Other Investments - NEE and FPL hold primarily debt and equity securities directly, as well as indirectly through commingled funds. Substantially all directly held equity securities are valued at their quoted market prices. For directly held debt securities, multiple prices and price types are obtained from pricing vendors whenever possible, which enables cross-provider validations. A primary price source is identified based on asset type, class or issue of each security. Commingled funds, which are similar to mutual funds, are maintained by banks or investment companies and hold certain investments in accordance with a stated set of objectives. The fair value of commingled funds is primarily derived from the quoted prices in active markets of the underlying securities. Because the fund shares are offered to a limited group of investors, they are not considered to be traded in an active market.

Derivative Instruments - NEE and FPL measure the fair value of commodity contracts on a daily basis using prices observed on commodities exchanges and in the over-the-counter markets, or through the use of industry-standard valuation techniques, such as option modeling or discounted cash flows techniques, incorporating both observable and unobservable valuation inputs. The resulting measurements are the best estimate of fair value as represented by the transfer of the asset or liability through an orderly transaction in the marketplace at the measurement date.

Most exchange-traded derivative assets and liabilities are valued directly using unadjusted quoted prices. For exchange-traded derivative assets and liabilities where the principal market is deemed to be inactive based on average daily volumes and open

interest, the measurement is established using settlement prices from the exchanges, and therefore considered to be valued using significant other observable inputs.

NEE and FPL also enter into over-the-counter commodity contract derivatives. The majority of these contracts are transacted at liquid trading points, and the prices for these contracts are verified using quoted prices in active markets from exchanges, brokers or pricing services for similar contracts. In instances where the reference markets are deemed to be inactive or do not have transactions for a similar contract, the derivative assets and liabilities may be valued using significant other observable inputs and potentially significant unobservable inputs. In such instances, the valuation for these contracts is established using techniques including extrapolation from or interpolation between actively traded contracts, or estimated basis adjustments from liquid trading points.

NEE, through NEER, also enters into full requirements contracts, which, in many cases, meet the definition of derivatives and are measured at fair value. These contracts typically have one or more inputs that are not observable and are significant to the valuation of the contract. In addition, certain exchange and non-exchange traded derivative options at NEE have one or more significant inputs that are not observable, and are valued using industry-standard option models.

In all cases where NEE and FPL use significant unobservable inputs for the valuation of a commodity contract, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This consideration includes, but is not limited to, assumptions about market liquidity, volatility and contract duration.

NEE uses interest rate and foreign currency swaps to mitigate and adjust interest rate and foreign currency exposure related to certain outstanding and forecasted debt issuances and borrowings. NEE estimates the fair value of these derivatives using a discounted cash flows valuation technique based on the net amount of estimated future cash inflows and outflows related to the swap agreements.

Recurring Fair Value Measurements - NEE's and FPL's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level are as follows:

	December 31, 2011				
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting[a]	Total
			(millions)		
Assets:					
Cash equivalents:					
NEE - equity securities	$ 159	$ —	$ —	$ —	$ 159
FPL - equity securities	$ 11	$ —	$ —	$ —	$ 11
Special use funds:					
NEE:					
Equity securities	$ 709	$ 1,206 [b]	$ —	$ —	$ 1,915
U.S. Government and municipal bonds	$ 508	$ 167	$ —	$ —	$ 675
Corporate debt securities	$ —	$ 516	$ —	$ —	$ 516
Mortgage-backed securities	$ —	$ 511	$ —	$ —	$ 511
Other debt securities	$ —	$ 47	$ —	$ —	$ 47
FPL:					
Equity securities	$ 128	$ 1,056 [b]	$ —	$ —	$ 1,184
U.S. Government and municipal bonds	$ 458	$ 134	$ —	$ —	$ 592
Corporate debt securities	$ —	$ 359	$ —	$ —	$ 359
Mortgage-backed securities	$ —	$ 434	$ —	$ —	$ 434
Other debt securities	$ —	$ 32	$ —	$ —	$ 32
Other investments:					
NEE:					
Equity securities	$ 4	$ —	$ —	$ —	$ 4
U.S. Government and municipal bonds	$ 8	$ —	$ —	$ —	$ 8
Corporate debt securities	$ —	$ 43	$ —	$ —	$ 43
Mortgage-backed securities	$ —	$ 33	$ —	$ —	$ 33
Other	$ 5	$ 5	$ —	$ —	$ 10
Derivatives:					
NEE:					
Commodity contracts	$ 2,448	$ 3,478	$ 1,071	$ (5,477)	$ 1,520 [c]
Interest rate swaps	$ —	$ 37	$ —	$ —	$ 37 [c]
Foreign currency swaps	$ —	$ 27	$ —	$ —	$ 27 [c]
FPL - commodity contracts	$ —	$ 8	$ 6	$ (2)	$ 12 [c]
Liabilities:					
Derivatives:					
NEE:					
Commodity contracts	$ 2,588	$ 3,582	$ 585	$ (5,453)	$ 1,302 [c]
Interest rate swaps	$ —	$ 320	$ —	$ —	$ 320 [c]
Foreign currency swaps	$ —	$ 9	$ —	$ —	$ 9 [c]
FPL - commodity contracts	$ —	$ 513	$ 2	$ (2)	$ 513 [c]

(a) Includes the effect of the contractual ability to settle contracts under master netting arrangements and margin cash collateral payments and receipts.
(b) At NEE, approximately $1,086 million ($979 million at FPL) are invested in commingled funds whose underlying investments would be Level 1 if those investments were held directly by NEE or FPL.
(c) See Note 3 for a reconciliation of net derivatives to NEE's and FPL's consolidated balance sheets.

	December 31, 2010				
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Netting[a]	Total
			(millions)		
Assets:					
Cash equivalents:					
NEE - equity securities	$ —	$ 122	$ —	$ —	122
FPL - equity securities	$ —	$ 7	$ —	$ —	7
Special use funds:					
NEE:					
Equity securities	$ 741	$ 1,245 [b]	$ —	$ —	1,986
U.S. Government and municipal bonds	$ 495	$ 127	$ —	$ —	622
Corporate debt securities	$ —	$ 486	$ —	$ —	486
Mortgage-backed securities	$ —	$ 447	$ —	$ —	447
Other debt securities	$ —	$ 108	$ —	$ —	108
FPL:					
Equity securities	$ 125	$ 1,082 [b]	$ —	$ —	1,207
U.S. Government and municipal bonds	$ 458	$ 111	$ —	$ —	569
Corporate debt securities	$ —	$ 334	$ —	$ —	334
Mortgage-backed securities	$ —	$ 381	$ —	$ —	381
Other debt securities	$ —	$ 41	$ —	$ —	41
Other investments:					
NEE:					
Equity securities	$ 3	$ 1	$ —	$ —	4
U.S. Government and municipal bonds	$ 8	$ 4	$ —	$ —	12
Corporate debt securities	$ —	$ 32	$ —	$ —	32
Mortgage-backed securities	$ —	$ 58	$ —	$ —	58
Other	$ 5	$ 10	$ —	$ —	15
Derivatives:					
NEE:					
Commodity contracts	$ 1,755	$ 1,538	$ 824	$ (3,177)	$ 940 [c]
Interest rate swaps	$ —	$ 107	$ —	$ —	$ 107 [c]
Foreign currency swaps	$ —	$ 48	$ —	$ —	$ 48 [c]
FPL - commodity contracts	$ —	$ 14	$ 8	$ (13)	$ 9 [c]
Liabilities:					
Derivatives:					
NEE:					
Commodity contracts	$ 1,821	$ 1,509	$ 528	$ (3,206)	$ 652 [c]
Interest rate swaps	$ —	$ 123	$ —	$ —	$ 123 [c]
Foreign currency swaps	$ —	$ 4	$ —	$ —	$ 4 [c]
FPL - commodity contracts	$ —	$ 257	$ 1	$ (13)	$ 245 [c]

(a) Includes the effect of the contractual ability to settle contracts under master netting arrangements and margin cash collateral payments and receipts.
(b) At NEE, approximately $1,084 million ($980 million at FPL) are invested in commingled funds whose underlying investments would be Level 1 if those investments were held directly by NEE or FPL.
(c) See Note 3 for a reconciliation of net derivatives to NEE's and FPL's consolidated balance sheets.

The reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs is as follows:

	Years Ended December 31,					
	2011		2010		2009	
	NEE	FPL	NEE	FPL	NEE	FPL
	(millions)					
Fair value of net derivatives based on significant unobservable inputs at December 31 of prior year	$ 296	$ 7	$ 364	$ 11	$ 404	$ (1)
Realized and unrealized gains (losses):						
Included in earnings[(a)]	454	—	407	—	555	—
Included in regulatory assets and liabilities	3	3	1	1	7	7
Purchases, sales, settlements and issuances[(b)]	(258)	(6)	(432)	(5)	(521)	6
Transfers in[(c)]	6	—	2	—	16	—
Transfers out[(c)]	(15)	—	(46)	—	(97)	(1)
Fair value of net derivatives based on significant unobservable inputs at December 31	$ 486	$ 4	$ 296	$ 7	$ 364	$ 11
The amount of gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to derivatives still held at the reporting date[(d)]	$ 423	$ —	$ 170	$ —	$ 270	$ —

(a) For the years ended December 31, 2011, 2010 and 2009, $441 million, $384 million and $555 million, respectively, of realized and unrealized gains are reflected in the consolidated statements of income in operating revenues and the balance is reflected in fuel, purchased power and interchange.
(b) For the year ended December 31, 2011, includes $270 million of purchases, $166 million of settlements and $362 million of issuances.
(c) Transfers into Level 3 were a result of decreased observability of market data and transfers from Level 3 to Level 2 were a result of increased observability of market data. NEE's and FPL's policy is to recognize all transfers at the beginning of the reporting period.
(d) For the years ended December 31, 2011, 2010 and 2009, $423 million, $153 million and $270 million, respectively, of unrealized gains are reflected in the consolidated statements of income in operating revenues and the balance is reflected in fuel, purchased power and interchange.

Nonrecurring Fair Value Measurements - NEE tests long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In 2011, recent market value indications and the impact of newly proposed environmental regulations suggested that the carrying value of certain NEER assets, primarily wind assets in West Texas and oil-fired assets in Maine, may be impaired. NEER performed a fair value analysis and concluded that an impairment charge related to the long-lived assets, primarily property, plant and equipment, was necessary. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived assets held and used with a carrying amount of approximately $79 million were written down to their fair value of $28 million, resulting in an impairment charge of $51 million ($31 million after-tax), which is recorded as a separate line item in NEE's consolidated statements of income for the year ended December 31, 2011.

In 2011, subsidiaries of NEER completed the sales of their ownership interests in five natural gas-fired generating plants with a total generating capacity of approximately 2,700 mw for net cash proceeds of approximately $1.2 billion, after transaction costs and working capital and other adjustments. Approximately $363 million of these proceeds were used to repay debt associated with certain of the projects. A NEER affiliate will continue to operate the facilities included in the sales under service contracts: three facilities for a five-year period, one facility for a two-year period and the fifth facility for a one-year period. In connection with the sales, a loss of approximately $151 million ($98 million after-tax) was recorded in NEE's consolidated statements of income. The loss includes the reclassification of $30 million from AOCI as a result of the discontinuance of certain cash flow hedges because it became probable that the related forecasted transactions being hedged would not occur. See Note 3.

5. Financial Instruments

The carrying amounts of cash equivalents and commercial paper approximate their fair values. At December 31, 2011 and 2010, other investments of NEE, not included in the table below, included financial instruments of approximately $35 million and $97 million ($4 million and $4 million at FPL), respectively, including $2 million and $48 million included in current other receivables on the consolidated balance sheets (none at FPL), which primarily consist of notes receivable that are carried at estimated fair value or cost, which approximates fair value.

The following estimates of the fair value of financial instruments have been made primarily using available market information. However, the use of different market assumptions or methods of valuation could result in different estimated fair values.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(millions)			
NEE:				
Special use funds	$ 3,867 [a]	$ 3,867 [b]	$ 3,742 [a]	$ 3,742 [b]
Other investments:				
Notes receivable	$ 503	$ 535 [c]	$ 525	$ 583 [c]
Debt securities	$ 89 [d]	$ 89 [b]	$ 114 [d]	$ 114 [b]
Equity securities	$ 80	$ 159 [e]	$ 57	$ 125 [e]
Long-term debt, including current maturities	$ 21,614	$ 23,699 [f]	$ 19,929	$ 20,756 [f]
Interest rate swaps - net unrealized losses	$ (283)	$ (283) [g]	$ (16)	$ (16) [g]
Foreign currency swaps - net unrealized gains	$ 18	$ 18 [g]	$ 44	$ 44 [g]
FPL:				
Special use funds	$ 2,737 [a]	$ 2,737 [b]	$ 2,637 [a]	$ 2,637 [b]
Long-term debt, including current maturities	$ 7,533	$ 9,078 [f]	$ 6,727	$ 7,236 [f]

(a) At December 31, 2011, includes $164 million of investments accounted for under the equity method and $39 million of loans not measured at fair value on a recurring basis ($112 million and $24 million, respectively, for FPL). At December 31, 2010, includes $76 million of investments accounted for under the equity method and $17 million of loans not measured at fair value on a recurring basis ($94 million and $11 million, respectively, for FPL). For the remaining balance, see Note 4 for classification by major security type. The amortized cost of debt and equity securities is $1,638 million and $1,425 million, respectively, at December 31, 2011 and $1,616 million and $1,489 million, respectively, at December 31, 2010 ($1,321 million and $864 million, respectively, at December 31, 2011 and $1,281 million and $943 million, respectively, at December 31, 2010 for FPL).
(b) Based on quoted market prices for these or similar issues.
(c) Classified as held to maturity. Based on market prices provided by external sources. Notes receivable bear interest primarily at fixed rates and mature from 2014 to 2029. Notes receivable are considered impaired and placed in non-accrual status when it becomes probable that all amounts due cannot be collected in accordance with the contractual terms of the agreement. The assessment to place notes receivable in non-accrual status considers various credit indicators, such as credit standings and ratings and market-related information. As of December 31, 2011, neither NEE nor FPL had any notes receivable reported in non-accrual status.
(d) Classified as trading securities.
(e) Modeled internally based on latest market data.
(f) Provided by external sources based on market prices indicative of market conditions.
(g) Modeled internally based on market values using discounted cash flow analysis and credit valuation adjustment.

Special Use Funds - The special use funds consist of FPL's storm fund assets of $125 million and NEE's and FPL's nuclear decommissioning fund assets of $3,742 million and $2,612 million, respectively, at December 31, 2011. The investments held in the special use funds consist of equity and debt securities which are primarily classified as available for sale and carried at estimated fair value (see Note 4). For FPL's special use funds, consistent with regulatory treatment, changes in fair value, including any other than temporary impairment losses, result in a corresponding adjustment to the related regulatory liability accounts. For NEE's non-rate regulated operations, changes in fair value result in a corresponding adjustment to OCI, except for unrealized losses associated with marketable securities considered to be other than temporary, including any credit losses, which are recognized as other than temporary impairment losses on securities held in nuclear decommissioning funds in NEE's consolidated statements of income. Debt securities included in the nuclear decommissioning funds have a weighted-average maturity at December 31, 2011 of approximately six years at both NEE and FPL. FPL's storm fund primarily consists of debt securities with a weighted-average maturity at December 31, 2011 of approximately three years. The cost of securities sold is determined using the specific identification method.

Realized gains and losses and proceeds from the sale or maturity of available for sale securities are as follows:

	NEE			FPL		
	Years Ended December 31,			Years Ended December 31,		
	2011	2010	2009	2011	2010	2009
	(millions)					
Realized gains	$ 183	$ 106	$ 108	$ 74	$ 49	$ 48
Realized losses	$ 88	$ 30	$ 30	$ 62	$ 22	$ 25
Proceeds from sale or maturity of securities	$ 4,348	$ 6,726	$ 4,592	$ 2,988	$ 5,079	$ 3,270

Unrealized losses on available for sale debt securities at December 31, 2011 and 2010 were not material to NEE or FPL. The unrealized gains on available for sale securities are as follows:

	NEE		FPL	
	December 31,		December 31,	
	2011	2010	2011	2010
	(millions)			
Equity securities	$ 546	$ 612	$ 376	$ 384
U.S. Government and municipal bonds	$ 46	$ 15	$ 43	$ 15
Corporate debt securities	$ 31	$ 23	$ 24	$ 19
Mortgage-backed securities	$ 27	$ 20	$ 24	$ 18
Other debt securities	$ 3	$ 2	$ 3	$ 1

Regulations issued by the FERC and the NRC provide general risk management guidelines to protect nuclear decommissioning funds and to allow such funds to earn a reasonable return. The FERC regulations prohibit, among other investments, investments in any securities of NEE or its subsidiaries, affiliates or associates, excluding investments tied to market indices or mutual funds. Similar restrictions applicable to the decommissioning funds for NEER's nuclear plants are included in the NRC operating licenses for those facilities or in NRC regulations applicable to NRC licensees not in cost-of-service environments. With respect to the decommissioning fund for Seabrook, decommissioning fund contributions and withdrawals are also regulated by the NDFC pursuant to New Hampshire law.

The nuclear decommissioning reserve funds are managed by investment managers who must comply with the guidelines of NEE and FPL and the rules of the applicable regulatory authorities. The funds' assets are invested giving consideration to taxes, liquidity, risk, diversification and other prudent investment objectives.

Interest Rate and Foreign Currency Swaps - NEE and its subsidiaries use a combination of fixed rate and variable rate debt to manage interest rate exposure. Interest rate swaps are used to mitigate and adjust interest rate exposure when deemed appropriate based upon market conditions or when required by financing agreements. In addition, with respect to certain debt issuances and borrowings, NEECH has two cross currency swaps to hedge against currency movements with respect to both interest and principal payments. See Note 3.

6. Income Taxes

The components of income taxes are as follows:

	NEE			FPL		
	Years Ended December 31,			Years Ended December 31,		
	2011	2010	2009	2011	2010	2009
	(millions)					
Federal:						
Current[(a)]	$ (35)	$ 11	$ (18)	$ (64)	$ 113	$ 63
Deferred	572	434	290	622	385	342
Total federal	537	445	272	558	498	405
State:						
Current[(a)]	11	11	77	43	49	57
Deferred	(19)	76	(22)	53	33	11
Total state	(8)	87	55	96	82	68
Total income taxes	$ 529	$ 532	$ 327	$ 654	$ 580	$ 473

(a) Includes provision for unrecognized tax benefits.

A reconciliation between the effective income tax rates and the applicable statutory rates is as follows:

	NEE			FPL		
	Years Ended December 31,			Years Ended December 31,		
	2011	2010	2009	2011	2010	2009
Statutory federal income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increases (reductions) resulting from:						
State income taxes - net of federal income tax benefit	(0.2)	2.4	1.9	3.6	3.5	3.4
PTCs and ITCs - NEER	(11.1)	(12.2)	(13.1)	—	—	—
Convertible ITCs - NEER	(0.1)	(2.5)	(4.3)	—	—	—
Other - net	(2.0)	(1.3)	(2.6)	(0.6)	(0.5)	(2.1)
Effective income tax rate	21.6%	21.4%	16.9%	38.0%	38.0%	36.3%

The income tax effects of temporary differences giving rise to consolidated deferred income tax liabilities and assets are as follows:

	NEE		FPL	
	December 31,		December 31,	
	2011	2010	2011	2010
	(millions)			
Deferred tax liabilities:				
Property-related	$ 8,727	$ 7,795	$ 5,260	$ 4,532
Pension	394	485	420	399
Storm reserve deficiency	235	258	235	258
Nuclear decommissioning trusts	117	146	—	—
Net unrealized gains on derivatives	209	226	—	—
Deferred fuel costs	40	101	40	101
Other	573	638	151	187
Total deferred tax liabilities	10,295	9,649	6,106	5,477
Deferred tax assets and valuation allowance:				
Decommissioning reserves	406	393	336	323
Postretirement benefits	170	175	118	130
Net operating loss carryforwards	557	663	—	—
Tax credit carryforwards	2,111	1,819	—	—
ARO and accrued asset removal costs	884	895	788	802
Other	830	790	261	309
Valuation allowance[(a)]	(228)	(246)	—	—
Net deferred tax assets	4,730	4,489	1,503	1,564
Net accumulated deferred income taxes	$ 5,565	$ 5,160	$ 4,603	$ 3,913

(a) Amount relates to deferred state tax credits and state operating loss carryforwards.

Deferred tax assets and liabilities are included on the consolidated balance sheets as follows:

	NEE		FPL	
	December 31,		December 31,	
	2011	2010	2011	2010
	(millions)			
Other current assets	$ 10	$ 17	$ —	$ —
Other assets	153	106	—	—
Other current liabilities	(47)	(174)	(10)	(78)
Accumulated deferred income taxes	(5,681)	(5,109)	(4,593)	(3,835)
Net accumulated deferred income taxes	$ (5,565)	$ (5,160)	$ (4,603)	$ (3,913)

The components of NEE's deferred tax assets relating to net operating loss carryforwards and tax credit carryforwards at December 31, 2011 are as follows:

	Amount	Expiration Dates
	(millions)	
Net operating loss carryforwards:		
Federal	$ 433	2026-2031
State	110	2014-2031
Foreign	14	2021-2031
Net operating loss carryforwards	$ 557	
Tax credit carryforwards:		
Federal	$ 1,813	2022-2031
State	298	2012-2035
Net tax credit carryforwards	$ 2,111	

Unrecognized Tax Benefits - The majority of the liabilities for unrecognized tax benefits represent tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A disallowance of the shorter deductibility period for these tax positions would not affect the annual effective income tax rate. Amounts included in the liabilities for unrecognized tax benefits at December 31, 2011, 2010 and 2009 at NEE and FPL that, if disallowed, could impact the annual effective income tax rate were not significant.

At December 31, 2010 and 2009, NEE's liabilities for unrecognized tax benefits totaled $264 million and $279 million ($215 million and $247 million for FPL), respectively. During 2011, NEE settled the majority of the uncertainties giving rise to the unrecognized tax benefits with the Internal Revenue Service (IRS). As part of the settlement, NEE received a cash refund of approximately $278 million, including interest of approximately $131 million, related to the 1988 through 2005 tax years and finalized the examination of the 2006 through 2008 tax years (collectively, IRS settlement). The IRS settlement primarily related to the timing of certain NEE and FPL deductions for repairs, casualty losses and indirect service costs. At December 31, 2011, NEE's and FPL's liabilities for unrecognized tax benefits were not material.

NEE and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various states, the most significant of which is Florida, and certain foreign jurisdictions. With the exception of a few states, NEE and FPL are effectively no longer subject to U.S. federal, state and foreign examinations by taxing authorities for years before 2009. Income tax returns for 2009 and 2010 are under examination by the IRS. The amounts of unrecognized tax benefits and related interest accruals may change within the next 12 months; however, NEE and FPL do not expect these changes to have a significant impact on NEE’s or FPL’s financial statements.

7. Comprehensive Income

The components of NEE's comprehensive income and accumulated other comprehensive income (loss) are as follows:

	Net Income	Accumulated Other Comprehensive Income (Loss)			Comprehensive Income
		Net Unrealized Gains (Losses) On Cash Flow Hedges	Other	Total	
			(millions)		
Balances, December 31, 2008		$ 5	$ (18)	$ (13)	
Net income of NEE	$ 1,615				$ 1,615
Net unrealized gains (losses) on cash flow hedges:					
Effective portion of net unrealized gains (net of $90 tax expense)		137	—	137	137
Reclassification from AOCI to net income (net of $50 tax benefit)[(a)]		(75)	—	(75)	(75)
Net unrealized gains (losses) on available for sale securities:					
Net unrealized gains on securities still held (net of $77 tax expense)		—	119	119	119
Reclassification from AOCI to net income (net of $17 tax benefit)		—	(27)	(27)	(27)
Adjustments between AOCI and retained earnings		—	(5)	(5)	—
Defined benefit pension and other benefits plans (net of $14 tax expense)		—	22	22	22
Net unrealized gains on foreign currency translation (net of $5 tax expense)		—	11	11	11
Balances, December 31, 2009		67	102	169	$ 1,802
Net income of NEE	$ 1,957				$ 1,957
Net unrealized gains (losses) on cash flow hedges:					
Effective portion of net unrealized losses (net of $3 tax benefit)		(5)	—	(5)	(5)
Reclassification from AOCI to net income (net of $35 tax benefit)		(38)	—	(38)	(38)
Net unrealized gains (losses) on available for sale securities:					
Net unrealized gains on securities still held (net of $41 tax expense)		—	60	60	60
Reclassification from AOCI to net income (net of $16 tax benefit)		—	(21)	(21)	(21)
Defined benefit pension and other benefits plans (net of $1 tax expense)		—	2	2	2
Net unrealized losses on foreign currency translation		—	(1)	(1)	(1)
Balances, December 31, 2010		24	142	166	$ 1,954
Net income of NEE	$ 1,923				$ 1,923
Net unrealized gains (losses) on cash flow hedges:					
Effective portion of net unrealized losses (net of $135 tax benefit)		(265)	—	(265)	(265)
Reclassification from AOCI to net income (net of $18 tax expense)		37	—	37	37
Net unrealized gains (losses) on available for sale securities:					
Net unrealized gain on securities still held (net of $13 tax expense)		—	19	19	19
Reclassification from AOCI to net income (net of $34 tax benefit)		—	(49)	(49)	(49)
Defined benefit pension and other benefits plans (net of $32 tax benefit)		—	(45)	(45)	(45)
Net unrealized losses on foreign currency translation (net of $3 tax benefit)		—	(5)	(5)	(5)
Other comprehensive loss related to equity method investee (net of $8 tax benefit)		—	(12)	(12)	(12)
Balances, December 31, 2011		$ (204) [(b)]	$ 50	$ (154)	$ 1,603

(a) Includes amounts reclassified into earnings due to discontinuance of cash flow hedges of approximately $3 million (net of $2 million tax benefit) for which the hedged transactions are no longer probable of occurring.

(b) Approximately $13 million of losses, related to derivative instruments, is expected to be reclassified into earnings within the next 12 months as either the principal and/or interest payments are made or electricity is sold. Such amount assumes no change in power prices, interest rates or scheduled principal payments.

8. Jointly-Owned Electric Plants

Certain NEE subsidiaries own undivided interests in the jointly-owned facilities described below, and are entitled to a proportionate share of the output from those facilities. The subsidiaries are responsible for their share of the operating costs, as well as providing their own financing. Accordingly, each subsidiary includes its proportionate share of the facilities and related revenues and expenses in the appropriate balance sheet and statement of income captions. NEE's and FPL's respective shares of direct expenses for these facilities are included in fuel, purchased power and interchange, O&M, depreciation and amortization and taxes other than income taxes and other in NEE's and FPL's consolidated statements of income.

NEE's and FPL's proportionate ownership interest in jointly-owned facilities is as follows:

	December 31, 2011			
	Ownership Interest	Gross Investment[(a)]	Accumulated Depreciation[(a)]	Construction Work in Progress
		(millions)		
FPL:				
St. Lucie Unit No. 2	85%	$ 1,424	$ 550	$ 138
St. Johns River Power Park units and coal terminal	20%	$ 389	$ 157	$ 6
Scherer Unit No. 4	76%	$ 720	$ 232	$ 323
NEER:				
Duane Arnold	70%	$ 330	$ 76	$ 50
Seabrook	88.23%	$ 884	$ 145	$ 75
Wyman Station Unit No. 4	84.35%	$ 105	$ 41	$ 1
Corporate and Other:				
Transmission substation assets located in Seabrook, New Hampshire	88.23%	$ 60	$ 12	$ 2

(a) Excludes nuclear fuel.

9. Variable Interest Entities

As of December 31, 2011, NEE has eight VIEs which it consolidates and has interests in certain other VIEs which it does not consolidate.

FPL - FPL is considered the primary beneficiary of, and therefore consolidates, a VIE that is a wholly-owned bankruptcy remote special purpose subsidiary that it formed in 2007 for the sole purpose of issuing storm-recovery bonds pursuant to the securitization provisions of the Florida Statutes and a financing order of the FPSC. FPL is considered the primary beneficiary because FPL has the power to direct the significant activities of the VIE, and its equity investment, which is subordinate to the bondholder's interest in the VIE, is at risk. Storm restoration costs incurred by FPL during 2005 and 2004 exceeded the amount in FPL's funded storm and property insurance reserve, resulting in a storm reserve deficiency. In 2007, the VIE issued $652 million aggregate principal amount of senior secured bonds (storm-recovery bonds), primarily for the after-tax equivalent of the total of FPL's unrecovered balance of the 2004 storm restoration costs, the 2005 storm restoration costs and approximately $200 million to reestablish FPL's storm and property insurance reserve. In connection with this financing, net proceeds, after debt issuance costs, to the VIE (approximately $644 million) were used to acquire the storm-recovery property, which includes the right to impose, collect and receive a storm-recovery charge from all customers receiving electric transmission or distribution service from FPL under rate schedules approved by the FPSC or under special contracts, certain other rights and interests that arise under the financing order issued by the FPSC and certain other collateral pledged by the VIE that issued the bonds. The storm-recovery bonds are payable only from and are secured by the storm-recovery property. The bondholders have no recourse to the general credit of FPL. The assets of the VIE were approximately $406 million and $444 million at December 31, 2011 and December 31, 2010, respectively, and consisted primarily of storm-recovery property, which are included in securitized storm-recovery costs on NEE's and FPL's consolidated balance sheets. The liabilities of the VIE were approximately $496 million and $542 million at December 31, 2011 and December 31, 2010, respectively, and consisted primarily of storm-recovery bonds, which are included in long-term debt on NEE's and FPL's consolidated balance sheets.

FPL identified a potential VIE, which is considered a qualifying facility as defined by the Public Utility Regulatory Policies Act of 1978, as amended (PURPA). PURPA requires utilities, such as FPL, to purchase the electricity output of a qualifying facility. FPL entered into a PPA effective in 1994 with this 250 mw coal-fired qualifying facility to purchase substantially all of the facility's capacity and electrical output over a substantial portion of its estimated useful life. FPL absorbs a portion of the facility's variability related to changes in the market price of coal through the price it pays per mwh (energy payment). After making exhaustive efforts, FPL

was unable to obtain the information from the facility necessary to determine whether the facility is a VIE or whether FPL is the primary beneficiary of the facility. The PPA with the facility contains no provision which legally obligates the facility to release this information to FPL. The energy payments paid by FPL will fluctuate as coal prices change. This fluctuation does not expose FPL to losses since the energy payments paid by FPL to the facility are passed on to FPL's customers through the fuel clause as approved by the FPSC. Notwithstanding the fact that FPL's energy payments are recovered through the fuel clause, if the facility was determined to be a VIE, the absorption of some of the facility's fuel price variability might cause FPL to be considered the primary beneficiary. During the years ended December 31, 2011, 2010 and 2009, FPL purchased 1,188,649 mwh, 1,502,234 mwh and 1,604,735 mwh, respectively, from the facility at a total cost of approximately $189 million, $184 million and $173 million, respectively.

Additionally, FPL entered into a PPA effective in 1995 with a 330 mw coal-fired qualifying facility to purchase substantially all of the facility's electrical output over a substantial portion of its estimated useful life. The facility is considered a VIE because FPL absorbs a portion of the facility's variability related to changes in the market price of coal through the energy payment. Since FPL does not control the most significant activities of the facility, including operations and maintenance, FPL is not the primary beneficiary and does not consolidate this VIE. The energy payments paid by FPL will fluctuate as coal prices change. This fluctuation does not expose FPL to losses since the energy payments paid by FPL to the facility are passed on to FPL's customers through the fuel clause as approved by the FPSC.

NEER - NEE consolidates seven NEER VIEs. NEER is considered the primary beneficiary of these VIEs since NEER controls the most significant activities of these VIEs, including operations and maintenance, and through its 100% equity ownership has the obligation to absorb expected losses of these VIEs.

An NEER VIE consolidates two entities which own and operate natural gas/oil electric generating facilities with the capability of producing 110 mw. This VIE sells its electric output under power sales contracts to a third party, with expiration dates in 2018 and 2020. The power sales contracts provide the offtaker the ability to dispatch the facilities and require the offtaker to absorb the cost of fuel. This VIE uses third party debt and equity to finance its operations. The debt is secured by liens against the generating facilities and the other assets of these entities. The debt holders have no recourse to the general credit of NEER. The assets and liabilities of the VIE were approximately $105 million and $82 million, respectively, at December 31, 2011 and $99 million and $82 million, respectively, at December 31, 2010, and consisted primarily of property, plant and equipment and long-term debt. In November 2011, NEER sold its ownership interest in certain natural gas-fired generating plants (see Note 4), of which two were VIEs with the capability of producing a total of 1,175 mw. At December 31, 2010, the assets and liabilities of these two VIEs totaled approximately $730 million and $373 million, respectively, and consisted primarily of property, plant and equipment and long-term debt.

The other six NEER VIEs consolidate several entities which own and operate wind electric generating facilities with the capability of producing a total of 1,916 mw. These VIEs sell their electric output under power sales contracts to third parties with expiration dates ranging from 2018 through 2037. The VIEs use third-party debt and/or equity to finance their operations. Certain investors that hold no equity interest in the VIEs hold differential membership interests, which give them the right to receive a portion of the economic attributes of the generating facilities, including certain tax attributes. The debt is secured by liens against the generating facilities and the other assets of these entities. The debt holders have no recourse to the general credit of NEER. The assets and liabilities of these VIEs totaled approximately $3.2 billion and $2.6 billion, respectively, at December 31, 2011. Three of the VIEs were consolidated at December 31, 2010, and the assets and liabilities of those VIEs totaled approximately $1.7 billion and $1.6 billion, respectively, at December 31, 2010. At December 31, 2011 and December 31, 2010, the assets and liabilities of the VIEs consisted primarily of property, plant and equipment, deferral related to differential membership interests and long-term debt.

Other - As of December 31, 2011 and December 31, 2010, several NEE subsidiaries have investments totaling approximately $668 million ($526 million at FPL) and $646 million ($480 million at FPL), respectively, in certain special purpose entities, which consisted primarily of investments in mortgage-backed securities. These investments are included in special use funds and other investments on NEE's consolidated balance sheets and in special use funds on FPL's consolidated balance sheets. As of December 31, 2011, NEE subsidiaries are not the primary beneficiary and therefore do not consolidate any of these entities because they do not control any of the ongoing activities of these entities, were not involved in the initial design of these entities and do not have a controlling financial interest in these entities. Prior to December 31, 2011, NEE consolidated one of these entities; however, NEE is no longer the primary beneficiary of this entity and therefore no longer consolidates this entity. Upon deconsolidation, NEE's investment in this entity is accounted for under the equity method. NEE did not recognize any gain or loss and there was no significant effect on NEE's consolidated balance sheets as a result of the deconsolidation.

10. Investments in Partnerships and Joint Ventures

NEER - NEER has non-controlling non-majority owned interests in various partnerships and joint ventures, essentially all of which own electric generating facilities. At December 31, 2011 and 2010, NEER's investments in partnerships and joint ventures totaled approximately $193 million and $217 million, respectively, which is included in other investments on NEE's consolidated balance sheets. NEER's interest in these partnerships and joint ventures range from approximately 5.5% to 50%. At December 31, 2011, the principal operating entities included in NEER's investments in partnerships and joint ventures were Northeast Energy, LP, Desert Sunlight Investment Holdings, LLC, Mojave 3/4/5 LLC, Luz Solar Partners Ltd., III, Luz Solar Partners Ltd., V and in 2010 also included Luz Solar Partners Ltd., IV.

Summarized combined information for these principal operating entities is as follows:

	2011	2010
	(millions)	
Net income	$ 72	$ 81
Total assets	$ 873	$ 660
Total liabilities	$ 508	$ 210
Partners'/members' equity	$ 365	$ 450
NEER's share of underlying equity in the principal operating entities	$ 182	$ 223
Difference between investment carrying amount and underlying equity in net assets[(a)]	(19)	(26)
NEER's investment carrying amount for the principal operating entities	$ 163	$ 197

(a) The majority of the difference between the investment carrying amount and the underlying equity in net assets is being amortized over the remaining life of the investee's assets.

Certain subsidiaries of NEER provide services to the partnerships and joint ventures, including operations and maintenance and business management services. NEE's operating revenues for the years ended December 31, 2011, 2010 and 2009 include approximately $26 million, $25 million and $21 million, respectively, related to such services. The net receivables at December 31, 2011 and 2010, for these services, as well as for affiliate energy commodity transactions, payroll and other payments made on behalf of these investees, were approximately $19 million and $36 million, respectively, and are included in other receivables on NEE's consolidated balance sheets.

NEE - In 2004, a trust created by NEE sold $300 million of 5 7/8% preferred trust securities to the public and $9 million of common trust securities to NEE. The trust is an unconsolidated 100%-owned finance subsidiary. The proceeds from the sale of the preferred and common trust securities were used to buy 5 7/8% junior subordinated debentures maturing in March 2044 from NEECH. NEE has fully and unconditionally guaranteed the preferred trust securities and the junior subordinated debentures.

11. Common and Preferred Stock

Earnings Per Share - The reconciliation of NEE's basic and diluted earnings per share of common stock is as follows:

	Years Ended December 31,		
	2011	2010	2009
	(millions, except per share amounts)		
Numerator - net income	$ 1,923	$ 1,957	$ 1,615
Denominator:			
Weighted-average number of common shares outstanding - basic	416.6	410.3	404.4
Performance share awards, options, restricted stock, equity units and warrants[(a)]	2.4	2.7	2.8
Weighted-average number of common shares outstanding - assuming dilution	419.0	413.0	407.2
Earnings per share of common stock:			
Basic	$ 4.62	$ 4.77	$ 3.99
Assuming dilution	$ 4.59	$ 4.74	$ 3.97

(a) Performance share awards are included in diluted weighted-average number of common shares outstanding based upon what would be issued if the end of the reporting period was the end of the term of the award. Options, performance share awards, restricted stock, equity units and warrants are included in diluted weighted-average number of common shares outstanding by applying the treasury stock method.

Common shares issuable pursuant to equity units and stock options, restricted stock and performance share awards which were not included in the denominator above due to their antidilutive effect were approximately 14.6 million, 9.1 million and 0.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Common Stock Dividend Restrictions - NEE's charter does not limit the dividends that may be paid on its common stock. FPL's mortgage securing FPL's first mortgage bonds contains provisions which, under certain conditions, restrict the payment of dividends and other distributions to NEE. These restrictions do not currently limit FPL's ability to pay dividends to NEE.

Employee Stock Ownership Plan - The employee retirement savings plans of NEE include a leveraged ESOP feature. Shares of common stock held by the trust for the employee retirement savings plans (Trust) are used to provide all or a portion of the employers' matching contributions. Dividends received on all shares, along with cash contributions from the employers, are used to pay principal and interest on an ESOP loan held by a subsidiary of NEECH. Dividends on shares allocated to employee accounts and used by the Trust for debt service are replaced with shares of common stock, at prevailing market prices, in an equivalent amount. For purposes of computing basic and fully diluted earnings per share, ESOP shares that have been committed to be released are considered outstanding.

ESOP-related compensation expense was approximately $42 million, $37 million and $42 million in 2011, 2010 and 2009, respectively. The related share release was based on the fair value of shares allocated to employee accounts during the period. Interest income on the ESOP loan is eliminated in consolidation. ESOP-related unearned compensation included as a reduction of common shareholders' equity at December 31, 2011 was approximately $53 million, representing unallocated shares at the original issue price. The fair value of the ESOP-related unearned compensation account using the closing price of NEE common stock at December 31, 2011 was approximately $224 million.

Stock-Based Compensation - Net income for the years ended December 31, 2011, 2010 and 2009 includes approximately $49 million, $57 million and $51 million, respectively, of compensation costs and $19 million, $22 million and $20 million, respectively, of income tax benefits related to stock-based compensation arrangements. Compensation cost capitalized for the years ended December 31, 2011, 2010 and 2009 was not material. As of December 31, 2011, there were approximately $58 million of unrecognized compensation costs related to nonvested/nonexercisable stock-based compensation arrangements. These costs are expected to be recognized over a weighted-average period of 1.8 years.

At December 31, 2011, approximately 23 million shares of common stock were authorized for awards to officers, employees and non-employee directors of NEE and its subsidiaries under NEE's: (a) 2011 Long Term Incentive Plan, (b) 2007 Non-Employee Directors Stock Plan and (c) earlier equity compensation plans under which shares are reserved for issuance under existing grants, but no additional shares are available for grant under the earlier plans. NEE satisfies restricted stock and performance share awards by issuing new shares of its common stock or by purchasing shares of its common stock in the open market. NEE satisfies stock option exercises by issuing new shares of its common stock. NEE generally grants most of its stock-based compensation awards in the first quarter of each year.

Restricted Stock and Performance Share Awards - Restricted stock typically vests within three years after the date of grant and is subject to, among other things, restrictions on transferability prior to vesting. The fair value of restricted stock is measured based upon the closing market price of NEE common stock as of the date of grant. Performance share awards are typically payable at the end of a three-year performance period if the specified performance criteria are met. The fair value of performance share awards is estimated based upon the closing market price of NEE common stock as of the date of grant less the present value of expected dividends, multiplied by an estimated performance multiple which is subsequently trued up based on actual performance.

The activity in restricted stock and performance share awards for the year ended December 31, 2011 was as follows:

	Shares	Weighted-Average Grant Date Fair Value Per Share
Restricted Stock:		
Nonvested balance, January 1, 2011	1,154,590	$ 50.40
Granted	452,488	$ 54.77
Vested	(521,882)	$ 53.22
Forfeited	(52,908)	$ 51.34
Nonvested balance, December 31, 2011	1,032,288	$ 50.84
Performance Share Awards:		
Nonvested balance, January 1, 2011	1,318,398	$ 45.96
Granted	566,386	$ 50.13
Vested	(448,416)	$ 58.42
Forfeited	(85,294)	$ 43.34
Nonvested balance, December 31, 2011	1,351,074	$ 43.72

The weighted-average grant date fair value per share of restricted stock granted for the years ended December 31, 2010 and 2009 was $46.72 and $51.50 respectively. The weighted-average grant date fair value per share of performance share awards granted for the years ended December 31, 2010 and 2009 was $42.95 and $42.66, respectively.

The total fair value of restricted stock and performance share awards vested was $53 million, $47 million and $46 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Options - Options typically vest within three years after the date of grant and have a maximum term of ten years. The exercise price of each option granted equals the closing market price of NEE common stock on the date of grant. The fair value of the options is estimated on the date of the grant using the Black-Scholes option-pricing model and based on the following assumptions:

	2011	2010	2009
Expected volatility[(a)]	21.54%	20.74 - 21.64%	19.02 - 20.23%
Expected dividends	4.03%	3.61 - 4.39%	3.35 - 3.71%
Expected term (years)[(b)]	6	6	6
Risk-free rate	2.80%	1.65 - 2.91%	2.68 - 2.97%

(a) Based on historical experience.
(b) Based on historical exercise and post-vesting cancellation experience adjusted for outstanding awards.

Option activity for the year ended December 31, 2011 was as follows:

	Shares Underlying Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (millions)
Balance, January 1, 2011	5,036,652	$ 38.69		
Granted	536,302	$ 54.59		
Exercised	(1,065,939)	$ 29.14		
Forfeited	(102,451)	$ 50.49		
Expired	(18,699)	$ 47.42		
Balance, December 31, 2011	4,385,865	$ 42.64	4.7	$ 81
Exercisable, December 31, 2011	3,348,329	$ 40.15	3.6	$ 71

The weighted-average grant date fair value of options granted was $7.78, $6.22 and $6.79 per share for the years ended December 31, 2011, 2010 and 2009, respectively. The total intrinsic value of stock options exercised was approximately $29 million, $32 million and $9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Cash received from option exercises was approximately $31 million, $41 million and $10 million for the years ended December 31, 2011, 2010 and 2009, respectively. The tax benefits realized from options exercised were approximately $11 million, $12 million and $3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Accelerated Share Repurchase (ASR) of NEE Common Stock - In December 2011, NEE purchased approximately 6.7 million shares of its common stock at a price of $55.76 per share for an aggregate price of $375 million pursuant to an ASR agreement. The approximately 6.7 million shares repurchased were retired, which resulted in a decrease in common stock and additional paid-in capital on NEE's consolidated balance sheet. On February 24, 2012, NEE elected to settle the ASR agreement in cash, which settlement is expected to be complete within three business days of such date; the settlement amount is not expected to be material.

Continuous Offering of NEE Common Stock - In December 2010, NEE completed the program it commenced in January 2009 under which it offered and sold, from time to time, NEE common stock having a gross sales price of up to $400 million. During 2010 and 2009, NEE received gross proceeds through the sale and issuance of common stock under this program of approximately $240 million and $160 million, respectively.

Preferred Stock - NEE's charter authorizes the issuance of 100 million shares of serial preferred stock, $0.01 par value, none of which are outstanding. FPL's charter authorizes the issuance of 10,414,100 shares of preferred stock, $100 par value; 5 million shares of subordinated preferred stock, no par value and 5 million shares of preferred stock, no par value, none of which are outstanding.

12. Debt

Long-term debt consists of the following:

	December 31,	
	2011	2010
	(millions)	
FPL:		
First mortgage bonds - maturing 2013 through 2042 - 4.125% to 6.20%	$ 6,390	$ 5,540
Storm-recovery bonds - maturing 2013 through 2021 - 5.0440% to 5.2555%[a]	487	531
Pollution control, solid waste disposal and industrial development revenue bonds - maturing 2020 through 2029 - variable, 0.1% and 0.3% weighted-average interest rates, respectively[b]	633	633
Other long-term debt - maturing 2012 through 2040 - 4.000% to 5.250%	57	57
Unamortized discount	(34)	(34)
Total long-term debt of FPL	7,533	6,727
Less current maturities of long-term debt	50	45
Long-term debt of FPL, excluding current maturities	7,483	6,682
NEECH:		
Debentures - maturing 2013 through 2021 - 2.55% to 7 7/8%[c]	2,300	2,500
Debentures - maturing 2012 - variable, 0.77% and 1.0% weighted-average interest rate, respectively[d]	200	450
Debentures, related to NEE's equity units - maturing 2014 and 2015 - 3.60% and 1.90%	753	753
Junior Subordinated Debentures - maturing 2044 through 2069 - 5 7/8% to 8.75%	2,353	2,353
Senior secured bonds - maturing 2030 - 7.500%[e]	500	500
Japanese yen denominated senior notes - maturing 2030 - 5.1325%[c]	130	123
Japanese yen denominated term loans - maturing 2014 and 2011 - variable, 1.9% and 2.2% weighted-average interest rate, respectively[c][d]	442	327
Term loans - maturing 2012 through 2016 - primarily variable, 1.39% and 1.2% weighted-average interest rate, respectively[d]	1,533	950
Fair value swap	32	3
Unamortized discount	(6)	(8)
Total long-term debt of NEECH	8,237	7,951
Less current maturities of long-term debt	350	1,485
Long-term debt of NEECH, excluding current maturities	7,887	6,466
NEER:		
Senior secured limited-recourse bonds and notes - maturing 2013 through 2038 - 4.125% to 7.59%	3,147	2,652
Other long-term debt - maturing 2012 through 2030 - primarily limited-recourse and variable, 2.6% weighted-average interest rate[c][d]	2,529	2,521
Canadian revolving credit facility - maturing 2013 - variable, 1.3% weighted-average interest rate[d]	172	82
Total long-term debt of NEER	5,848	5,255
Less current maturities of long-term debt	408	390
Long-term debt of NEER, excluding current maturities	5,440	4,865
Total long-term debt	$ 20,810	$ 18,013

(a) Principal on the storm-recovery bonds is due on the final maturity date (the date by which the principal must be repaid to prevent a default) for each tranche, however, it began being paid semiannually and sequentially on February 1, 2008, when the first semiannual interest payment became due.
(b) Tax exempt bonds that permit individual bond holders to tender the bonds for purchase at any time prior to maturity. In the event bonds are tendered for purchase, they would be remarketed by a designated remarketing agent in accordance with the related indenture. If the remarketing is unsuccessful, FPL would be required to purchase the tax exempt bonds. As of December 31, 2011, all tax exempt bonds tendered for purchase have been successfully remarketed. FPL's bank revolving lines of credit are available to support the purchase of tax exempt bonds.
(c) Interest rate swap agreements have been entered into for the majority of these debt issuances.
(d) Variable rate is based on an underlying index plus a margin.
(e) Issued by a wholly-owned subsidiary of NEECH and collateralized by a third-party note receivable held by that subsidiary. See Note 5.

Minimum annual maturities of long-term debt for NEE are approximately $808 million, $2,435 million, $1,974 million, $1,837 million and $695 million for 2012, 2013, 2014, 2015 and 2016, respectively. The respective amounts for FPL are approximately $50 million, $453 million, $56 million, $60 million and $64 million.

At December 31, 2011 and 2010, commercial paper borrowings had a weighted-average interest rate of 0.48% (0.26% for FPL) and 0.39% (0.26% for FPL), respectively. Available lines of credit aggregated approximately $7.4 billion ($4.4 billion for NEECH and $3.0 billion for FPL) at December 31, 2011 and were available to support NEECH's and FPL's commercial paper programs. These facilities provide for the issuance of letters of credit of up to approximately $6.4 billion. The issuance of letters of credit is subject to the aggregate commitment under the applicable facility. While no direct borrowings were outstanding at

December 31, 2011, letters of credit totaling $1,238 million and $34 million were outstanding under the NEECH and FPL credit facilities, respectively. On February 9, 2012, NEECH and FPL refinanced a portion of their credit facilities and reduced the amount of letters of credit that could be issued under the facilities from 100% to 50% of the facility amount.

NEE has guaranteed certain payment obligations of NEECH, including most of those under NEECH's debt, including all of its debentures and commercial paper issuances, as well as most of its guarantees. NEECH has guaranteed certain debt and other obligations of NEER and its subsidiaries.

In 2008, FPL entered into a reclaimed water agreement with Palm Beach County, Florida (PBC) to provide FPL's WCEC with reclaimed water for cooling purposes beginning in January 2011. Under the reclaimed water agreement, FPL constructed a reclaimed water system, including modifications to an existing treatment plant and a water pipeline, that PBC legally owns and operates. The reclaimed water agreement also required PBC to issue bonds for the purpose of paying the costs associated with the construction of the reclaimed water system. In 2009, PBC issued approximately $68 million principal amount of Palm Beach County, Florida Water and Sewer Revenue Bonds. Under the reclaimed water agreement, FPL will pay PBC an operating fee for the reclaimed water delivered which will be used by PBC to, among other things, service the principal of, and interest on, the bonds. The portion of the operating fee related to PBC's servicing principal of, and interest on, the bonds will be paid by FPL, beginning October 2011, until final maturity of the bonds. FPL does not have a direct obligation to the bondholders; however, if FPL or PBC were to terminate the reclaimed water agreement, FPL would be obligated to continue to pay the portion of the operating fee intended to reimburse PBC for costs related to issuance of the bonds, including amounts to be used by PBC to service the principal of, and interest on, the bonds. In the event of a default by PBC under the reclaimed water agreement, FPL would have certain rights, including, among other things, the right to appoint a third-party contractor to repair, and restore operations of, the reclaimed water treatment plant, and, in the event of a termination of the reclaimed water agreement by FPL relating to a PBC default, the right to assume ownership of the reclaimed water pipeline from PBC. For financial reporting purposes, FPL is considered the owner of the reclaimed water system and FPL and NEE have recorded electric utility plant in service and other property and long-term debt (see FPL's other long-term debt in the table above) as costs were reimbursed by PBC to FPL.

In 2009, NEE sold $350 million of equity units (initially consisting of Corporate Units). Each equity unit has a stated amount of $50 and consists of a contract to purchase NEE common stock (stock purchase contract) and, initially, a 1/20, or 5%, undivided beneficial ownership interest in a Series C Debenture due June 1, 2014 issued in the principal amount of $1,000 by NEECH (see table above). Each stock purchase contract requires the holder to purchase by no later than June 1, 2012 (the final settlement date) for a price of $50 in cash, a number of shares of NEE common stock (subject to antidilution adjustments) based on a price per share range of $55.67 to $66.80. If purchased on the final settlement date, as of December 31, 2011, the number of shares issued would (subject to antidilution adjustments) range from 0.9051 shares if the applicable market value of a share of common stock is less than or equal to $55.67, to 0.7544 shares if the applicable market value of a share is equal to or greater than $66.80, with applicable market value to be determined using the average closing prices of NEE common stock over a 20-day trading period ending May 29, 2012. Total annual distributions on the equity units will be at the rate of 8.375%, consisting of interest on the debentures (3.60% per year) and payments under the stock purchase contracts (4.775% per year). The interest rate on the debentures is expected to be reset no later than May 2012. The holder of an equity unit may satisfy its purchase obligation with proceeds raised from remarketing the NEECH debentures that are part of its equity unit. The undivided beneficial ownership interest in the NEECH debenture that is a component of each Corporate Unit is pledged to NEE to secure the holder's obligation to purchase NEE common stock under the related stock purchase contract. If a successful remarketing does not occur on or before the third business day prior to the final settlement date, and a holder has not notified NEE of its intention to settle the stock purchase contract with cash, NEE would exercise its rights as a secured party in the debentures to satisfy in full the holders' obligations to purchase NEE common stock under the related stock purchase contracts on the final settlement date. The debentures are fully and unconditionally guaranteed by NEE.

In 2010, NEE sold $402.5 million of equity units (initially consisting of Corporate Units). Each equity unit has a stated amount of $50 and consists of a contract to purchase NEE common stock (stock purchase contract) and, initially, a 1/20, or 5%, undivided beneficial ownership interest in a Series D Debenture due September 1, 2015 issued in the principal amount of $1,000 by NEECH (see table above). Each stock purchase contract requires the holder to purchase by no later than September 1, 2013 (the final settlement date) for a price of $50 in cash, a number of shares of NEE common stock (subject to antidilution adjustments) based on a price per share range of $55.02 to $68.78. If purchased on the final settlement date, as of December 31, 2011, the number of shares issued would (subject to antidilution adjustments) range from 0.9121 shares if the applicable market value of a share of common stock is less than or equal to $55.02, to 0.7296 shares if the applicable market value of a share is equal to or greater than $68.78, with applicable market value to be determined using the average closing prices of NEE common stock over a 20-day trading period ending August 28, 2013. Total annual distributions on the equity units will be at the rate of 7.00%, consisting of interest on the debentures (1.90% per year) and payments under the stock purchase contracts (5.10% per year). The interest rate on the debentures is expected to be reset on or after March 1, 2013. The holder of an equity unit may satisfy its purchase obligation with proceeds raised from remarketing the NEECH debentures that are part of its equity unit. The undivided beneficial ownership interest in the NEECH debenture that is a component of each Corporate Unit is pledged to NEE to secure the holder's obligation to purchase NEE common stock under the related stock purchase contract. If a successful remarketing does not occur on or before the third business day prior to the final settlement date, and a holder has not notified NEE of its intention to settle the stock purchase contract with cash, NEE would exercise its rights as a secured party in the debentures to satisfy in full the holders' obligations to purchase

NEE common stock under the related stock purchase contracts on the final settlement date. The debentures are fully and unconditionally guaranteed by NEE.

Prior to the issuance of NEE's common stock, the stock purchase contracts will be reflected in NEE's diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of NEE common stock used in calculating diluted earnings per share is deemed to be increased by the excess, if any, of the number of shares that would be issued upon settlement of the stock purchase contracts over the number of shares that could be purchased by NEE in the market, at the average market price during the period, using the proceeds receivable upon settlement.

13. Asset Retirement Obligations

FPL's ARO relates primarily to the nuclear decommissioning obligation of its nuclear units. FPL's AROs other than nuclear decommissioning are not significant. The accounting provisions result in timing differences in the recognition of legal asset retirement costs for financial reporting purposes and the method the FPSC allows FPL to recover in rates. NEER's ARO relates primarily to the nuclear decommissioning obligation of its nuclear plants and obligations for the dismantlement of its wind facilities located on leased property. See Note 1 - Decommissioning of Nuclear Plants, Dismantlement of Plants and Other Accrued Asset Removal Costs.

A rollforward of NEE's and FPL's ARO is as follows:

	FPL	NEER	NEE
		(millions)	
Balances, December 31, 2009	$ 1,833	$ 585	$ 2,418
Liabilities incurred	—	3	3
Accretion expense	101	36	137
Liabilities settled	—	(1)	(1)
Revision in estimated cash flows - net	(851) [a]	(67) [b]	(918)
Balances, December 31, 2010	1,083	556	1,639
Liabilities incurred	3	3	6
Accretion expense	58	31	89
Revision in estimated cash flows - net	—	(123) [c]	(123)
Balances, December 31, 2011	$ 1,144	$ 467	$ 1,611

(a) Primarily reflects the effect of a decrease in the escalation rates used to determine the ultimate projected costs of decommissioning FPL's nuclear units and lower costs due to the expected future reimbursement by the DOE of certain spent fuel storage costs as stipulated by a spent fuel settlement agreement.
(b) Primarily reflects the effect of revised probability assessments regarding when assets will be retired and ultimately decommissioned and lower costs due to the expected future reimbursement by the DOE of certain spent fuel storage costs as stipulated by a spent fuel settlement agreement.
(c) Primarily reflects the effect of revised cost estimates and probability assessments regarding when assets will be decommissioned.

Restricted funds for the payment of future expenditures to decommission NEE's and FPL's nuclear units included in special use funds on NEE's and FPL's consolidated balance sheets are as follows (see Note 5):

	FPL	NEER	NEE
		(millions)	
Balances, December 31, 2011	$ 2,612	$ 1,130	$ 3,742
Balances, December 31, 2010	$ 2,512	$ 1,105	$ 3,617

NEE and FPL have identified but not recognized ARO liabilities related to electric transmission and distribution and telecommunications assets resulting from easements over property not owned by NEE or FPL. In addition, NEE has identified but not recognized ARO liabilities related to the majority of NEER's hydro facilities. These easements are generally perpetual and, along with the hydro facilities, only require retirement action upon abandonment or cessation of use of the property or facility for its specified purpose. The ARO liability is not estimable for such easements and hydro facilities as NEE and FPL intend to use these properties and facilities indefinitely. In the event NEE and FPL decide to abandon or cease the use of a particular easement and/or hydro facility, an ARO liability would be recorded at that time.

14. Commitments and Contingencies

Commitments - NEE and its subsidiaries have made commitments in connection with a portion of their projected capital expenditures. Capital expenditures at FPL include, among other things, the cost for construction or acquisition of additional facilities and equipment to meet customer demand, as well as capital improvements to and maintenance of existing facilities and the procurement of nuclear fuel. At NEER, capital expenditures include, among other things, the cost, including capitalized interest, for construction of wind and solar projects and the procurement of nuclear fuel. Capital expenditures for Corporate and Other primarily include the cost for construction of a transmission line and other associated facilities by Lone Star Transmission, LLC (Lone Star), a rate-regulated transmission service provider in Texas, and the cost to meet customer-specific requirements and maintain the fiber-optic network for the fiber-optic telecommunications business (FPL FiberNet).

At December 31, 2011, estimated planned capital expenditures for 2012 through 2016 were as follows:

	2012	2013	2014	2015	2016	Total
			(millions)			
FPL:						
Generation:[a]						
New[b][c]	$ 1,780	$ 625	$ 85	$ —	$ —	$ 2,490
Existing	730	660	660	525	430	3,005
Transmission and distribution	830	705	690	660	705	3,590
Nuclear fuel	205	125	205	250	250	1,035
General and other	130	190	120	80	85	605
Total	$ 3,675	$ 2,305	$ 1,760	$ 1,515	$ 1,470	$ 10,725
NEER:						
Wind[d]	$ 1,490	$ 30	$ 20	$ 5	$ 5	$ 1,550
Solar[e]	1,435	715	145	45	—	2,340
Nuclear[f]	310	255	265	280	275	1,385
Other[g]	175	80	95	100	65	515
Total	$ 3,410	$ 1,080	$ 525	$ 430	$ 345	$ 5,790
Corporate and Other[h]	$ 530	$ 85	$ 85	$ 75	$ 75	$ 850

(a) Includes AFUDC of approximately $70 million, $87 million and $33 million in 2012 to 2014, respectively.
(b) Includes land, generating structures, transmission interconnection and integration and licensing.
(c) Consists of projects that have received FPSC approval. Includes pre-construction costs and carrying charges (equal to a pretax AFUDC rate) on construction costs recoverable through the capacity clause of approximately $109 million, $40 million and $2 million in 2012 to 2014, respectively. Excludes capital expenditures for the construction costs for the two additional nuclear units at FPL's Turkey Point site beyond what is required to receive an NRC license for each unit. Excludes capital expenditures for the modernization of the Port Everglades facility, which if the project proceeds and the required regulatory approvals are obtained is expected to cost approximately $1.2 billion and be placed in-service in 2016.
(d) Consists of capital expenditures for planned new wind projects that have received applicable internal approvals and related transmission. NEER plans to add new wind generation of approximately 1,150 mw to 1,500 mw in 2012, at a total cost of approximately $2 billion to $3 billion.
(e) Consists of capital expenditures for planned new solar projects totaling 665 mw that have received applicable internal approvals and related transmission, including equity contributions associated with an equity method investment in a 550 mw solar project. Excludes solar projects requiring internal approvals with generation totaling 270 mw with an estimated cost of approximately $1 billion.
(f) Includes nuclear fuel.
(g) Consists of capital expenditures that have received applicable internal approvals. NEER plans to add natural gas infrastructure projects at a total cost of approximately $400 million to $600 million in 2010 through 2014.
(h) Consists of capital expenditures that have received applicable internal approvals and includes AFUDC related to Lone Star of approximately $41 million and $14 million in 2012 and 2013, respectively.

These estimates are subject to continuing review and adjustment and actual capital expenditures may vary significantly from these estimates.

At December 31, 2011, subsidiaries of NEE, other than FPL, in the normal course of business, have guaranteed certain debt service and fuel payments of non-consolidated entities. The terms of the guarantees relating to the non-consolidated entities are equal to the terms of the related agreements, with remaining terms ranging from less than one year to six years. The maximum potential amount of future payments that could be required under these guarantees at December 31, 2011 was approximately $50 million. At December 31, 2011, NEE did not have any liabilities recorded for these guarantees. In certain instances, NEE can seek recourse from third parties for amounts paid under the guarantees. At December 31, 2011, the fair value of the guarantees was not material. In addition to the guarantees relating to non-consolidated entities, NEE has guaranteed certain payment obligations of NEECH, including most payment obligations under NEECH's debt and guarantees.

Contracts - In addition to the estimated planned capital expenditures included in the table in Commitments above, FPL has commitments under long-term purchased power and fuel contracts. FPL is obligated under take-or-pay purchased power contracts with JEA and with subsidiaries of The Southern Company (Southern subsidiaries) to pay for approximately 1,330 mw annually through 2015 and 375 mw annually thereafter through 2021. FPL also has various firm pay-for-performance contracts to purchase approximately 705 mw from certain cogenerators and small power producers (qualifying facilities) with expiration dates ranging from 2024 through 2034. The purchased power contracts provide for capacity and energy payments. Energy payments are based on the actual power taken under these contracts. Capacity payments for the pay-for-performance contracts are subject to the qualifying facilities meeting certain contract conditions. FPL has one agreement with an electricity supplier to purchase approximately 155 mw of power with an expiration date of May 2012. In general, the agreement requires FPL to make a capacity payment and supply the fuel consumed by the plant under the contract. FPL has contracts with expiration dates through 2036 for the purchase and transportation of natural gas and coal, and storage of natural gas.

NEER has entered into contracts primarily for the purchase of wind turbines and towers, solar reflectors, steam turbine generators and heat collection elements and related construction and development activities, as well as for the supply of uranium, conversion, enrichment and fabrication of nuclear fuel, with expiration dates ranging from March 2012 through 2031, approximately $2.6 billion of which is included in the estimated planned capital expenditures table in Commitments above. In addition, NEER has contracts primarily for the purchase, transportation and storage of natural gas and firm transmission service with expiration dates ranging from March 2012 through 2033.

The transmission business included in Corporate and Other has entered into contracts primarily for development and construction activities relating to Lone Star's transmission line and other associated facilities, all of which is included in the estimated planned capital expenditures table in Commitments above.

The required capacity and/or minimum payments under the contracts discussed above as of December 31, 2011 were estimated as follows:

	2012	2013	2014	2015	2016	Thereafter
	(millions)					
FPL:						
Capacity charges:[a]						
Qualifying facilities	$ 295	$ 270	$ 275	$ 280	$ 240	$ 2,395
JEA and Southern subsidiaries	$ 225	$ 225	$ 205	$ 180	$ 55	$ 145
Other electricity suppliers	$ 5	$ —	$ —	$ —	$ —	$ —
Minimum charges, at projected prices:						
Natural gas, including transportation and storage[b]	$ 1,705	$ 925	$ 575	$ 565	$ 525	$ 6,925
Coal[b]	$ 80	$ 85	$ 30	$ 5	$ 5	$ 5
NEER[c]	$ 1,970	$ 475	$ 140	$ 110	$ 100	$ 590
Corporate and Other	$ 250	$ 15	$ —	$ —	$ —	$ —

(a) Capacity charges under these contracts, substantially all of which are recoverable through the capacity clause, totaled approximately $511 million, $537 million and $603 million for the years ended December 31, 2011, 2010 and 2009, respectively. Energy charges under these contracts, which are recoverable through the fuel clause, totaled approximately $403 million, $434 million and $439 million for the years ended December 31, 2011, 2010 and 2009, respectively.
(b) Recoverable through the fuel clause.
(c) Includes termination payments associated with wind turbine contracts for projects that have not yet received applicable internal approvals.

Insurance - Liability for accidents at nuclear power plants is governed by the Price-Anderson Act, which limits the liability of nuclear reactor owners to the amount of insurance available from both private sources and an industry retrospective payment plan. In accordance with this Act, NEE maintains $375 million of private liability insurance per site, which is the maximum obtainable, and participates in a secondary financial protection system, which provides up to $12.2 billion of liability insurance coverage per incident at any nuclear reactor in the United States. Under the secondary financial protection system, NEE is subject to retrospective assessments of up to $940 million ($470 million for FPL), plus any applicable taxes, per incident at any nuclear reactor in the United States, payable at a rate not to exceed $140 million ($70 million for FPL) per incident per year. NEE and FPL are contractually entitled to recover a proportionate share of such assessments from the owners of minority interests in Seabrook, Duane Arnold and St. Lucie Unit No. 2, which approximates $14 million, $35 million and $18 million, plus any applicable taxes, per incident, respectively.

NEE participates in a nuclear insurance mutual company that provides $2.75 billion of limited insurance coverage per occurrence per site for property damage, decontamination and premature decommissioning risks at its nuclear plants. The proceeds from such insurance, however, must first be used for reactor stabilization and site decontamination before they can be used for plant repair. NEE

also participates in an insurance program that provides limited coverage for replacement power costs if a nuclear plant is out of service for an extended period of time because of an accident. In the event of an accident at one of NEE's or another participating insured's nuclear plants, NEE could be assessed up to $165 million ($93 million for FPL), plus any applicable taxes, in retrospective premiums in a policy year. NEE and FPL are contractually entitled to recover a proportionate share of such assessments from the owners of minority interests in Seabrook, Duane Arnold and St. Lucie Unit No. 2, which approximates $2 million, $4 million and $3 million, plus any applicable taxes, respectively.

Due to the high cost and limited coverage available from third-party insurers, NEE does not have insurance coverage for a substantial portion of its transmission and distribution property and has no insurance coverage for FPL FiberNet's fiber-optic cable. Should FPL's future storm restoration costs exceed the reserve amount established through the issuance of storm-recovery bonds by a VIE in 2007, FPL may recover storm restoration costs, subject to prudence review by the FPSC, either through surcharges approved by the FPSC or through securitization provisions pursuant to Florida law.

In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers in the case of FPL, would be borne by NEE and FPL and could have a material adverse effect on NEE's and FPL's financial condition, results of operations and liquidity.

Legal Proceedings - In November 1999, the Attorney General of the United States, on behalf of the U.S. Environmental Protection Agency (EPA), brought an action in the U.S. District Court for the Northern District of Georgia against Georgia Power Company and other subsidiaries of The Southern Company for certain alleged violations of the Prevention of Significant Deterioration (PSD) provisions and the New Source Performance Standards (NSPS) of the Clean Air Act. In May 2001, the EPA amended its complaint to allege, among other things, that Georgia Power Company constructed and is continuing to operate Scherer Unit No. 4, in which FPL owns a 76% interest, without obtaining a PSD permit, without complying with NSPS requirements, and without applying best available control technology for nitrogen oxides, sulfur dioxides and particulate matter as required by the Clean Air Act. It also alleges that unspecified major modifications have been made at Scherer Unit No. 4 that require its compliance with the aforementioned Clean Air Act provisions. The EPA seeks injunctive relief requiring the installation of best available control technology and civil penalties. Under the EPA's civil penalty rules, the EPA could assess up to $25,000 per day for each violation from an unspecified date after June 1, 1975 through January 30, 1997, up to $27,500 per day for each violation from January 31, 1997 through March 15, 2004, up to $32,500 per day for each violation from March 16, 2004 through January 12, 2009 and up to $37,500 per day for each violation thereafter. Georgia Power Company has answered the amended complaint, asserting that it has complied with all requirements of the Clean Air Act, denying the plaintiff's allegations of liability, denying that the plaintiff is entitled to any of the relief that it seeks and raising various other defenses. In June 2001, a federal district court stayed discovery and administratively closed the case and the EPA has not yet moved to reopen the case. In April 2007, the U.S. Supreme Court in a separate unrelated case rejected an argument that a "major modification" occurs at a plant only when there is a resulting increase in the hourly rate of air emissions. Georgia Power Company has made a similar argument in defense of its case, but has other factual and legal defenses that are unaffected by the U.S. Supreme Court's decision.

In 1995 and 1996, NEE, through an indirect subsidiary, purchased from Adelphia Communications Corporation (Adelphia) 1,091,524 shares of Adelphia common stock and 20,000 shares of Adelphia preferred stock (convertible into 2,358,490 shares of Adelphia common stock) for an aggregate price of approximately $35,900,000. On January 29, 1999, Adelphia repurchased all of these shares for $149,213,130 in cash. In June 2004, Adelphia, Adelphia Cablevision, L.L.C. and the Official Committee of Unsecured Creditors of Adelphia filed a complaint against NEE and its indirect subsidiary in the U.S. Bankruptcy Court, Southern District of New York. The complaint alleges that the repurchase of these shares by Adelphia was a fraudulent transfer, in that at the time of the transaction Adelphia (i) was insolvent or was rendered insolvent, (ii) did not receive reasonably equivalent value in exchange for the cash it paid, and (iii) was engaged or about to engage in a business or transaction for which any property remaining with Adelphia had unreasonably small capital. The complaint seeks the recovery for the benefit of Adelphia's bankruptcy estate of the cash paid for the repurchased shares, plus interest from January 29, 1999. NEE has filed an answer to the complaint. NEE believes that the complaint is without merit because, among other reasons, Adelphia will be unable to demonstrate that (i) Adelphia's repurchase of shares from NEE, which repurchase was at the market value for those shares, was not for reasonably equivalent value, (ii) Adelphia was insolvent at the time of the repurchase, or (iii) the repurchase left Adelphia with unreasonably small capital. The case has been scheduled for trial in April 2012.

In October 2004, TXU Portfolio Management Company (TXU) served FPL Energy Pecos Wind I, LP, FPL Energy Pecos Wind I GP, LLC, FPL Energy Pecos Wind II, LP, FPL Energy Pecos Wind II GP, LLC and Indian Mesa Wind Farm, LP (NEER Affiliates) as defendants in a civil action filed in the District Court in Dallas County, Texas. FPL Energy, LLC, now known as NextEra Energy Resources, LLC, was added as a defendant in 2005. The petition alleged that the NEER Affiliates had contractual obligations to produce and sell to TXU a minimum quantity of energy and renewable energy credits each year during the period from 2002 through 2005 and that the NEER Affiliates failed to meet this obligation. The plaintiff asserted claims for breach of contract and declaratory judgment and sought damages of approximately $34 million. Following a jury trial in 2007, among other findings, both TXU and the NEER Affiliates were found to have breached the contracts. In August 2008, the trial court issued a final judgment holding that the contracts were not terminated and neither party was entitled to recover any damages. In November 2008, TXU appealed the final judgment to the Fifth District Court of Appeals in Dallas, Texas. In an opinion issued in July 2010, the appellate court reversed portions of the trial court's judgment, ruling that the contracts' liquidated damage provision is an enforceable liquidated damage

clause. The appellate court ordered that the case be remanded back to the trial court for further proceedings to determine the amount of damages payable by the NEER Affiliates. The NEER Affiliates filed a motion for rehearing of the appellate court's decision, which motion was denied, and in April 2011 filed a petition for review of the appellate court decision with the Texas Supreme Court. In February 2012, the Texas Supreme Court granted the petition for review and will be scheduling the case for oral argument.

NEE and FPL are vigorously defending, and believe that they or their affiliates have meritorious defenses to, the lawsuits described above. In addition to the legal proceedings discussed above, NEE and its subsidiaries, including FPL, are involved in other legal and regulatory proceedings, actions and claims in the ordinary course of their businesses. Generating plants in which NEE or FPL has an ownership interest are also involved in legal and regulatory proceedings, actions and claims, the liabilities from which, if any, would be shared by NEE or FPL. In the event that NEE and FPL, or their affiliates, do not prevail in the lawsuits described above or these other legal and regulatory proceedings, actions and claims, there may be a material adverse effect on their financial statements. While management is unable to predict with certainty the outcome of the lawsuits described above or these other legal and regulatory proceedings, actions and claims, based on current knowledge it is not expected that their ultimate resolution, individually or collectively, will have a material adverse effect on the financial statements of NEE or FPL.

15. Segment Information

NEE's reportable segments are FPL, a rate-regulated electric utility, and NEER, a competitive energy business. NEER's segment information includes an allocation of interest expense from NEECH based on a deemed capital structure of 70% debt and allocated shared service costs. Corporate and Other represents other business activities, other segments that are not separately reportable and eliminating entries. NEE's operating revenues derived from the sale of electricity represented approximately 95%, 95% and 98% of NEE's operating revenues for the years ended December 31, 2011, 2010 and 2009. Less than 1% of operating revenues were from foreign sources for each of the three years ended December 31, 2011, 2010 and 2009. At December 31, 2011 and 2010, approximately 2% and 1%, respectively, of long-lived assets were located in foreign countries.

NEE's segment information is as follows:

	2011				2010				2009			
	FPL	NEER[a]	Corp. and Other	Total	FPL	NEER[a]	Corp. and Other	Total	FPL	NEER[a]	Corp. and Other	Total
	(millions)											
Operating revenues	$10,613	$ 4,502	$ 226	$15,341	$10,485	$ 4,636	$ 196	$15,317	$11,491	$ 3,997	$ 155	$15,643
Operating expenses[b]	$ 8,537	$ 3,233	$ 193	$11,963	$ 8,636	$ 3,286	$ 152	$12,074	$ 9,910	$ 3,024	$ 115	$13,049
Interest expense	$ 387	$ 530	$ 118	$ 1,035	$ 361	$ 515	$ 103	$ 979	$ 318	$ 460	$ 71	$ 849
Interest income	$ 3	$ 23	$ 53	$ 79	$ —	$ 21	$ 70	$ 91	$ 1	$ 23	$ 54	$ 78
Depreciation and amortization	$ 798	$ 736	$ 33	$ 1,567	$ 1,008	$ 759	$ 21	$ 1,788	$ 1,097	$ 651	$ 17	$ 1,765
Equity in earnings of equity method investees	$ —	$ 55	$ —	$ 55	$ —	$ 58	$ —	$ 58	$ —	$ 52	$ —	$ 52
Income tax expense (benefit)[c][d]	$ 654	$ (24)	$ (101)	$ 529	$ 580	$ (11)	$ (37)	$ 532	$ 473	$ (158)	$ 12	$ 327
Net income (loss)[b][e]	$ 1,068	$ 774	$ 81	$ 1,923	$ 945	$ 980	$ 32	$ 1,957	$ 831	$ 759	$ 25	$ 1,615
Capital expenditures, independent power and other investments and nuclear fuel purchases	$ 3,502	$ 2,774	$ 352	$ 6,628	$ 2,706	$ 3,072	$ 68	$ 5,846	$ 2,717	$ 3,235	$ 54	$ 6,006
Property, plant and equipment	$35,170	$ 21,482	$ 900	$57,552	$32,423	$ 21,304	$ 494	$54,221	$30,982	$ 18,844	$ 343	$50,169
Accumulated depreciation and amortization	$10,916	$ 3,914	$ 232	$15,062	$10,871	$ 4,073	$ 202	$15,146	$10,578	$ 3,341	$ 172	$14,091
Total assets	$31,816	$ 23,459	$ 1,913	$57,188	$28,698	$ 22,389	$ 1,907	$52,994	$26,812	$ 20,136	$ 1,510	$48,458
Investment in equity method investees	$ —	$ 193	$ 9	$ 202	$ —	$ 217	$ 10	$ 227	$ —	$ 173	$ 10	$ 183

(a) Interest expense allocated from NEECH to NEER is based on a deemed capital structure of 70% debt. For this purpose, the deferred credit associated with differential membership interests sold by NEER subsidiaries is included with debt. Residual non-utility interest expense is included in Corporate and Other.
(b) In 2011, NEER includes impairment charges of approximately $51 million ($31 million after-tax). See Note 4 - Nonrecurring Fair Value Measurements.
(c) NEER includes PTCs that were recognized based on its tax sharing agreement with NEE. See Note 1 - Income Taxes.
(d) In 2011, Corporate and Other includes state deferred income tax benefits of approximately $64 million, net of federal income taxes, related to state tax law changes and an income tax benefit of $41 million related to the dissolution of a subsidiary.
(e) In 2011, NEER and Corporate and Other include an after-tax loss on sale of natural gas-fired generating assets of $92 million and $6 million, respectively. See Note 4 - Nonrecurring Fair Value Measurements.

16. Summarized Financial Information of NEECH

NEECH, a 100% owned subsidiary of NEE, provides funding for, and holds ownership interests in, NEE's operating subsidiaries other than FPL. Most of NEECH's debt, including its debentures, and payment guarantees are fully and unconditionally guaranteed by NEE. Condensed consolidating financial information is as follows:

Condensed Consolidating Statements of Income

	Year Ended December 31, 2011				Year Ended December 31, 2010				Year Ended December 31, 2009			
	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated
	(millions)											
Operating revenues	$ —	$ 4,740	$10,601	$ 15,341	$ —	$ 4,843	$10,474	$ 15,317	$ —	$ 4,164	$11,479	$ 15,643
Operating expenses	(15)	(3,423)	(8,525)	(11,963)	(4)	(3,446)	(8,624)	(12,074)	—	(3,151)	(9,898)	(13,049)
Interest expense	(14)	(645)	(376)	(1,035)	(15)	(618)	(346)	(979)	(17)	(531)	(301)	(849)
Equity in earnings of subsidiaries	1,878	—	(1,878)	—	1,931	—	(1,931)	—	1,618	—	(1,618)	—
Other income (deductions) - net	1	85	23	109	16	188	21	225	14	160	23	197
Income (loss) before income taxes	1,850	757	(155)	2,452	1,928	967	(406)	2,489	1,615	642	(315)	1,942
Income tax expense (benefit)	(73)	(53)	655	529	(29)	(19)	580	532	—	(145)	472	327
Net income (loss)	$ 1,923	$ 810	$ (810)	$ 1,923	$ 1,957	$ 986	$ (986)	$ 1,957	$ 1,615	$ 787	$ (787)	$ 1,615

(a) Represents FPL and consolidating adjustments.

Condensed Consolidating Balance Sheets

	December 31, 2011				December 31, 2010			
	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated
	(millions)							
PROPERTY, PLANT AND EQUIPMENT								
Electric utility plant in service and other property	$ 31	$ 22,351	$ 35,170	$ 57,552	$ 19	$ 21,779	$ 32,423	$ 54,221
Less accumulated depreciation and amortization	(3)	(4,143)	(10,916)	(15,062)	—	(4,275)	(10,871)	(15,146)
Total property, plant and equipment - net	28	18,208	24,254	42,490	19	17,504	21,552	39,075
CURRENT ASSETS								
Cash and cash equivalents	1	339	37	377	—	282	20	302
Receivables	84	1,026	692	1,802	654	1,380	548	2,582
Other	5	1,075	1,613	2,693	9	1,024	1,341	2,374
Total current assets	90	2,440	2,342	4,872	663	2,686	1,909	5,258
OTHER ASSETS								
Investment in subsidiaries	14,879	—	(14,879)	—	14,150	—	(14,150)	—
Other	513	4,849	4,464	9,826	365	3,845	4,451	8,661
Total other assets	15,392	4,849	(10,415)	9,826	14,515	3,845	(9,699)	8,661
TOTAL ASSETS	$ 15,510	$ 25,497	$ 16,181	$ 57,188	$ 15,197	$ 24,035	$ 13,762	$ 52,994
CAPITALIZATION								
Common shareholders' equity	$ 14,943	$ 4,030	$ (4,030)	$ 14,943	$ 14,461	$ 4,359	$ (4,359)	$ 14,461
Long-term debt	—	13,327	7,483	20,810	—	11,331	6,682	18,013
Total capitalization	14,943	17,357	3,453	35,753	14,461	15,690	2,323	32,474
CURRENT LIABILITIES								
Debt due within one year	—	1,778	379	2,157	—	2,664	145	2,809
Accounts payable	—	512	679	1,191	—	571	553	1,124
Other	250	1,520	1,601	3,371	352	1,361	1,258	2,971
Total current liabilities	250	3,810	2,659	6,719	352	4,596	1,956	6,904
OTHER LIABILITIES AND DEFERRED CREDITS								
Asset retirement obligations	—	466	1,145	1,611	—	556	1,083	1,639
Accumulated deferred income taxes	68	1,376	4,237	5,681	53	1,336	3,720	5,109
Other	249	2,488	4,687	7,424	331	1,857	4,680	6,868
Total other liabilities and deferred credits	317	4,330	10,069	14,716	384	3,749	9,483	13,616
COMMITMENTS AND CONTINGENCIES								
TOTAL CAPITALIZATION AND LIABILITIES	$ 15,510	$ 25,497	$ 16,181	$ 57,188	$ 15,197	$ 24,035	$ 13,762	$ 52,994

(a) Represents FPL and consolidating adjustments.

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2011				Year Ended December 31, 2010				Year Ended December 31, 2009			
	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated	NEE (Guarantor)	NEECH	Other[a]	NEE Consolidated
	(millions)											
CASH FLOWS FROM OPERATING ACTIVITIES												
Dividends from FPL	$ 400	$ —	$ (400)	$ —	$ 250	$ —	$ (250)	$ —	$ 485	$ —	$ (485)	$ —
Dividends from NEECH	898	—	(898)	—	970	—	(970)	—	25	—	(25)	—
Other	383	1,446	2,245	4,074	(42)	1,940	1,936	3,834	81	1,513	2,869	4,463
Net cash provided by operating activities	1,681	1,446	947	4,074	1,178	1,940	716	3,834	591	1,513	2,359	4,463
CASH FLOWS FROM INVESTING ACTIVITIES												
Capital expenditures, independent power and other investments and nuclear fuel purchases	(16)	(3,109)	(3,503)	(6,628)	—	(3,140)	(2,706)	(5,846)	—	(3,289)	(2,717)	(6,006)
Capital contribution to FPL	(410)	—	410	—	(660)	—	660	—	—	—	—	—
Cash grants under the Recovery Act	—	406	218	624	—	428	160	588	—	100	—	100
Sale of natural gas-fired generating assets	—	1,204	—	1,204	—	—	—	—	—	—	—	—
Loan proceeds restricted for construction	—	(565)	—	(565)	—	—	—	—	—	—	—	—
Other - net	16	60	10	86	—	5	(31)	(26)	(7)	1	(23)	(29)
Net cash used in investing activities	(410)	(2,004)	(2,865)	(5,279)	(660)	(2,707)	(1,917)	(5,284)	(7)	(3,188)	(2,740)	(5,935)
CASH FLOWS FROM FINANCING ACTIVITIES												
Issuances of long-term debt	—	3,100	840	3,940	—	2,800	924	3,724	—	2,704	516	3,220
Retirements of long-term debt	—	(2,076)	(45)	(2,121)	—	(727)	(42)	(769)	—	(1,371)	(264)	(1,635)
Proceeds from sale of differential membership interests	—	466	—	466	—	261	—	261	—	—	—	—
Net change in short-term debt	—	231	229	460	—	(414)	(716)	(1,130)	—	110	44	154
Dividends on common stock	(920)	—	—	(920)	(823)	—	—	(823)	(766)	—	—	(766)
Dividends to NEE[b]	—	(898)	898	—	—	(970)	970	—	—	(25)	25	—
Other - net	(350)	(208)	13	(545)	305	(57)	3	251	182	(1)	21	202
Net cash provided by (used in) financing activities	(1,270)	615	1,935	1,280	(518)	893	1,139	1,514	(584)	1,417	342	1,175
Net increase (decrease) in cash and cash equivalents	1	57	17	75	—	126	(62)	64	—	(258)	(39)	(297)
Cash and cash equivalents at beginning of year	—	282	20	302	—	156	82	238	—	414	121	535
Cash and cash equivalents at end of year	$ 1	$ 339	$ 37	$ 377	$ —	$ 282	$ 20	$ 302	$ —	$ 156	$ 82	$ 238

(a) Represents FPL and consolidating adjustments.
(b) Other column also includes cash dividends from FPL to NEE of $400 million, $250 million and $485 million, respectively, and corresponding consolidating adjustments.

17. Quarterly Data (Unaudited)

Condensed consolidated quarterly financial information is as follows:

	March 31(a)	June 30(a)	September 30(a)	December 31(a)
	(millions, except per share amounts)			
NEE:				
2011				
Operating revenues[b]	$ 3,134	$ 3,961	$ 4,382	$ 3,864
Operating income[b]	$ 428	$ 907	$ 911	$ 1,132
Net income[b]	$ 268	$ 580	$ 407	$ 667
Earnings per share[c]	$ 0.64	$ 1.39	$ 0.98	$ 1.60
Earnings per share - assuming dilution[c]	$ 0.64	$ 1.38	$ 0.97	$ 1.59
Dividends per share	$ 0.55	$ 0.55	$ 0.55	$ 0.55
High-low common stock sales prices	$55.86 - 51.54	$58.98 - 54.16	$58.25 - 49.00	$61.20 - 51.33
2010				
Operating revenues[b]	$ 3,622	$ 3,591	$ 4,691	$ 3,413
Operating income[b]	$ 939	$ 709	$ 1,125	$ 469
Net income[b]	$ 556	$ 417	$ 720	$ 263
Earnings per share[c]	$ 1.36	$ 1.02	$ 1.75	$ 0.64
Earnings per share - assuming dilution[c]	$ 1.36	$ 1.01	$ 1.74	$ 0.63
Dividends per share	$ 0.50	$ 0.50	$ 0.50	$ 0.50
High-low common stock sales prices	$53.75 - 45.29	$53.50 - 47.96	$55.98 - 48.44	$56.26 - 50.00
FPL:				
2011				
Operating revenues[b]	$ 2,246	$ 2,801	$ 3,152	$ 2,414
Operating income[b]	$ 406	$ 571	$ 656	$ 442
Net income[b]	$ 205	$ 301	$ 347	$ 216
2010				
Operating revenues[b]	$ 2,328	$ 2,580	$ 3,116	$ 2,461
Operating income[b]	$ 393	$ 501	$ 584	$ 371
Net income[b]	$ 191	$ 265	$ 308	$ 181

(a) In the opinion of NEE and FPL, all adjustments, which consist of normal recurring accruals necessary to present a fair statement of the amounts shown for such periods, have been made. Results of operations for an interim period generally will not give a true indication of results for the year.
(b) The sum of the quarterly amounts may not equal the total for the year due to rounding.
(c) The sum of the quarterly amounts may not equal the total for the year due to rounding and changes in weighted-average number of common shares outstanding.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As of December 31, 2011, each of NEE and FPL had performed an evaluation, under the supervision and with the participation of its management, including NEE's and FPL's chief executive officer and chief financial officer, of the effectiveness of the design and operation of each company's disclosure controls and procedures (as defined in the Securities Exchange Act of 1934 Rule 13a-15 (e) or 15d-15(e)). Based upon that evaluation, the chief executive officer and chief financial officer of each of NEE and FPL concluded that the company's disclosure controls and procedures were effective as of December 31, 2011.

Internal Control Over Financial Reporting

(a) Management's Annual Report on Internal Control Over Financial Reporting

See Item 8. Financial Statements and Supplementary Data.

(b) Attestation Report of the Independent Registered Public Accounting Firm

See Item 8. Financial Statements and Supplementary Data.

(c) Changes in Internal Control Over Financial Reporting

NEE and FPL are continuously seeking to improve the efficiency and effectiveness of their operations and of their internal controls. This results in refinements to processes throughout NEE and FPL. However, there has been no change in NEE's or FPL's internal control over financial reporting that occurred during NEE's and FPL's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, NEE's or FPL's internal control over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item will be included under the headings "Business of the Annual Meeting," "Corporate Governance and Board Matters" and "Information About NextEra Energy and Management" in NEE's Proxy Statement which will be filed with the SEC in connection with the 2012 Annual Meeting of Shareholders (NEE's Proxy Statement) and is incorporated herein by reference, or is included in Item 1. Business - Executive Officers of NEE.

NEE has adopted the NextEra Energy, Inc. Code of Ethics for Senior Executive and Financial Officers (the Senior Financial Executive Code), which is applicable to the chief executive officer, the chief financial officer, the chief accounting officer and other senior executive and financial officers. The Senior Financial Executive Code is available under Corporate Governance in the Investor Relations section of NEE's internet website at www.nexteraenergy.com. Any amendments to, or waivers of any provision of, the Senior Financial Executive Code which are required to be disclosed to shareholders under applicable SEC rules will be disclosed on the NEE website at the address listed above within the time period required under SEC rules from time to time.

Item 11. Executive Compensation

The information required by this item will be included in NEE's Proxy Statement under the headings "Executive Compensation" and "Corporate Governance and Board Matters" and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item relating to security ownership of certain beneficial owners and management will be included in NEE's Proxy Statement under the heading "Information About NextEra Energy and Management" and is incorporated herein by reference.

Securities Authorized For Issuance Under Equity Compensation Plans

NEE's equity compensation plan information as of December 31, 2011 is as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	6,999,099 [(a)]	$ 42.64 [(b)]	14,549,515
Equity compensation plans not approved by security holders[(c)]	2,523	$ 27.11	—
Total	7,001,622	$ 42.63 [(b)]	14,549,515

(a) Includes an aggregate of 4,385,865 outstanding options, 2,197,680 unvested performance share awards (at maximum payout), 287,201 deferred fully vested performance shares and 102,813 deferred stock awards (including future reinvested dividends) under the former LTIP and 25,540 fully vested shares deferred by directors under the NextEra Energy, Inc. 2007 Non-Employee Directors Stock Plan and its predecessor, the FPL Group, Inc. Amended and Restated Non-Employee Directors Stock Plan at December 31, 2011.

(b) Relates to outstanding options only.

(c) Represents options granted by Gexa Corp. under its Amended and Restated 2004 Incentive Plan and pursuant to various individual grants, all of which were made prior to NEE's acquisition of Gexa Corp. All such options were assumed by NEE in connection with the acquisition of Gexa Corp. and are fully vested and exercisable for shares of NEE common stock. No further grants of stock options will be made under this plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item, to the extent applicable, will be included in NEE's Proxy Statement under the heading "Corporate Governance and Board Matters" and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

NEE - The information required by this item will be included in NEE's Proxy Statement under the heading "Audit-Related Matters" and is incorporated herein by reference.

FPL - The following table presents fees billed for professional services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, Deloitte & Touche) for the fiscal years ended December 31, 2011 and 2010. The amounts presented below reflect allocations from NEE for FPL's portion of the fees, as well as amounts billed directly to FPL.

	2011	2010
Audit fees[(a)]	$ 3,109,000	$ 2,724,000
Audit-related fees[(b)]	327,000	423,000
Tax fees[(c)]	130,000	33,000
All other fees[(d)]	16,000	197,000
Total	$ 3,582,000	$ 3,377,000

(a) Audit fees consist of fees billed for professional services rendered for the audit of FPL's and NEE's annual consolidated financial statements for the fiscal year, the reviews of the financial statements included in FPL's and NEE's Quarterly Reports on Form 10-Q for the fiscal year and the audit of the effectiveness of internal control over financial reporting, comfort letters, consents, and other services related to SEC matters, services in connection with annual and semi-annual filings of NEE's financial statements with the Japanese Ministry of Finance and accounting consultations to the extent necessary for Deloitte & Touche to fulfill its responsibility under Public Company Accounting Oversight Board standards.

(b) Audit-related fees consist of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of FPL's and NEE's consolidated financial statements and are not reported under audit fees. These fees primarily related to audits of subsidiary financial statements, comfort letters, consents and other services related to subsidiary (non-SEC registrant) financing activities, consultation on accounting standards and on transactions, agreed-upon procedures, attestation services and examinations related to applications for government grants.

(c) Tax fees consist of fees billed for professional services rendered for tax compliance, tax advice and tax planning. In 2011, $32,000 of tax fees paid related to tax compliance services and $98,000 related to tax advice and planning services. In 2010, all tax fees paid related to tax compliance services.

(d) All other fees consist of fees for products and services other than the services reported under the other named categories. In 2011, these fees related to training and an assessment of the record management processes. In 2010, these fees related to training and to the reviews of a government grant process and enterprise risk management reporting.

In accordance with the requirements of Sarbanes-Oxley Act of 2002, the Audit Committee Charter and the Audit Committee's pre-approval policy for services provided by the independent registered public accounting firm, all services performed by Deloitte & Touche are approved in advance by the Audit Committee, except for audits of certain trust funds where the fees are paid by the trust. Audit and audit-related services specifically identified in an appendix to the pre-approval policy are pre-approved by the Audit Committee each year. This pre-approval allows management to request the specified audit and audit-related services on an as-needed basis during the year, provided any such services are reviewed with the Audit Committee at its next regularly scheduled meeting. Any audit or audit-related service for which the fee is expected to exceed $250,000, or that involves a service not listed on the pre-approval list, must be specifically approved by the Audit Committee prior to commencement of such service. In addition, the Audit Committee approves all services other than audit and audit-related services performed by Deloitte & Touche in advance of the commencement of such work. The Audit Committee has delegated to the Chair of the committee the right to approve audit, audit-related, tax and other services, within certain limitations, between meetings of the Audit Committee, provided any such decision is presented to the Audit Committee at its next regularly scheduled meeting. At each Audit Committee meeting (other than meetings held to review earnings materials), the Audit Committee reviews a schedule of services for which Deloitte & Touche has been engaged since the prior Audit Committee meeting under existing pre-approvals and the estimated fees for those services. In 2011 and 2010, none of the amounts presented above represent services provided to NEE or FPL by Deloitte & Touche that were approved by the Audit Committee after services were rendered pursuant to Rule 2-01(c)(7)(i)(C) of Regulation S-X (which provides for a waiver of the otherwise applicable pre-approval requirement if certain conditions are met).

PART IV

Item 15. Exhibits, Financial Statement Schedules

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2. Financial Statement Schedules - Schedules are omitted as not applicable or not required.

3. Exhibits (including those incorporated by reference)

Certain exhibits listed below refer to "FPL Group" and "FPL Group Capital," and were effective prior to the change of the name FPL Group, Inc. to NextEra Energy, Inc., and of the name FPL Group Capital Inc to NextEra Energy Capital Holdings, Inc., during 2010.

Exhibit Number	Description	NEE	FPL
*3(i)a	Restated Articles of Incorporation of NEE (filed as Exhibit 3(i) to Form 10-Q for the quarter ended June 30, 2010, File No. 1-8841)	x	
*3(i)b	Restated Articles of Incorporation of FPL (filed as Exhibit 3(i)b to Form 10-K for the year ended December 31, 2010, File No. 2-27612)		x
*3(ii)a	Amended and Restated Bylaws of NEE, as amended through May 21, 2010 (filed as Exhibit 3(ii) to Form 10-Q for the quarter ended June 30, 2010, File No. 1-8841)	x	
*3(ii)b	Amended and Restated Bylaws of FPL, as amended through October 17, 2008 (filed as Exhibit 3(ii)b to Form 10-Q for the quarter ended September 30, 2008, File No. 2-27612)		x

Exhibit Number	Description	NEE	FPL
*4(a)	Mortgage and Deed of Trust dated as of January 1, 1944, and One hundred and eighteen Supplements thereto, between FPL and Deutsche Bank Trust Company Americas, Trustee (filed as Exhibit B-3, File No. 2-4845; Exhibit 7(a), File No. 2-7126; Exhibit 7(a), File No. 2-7523; Exhibit 7(a), File No. 2-7990; Exhibit 7(a), File No. 2-9217; Exhibit 4(a)-5, File No. 2-10093; Exhibit 4(c), File No. 2-11491; Exhibit 4(b)-1, File No. 2-12900; Exhibit 4(b)-1, File No. 2-13255; Exhibit 4(b)-1, File No. 2-13705; Exhibit 4 (b)-1, File No. 2-13925; Exhibit 4(b)-1, File No. 2-15088; Exhibit 4(b)-1, File No. 2-15677; Exhibit 4(b)-1, File No. 2-20501; Exhibit 4(b)-1, File No. 2-22104; Exhibit 2 (c), File No. 2-23142; Exhibit 2(c), File No. 2-24195; Exhibit 4(b)-1, File No. 2-25677; Exhibit 2(c), File No. 2-27612; Exhibit 2(c), File No. 2-29001; Exhibit 2(c), File No. 2-30542; Exhibit 2(c), File No. 2-33038; Exhibit 2(c), File No. 2-37679; Exhibit 2 (c), File No. 2-39006; Exhibit 2(c), File No. 2-41312; Exhibit 2(c), File No. 2-44234; Exhibit 2(c), File No. 2-46502; Exhibit 2(c), File No. 2-48679; Exhibit 2(c), File No. 2-49726; Exhibit 2(c), File No. 2-50712; Exhibit 2(c), File No. 2-52826; Exhibit 2(c), File No. 2-53272; Exhibit 2(c), File No. 2-54242; Exhibit 2(c), File No. 2-56228; Exhibits 2(c) and 2(d), File No. 2-60413; Exhibits 2(c) and 2(d), File No. 2-65701; Exhibit 2(c), File No. 2-66524; Exhibit 2(c), File No. 2-67239; Exhibit 4(c), File No. 2-69716; Exhibit 4(c), File No. 2-70767; Exhibit 4(b), File No. 2-71542; Exhibit 4(b), File No. 2-73799; Exhibits 4(c), 4(d) and 4(e), File No. 2-75762; Exhibit 4(c), File No. 2-77629; Exhibit 4(c), File No. 2-79557; Exhibit 99(a) to Post-Effective Amendment No. 5 to Form S-8, File No. 33-18669; Exhibit 99(a) to Post-Effective Amendment No. 1 to Form S-3, File No. 33-46076; Exhibit 4(b) to Form 10-K for the year ended December 31, 1993, File No. 1-3545; Exhibit 4(i) to Form 10-Q for the quarter ended June 30, 1994, File No. 1-3545; Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 1995, File No. 1-3545; Exhibit 4(a) to Form 10-Q for the quarter ended March 31,1996, File No. 1-3545; Exhibit 4 to Form 10-Q for the quarter ended June 30, 1998, File No. 1-3545; Exhibit 4 to Form 10-Q for the quarter ended March 31, 1999, File No. 1-3545; Exhibit 4(f) to Form 10-K for the year ended December 31, 2000, File No. 1-3545; Exhibit 4 (g) to Form 10-K for the year ended December 31, 2000, File No. 1-3545; Exhibit 4 (o), File No. 333-102169; Exhibit 4(k) to Post-Effective Amendment No. 1 to Form S-3, File No. 333-102172; Exhibit 4(l) to Post-Effective Amendment No. 2 to Form S-3, File No. 333-102172; Exhibit 4(m) to Post-Effective Amendment No. 3 to Form S-3, File No. 333-102172; Exhibit 4(a) to Form 10-Q for the quarter ended September 30, 2004, File No. 2-27612; Exhibit 4(f) to Amendment No. 1 to Form S-3, File No. 333-125275; Exhibit 4(y) to Post-Effective Amendment No. 2 to Form S-3, File Nos. 333-116300, 333-116300-01 and 333-116300-02; Exhibit 4(z) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-116300, 333-116300-01 and 333-116300-02; Exhibit 4(b) to Form 10-Q for the quarter ended March 31, 2006, File No. 2-27612; Exhibit 4(a) to Form 8-K dated April 17, 2007, File No. 2-27612; Exhibit 4 to Form 8-K dated October 10, 2007, File No. 2-27612; Exhibit 4 to Form 8-K dated January 16, 2008, File No. 2-27612; Exhibit 4(a) to Form 8-K dated March 17, 2009, File No. 2-27612; Exhibit 4 to Form 8-K dated February 9, 2010, File No. 2-27612; Exhibit 4 to Form 8-K dated December 9, 2010, File No. 2-27612; Exhibit 4(a) to Form 8-K dated June 10, 2011, File No. 2-27612; and Exhibit 4 to Form 8-K dated December 13, 2011, File No. 2-27612)	x	x
*4(b)	Indenture (For Unsecured Debt Securities), dated as of June 1, 1999, between FPL Group Capital and The Bank of New York Mellon, as Trustee (filed as Exhibit 4(a) to Form 8-K dated July 16, 1999, File No. 1-8841)	x	
*4(c)	Guarantee Agreement, dated as of June 1, 1999, between FPL Group (as Guarantor) and The Bank of New York Mellon (as Guarantee Trustee) (filed as Exhibit 4(b) to Form 8-K dated July 16, 1999, File No. 1-8841)	x	
*4(d)	Officer's Certificate of FPL Group Capital, dated June 17, 2008, creating the 5.35% Debentures, Series due June 15, 2013 (filed as Exhibit 4(a) to Form 8-K dated June 17, 2008, File No. 1-8841)	x	
*4(e)	Officer's Certificate of FPL Group Capital, dated December 12, 2008, creating the 7 7/8% Debentures, Series due December 15, 2015 (filed as Exhibit 4 to Form 8-K dated December 12, 2008, File No. 1-8841)	x	
*4(f)	Officer's Certificate of FPL Group Capital, dated March 9, 2009, creating the 6.00% Debentures, Series due March 1, 2019 (filed as Exhibit 4 to Form 8-K dated March 9, 2009, file No. 1-8841)	x	

Exhibit Number	Description	NEE	FPL
*4(g)	Officer's Certificate of FPL Group Capital, dated May 26, 2009, creating the Series C Debentures due June 1, 2014 (filed as Exhibit 4(c) to Form 8-K dated May 22, 2009, File No. 1-8841)	x	
*4(h)	Officer's Certificate of FPL Group Capital, dated November 10, 2009, creating the Floating Rate Debentures, Series due November 9, 2012 (filed as Exhibit 4 to Form 8-K dated November 10, 2009, File No. 1-8841)	x	
*4(i)	Officer's Certificate of FPL Group Capital, dated May 18, 2010, creating the Debentures, 2.55% Series due November 15, 2013 (filed as Exhibit 4 to Form 8-K dated May 18, 2010, File No. 1-8841)	x	
*4(j)	Officer's Certificate of FPL Group Capital, dated August 31, 2010, creating the Debentures, 2.60% Series due September 1, 2015 (filed as Exhibit 4 to Form 8-K dated August 31, 2010, File No. 1-8841)	x	
*4(k)	Officer's Certificate of FPL Group Capital, dated September 21, 2010, creating the Series D Debentures due September 1, 2015 (filed as Exhibit 4(c) to Form 8-K dated September 15, 2010, File No. 1-8841)	x	
*4(l)	Officer's Certificate of NEECH, dated June 10, 2011, creating the 4.50% Debentures, Series due June 1, 2021 (filed as Exhibit 4(b) to Form 8-K dated June 10, 2011, File No. 1-8841)	x	
*4(m)	Indenture (For Unsecured Subordinated Debt Securities relating to Trust Securities), dated as of March 1, 2004, among FPL Group Capital, FPL Group (as Guarantor) and The Bank of New York Mellon (as Trustee) (filed as Exhibit 4(au) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-102173, 333-102173-01, 333-102173-02 and 333-102173-03)	x	
*4(n)	Preferred Trust Securities Guarantee Agreement, dated as of March 15, 2004, between FPL Group (as Guarantor) and The Bank of New York Mellon (as Guarantee Trustee) relating to FPL Group Capital Trust I (filed as Exhibit 4(aw) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-102173, 333-102173-01, 333-102173-02 and 333-102173-03)	x	
*4(o)	Amended and Restated Trust Agreement relating to FPL Group Capital Trust I, dated as of March 15, 2004 (filed as Exhibit 4(at) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-102173, 333-102173-01, 333-102173-02 and 333-102173-03)	x	
*4(p)	Agreement as to Expenses and Liabilities of FPL Group Capital Trust I, dated as of March 15, 2004 (filed as Exhibit 4(ax) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-102173, 333-102173-01, 333-102173-02 and 333-102173-03)	x	
*4(q)	Officer's Certificate of FPL Group Capital and FPL Group, dated March 15, 2004, creating the 5 7/8% Junior Subordinated Debentures, Series due March 15, 2044 (filed as Exhibit 4(av) to Post-Effective Amendment No. 3 to Form S-3, File Nos. 333-102173, 333-102173-01, 333-102173-02 and 333-102173-03)	x	
*4(r)	Indenture (For Unsecured Subordinated Debt Securities), dated as of September 1, 2006, among FPL Group Capital, FPL Group (as Guarantor) and The Bank of New York Mellon (as Trustee) (filed as Exhibit 4(a) to Form 8-K dated September 19, 2006, File No. 1-8841)	x	
*4(s)	Officer's Certificate of FPL Group Capital and FPL Group, dated September 19, 2006, creating the Series A Enhanced Junior Subordinated Debentures due 2066 (filed as Exhibit 4(b) to Form 8-K dated September 19, 2006, File No. 1-8841)	x	
*4(t)	Officer's Certificate of FPL Group Capital and FPL Group, dated September 19, 2006, creating the Series B Enhanced Junior Subordinated Debentures due 2066 (filed as Exhibit 4(c) to Form 8-K dated September 19, 2006, File No. 1-8841)	x	
*4(u)	Replacement Capital Covenant, dated September 19, 2006, by FPL Group Capital and FPL Group relating to FPL Group Capital's Series A and Series B Enhanced Junior Subordinated Debentures due 2066 (filed as Exhibit 4(d) to Form 8-K dated September 19, 2006, File No. 1-8841)	x	
*4(v)	Officer's Certificate of FPL Group Capital and FPL Group, dated June 12, 2007, creating the Series C Junior Subordinated Debentures due 2067 (filed as Exhibit 4(a) to Form 8-K dated June 12, 2007, File No. 1-8841)	x	

Exhibit Number	Description	NEE	FPL
*4(w)	Replacement Capital Covenant, dated June 12, 2007, by FPL Group Capital and FPL Group relating to FPL Group Capital's Series C Junior Subordinated Debentures due 2067 (filed as Exhibit 4(b) to Form 8-K dated June 12, 2007, File No. 1-8841)	x	
*4(x)	Officer's Certificate of FPL Group Capital and FPL Group, dated September 17, 2007, creating the Series D Junior Subordinated Debentures due 2067 (filed as Exhibit 4(a) to Form 8-K dated September 17, 2007, File No. 1-8841)	x	
*4(y)	Officer's Certificate of FPL Group Capital and FPL Group, dated September 18, 2007, creating the Series E Junior Subordinated Debentures due 2067 (filed as Exhibit 4(b) to Form 8-K dated September 17, 2007, File No. 1-8841)	x	
*4(z)	Replacement Capital Covenant, dated September 18, 2007, by FPL Group Capital and FPL Group relating to FPL Group Capital's Series D and Series E Junior Subordinated Debentures due 2067 (filed as Exhibit 4(c) to Form 8-K dated September 17, 2007, File No. 1-8841)	x	
*4(aa)	Officer's Certificate of FPL Group Capital and FPL Group, dated March 19, 2009, creating the Series F Junior Subordinated Debentures due 2069 (filed as Exhibit 4(b) to Form 8-K dated March 17, 2009, File No. 1-8841)	x	
*4(bb)	Replacement Capital Covenant, dated March 19, 2009, by FPL Group Capital and FPL Group relating to FPL Group Capital's Series F Junior Subordinated Debentures due 2069 (filed as Exhibit 4(c) to Form 8-K dated March 17, 2009, File No. 1-8841)	x	
*4(cc)	Indenture (For Securing Senior Secured Bonds, Series A), dated May 22, 2007, between FPL Recovery Funding LLC (as Issuer) and The Bank of New York Mellon (as Trustee and Securities Intermediary) (filed as Exhibit 4.1 to Form 8-K dated May 22, 2007 and filed June 1, 2007, File No. 333-141357)		x
*4(dd)	Purchase Contract Agreement, dated as of May 1, 2009, between FPL Group and The Bank of New York Mellon, as Purchase Contract Agent (filed as Exhibit 4(a) to Form 8-K dated May 22, 2009, File No. 1-8841)	x	
*4(ee)	Pledge Agreement, dated as of May 1, 2009, among FPL Group, Deutsche Bank Trust Company Americas, as Collateral Agent, Custodial Agent and Securities Intermediary, and The Bank of New York Mellon, as Purchase Contract Agent and Trustee (filed as Exhibit 4(b) to Form 8-K dated May 22, 2009, File No. 1-8841)	x	
*4(ff)	Purchase Contract Agreement, dated as of September 1, 2010, between NEE and The Bank of New York Mellon, as Purchase Contract Agent (filed as Exhibit 4(a) to Form 8-K dated September 15, 2010, File No. 1-8841)	x	
*4(gg)	Pledge Agreement, dated as of September 1, 2010, among NEE, Deutsche Bank Trust Company Americas, as Collateral Agent, Custodial Agent and Securities Intermediary, and The Bank of New York Mellon, as Purchase Contract Agent (filed as Exhibit 4(b) to Form 8-K dated September 15, 2010, File No. 1-8841)	x	
*10(a)	FPL Group Supplemental Executive Retirement Plan, amended and restated effective April 1, 1997 (SERP) (filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 1999, File No. 1-8841)	x	x
*10(b)	FPL Group Supplemental Executive Retirement Plan, amended and restated effective January 1, 2005 (Restated SERP) (filed as Exhibit 10(b) to Form 8-K dated December 12, 2008, File No. 1-8841)	x	x
*10(c)	Amendment Number 1 to the Restated SERP changing name to NextEra Energy, Inc. Supplemental Executive Retirement Plan (filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2010, File No. 1-8841)	x	x
10(d)	Appendix A1 (revised as of December 1, 2011) to the Restated SERP	x	x
10(e)	Appendix A2 (revised as of December 1, 2011) to the Restated SERP	x	x
*10(f)	Amended and Restated Supplement to the Restated SERP as it applies to Lewis Hay, III effective January 1, 2005 (filed as Exhibit 10(c) to Form 8-K dated December 12, 2008, File No. 1-8841)	x	x

Exhibit Number	Description	NEE	FPL
*10(g)	Supplement to the SERP as it applies to Lewis Hay, III effective March 22, 2002 (filed as Exhibit 10(g) to Form 10-K for the year ended December 31, 2001, File No. 1-8841)	x	x
*10(h)	Supplement to the Restated SERP relating to a special credit to certain executive officers and other officers effective February 15, 2008 (filed as Exhibit 10(g) to Form 10-K for the year ended December 31, 2007, File No. 1-8841)	x	x
*10(i)	Supplement to the Restated SERP effective February 15, 2008 as it applies to Armando Pimentel, Jr. (filed as Exhibit 10(i) to Form 10-K for the year ended December 31, 2007, File No. 1-8841)	x	x
*10(j)	Supplement to the SERP effective December 14, 2007 as it applies to Manoochehr K. Nazar (filed as Exhibit 10(j) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(k)	NEE (formerly known as FPL Group) Amended and Restated Long-Term Incentive Plan, most recently amended and restated on May 22, 2009 (filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2009, File No. 1-8841)	x	x
*10(l)	FPL Group Long-Term Incentive Plan of 1985, as amended (filed as Exhibit 99(h) to Post-Effective Amendment No. 5 to Form S-8, File No. 33-18669)	x	x
*10(m)	NEE 2011 Long Term Incentive Plan (filed as Exhibit 10(a) to Form 8-K dated May 20, 2011, File No. 1-8841)	x	x
*10(n)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Performance Share Award Agreement effective February 15, 2008 (filed as Exhibit 10(c) to Form 8-K dated February 15, 2008, File No. 1-8841)	x	x
*10(o)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Performance Share Award Agreement effective February 13, 2009 with Christopher A. Bennett, Paul I. Cutler, Chris N. Froggatt, Joseph T. Kelliher, Robert L. McGrath and Antonio Rodriguez (filed as Exhibit 10(l) to Form 10-K for the year ended December 31, 2008, File No. 1-8841)	x	x
*10(p)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Amended and Restated Performance Share Award Agreement effective December 10, 2009 with Lewis Hay, III, Manoochehr K. Nazar, Armando J. Olivera, Armando Pimentel, Jr., James L. Robo and Charles E. Sieving (filed as Exhibit 10(p) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(q)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Performance Share Award Agreement effective February 12, 2010 (filed as Exhibit 10(q) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(r)	Form of NEE Amended and Restated Long-Term Incentive Plan Performance Share Award Agreement effective February 18, 2011 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, File No. 1-8841)	x	x
*10(s)	Form of Performance Share Award Agreement under the NEE 2011 Long Term Incentive Plan (filed as Exhibit 10(a) to Form 8-K dated October 13, 2011, File No. 1-8841)	x	x
*10(t)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Restricted Stock Award Agreement effective February 15, 2007 (filed as Exhibit 10(l) to Form 10-K for the year ended December 31, 2006, File No. 1-8841)	x	x
*10(u)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Restricted Stock Award Agreement effective February 15, 2008 (filed as Exhibit 10(a) to Form 8-K dated February 15, 2008, File No. 1-8841)	x	x
*10(v)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Restricted Stock Award Agreement effective February 13, 2009 (filed as Exhibit 10(q) to Form 10-K for the year ended December 31, 2008, File No. 1-8841)	x	x
*10(w)	Form of Amendment to Restricted Stock Award Agreements under the FPL Group Amended and Restated Long-Term Incentive Plan executed March 2009 between FPL Group and each of Christopher A. Bennett, Lewis Hay, III, Robert L. McGrath, Armando J. Olivera, Armando Pimentel, Jr., James L. Robo and Antonio Rodriguez (filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2009, File No. 1-8841)	x	x

Exhibit Number	Description	NEE	FPL
*10(x)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Restricted Stock Award Agreement effective February 12, 2010 (filed as Exhibit 10(w) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(y)	Form of NEE Amended and Restated Long-Term Incentive Plan Restricted Stock Award Agreement effective February 18, 2011 (filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2011, File No. 1-8841)	x	x
*10(z)	Form of Restricted Stock Award Agreement under the NEE 2011 Long Term Incentive Plan (filed as Exhibit 10(c) to Form 8-K dated October 13, 2011, File No. 1-8841)	x	x
*10(aa)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Stock Option Award - Non-Qualified Stock Option Agreement (filed as Exhibit 10(c) to Form 8-K dated December 29, 2004, File No. 1-8841)	x	x
*10(bb)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Stock Option Award - Non-Qualified Stock Option Agreement (filed as Exhibit 10(d) to Form 8-K dated December 29, 2004, File No. 1-8841)	x	x
*10(cc)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Stock Option Award - Non-Qualified Stock Option Agreement effective February 15, 2008 (filed as Exhibit 10(b) to Form 8-K dated February 15, 2008, File No. 1-8841)	x	x
*10(dd)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Stock Option Award - Non-Qualified Stock Option Agreement effective February 13, 2009 (filed as Exhibit 10(u) to Form 10-K for the year ended December 31, 2008, File No. 1-8841)	x	x
*10(ee)	Form of FPL Group Amended and Restated Long-Term Incentive Plan - Non-Qualified Stock Option Agreement effective February 12, 2010 (filed as Exhibit 10(bb) to Form 10-K for the year December 31, 2009, File No. 1-8841)	x	x
*10(ff)	Form of NEE Amended and Restated Long-Term Incentive Plan - Non-Qualified Stock Option Agreement effective February 18, 2011 (filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2011, File No. 1-8841)	x	x
*10(gg)	Form of Non-Qualified Stock Option Award Agreement under the NEE 2011 Long Term Incentive Plan (filed as Exhibit 10(b) to Form 8-K dated October 13, 2011, File No. 1-8841)	x	x
*10(hh)	Form of FPL Group Amended and Restated Long-Term Incentive Plan Amended and Restated Deferred Stock Award Agreement effective February 12, 2010 between FPL Group and each of Moray P. Dewhurst and James L. Robo (filed as Exhibit 10(dd) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(ii)	FPL Group Executive Annual Incentive Plan as amended and restated on December 12, 2008 (filed as Exhibit 10(a) to Form 8-K dated December 12, 2008, File No. 1-8841)	x	x
*10(jj)	NEE Deferred Compensation Plan effective January 1, 2005 as amended and restated through October 15, 2010 (filed as Exhibit 10(dd) to Form 10-K for the year ended December 31, 2010, File No. 1-8841)	x	x
*10(kk)	Amendment 1 (effective May 25, 2011) to the NEE Deferred Compensation Plan effective January 1, 2005, as amended and restated through October 15, 2010 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2011, File No. 1-8841)	x	x
10(ll)	Amendment 2 (effective November 16, 2011) to the NEE Deferred Compensation Plan effective January 1, 2005, as amended and restated through October 15, 2010	x	x
*10(mm)	FPL Group Deferred Compensation Plan, amended and restated effective January 1, 2003 (filed as Exhibit 10(k) to Form 10-K for the year ended December 31, 2002, File No. 1-8841)	x	x
*10(nn)	FPL Group Executive Long-Term Disability Plan effective January 1, 1995 (filed as Exhibit 10(g) to Form 10-K for the year ended December 31, 1995, File No. 1-8841)	x	x

Exhibit Number	Description	NEE	FPL
*10(oo)	FPL Group Amended and Restated Non-Employee Directors Stock Plan, as amended and restated October 13, 2006 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2006, File No. 1-8841)	x	
*10(pp)	FPL Group 2007 Non-Employee Directors Stock Plan (filed as Exhibit 99 to Form S-8, File No. 333-143739)	x	
*10(qq)	NEE Non-Employee Director Compensation Summary effective January 1, 2011 (filed as Exhibit 10(jj) to Form 10-K for the year ended December 31, 2010, File No. 1-8841)	x	
10 (rr)	NEE Non-Employee Director Compensation Summary effective January 1, 2012	x	
*10(ss)	Form of Amended and Restated Executive Retention Employment Agreement, as of December 12, 2008, between FPL Group and each of Christopher A. Bennett, Robert L. McGrath and Antonio Rodriguez (filed as Exhibit 10(g) to Form 8-K dated December 12, 2008, File No. 1-8841)	x	x
*10(tt)	Form of Amended and Restated Executive Retention Employment Agreement effective December 10, 2009 between FPL Group and each of Lewis Hay, III, Moray P. Dewhurst, James L. Robo, Armando J. Olivera, Armando Pimentel, Jr., and Charles E. Sieving (filed as Exhibit 10(nn) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(uu)	Amended and Restated Employment Letter with Lewis Hay, III dated December 10, 2009 (filed as Exhibit 10(pp) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(vv)	Executive Retention Employment Agreement between FPL Group and Joseph T. Kelliher dated as of May 21, 2009 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2009, File No. 1-8841)	x	x
*10(ww)	Executive Retention Employment Agreement between FPL Group and Manoochehr K. Nazar dated as of January 1, 2010 (filed as Exhibit 10(rr) to Form 10-K for the year ended December 31, 2009, File No. 1-8841)	x	x
*10(xx)	Executive Retention Employment Agreement between NEE and Shaun J. Francis dated as of August 16, 2010 (filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2010, File No. 1-8841)	x	x
*10(yy)	Retention Agreement between FPL Group and Robert L. McGrath (filed as Exhibit 10 (a) to Form 10-Q for the quarter ended June 30, 2010, File No. 1-8841)	x	x
*10(zz)	Guarantee Agreement between FPL Group and FPL Group Capital, dated as of October 14, 1998 (filed as Exhibit 10(y) to Form 10-K for the year ended December 31, 2001, File No. 1-8841)	x	
12(a)	Computation of Ratios	x	
12(b)	Computation of Ratios		x
21	Subsidiaries of NEE	x	
23	Consent of Independent Registered Public Accounting Firm	x	x
31(a)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of NEE	x	
31(b)	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer of NEE	x	
31(c)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of FPL		x
31(d)	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer of FPL		x
32(a)	Section 1350 Certification of NEE	x	
32(b)	Section 1350 Certification of FPL		x

Exhibit Number	Description	NEE	FPL
101.INS	XBRL Instance Document	x	x
101.SCH	XBRL Schema Document	x	x
101.PRE	XBRL Presentation Linkbase Document	x	x
101.CAL	XBRL Calculation Linkbase Document	x	x
101.LAB	XBRL Label Linkbase Document	x	x
101.DEF	XBRL Definition Linkbase Document	x	x

* Incorporated herein by reference

NEE and FPL agree to furnish to the SEC upon request any instrument with respect to long-term debt that NEE and FPL have not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

NEXTERA ENERGY, INC. SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NextEra Energy, Inc.

JAMES L. ROBO

James L. Robo
President and Chief Operating Officer

Date: February 27, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature and Title as of February 27, 2012:

LEWIS HAY, III

Lewis Hay, III
Chairman and Chief Executive Officer
and Director
(Principal Executive Officer)

CHRIS N. FROGGATT

Chris N. Froggatt
Vice President, Controller and Chief Accounting Officer
(Principal Accounting Officer)

MORAY P. DEWHURST

Moray P. Dewhurst
Vice Chairman and Chief Financial Officer,
and Executive Vice President - Finance
(Principal Financial Officer)

Directors:

SHERRY S. BARRAT

Sherry S. Barrat

TONI JENNINGS

Toni Jennings

ROBERT M. BEALL, II

Robert M. Beall, II

Oliver D. Kingsley, Jr.

J. HYATT BROWN

J. Hyatt Brown

RUDY E. SCHUPP

Rudy E. Schupp

JAMES L. CAMAREN

James L. Camaren

WILLIAM H. SWANSON

William H. Swanson

KENNETH B. DUNN

Kenneth B. Dunn

MICHAEL H. THAMAN

Michael H. Thaman

J. BRIAN FERGUSON

J. Brian Ferguson

HANSEL E. TOOKES, II

Hansel E. Tookes, II

FLORIDA POWER & LIGHT COMPANY SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized and in the capacities and on the date indicated.

Florida Power & Light Company

ARMANDO J. OLIVERA

Armando J. Olivera
Chief Executive Officer and Director
(Principal Executive Officer)

Date: February 27, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature and Title as of February 27, 2012:

MORAY P. DEWHURST

Moray P. Dewhurst
Executive Vice President, Finance
and Chief Financial Officer and Director
(Principal Financial Officer)

KIMBERLY OUSDAHL

Kimberly Ousdahl
Vice President, Controller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

LEWIS HAY, III

Lewis Hay, III

JAMES L. ROBO

James L. Robo

ANTONIO RODRIGUEZ

Antonio Rodriguez

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Securities Exchange Act of 1934 by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Securities Exchange Act of 1934

No annual report, proxy statement, form of proxy or other proxy soliciting material has been sent to security holders of FPL during the period covered by this Annual Report on Form 10-K for the fiscal year ended December 31, 2011.

Exhibit 12(a)

NEXTERA ENERGY, INC. AND SUBSIDIARIES
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS[(a)]

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(millions of dollars)				
Earnings, as defined:					
Net income	$ 1,923	$1,957	$ 1,615	$1,639	$ 1,312
Income taxes	529	532	327	450	368
Fixed charges included in the determination of net income, as below	1,094	1,025	899	859	799
Amortization of capitalized interest	21	21	17	15	12
Distributed income of equity method investees	95	74	69	124	175
Less: Equity in earnings of equity method investees	55	58	52	93	68
Total earnings, as defined	$ 3,607	$3,551	$ 2,875	$2,994	$ 2,598
Fixed charges, as defined:					
Interest expense	$ 1,035	$ 979	$849	$813	$762
Rental interest factor	41	32	28	28	23
Allowance for borrowed funds used during construction	18	14	22	18	14
Fixed charges included in the determination of net income	1,094	1,025	899	859	799
Capitalized interest	107	75	88	55	40
Total fixed charges, as defined	$ 1,201	$1,100	$ 987	$ 914	$ 839
Ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred stock dividends[(a)]	3.00	3.23	2.91	3.28	3.10

(a) NextEra Energy, Inc. has no preference equity securities outstanding; therefore, the ratio of earnings to fixed charges is the same as the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 12(b)

FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND
RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS[(a)]

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(millions of dollars)				
Earnings, as defined:					
Net income	$1,068	$ 945	$ 831	$ 789	$ 836
Income taxes	654	580	473	443	451
Fixed charges included in the determination of net income, as below	411	382	347	359	325
Total earnings, as defined	$2,133	$1,907	$ 1,651	$1,591	$ 1,612
Fixed charges, as defined:					
Interest expense	$ 387	$ 361	$ 318	$ 334	$ 304
Rental interest factor	8	8	7	7	7
Allowance for borrowed funds used during construction	16	13	22	18	14
Fixed charges included in the determination of net income	411	382	347	359	325
Capitalized interest	1	3	2	—	—
Total fixed charges, as defined	$ 412	$ 385	$ 349	$ 359	$ 325
Ratio of earnings to fixed charges and ratio of earnings to combined fixed charges and preferred stock dividends[(a)]	5.18	4.95	4.73	4.43	4.96

(a) Florida Power & Light Company has no preference equity securities outstanding; therefore, the ratio of earnings to fixed charges is the same as the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 21

SUBSIDIARIES OF NEXTERA ENERGY, INC.

NextEra Energy, Inc.'s principal subsidiaries as of December 31, 2011 are listed below.

	Subsidiary	State or Jurisdiction of Incorporation or Organization
1.	Florida Power & Light Company (100%-owned)	Florida
2.	NextEra Energy Capital Holdings, Inc. (100%-owned)	Florida
3.	NextEra Energy Resources, LLC[(a)(b)]	Delaware
4.	Palms Insurance Company, Limited[(b)]	Cayman Islands

(a) Includes 477 subsidiaries that operate in the United States and 55 subsidiaries that operate in foreign countries in the same line of business as NextEra Energy Resources, LLC.
(b) 100%-owned subsidiary of NextEra Energy Capital Holdings, Inc.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements of our reports dated February 27, 2012, relating to the consolidated financial statements of NextEra Energy, Inc. and subsidiaries (NextEra Energy) and Florida Power & Light Company and subsidiaries (FPL) and the effectiveness of NextEra Energy's and FPL's internal control over financial reporting, appearing in this Annual Report on Form 10-K of NextEra Energy and FPL for the year ended December 31, 2011:

NextEra Energy, Inc.

Form S-8	No. 33-11631
Form S-8	No. 33-57673
Form S-8	No. 333-27079
Form S-8	No. 333-88067
Form S-8	No. 333-114911
Form S-8	No. 333-116501
Form S-3	No. 333-125275
Form S-8	No. 333-125954
Form S-8	No. 333-130479
Form S-3	No. 333-160987
Form S-8	No. 333-143739
Form S-3	No. 333-159011
Form S-8	No. 333-174799

FPL Group Trust I

Form S-3	No. 333-160987-02

FPL Group Trust II

Form S-3	No. 333-160987-01

Florida Power & Light Company

Form S-3	No. 333-160987-07

Florida Power & Light Company Trust I

Form S-3	No. 333-160987-06

Florida Power & Light Company Trust II

Form S-3	No. 333-160987-05

NextEra Energy Capital Holdings, Inc.

Form S-3	No. 333-160987-08

FPL Group Capital Trust II

Form S-3	No. 333-160987-04

FPL Group Capital Trust III

Form S-3	No. 333-160987-03

DELOITTE & TOUCHE LLP

Miami, Florida
February 27, 2012

Exhibit 31(a)

Rule 13a-14(a)/15d-14(a) Certification

I, Lewis Hay, III, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2011 of NextEra Energy, Inc. (the registrant);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

LEWIS HAY, III

Lewis Hay, III
Chairman and Chief Executive Officer
of NextEra Energy, Inc.

Exhibit 31(b)

Rule 13a-14(a)/15d-14(a) Certification

I, Moray P. Dewhurst, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2011 of NextEra Energy, Inc. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

MORAY P. DEWHURST

Moray P. Dewhurst
Vice Chairman and Chief Financial Officer,
and Executive Vice President - Finance
of NextEra Energy, Inc.

Exhibit 31(c)

Rule 13a-14(a)/15d-14(a) Certification

I, Armando J. Olivera, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2011 of Florida Power & Light Company. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

ARMANDO J. OLIVERA

Armando J. Olivera
Chief Executive Officer
of Florida Power & Light Company

Exhibit 31(d)

Rule 13a-14(a)/15d-14(a) Certification

I, Moray P. Dewhurst, certify that:

1. I have reviewed this Form 10-K for the annual period ended December 31, 2011 of Florida Power & Light Company. (the registrant);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

MORAY P. DEWHURST

Moray P. Dewhurst
Executive Vice President, Finance
and Chief Financial Officer of
Florida Power & Light Company

Exhibit 32(a)

Section 1350 Certification

We, Lewis Hay, III and Moray P. Dewhurst, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Annual Report on Form 10-K of NextEra Energy, Inc. (the registrant) for the annual period ended December 31, 2011 (Report) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

Dated: February 27, 2012

LEWIS HAY, III

Lewis Hay, III
Chairman and Chief Executive Officer
of NextEra Energy, Inc.

MORAY P. DEWHURST

Moray P. Dewhurst
Vice Chairman and Chief Financial Officer,
and Executive Vice President - Finance
of NextEra Energy, Inc.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 and, accordingly, is not being filed with the Securities and Exchange Commission as part of the Report and is not to be incorporated by reference into any filing of the registrant under the Securities Act of 1933 or the Securities Exchange Act of 1934 (whether made before or after the date of the Report, irrespective of any general incorporation language contained in such filing).

Exhibit 32(b)

Section 1350 Certification

We, Armando J. Olivera and Moray P. Dewhurst, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Annual Report on Form 10-K of Florida Power & Light Company (the registrant) for the annual period ended December 31, 2011 (Report) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

Dated: February 27, 2012

ARMANDO J. OLIVERA

Armando J. Olivera
Chief Executive Officer of
Florida Power & Light Company

MORAY P. DEWHURST

Moray P. Dewhurst
Executive Vice President, Finance
and Chief Financial Officer of
Florida Power & Light Company

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 and, accordingly, is not being filed with the Securities and Exchange Commission as part of the Report and is not to be incorporated by reference into any filing of the registrant under the Securities Act of 1933 or the Securities Exchange Act of 1934 (whether made before or after the date of the Report, irrespective of any general incorporation language contained in such filing).

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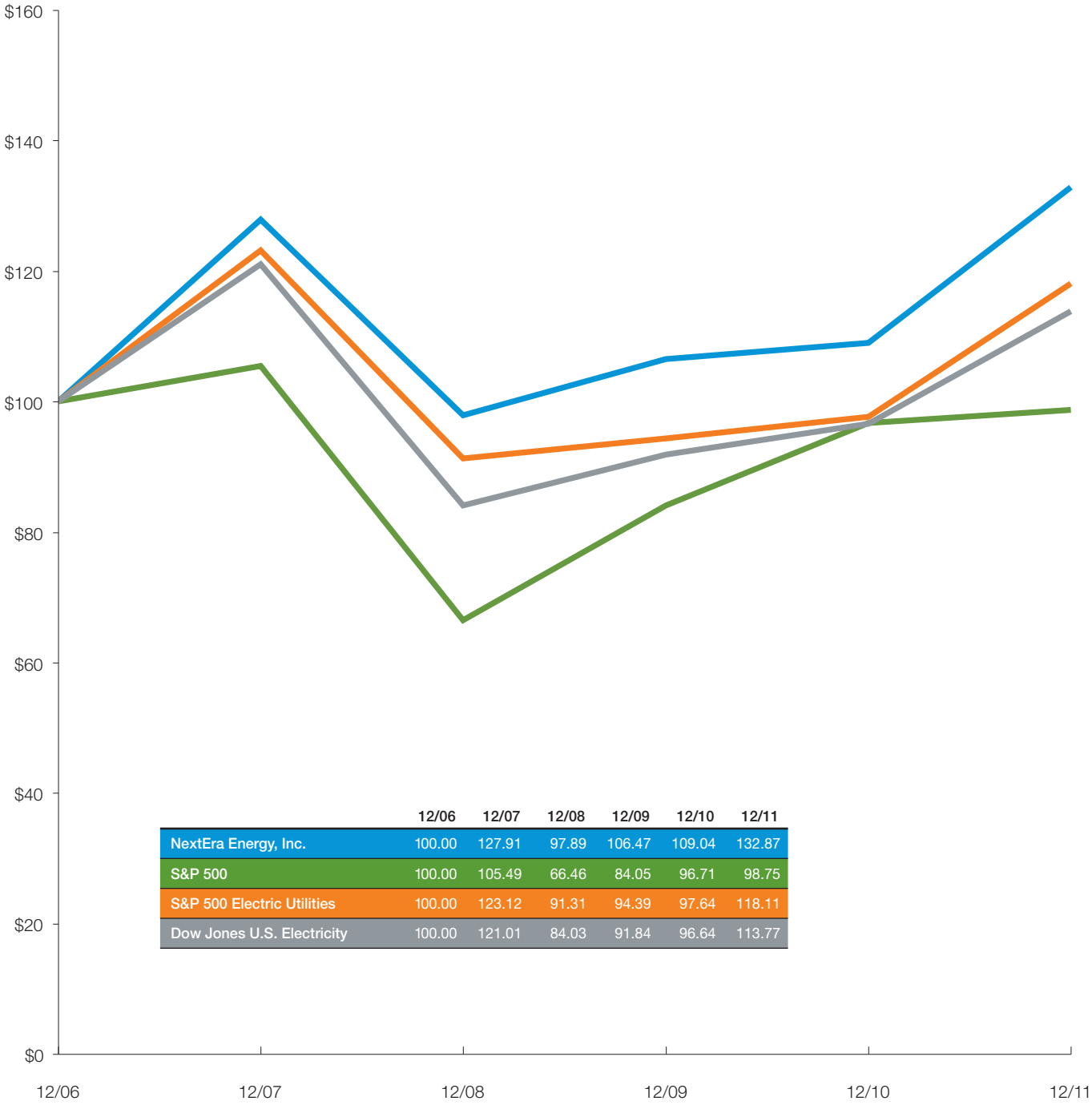
Performance Graph

The following graph compares the cumulative 5-year total shareholder return on NextEra Energy, Inc.'s common stock with the cumulative total returns of the S&P 500 Index, the S&P 500 Electric Utilities Index and the Dow Jones U.S. Electricity Index. The graph tracks the performance of an investment of $100 (with reinvestment of all dividends) in our common stock and in each index from 12/31/2006 to 12/31/2011.

Comparison of 5-Year Cumulative Total Return*



	12/06	12/07	12/08	12/09	12/10	12/11
NextEra Energy, Inc.	100.00	127.91	97.89	106.47	109.04	132.87
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
S&P 500 Electric Utilities	100.00	123.12	91.31	94.39	97.64	118.11
Dow Jones U.S. Electricity	100.00	121.01	84.03	91.84	96.64	113.77

*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

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NextEra Energy, Inc.

Reconciliation of Adjusted Return on Equity (ROE) to GAAP ROE

Year Ended December 31, 2011 (millions, except percentage amounts)	
Net Income	$1,923
Adjustments, net of income taxes:	
Net unrealized mark-to-market gains associated with non-qualifying hedges (NQH)	(190)
Loss on sale of natural gas-fired generating assets	98
Other than temporary impairment (OTTI) losses – net	6
Adjusted Earnings	**$1,837**

Average Common Shareholders' Equity	$14,759
Adjustments:	
Accumulated Other Comprehensive Income	(43)
Cumulative NQH gains	(229)
Cumulative OTTI losses - net	94
Cumulative loss on sale of natural gas-fired generating assets	38
Adjusted	$14,619

GAAP ROE [1]	**13.0%**
Adjusted ROE [2]	**12.6%**

GAAP Net Income by Segment

(millions)	2010	2011
Florida Power & Light	$945	$1,068
NextEra Energy Resources	980	774
Corporate and Other	32	81
NextEra Energy, Inc. Consolidated	$1,957	$1,923

GAAP Earnings Per Share (assuming dilution) by Segment

	2010	2011
Florida Power & Light	$2.29	$2.55
NextEra Energy Resources	2.37	1.85
Corporate and Other	0.08	0.19
NextEra Energy, Inc. Consolidated	$4.74	$4.59

Reconciliation of Adjusted Earnings Per Share to Earnings Per Share

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Earnings Per Share (assuming dilution)	$2.34	$1.38	$2.53	$2.48	$2.34	$3.23	$3.27	$4.07	$3.97	$4.74	$4.59
Adjustments:											
NQH (gains) losses	(0.02)		(0.06)	0.01	0.29	(0.23)	0.21	(0.42)	0.05	(0.43)	(0.45)
OTTI losses, net							0.01	0.19	0.03	(0.01)	0.01
Cumulative effect of change in accounting principle, net		0.64	0.01								
Impairment/other charges, net		0.39									
Merger-related expenses	0.06					0.04					
Loss on sale of natural gas-fired generating assets											0.24
Adjusted Earnings Per Share (assuming dilution)	$2.38	$2.41	$2.48	$2.49	$2.63	$3.04	$3.49	$3.84	$4.05	$4.30	$4.39

NextEra Energy Resources

Reconciliation of Adjusted Earnings to GAAP Net Income

(millions)	2010	2011
Net Income	$980	$774
Adjustments, net of income taxes:		
NQH gains	(176)	(193)
Loss on sale of natural gas-fired generating assets		92
OTTI losses – net	(4)	6
Adjusted Earnings	$800	$679

Reconciliation of Adjusted Earnings Per Share to GAAP Earnings Per Share

	2010	2011
Earnings Per Share (assuming dilution)	$2.37	$1.85
Adjustments:		
NQH gains	(0.43)	(0.46)
Loss on sale of natural gas-fired generating assets		0.22
OTTI losses – net	(0.01)	0.01
Adjusted Earnings Per Share (assuming dilution)	$1.93	$1.62

[1] Net income divided by five-quarter average common shareholders' equity per book.
[2] Adjusted earnings divided by five-quarter adjusted average common shareholders' equity.

Officers

NEXTERA ENERGY, INC.

LEWIS HAY, III
Chairman and Chief Executive Officer

JAMES L. ROBO
President and Chief Operating Officer

MORAY P. DEWHURST
Vice Chairman and
Chief Financial Officer, and
Executive Vice President - Finance

MANO K. NAZAR
Executive Vice President, Nuclear
Division and Chief Nuclear Officer

ANTONIO RODRIGUEZ
Executive Vice President,
Power Generation Division

ROBERT L. MCGRATH
Executive Vice President,
Engineering, Construction and
Corporate Services

CHRISTOPHER A. BENNETT
Executive Vice President & Chief
Strategy, Policy and Business
Process Improvement Officer

SHAUN J. FRANCIS
Executive Vice President,
Human Resources

JOSEPH T. KELLIHER
Executive Vice President,
Federal Regulatory Affairs

CHARLES E. SIEVING
Executive Vice President &
General Counsel

MARIA V. FOGARTY
Senior Vice President,
Internal Audit & Compliance

PAUL I. CUTLER
Treasurer

CHRIS N. FROGGATT
Vice President, Controller and
Chief Accounting Officer

ALISSA E. BALLOT
Vice President & Corporate Secretary

JAMES P. HIGGINS
Vice President, Tax

MICHAEL M. WILSON
Vice President, Governmental Affairs
- Federal

FLORIDA POWER & LIGHT COMPANY

ARMANDO J. OLIVERA
Chief Executive Officer

ERIC E. SILAGY
President

DEBORAH H. CAPLAN
Vice President &
Chief Operating Officer

ROBERT E. BARRETT, JR.
Vice President, Finance

G. KEITH HARDY
Vice President, Distribution

MANUEL B. MIRANDA
Vice President,
Transmission and Substation

MARLENE M. SANTOS
Vice President, Customer Service

LAKSHMAN CHARANJIVA
Vice President and
Chief Information Officer

TIMOTHY FITZPATRICK
Vice President,
Marketing & Communication

RANDALL R. LABAUVE
Vice President,
Environmental Services

R. WADE LITCHFIELD
Vice President & General Counsel

KIMBERLY OUSDAHL
Vice President, Controller and
Chief Accounting Officer

PAMELA M. RAUCH
Vice President, Development and
External Affairs

NEXTERA ENERGY RESOURCES, LLC

ARMANDO PIMENTEL, JR.
President and Chief Executive Officer

TJ TUSCAI
Chief Operating Officer

MARK R. SORENSEN
Senior Vice President, Finance and
Chief Financial Officer

MICHAEL O'SULLIVAN
Senior Vice President, Development

MARK MAISTO
President,
Commodities and Retail Markets

BRIAN LANDRUM
President, Gexa Energy GP, LLC

JOHN W. KETCHUM
Vice President, General Counsel and
Secretary

FPL FIBERNET, LLC

CARMEN M. PEREZ
President

Board of Directors

SHERRY S. BARRAT
Vice Chairman, The Northern Trust
Company (banking corporation)
Director since 1998.
Member: Audit Committee,
Governance & Nominating Committee.

ROBERT M. BEALL, II
Chairman, Beall's, Inc.
(department stores)
Director since 1989. Member:
Compensation Committee,
Finance & Investment Committee.

J. HYATT BROWN
Chairman, Brown & Brown, Inc.
(insurance broker)
Director since 1989. Chair:
Governance & Nominating Committee.
Member: Executive Committee,
Finance & Investment Committee.

JAMES L. CAMAREN
Private Investor. Formerly Chairman &
Chief Executive Officer, Utilities, Inc.
(water utilities)
Director since 2002.
Member: Audit Committee,
Governance & Nominating Committee.

KENNETH B. DUNN
Professor of Financial Economics
and former Dean, Tepper School of
Business, Carnegie Mellon University
(higher education)
Director since July 2010.
Member: Compensation Committee,
Finance & Investment Committee.

J. BRIAN FERGUSON
Retired. Formerly Chairman,
Eastman Chemical Company
(chemical company)
Director since 2005.
Chair: Compensation Committee.
Member: Executive Committee,
Governance & Nominating Committee.

LEWIS HAY, III
Chairman and Chief Executive
Officer, NextEra Energy, Inc.
Director since 2001.
Chair: Executive Committee.

TONI JENNINGS
Chairman, Jack Jennings & Sons, Inc.
(construction)
Former Lt. Governor, State of Florida
Director since 2007. Member:
Compensation Committee, Finance &
Investment Committee.

OLIVER D. KINGSLEY, JR.
Retired. Formerly President
and Chief Operating Officer,
Exelon Corporation
(integrated utility company)
Director since 2007.
Member: Audit Committee,
Nuclear Committee.

RUDY E. SCHUPP
President and Chief Executive
Officer, 1st United Bank, and
Chief Executive Officer,
1st United Bancorp, Inc.
(commercial bank)
Director since 2005. Chair:
Finance & Investment Committee.
Member: Compensation Committee,
Executive Committee.

WILLIAM H. SWANSON
Chairman and Chief Executive Officer,
Raytheon Company
(global defense technology)
Director since 2009.
Member: Audit Committee,
Governance & Nominating Committee.

MICHAEL H. THAMAN
Chairman, President and Chief
Executive Officer, Owens Corning
(manufacturer)
Director since 2003.
Chair: Audit Committee.
Member: Executive Committee.

HANSEL E. TOOKES, II
Retired. Formerly President,
Raytheon International
(defense and aerospace systems)
Director since 2005.
Member: Finance & Investment
Committee, Governance &
Nominating Committee.

Investor Information

CORPORATE OFFICES
NextEra Energy, Inc.
700 Universe Blvd.
Juno Beach, FL 33408-0420

EXCHANGE LISTING
Common Stock
New York Stock Exchange
Ticker Symbol: NEE

NextEra Energy Capital Holdings, Inc. Series A Enhanced Junior Subordinated Debentures
New York Stock Exchange
Ticker Symbol: FGC

NextEra Energy Capital Holdings, Inc. Series E Junior Subordinated Debentures
New York Stock Exchange
Ticker Symbol: FGE

NextEra Energy Capital Holdings, Inc. Series F Junior Subordinated Debentures
New York Stock Exchange
Ticker Symbol: NEE.PRF

FPL Group Capital Trust I Preferred Trust Securities
New York Stock Exchange
Ticker Symbol: NEE.PRC

NEWSPAPER LISTING
Common Stock: NEE

REGISTRAR, TRANSFER AND PAYING AGENTS
NextEra Energy, Inc. Common Stock

NextEra Energy, Inc.
c/o Computershare
Trust Company, N.A.
250 Royall Street
Canton, MA 02021
888-218-4392

Florida Power & Light Company First Mortgage Bonds

DB Services Americas, Inc.
5022 Gate Parkway
Suite 200
Jacksonville, FL 32256
800-735-7777

NextEra Energy Capital Holdings, Inc. Debentures

NextEra Energy Capital Holdings, Inc. Junior Subordinated Debentures

NextEra Energy Capital Holdings, Inc. Enhanced Junior Subordinated Debentures

FPL Group Capital Trust I Preferred Trust Securities

The Bank of New York Mellon
Corporate Trust Operations
111 Sanders Creek Parkway
East Syracuse, NY 13057
800-254-2826

SHAREHOLDER INQUIRIES
Communications concerning transfer requirements, lost certificates, dividend checks, address changes, stock accounts and the dividend reinvestment and direct stock purchase plan should be directed to Computershare: 888-218-4392 or www.computershare.com/nee.

Other shareholder communications to: Shareholder Services 800-222-4511, 561-691-7272 (fax)

ANNUAL MEETING
May 25, 2012, 10:00 a.m.
NextEra Energy, Inc.
Juno Beach Auditorium
700 Universe Blvd.
Juno Beach, FL 33408-0420

ELECTRONIC PROXY MATERIAL
Shareholders may elect to receive proxy materials electronically by accessing **https://enroll1.icsdelivery.com/nee/default.aspx**

DIRECT DEPOSIT OF DIVIDENDS
Cash dividends may be deposited directly to personal accounts at financial institutions. Call Computershare for authorization forms.

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN
NextEra Energy offers a plan for the reinvestment of dividends and the purchase of common stock. Enrollment materials may be obtained by calling Computershare or by accessing **www.computershare.com/nee**.

DIRECT REGISTRATION SERVICES
NextEra Energy common stock can be issued in direct registration (book entry) form.

ONLINE INVESTOR INFORMATION
Visit our investor information site at **www.NextEraEnergy.com/investors** to get stock quotes, earnings reports, financial releases, SEC filings and other news. You can also request and receive information via email. Shareholders of record can receive secure online account access through a link to our transfer agent, Computershare.

SEC FILINGS
All Securities and Exchange Commission filings appear on our website at **www.NextEraEnergy.com/investors**. Copies of SEC filings also are available without charge by writing to NextEra Energy, Shareholder Services.

NEWS AND FINANCIAL INFORMATION
Get the latest news and financial information about NextEra Energy by visiting **www.NextEraEnergy.com**.

ANALYST INQUIRIES
Investor Relations
561-694-4697
561-691-7272 (fax)

NEWS MEDIA INQUIRIES
Media Relations
305-552-3888

CERTIFIED PUBLIC ACCOUNTANTS
Deloitte & Touche LLP
333 Southeast Second Avenue
Suite 3600
Miami, FL 33131-2387

PROPOSED 2012 COMMON STOCK DIVIDEND DATES*

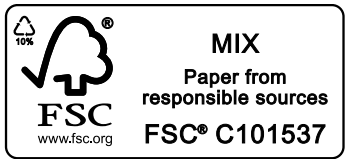
Declaration	Ex-Dividend	Record	Payment
February 17	February 29	March 2	March 15
May 25	June 1	June 4	June 15
July 27	August 29	August 31	September 17
October 12	November 28	November 30	December 17

*Declaration of dividends and dates shown are subject to the discretion of the Board of Directors of NextEra Energy. Dates shown are based on the assumption that past patterns will prevail.



NextEra Energy, Inc.
700 Universe Boulevard
Juno Beach, Florida 33408

For more information, go to:
www.NextEraEnergy.com
www.FPL.com
www.NextEraEnergyResources.com



Filed: 2013-01-04
EB-2011-0140
Upper Canada Transmission, Inc. (o/a NextBridge)
East-West Tie Designation Application
Appendix 1

NextEra 2012 Corporate Responsibility Report

TAB A1b

NEXTera ENERGY

CORPORATE RESPONSIBILITY REPORT 2012



Line workers connect a 345-kV transmission line near Abilene, Texas. NextEra Energy's Lone Star Transmission is building the capacity to bring renewable energy from the wind to major population centers in central Texas.

For more on NextEra Energy's corporate responsibility initiatives, visit
www.NextEraEnergy.com/CorporateResponsibility

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NextEra Energy Highlights (2011)

Operating Revenues	$15.3 billion
Operating Expenses	$12 billion
Net Income	$1.9 billion
Earnings per Share (assuming dilution)	$4.59
Adjusted Earnings per Share (assuming dilution)[1]	$4.39
Retained Earnings	$9.9 billion
Cash Flows from Operating Activities	$4.1 billion
Capital Expenditures	$6.6 billion
Total Assets	$57.2 billion
Total Capitalization	$35.8 billion
Total Generating Capacity[2]	41,067 megawatts
Employees (year-end)	14,800
Geographic Presence	24 states, Canada and Spain

[1] See Page 33 for reconciliation of adjusted earnings per share to earnings per share.
[2] Includes purchased power.
Note: In 2011, and to date in 2012, NextEra Energy has issued no restatements of financial results due to errors.

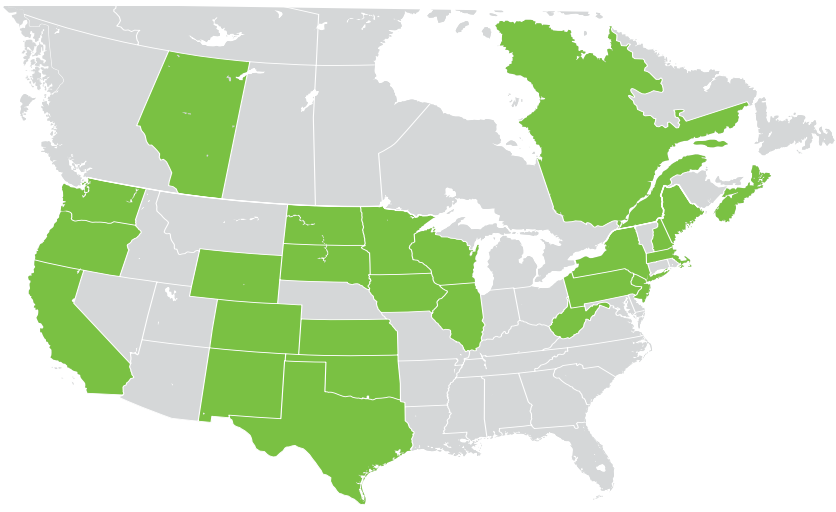
Markets Served by NextEra Energy

As of Dec. 31, 2011

Majority Subsidiary	Geography	Sectors	Types of Customers
NextEra Energy Resources, LLC	22 states, Canada and Spain	Competitive generation	Utilities, retail and marketing and trading counterparties
Florida Power & Light Company (FPL)	35 Florida counties	Rate-regulated electric utility	Residential, commercial, industrial

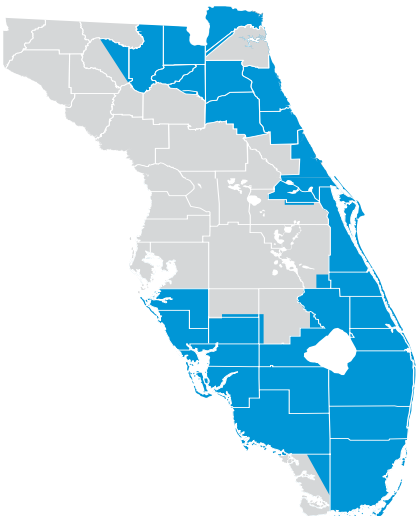
NextEra Energy Resources

As of Dec. 31, 2011



FPL Service Territory

As of Dec. 31, 2011



To Our Stakeholders

At NextEra Energy, Inc., we hold ourselves to high standards, and we know that you also expect the best from us. Our 2012 Corporate Responsibility Report summarizes many of our achievements over the past year, as well as how we are continuing to improve our performance across the enterprise.

We have two outstanding primary businesses, one with a long history and the other with a relatively short history that we have grown to become the equivalent of a Fortune 500-sized company in its own right in just over a decade.

At FPL, our rate-regulated utility, the core of our strategy for many years has been to strive constantly to improve the value we deliver to our 4.6 million customers. Today, FPL offers its typical residential customers a bill that is the lowest in Florida and 24 percent below the national average, coupled with top quartile reliability, award-winning customer service, and one of the lowest emissions profiles among U.S. utilities. We are investing heavily in the business to ensure this tremendous value proposition gets even better over time. We project that our investments in new, highly efficient power generation capacity will save customers billions of dollars in fuel costs and improve our emissions profile, and that investments in our transmission and distribution infrastructure will increase our system's resiliency, reliability and compatibility with the environment.

At NextEra Energy Resources, our competitive generation business, our strategy is not as easy to capture in a few words, but it has always reflected a balance between a long-term vision of scale, skills and scope, and a pragmatic recognition that every goal in the competitive power space must be pursued opportunistically. More than a decade of sustained effort has



President and CEO Jim Robo

constructed a business that is the country's largest producer of renewable energy from the wind and the sun. NextEra Energy Resources also contains many other business capabilities, and we continue to seek ways to expand the business based on the growth opportunities we see.

Across both FPL and NextEra Energy Resources, we will maintain our focus on clean energy, on being low cost, and on maintaining our track record of safe, excellent execution and continuous improvement.

This report illustrates many of those continuous improvements. We are focused on our environment by keeping an air emissions rate that is among the lowest in our industry, and by continuing our efforts to preserve water, land and wildlife. We are focused on our customers by offering compelling value as well as a range of programs and services to help them save energy and save money. We are focused on our communities through financial support, lots of volunteer work, and a particular passion for helping to educate our young people. And we're focused on our nearly 15,000 employees by investing in an award-winning health and wellness program, an in-house university that's developing cutting-edge job skills, and a shared safety culture with a goal of zero injuries every day.

In this report, we also document how NextEra Energy has flourished under the leadership of Lew Hay. During his 11 years as CEO, our company significantly outperformed our industry benchmark, as well as the S&P 500 index. Along the way, our company added more than $24 billion in shareholder value – $18 billion through price appreciation and more than $6 billion through dividends – all while building one of the cleanest and most efficient asset portfolios in the United States.

As the new CEO of NextEra Energy, I consider myself very fortunate. I have been an integral part of all the major decisions of the past decade that have helped generate the success illustrated in these pages. I am intimately familiar with the expectations of you, our stakeholders. I am confident in the ability of our team to meet them. And I am focused constantly on our company's opportunities and challenges. Our business is in great shape, and we continue to invest in growing it.

Not the least of our achievements over the past decade has been the development of the team that continues to lead this company, a team that remains committed to corporate responsibility and accountability. On behalf of the nearly 15,000 members of our team, thank you for taking the time to see how far we have traveled, and why we are so optimistic about what's yet to come.



Jim Robo



Near Abilene, Texas, NextEra Energy's Lone Star Transmission subsidiary is constructing an approximately 320-mile, 345-kV transmission line to strengthen the electric grid and enhance the reliable transmission of electricity from all generation sources, including renewable sources like wind.

An Environmental Leader

A Sensitivity to Our Environment Permeates Our Culture

At NextEra Energy, being responsible stewards of our environment is ingrained in our culture. We are mindful about how our business impacts the air we breathe, the water and land we use, and the flora and fauna that share our planet.

The NextEra Energy "Environmental Commitment" establishes a core environmental policy as part of our company's Code of Business Conduct & Ethics. Each year, officers and managers certify their compliance in writing and ensure that discussion sessions are held with employees. The policy reads:

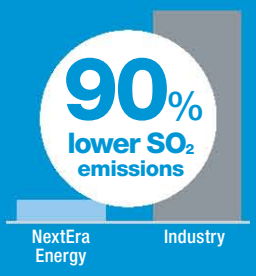
> It has been, and will continue to be, the intent of the Company to conduct its business in an environmentally responsible manner. Accordingly, the Company undertakes to: comply with the spirit and intent, as well as the letter, of environmental laws, regulations and standards; incorporate environmental protection and stewardship as an integral part of the design, construction, operation and maintenance of its facilities; encourage the wise use of energy to minimize the impact on the environment; communicate effectively on environmental issues; and conduct periodic self-evaluations and report performance.

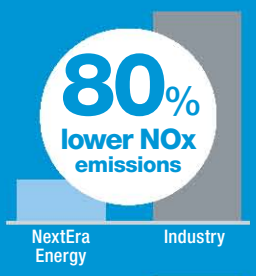
In conjunction with our environmental commitment and policy, NextEra Energy has defined five major areas of environmental focus: air emissions, water use, wildlife protection, waste minimization, and risk mitigation.

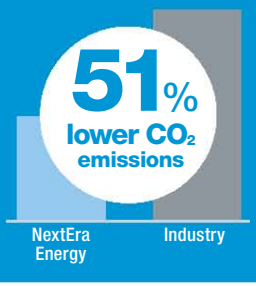
In 2011…

52 million tons of CO_2 avoided from zero-emitting generation and customer energy efficiency programs

Emissions rates better than our industry's average







Lower Air Emissions*

At NextEra Energy, we demonstrate every day that an electric power company can be clean and still provide low-cost, reliable electricity at the same time. In fact, FPL had the lowest average customer bill of any of the 55 utility providers in Florida for the third year in a row. In 2011, we recorded our lowest air emissions rates ever. In addition, our emissions rates were also significantly below national averages.

Our emissions rate for sulfur dioxide (SO_2) was 0.25 pounds per megawatt hour (MWh) in 2011, which was 90 percent below the U.S. electric sector average of 2.44 pounds per MWh. The company's emissions rate for nitrogen oxides (NOx) was 0.23 pounds per MWh in 2011 – 80 percent below the industry average of 1.13 pounds per MWh. And our emissions rate for carbon dioxide (CO_2) was 609 pounds per MWh in 2011, or 51 percent below the industry average of 1,244 pounds per MWh.

Even though our generation fleet has grown by 260 percent since 1990, we have managed to reduce our SO_2, NOx and CO_2 emissions rate by 94 percent, 93 percent and 36 percent, respectively, during the same time span. Achieving these industry-leading emissions rates is a result of our multifaceted approach.

See Page 33 for discussion of Environmental Attributes.

Pursuing Renewables

We are developing, building and operating zero-emissions renewable energy generation.

No. 1 in Wind Energy – NextEra Energy was one of the largest generators of wind-powered electricity in North America in 2011 with 8,569 megawatts (MW) of capacity at 88 facilities in 17 states and three Canadian provinces. In

2011 alone, we added 379 MW of wind generation in North America. Our roughly 8,800 wind turbines are capable of producing enough emissions-free energy to power more than 2 million homes.

Through 2011, we have invested more than $13 billion in zero-emissions wind generation. We estimate that more than 42,200 tons of SO_2, more than 24,500 tons of NOx, and more than 21.7 million tons of CO_2 were avoided in 2011 due to this wind generation. We are currently on track to add approximately 1,500 MW of new wind assets to our portfolio in the U.S. in 2012.

No. 1 Provider of Solar Energy – NextEra Energy is the largest generator of utility-scale solar power in the United States. The company co-owns and operates 310 MW of solar power at the Solar Electric Generating Systems (SEGS) sites in California's Mojave Desert.

Our rate-regulated utility in the Sunshine State, FPL, now has 110 MW of solar generation in operation. This includes our 75-MW Martin Next Generation Solar Energy Center in Martin County, the world's first hybrid solar power plant to combine a solar thermal array with an existing combined-cycle natural gas unit, and our 25-MW DeSoto Next Generation Solar Energy Center that debuted as the largest solar photovoltaic plant in the United States.

FPL supports the advancement of Florida's energy policy, and we have identified and permitted sites where more than 500 MW of new solar power could be built if the right policies were to be enacted.

NextEra Energy Resources continues to invest in solar power. We currently have long-term contracts in place for our four large-scale solar projects. Genesis, our 250-MW solar thermal project, consists of twin 125-MW units, which are expected to enter service in 2013 and 2014, respectively. The two 49.9-MW units at our Spain solar thermal project are on schedule to be operational in 2013. Desert Sunlight, a 550-MW solar photovoltaic project in which NextEra Energy Resources has 50 percent ownership, is expected to reach partial operations in 2013 and full operations in 2014. McCoy, our 250-MW solar photovoltaic project, is expected to reach partial operations in 2015 and full operations in 2016.



Supporting Customer Adoption of Electric Vehicles

Electric vehicles (EVs) reduce emissions, cost far less to "fill up" and maintain than a gas-powered car, and offer drivers cutting-edge technologies, safety and reliability.

FPL's Electric Vehicle Program supports customer adoption of EVs by addressing customer needs and serving as a source of information on EVs and safe, affordable charging. Because our typical residential customer bill is 24 percent below the national average, FPL customers enjoy an even greater value and can charge up for about 80 percent less than what drivers usually spend at the gas pump.

In addition to launching several customer-education initiatives, such as outreach presentations and demonstrations, FPL is actively working with municipalities, businesses and industry associations to share the expertise we've gained while building our green fleet.

As more EVs become available in our service territory, we will ensure the necessary infrastructure is in place to keep service reliability high.

Modernizing Fossil Plants

We are modernizing older, less-efficient fossil generation facilities and building efficient, state-of-the-art, clean, natural gas-fueled plants.

In 2011, FPL continued its efforts to modernize two 1960s-era power plants. Construction of the new Cape Canaveral Next Generation Clean Energy Center began in March, and site preparation work continued at the location of FPL's Riviera Beach plant. Both of the clean, highly efficient natural gas-fueled facilities, which are expected to be operational by mid-2013 and mid-2014, respectively, are projected to cut the CO_2 emissions rate in half and reduce air emissions by more than 90 percent when compared to the former plant.

In March 2012, FPL received state regulatory approval to modernize yet another 1960s-era power plant into a high-efficiency, natural gas-fired energy center. The company's Port Everglades plant, in Broward County, is expected to be operational in mid-2016.

As part of FPL's first "greenfield" power plant in many years, the third unit of FPL's new West County Energy Center came online in June 2011, making this state-of-the-art generating facility the largest combined-cycle, natural gas-fired power plant in the United States. West County is able to produce approximately 3,660 MW of electricity, enough to power approximately 750,000 homes and businesses.

Upgrading Nuclear Plants

NextEra Energy's nuclear fleet consists of eight nuclear units operating at five locations in four states. As of October 2012, the fleet generates a total of 5,966 MW of safe and reliable power.

Over the past two years, NextEra Energy has been working to upgrade six of these units through "power uprate" projects. Power uprates are a safe, proven way to expand the capacity of existing nuclear power plants while maintaining the same physical plant footprint.

To date, uprate projects have been completed on four of the six units (two at our Point Beach Nuclear Plant in Wisconsin, and one each at our St. Lucie

and Turkey Point plants in Florida). The final unit at St. Lucie is due to be completed in late 2012, and the final unit at Turkey Point is due to be complete in the spring of 2013.

The Point Beach uprate project, completed in 2011, added an additional 170 MW of emissions-free power to NextEra Energy Resources' existing clean energy portfolio.

In Florida alone, approximately $3 billion has been invested in the St. Lucie and Turkey Point plants. These investments are now expected to provide at least an additional 526 MW of clean, emissions-free energy to FPL customers and save customers nearly $4 billion in fossil fuel charges over the operating lifetime of these units. Additionally, the Florida uprate projects will reduce fossil fuel use by an equivalent six million barrels of foreign oil, 38 billion cubic feet of natural gas and reduce greenhouse gas emissions by an estimated 32 million tons over the life of the project, which is the U.S. Environmental Protection Agency (EPA)-equivalent of removing about five million cars from the road annually.

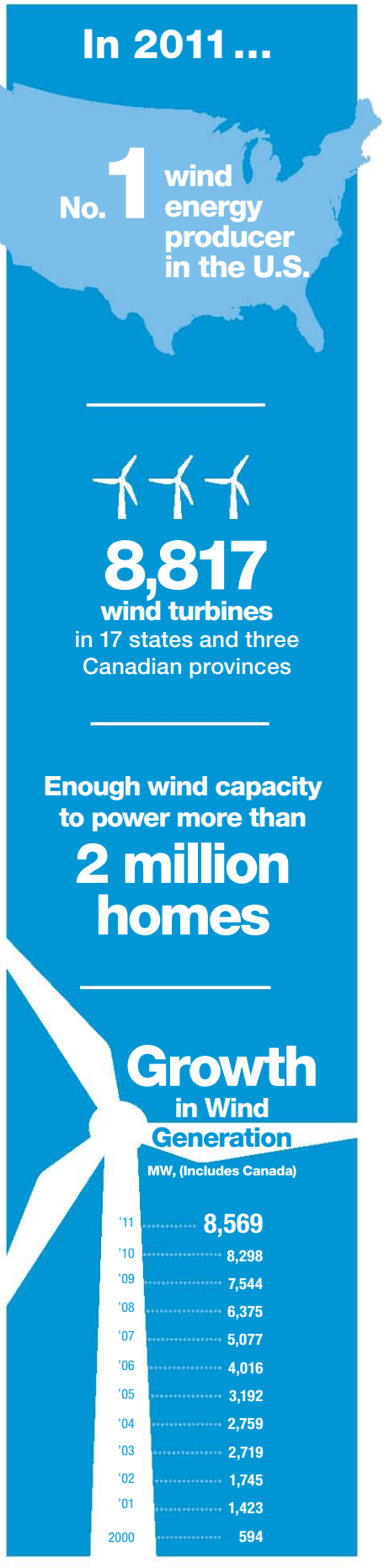
In addition, FPL is in the process of licensing two new nuclear units at its existing Turkey Point site. FPL projects these units would save customers approximately $58 billion in fossil fuel costs over the length of their initial operating license (40 years) if built.

Installing Emissions Controls

We are installing the best available environmental controls at fossil plants to dramatically lower air pollutant emissions.

NextEra Energy is committed to burning cleaner fossil fuels using the best-available generating technologies. In 2004, the company began installing emission controls to reduce particulate matter such as dust and dirt. To date, these controls have been installed in eight units in Florida, Georgia and Maine, and are currently being installed, or planned, at four additional units in Florida.

In response to the proposed regulation by the EPA of SO_2, NOx and mercury from coal-fired units, FPL has committed to install selective catalytic reduction, flue gas desulphurization, and activated carbon sorbent injection technology on Unit 4 at the Scherer plant in Georgia. FPL is a part owner of Unit 4 at Scherer, which is operated by Georgia Power, a subsidiary of Southern Company. Our actions will result in the Scherer unit having one of the lowest emission rates of air pollutants of coal-fired units in the United States once construction is complete in late 2012.



Carrying Renewable Energy to Where It's Needed

In addition to building renewable generation, we are also developing transmission to carry that power from the remote locations where it is generated to the population centers that use it. We own various transmission lines across the country and are pursuing additional large-scale opportunities to develop, build and operate transmission facilities.

Lone Star Transmission, NextEra Energy's regulated utility in Texas, has received approvals to construct, operate and maintain Competitive Renewable Energy Zone transmission facilities in Texas. Lone Star is now building an approximately 320-mile transmission line from West Texas to just south of Dallas to bring wind energy to major metropolitan areas. Plans are for the line to be operational in 2013.

Making Our Vehicle Fleet Cleaner

In pursuing a clean energy future, we at NextEra Energy go beyond our power generation infrastructure.

In fact, FPL was an early adopter of clean transportation technologies and today operates one of the largest green fleets in the investor-owned utility industry, with 1,700 biodiesel-powered vehicles and 471 plug-in or hybrid-electric vehicles. These represent 85 percent of our entire vehicle fleet. Using these vehicles has saved the company more than 565,517 gallons of fuel in 2011 alone, and reduced our carbon footprint by more than 5,000 metric tons of CO_2.

Our biodiesel hybrids operate on a custom-blended mixture of 20 percent soybean oil and 80 percent diesel fuel. Industrial hybrid-electric trucks use 40 to 60 percent less fuel than traditional diesel-burning trucks, and when used with biodiesel they reduce exhaust emissions as much as 90 percent.

Expanding EarthEra Renewable Energy Trust

Realizing that many individuals, businesses and organizations are seeking strategies to contribute to a low-carbon economy, NextEra Energy Resources launched the EarthEra Renewable Energy Trust in 2009. When customers purchase EarthEra renewable energy certificates and emissions reduction products, 100 percent of the proceeds support new renewable projects that will be built, owned and operated by NextEra Energy Resources.

As of June 30, 2012, approximately $44 million has been committed to the EarthEra Renewable Energy Trust.

Participants include: Becton Dickinson and Company, BNY Mellon, Citigroup, HSBC Bank, SAP, Unilever, National Geographic, Harris Bank, ING, Neenah Paper, Dow Corning, City of Denton, Texas, Monadnock Paper Mills, Office Depot, International Speedway Corp., Norwegian Cruise Lines, New York Universtiy, University of Denver, University of Phoenix, Port of Portland, PGA of America, Cisco Systems, CBRE Group, Inc., Honda Power Equipment, University of Washington Bothell, Interface, Inc., and Carey International.

More information about the EarthEra Renewable Energy Trust is available at **www.EarthEra.com**.



Robert Perrone, production technician, at NextEra Energy's 5-MW Paradise Solar Energy Center in Gloucester County, NJ. Paradise is the first site to be built solely with funds committed to the EarthEra Renewable Energy Trust.

The Water and Energy Connection

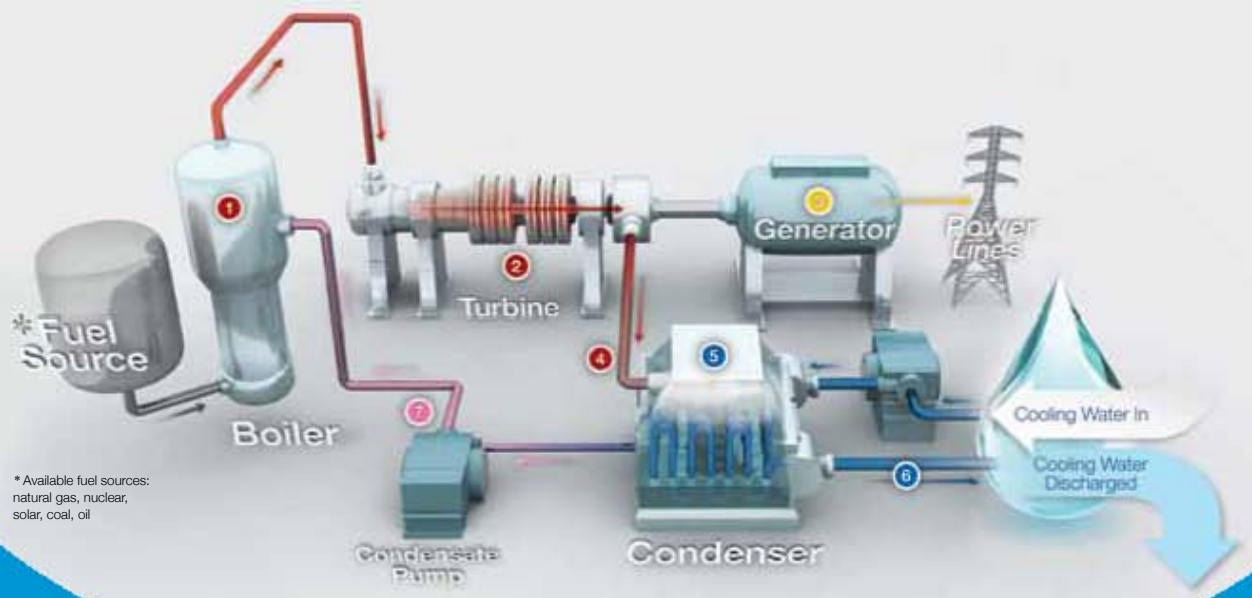
At NextEra Energy, we recognize that a critical connection exists between water and thermoelectric (steam electric) power generation. Water is used in two separate processes at steam power plants: 1) to produce steam to spin the turbines that produce electricity, and 2) as cooling water to cool various components and to condense the steam so that it can be reused. Because water is such an essential component of power production, NextEra Energy continuously works toward being a good steward of water resources and to become a leader in responsible water usage and conservation.

EPA, states and local water management districts regulate all withdrawals of surface water used as plant cooling water, to ensure that adverse environmental impacts are minimized and that each site has an approved water conservation plan. All of our facilities are required to obtain withdrawal permits and to evaluate their use of water every 5 to 20 years. This process typically includes looking at opportunities for recycling, minimizing usage and finding ways to use "lower quality" water such as reclaimed or non-potable water.

Where we must use water, our company strives to use the least amount of water per MWh of electricity produced. We also try to use reclaimed and other non-potable water wherever possible, so we are not competing for potable sources that need to be used for other purposes or may be more susceptible to drought. As in other areas of our operations, our water strategy emphasizes adopting best management practices in order to minimize our generating stations' environmental footprint while optimizing operational and financial performance.

Of the water NextEra Energy withdrew in 2011, nearly 78 percent came from marine (ocean and estuarine) sources, which are non-potable and drought proof. Importantly, approximately 98 percent of the water NextEra Energy withdrew for power plant cooling purposes was returned to its original source, such as an ocean or river. Some of our power plants use once-through cooling technology where water is immediately returned to its source. Others use closed-loop

Water Use By Electric Utilities - A Primer



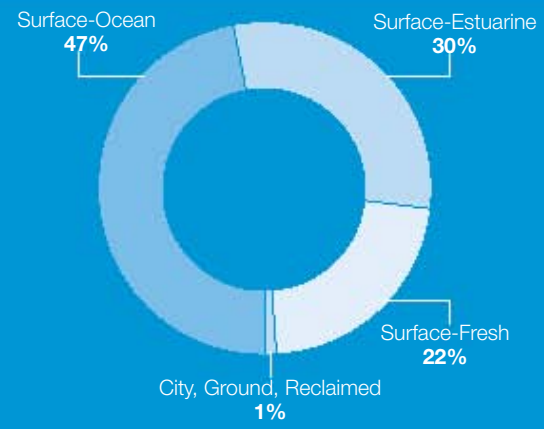
* Available fuel sources: natural gas, nuclear, solar, coal, oil



Ocean | Cooling Towers/Ponds | Rivers | City Wastewater | Lakes | Deep-Well Injection

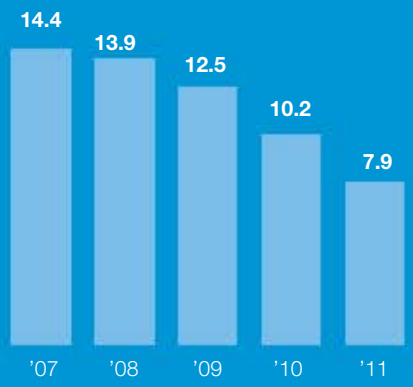
1. A *Fuel Source* heats up the process water in the *Boiler* converting it into steam.
2. The steam goes to the *Turbine*, making the blades turn.
3. The spinning blades turn the *Generator*, which generates electricity that is transmitted to homes and businesses via *Power Lines*.
4. The steam exits the *Turbine* and goes to the *Condenser*.
5. Cooling water is sent through the *Condenser* to cool the steam and convert it back into its liquid state (condensate).
6. The cooling water is either discharged back to its original water source, cooled and reused via cooling towers/ponds, or redirected underground.
7. *Condensate Pumps* send the process water back to the *Boiler* to be heated up by the *Fuel*, thus beginning the whole process again.

Where FPL Power Plants' Water Comes From



How NextEra Energy Conserves Water

2011 water withdrawal rate in thousands of gallons per MWh



cooling, which allows water to be reused continuously. Closed-loop cooling has the advantage of reducing the total amount of water withdrawn; however, water is not returned to the source and some is lost through evaporation.

Reducing Our Water Usage

Though the water footprint for generating electricity can vary tremendously depending on fuel type, generating efficiency, cooling technology, climate, geography, the body of water used for cooling and the physical layout of the power plant site, NextEra Energy's water withdrawal rate has steadily improved since we began tracking it in 2007. In 2011, our water withdrawal rate was 7,900 gallons per MWh of electricity produced, which is nearly 45 percent lower than our rate of 14,400 gallons per MWh in 2007. This improvement is due to greater efficiency and proper maintenance of equipment at our power generation sites that require water, as well as our increase in generation from renewables. Nearly 25 million MWh, or 14 percent of the more than 172 million MWh of electricity generated by NextEra Energy in 2011, came from wind or solar photovoltaic energy sources, neither of which require water withdrawals to operate.

Since water conservation is intrinsic to our business, we have established a Water Strategy Team to develop corporate-wide water management policies, strategies and plans that build on site-specific efforts and reflect our company's environmental commitment. The team is currently developing and implementing water use and management targets as well as risk assessment metrics that will help our facilities use water in a more sustainable way.

Addressing and Mitigating Water Supply Risks

In planning for new electric power generation facilities, one of our first steps is to conduct site-specific water analyses to select the appropriate generation and cooling technologies for the location. Next, we try to identify the lowest-quality water sources that meet our needs. These are important aspects of minimizing the water-related impact of our operations.

For existing generating sites, we employ water management and governance practices and goals that exemplify NextEra Energy's corporate culture of continuous improvement. Existing facilities are challenged to be innovative and to fine-tune their operations.

At our Bellingham power plant in Massachusetts and Sayreville plant in New Jersey, we use air-cooled condensers to minimize water demands. This technology is also proposed for our Genesis solar thermal power plant under development in California.

In addition, our Forney Energy Center in Texas and West County Energy Center in Florida use reclaimed water in the power generation process. Doing so offsets the demand for higher-quality water while providing a secondary beneficial reuse of municipal wastewater.

Wildlife and Habitat Protection

To enhance our commitment to sustainable operations, NextEra Energy adopts environmental policies and programs at the local level, where we can monitor the impact of existing operations and the potential impact of future operations on wildlife and their habitats. Many of these initiatives are detailed in the pages that follow, and at **www.NextEraEnergy.com/CorporateResponsibility**.

Land Conservation

As an energy company with a presence across much of the U.S. and in Canada and Spain, we respect the land where our facilities are located. We are constantly looking for ways to preserve and protect that land. During initial discussions about locating infrastructure, we consider the presence of any threatened or endangered species and the proximity to valuable wildlife corridors, wetlands or other ecologically important areas. Efforts are made to avoid these areas entirely. If development cannot be avoided, we seek to minimize and mitigate the impact to affected areas.

Protecting the Barley Barber Swamp

In 1972, when constructing the Martin power plant and cooling pond, FPL set aside the Barley Barber Swamp as a wildlife preserve. Located in western Martin County, the 400-acre area consists of a cypress-stand ecosystem that provides a rare glimpse of "Old Florida." A slough that retains surface water throughout much of the year, the Barley Barber Swamp sustains ancient cypress trees and is home to diverse fauna such as alligators, otters, wading birds and bald eagles. In addition to being a wildlife sanctuary, the site is also significant from an archaeological perspective. Pottery fragments and other artifacts have been found on the site, indicating use by Native Americans between 300 and 900 years ago. FPL has partnered with the Treasured Lands Foundation, a local non-profit organization, to provide free, public tours of the swamp. In 2011, more than 3,000 visitors enjoyed guided tours of this natural treasure.

For detailed tour information, please visit **www.BarleyBarber.org**.

Protecting Threatened and Endangered Species

Over the years, NextEra Energy has earned a reputation as a leader in the protection of threatened and endangered species.

FPL is making an important contribution to protect a number of vulnerable species. To that end, we follow all federal and state regulations including compliance with the Endangered Species Act, which is administered by the U.S. Fish and Wildlife Service (FWS) and the U.S. National Oceanic and Atmospheric Administration (NOAA) Fisheries Service.

For example, NextEra Energy Resources is working with scientists, non-governmental organizations (NGOs) and federal agencies to study and protect the black-capped vireo, whooping cranes and several species of bats.

Monitoring and Caring for Sea Turtles: For more than 30 years, FPL has embraced the monitoring and protection of sea turtles. Near our St. Lucie nuclear power plant on Florida's Atlantic coast, female sea turtles use the 2.5 miles of beach just east of the power plant as one of their most important nesting areas.

Due to the location of the plant and the design and operation of its intake cooling

water system, sea turtles sometimes inadvertently enter the plant's cooling canal system. Biologists are on site to monitor, remove and assess sea turtles that are found in the canal. An overwhelming majority of turtles are healthy and returned to the ocean after key biological data such as weight and body length are collected. Those with injuries or health issues are transported to an animal rescue center that the Florida Fish & Wildlife Conservation Commission recommends. Many are taken to Loggerhead Marinelife Center in Juno Beach, Fla., where experienced staff members have been treating and rehabilitating sick and injured sea turtles, as well as educating the public for more than 25 years. For more information on the Loggerhead Marinelife Center, visit **www.marinelife.org**.

During the summer months, FPL staff members conduct popular turtle walks along the beach to allow visitors to observe nesting turtles in their native habitat.

Enhancing Habitat for American Crocodiles: The American crocodile was on the brink of extinction in the late 1970s. Today, more than three decades after FPL produced a unique crocodile habitat at its Turkey Point power plant south of Miami, the crocodile is flourishing, and the U.S. government downlisted it from an endangered species to a threatened species – a notable accomplishment.

Turkey Point's 5,900-acre man-made cooling canal system offers ideal nesting conditions for the crocodile. Over the past 34 years, 5,943 hatchlings have been tagged from 377 recorded nests at Turkey Point. For the 2011 nesting season, FPL recorded 15 successful nests and 268 hatchlings. While the recorded hatchlings were lower than in previous years, they were comparable to the below-normal nest and hatchling numbers documented for North Key Largo and the Everglades National Park populations in 2011.



Twister, a loggerhead turtle, being transported to the ocean for release from the Loggerhead Marinelife Center (LMC) in Juno Beach, Fla. Found near FPL's St. Lucie nuclear plant, Twister was underweight, lethargic and covered with barnacles, and brought to LMC for rehabilitation and release.

Protecting Manatees: During cold weather, endangered Florida manatees congregate at the warm water outflows near FPL power plants. And for decades, FPL has been committed to protecting these marine mammals and to fostering public and employee education and support.

FPL has taken on a number of new initiatives for manatees.

- At our Riviera power plant – FPL demolished the aging Riviera Beach power plant in 2011 to make way for the new, state-of-the-art Riviera Beach Next Generation Clean Energy Center, and FPL has committed to build a manatee-viewing center adjacent to this modernized site. The company had operated one at the old site for years.
- At our Canaveral power plant – In 2010, FPL placed into service a temporary heating system at this facility in Brevard County so that manatees would continue to benefit from warm water during and after the demolition of this plant to make way for FPL's new Cape Canaveral Next Generation Clean Energy Center. The system will remain in service during the construction of the new facility, which is expected to be complete in 2013.
- Over the past year, FPL provided more than 3,000 brochures and bumper stickers to the public to promote manatee protection and conservation.

Promoting Sound Bird Research and Science: More than 400 species of birds call Florida home, and the state is also home to more than 1,300 bald eagle nests. As part of our continuing efforts to enhance our industry-leading Avian Protection Program, FPL has partnered with Normandeau Associates, Inc., to refine our industry-first Avian Risk Assessment Model to identify high-risk structures as part of our proactive retrofit program to make our poles and equipment more bird friendly. In 2011, we invested more than $9.2 million to retrofit

or construct more than 10,000 poles to avian-friendly standards.

Understanding the Impact of Wind Farms on Local Ecosystems

NextEra Energy recognizes that wind farms offer tremendous environmental advantages in the form of zero emissions and water use and believes they can be operated in a way that minimizes impacts on local ecosystems. The wind industry as a whole is in the process of gathering data to better understand bat and avian interactions with wind turbines to reduce or mitigate operational impacts on wildlife, specifically birds and bats.

In 2010, NextEra Energy Resources was one of the first wind energy companies to put a state-of-the-art, full-spectrum acoustic monitoring system on a turbine to measure bat activity at an operating wind farm. This pioneering approach, paired with a second year of data from other fieldwork, generated a rich database that is being analyzed to gain a better understanding of how bats navigate the wind farm and the turbines. In addition to this bat-monitoring project, NextEra Energy Resources has conducted extensive pre-construction bat acoustic monitoring at numerous other locations in the U.S. and Canada to help identify species and numbers of bats in prospective wind site development areas.

NextEra Energy Resources is also working hard to understand how birds nest and interact with habitats on a wind farm. Since 2009, we have gathered and analyzed extensive data on grassland and nesting birds, including the scissor-tailed flycatcher, eastern meadowlark, dickcissel, northern cardinal, white-eyed vireo and lark sparrow. In 2010, a workshop was held for FWS personnel to discuss findings and future areas of study. Results were also presented at two national conferences.

To enhance the conservation and maintenance of a migratory habitat for the endangered whooping crane in North Dakota, we have entered into a unique partnership with the American Foundation for Wildlife and Ducks Unlimited. Through our Baldwin Wind Energy Center, our company will provide a $200,000 Protection Fund, which will support conservation easements in the area, known as a high-use whooping crane migration corridor.

At NextEra Energy Resources, we have assisted the FWS for several years in gathering data about the black-capped vireo (BCV), an endangered, thumb-sized bird that lives in Texas and winters in Mexico. In 2010 and 2011, we funded research to support an in-depth study of the BCV at our Horse Hollow wind facility to understand the nature and extent of the relationship between commercial wind energy facilities and the habitat and fitness of shrub-nesting songbirds.



Max Avila, FPL materials management supervisor, holds an insulation jacket for an underground distribution cable. This insulation is one of many products recycled or refurbished at the company's Physical Distribution Center in Riviera Beach, Fla.

Minimizing Waste Across Our Operations

NextEra Energy is committed to reducing its waste footprint across its fleet and is actively seeking opportunities within our various businesses to identify and implement recycling and reuse programs.

Recycling Equipment and Materials

FPL has a major recycling program located at our Physical Distribution Center (PDC) in Riviera Beach, Fla. Working closely with our field operations team, our goal is to minimize waste sent to local landfills. Not only is this effort a benefit to the environment, it also benefits the community through its collaboration with the Palm Beach Habilitation Center, which provides employment for individuals with disabilities. In addition to the recycling efforts, FPL was able to save nearly $2.2 million by refurbishing old parts and manufacturing various adaptors and connectors in house, as well as generate nearly $6.2 million in revenues and credits from recycling

materials, which were reinvested in the activities at the PDC.

In 2011, we:

- Refurbished more than 148,000 pieces of hardware and 1,050 street light covers;
- Decommissioned and recycled more than 16,300 units of oil-filled equipment and 665 gallons of mineral oil;
- Recovered and recycled nearly 2.5 million pounds of scrap wire and 3.5 million pounds of scrap metal;
- Donated approximately 7,000 yards of wood to local recyclers; and
- Processed 352,580 pounds of paper and cardboard for recycling using the labor of employees from the Palm Beach Habilitation Center.

In addition to these efforts, NextEra Energy also works with contractors during remodeling and demolition projects to recycle materials instead of sending them to landfills. In 2011, our contractors recycled more than 98 percent of the demolition materials from our modernization projects at Cape Canaveral and Riviera Energy Centers. This included approximately 20,000 tons of ferrous metals, 1,400 tons of non-ferrous metals, and 30,000 tons of concrete at each site. We also recycled more than 416,000 pounds of carpet, which otherwise would have been sent to a landfill.

Each business unit continues to identify and pursue opportunities to recycle and reuse materials. While complete data is not available at this time, here are some highlights of our efforts.

A single-stream recycling program at our corporate offices in Juno Beach, Fla., yielded approximately 151 tons of material in 2011.

We recycled more than 4,400 pieces of electronics equipment totaling more than 220,000 pounds. This included more than 2,000 laptop and desktop computers and 600 monitors, which were sent to a certified e-waste recycler.

At our Pubnico Point wind site in Canada, provincial regulations require the site to separate materials and recycle 100 percent of the general waste instead of sending it to landfills.

In 2011...

96%

of energy was generated from clean or renewable sources

Net Energy Output

by Primary Energy Source and Regulatory Regime

NextEra Energy*

Primary Energy Source	Net Energy Output (MWh)	% of Total
Natural Gas	99,210,254	57.7
Nuclear	39,256,125	22.8
Wind	24,612,822	14.3
Coal	6,005,834	3.5
Hydro	1,713,196	1.0
Oil	845,808	0.5
Solar	402,035	0.2
Total	**172,046,074**	**100**

*See Page 33 for discussion of Environmental Attributes.
Excludes purchased power.

FPL (rate-regulated)

Primary Energy Source	Net Energy Output (MWh)	% of Total
Natural Gas	73,903,142	72.5
Nuclear	21,289,946	20.9
Coal	5,884,060	5.8
Oil	758,249	0.7
Solar	99,262	0.1
Total	**101,934,659**	**100**

Certain power plants owned by FPL generate renewable energy attributes, and those renewable attributes are for the benefit of FPL customers.
The MWs generated by the 75-MW Martin solar-thermal facility replace steam produced by the Martin combined-cycle unit and therefore are not incremental.
Excludes purchased power.

NextEra Energy Resources* (competitive)

Primary Energy Source	Net Energy Output (MWh)	% of Total
Natural Gas	25,307,112	36.1
Wind	24,612,822	35.1
Nuclear	17,966,179	25.6
Hydro	1,713,196	2.4
Solar	302,773	0.4
Oil	87,559	0.1
Coal	121,774	0.2
Total	**70,111,415**	**100****

*See Page 33 for discussion of Environmental Attributes.
**Reflects rounding.

Reducing Risk Through Environmental Auditing

Environmental risk management and mitigation are key drivers to ensuring safe and sustainable operations. At NextEra Energy, we have an environmental audit program to review and help ensure our facilities' compliance with environmental laws and regulations. These audits are a valuable tool to manage and mitigate our environmental risks and impacts, and to meet our stakeholders' expectations. This proactive approach helps identify potential noncompliance events, which can result in large fines or penalties from regulators, as well as negative attention from media and citizens. Good practices and improvement opportunities identified at one site are then shared with other sites.

Our Corporate Environmental Audit team conducts audits at various operational facilities, including power plants, distribution and transmission service centers and substations, office buildings and fuel oil terminals. In addition to the type of sites the team audits, the geographic diversity of our fleet requires the audit teams to understand the laws and regulations of different states. Facilities are typically audited once every four or five years, with higher-risk facilities audited more frequently. The audit team conducts multifaceted audits, where more than one environmental factor (air, water, waste, etc.) is assessed. In some cases, they audit the environmental management system or program that applies to more than one organization. In 2011, the audit team audited 48 sites across the company. In addition to these audits, all business units with identified or potential environmental risk exposure conduct regular self-audits and inspections to help reduce noncompliance events.

A Customer-Focused Business

Low Bills and High Reliability

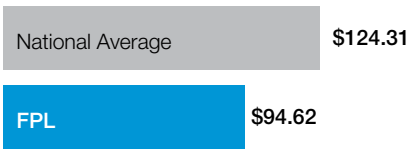
Most Affordable Electric Service in Florida

Because we have invested in smart, cost-efficient technologies and worked hard to keep operating costs down, FPL's typical residential customer bills were the lowest of the state's 55 electric companies serving Florida in 2011 and 24 percent lower than the winter 2012 national average, which was published in May 2012. Most FPL customers power all of the electricity needs of their home for a few dollars a day on average over the year (for more information, see **www.FPL.com/value**).

By installing state-of-the-art, combined-cycle, natural gas turbines at several power plants, FPL has cut fuel costs by $5.5 billion since 2001 and passed 100 percent of those savings on to customers. Fuel costs for our customers have averaged nearly $5 billion per year over the five years ending in 2011, so FPL's fuel efficiency since 2001 has saved our customers the equivalent of more than one year's supply of fuel.

We've worked hard to improve efficiency and productivity in every part of our business – in fact, FPL's operating and maintenance (O&M) performance ranks better than 90 percent of utilities nationwide – and we will continue to do so to help keep bills low.

FPL's Typical Residential Customer's Monthly Bill is 24 Percent Lower Than the National Average



All data as reported in EEI Typical Bills and Average Rates Report for Winter 2012, published May 2012.

Helping Customers Save Energy and Lower Their Bills

Beyond our own efforts to keep customer bills low, FPL customers who want to conserve energy and save money have numerous energy efficiency programs to choose from. Through 2011, FPL provided personalized energy efficiency recommendations to our customers through 3 million residential home energy surveys and 165,000 business energy evaluations. We provided 1.4 million rebates for high-efficiency residential air-conditioning systems, and installed upgraded lighting systems for nearly 20,000 business customers and air-conditioning upgrades for 16,000 business customers.

The nearly 800,000 FPL customers who have enrolled in the company's OnCall® Savings Program help control electrical demand during peak periods or emergency situations, help the environment and help keep all customers' bills low. Participating customers receive a credit on their monthly bill for allowing FPL to cycle off select equipment for short periods of time only when absolutely necessary.

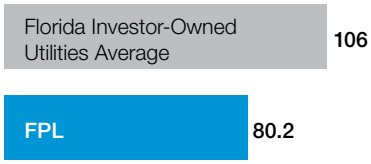
FPL accounted for 2 percent of the country's peak electricity demand in 2011, the most recent year for which data are available, and yet was responsible for 9 percent of the electricity demand avoided through energy efficiency. In other words, FPL avoided five times more electricity generation through energy efficiency than would be expected for a utility its size.

Thanks to our customers' participation in these and other energy-efficiency programs since 1981, we have eliminated the need to build 13 medium-sized power plants, saving our customers billions of dollars and reducing our environmental footprint substantially. In Florida we consider these demand-side management programs to be our "first fuel." Put another way, the cleanest and least expensive MW is the one that doesn't have to be generated in the first place.

For information on additional FPL customer programs, including those available to low-income families and others in need, please see Pages 16-17 of this report or visit our website at **www.FPL.com/customerprograms**.

FPL is No. 1 in Reliability Performance Among Florida's Investor-Owned Utilities for Five Years Running

5-Year Average (2006-2010) Minutes Without Power



Note: Power Systems SAIDI is an aggregate of Transmission and Distribution SAIDI performance. Florida Public Utilities Company (FPUC) is not included in the analysis due to its low customer base.

The Best Reliability in the State

FPL's strong service reliability ranks the best among Florida's investor-owned utilities and in the top 25 percent of comparable utilities nationwide. In Florida, FPL's overall reliability ranks No. 1 based on the past five years of reports filed with the Florida Public Service Commission by Florida's investor-owned utilities. FPL is proud to deliver better than 99.98 percent service reliability to its customers.

Investing in the Smart Grid

FPL is investing in smart grid technologies, including 4.5 million smart meters, as part of its commitment to building a smarter, more reliable and more efficient electric infrastructure. The company's smart grid initiative, Energy Smart Florida, will help keep service reliability high and give customers more information than ever before to better manage their energy use and costs. The company is also deploying more than 9,000 additional intelligent devices to



For about the price of a daily cup of coffee, we at FPL give our customers the energy they need to power their lives. We're working every day to deliver great value by providing the most reliable energy and the lowest bill in the state.

enhance the performance of the electric grid. FPL expects to complete its upgrade to smart meters in 2013.

Solid Financial Performance

Many observers view an organization's corporate responsibility in terms of its success in three areas: concern for the environment; economic or financial performance; and social responsibility. At NextEra Energy, we see these elements as a seamless whole. Our commitment to clean energy and environmental stewardship has been rewarded with financial success that, in turn, allows us to support the communities where we live and work and to invest in our employees who make it all happen.

Outperforming Our Peers in Total Shareholder Return and Dividend Growth

NextEra Energy continues to provide a strong track record of performance compared with our peers and the broader market. For the five years ending on Dec. 31, 2011, we delivered a total shareholder return of 33 percent, outpacing both the S&P 500 Index's -1.2 percent and the S&P Electric Utilities Index's 18 percent. Over the last decade, our performance is even more impressive, with a total return of 209 percent, compared with 33 percent for the S&P 500 Index and 129 percent for the S&P 500 Electric Utilities Index.

Dividends and dividend growth remain a core part of the overall value to NextEra Energy shareholders. For the 10 years ending Dec. 31, 2011, NextEra Energy achieved a compound annual growth rate in dividends per share of 7.0 percent, compared to 4.9 percent for the S&P 500 Electric Utilities Index.



Brad Tanzar is president of Florida Hydroseeding, a supplier that is responsible for cleaning mirrors at FPL's Martin Next Generation Solar Energy Center in Indiantown, Fla. As part of its commitment to ethics and integrity, NextEra Energy maintains a written Supplier Code of Conduct.

Continued Growth Opportunities

We have good growth opportunities at both of our businesses.

FPL expects to invest roughly $15 billion over the five-year period 2010 through 2014, or approximately $3 billion per year, in capital projects. Our regulatory capital invested is estimated to grow at an approximate 8 percent compound annual growth rate from 2011 through 2014.

At NextEra Energy Resources, we plan to invest in new generation opportunities where risk and return are aligned. The business is on track to add approximately 1,500 MW of new U.S. wind assets to the portfolio in 2012 and approximately 600 MW of contracted Canadian wind assets between 2012 and 2015. Additionally, NextEra Energy Resources expects to add roughly 900 MW of contracted solar generation to the portfolio between 2012 and 2016. NextEra Energy Resources plans to invest between $3.2 billion and $3.4 billion on wind projects between 2012 and 2014, and between $2.9 billion and $3.1 billion on solar projects between 2012 and 2014.

Maintaining Financial Strength and Discipline

One of the keys to our company's success has been financial strength, and our credit ratings are among the strongest in the industry. Our issuer credit rating is an "A-" at Standard & Poor's and a "Baa1" at Moody's – a result of pursuing projects that are strategic, financeable and enhance shareholder value.

Our financial position remains a key competitive advantage, particularly in a challenging economy. The company raised $7.3 billion in 2011 by accessing a variety of markets to support our strong credit position and enable us to invest wisely in future growth.

Integrity and Ethics Define Who We Are

Underscoring all of our business practices at NextEra Energy are three simple core values: We are committed to excellence.

Megawatts Saved Through Demand-Side Management Programs

Company	MW
Southern California Edison	4,770
FPL	4,097
Pacific Gas & Electric	2,808
Northern States Power - Minnesota	2,178
Progress Energy Florida	1,815

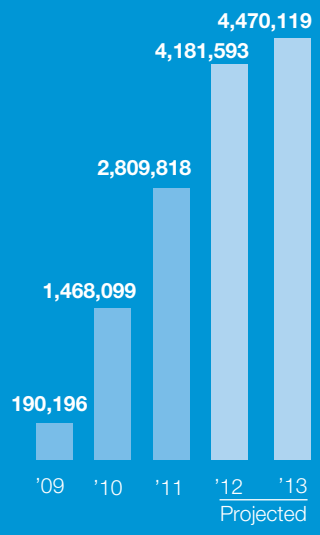
Source: U.S. Department of Energy, 2011

Customer Participation in FPL's Demand-Side Management Programs (1981-2011)

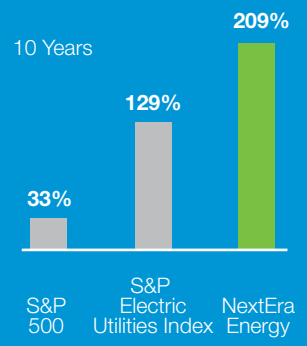
Residential Efficiency Programs	
Home energy surveys	3.1 million
High-efficiency A/C systems	1.45 million
Building envelope	807,986
Load management	799,812
A/C duct system tests and repairs	498,438
BuildSmart homes constructed	26,921

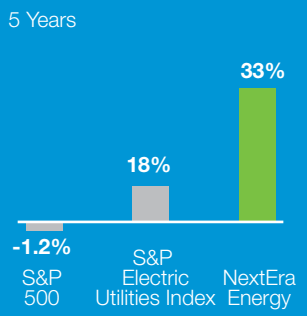
Commercial Efficiency Programs	
Business energy evaluation surveys	166,112
Small business load management	20,233
Upgraded lighting systems	19,962
High-efficiency A/C systems	16,319
Large business load management	943

Cumulative Smart Meter Deployment at FPL



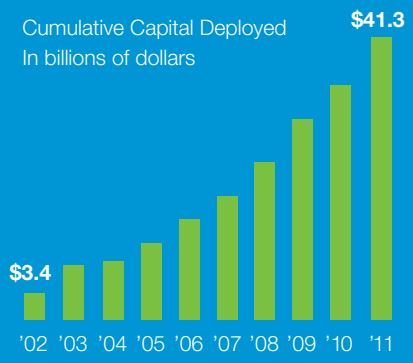
Total Shareholder Return

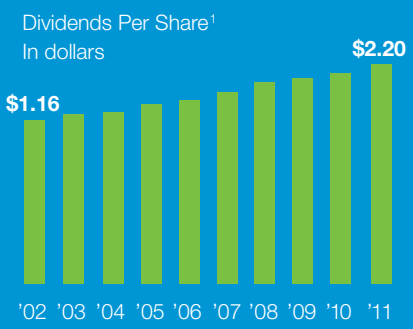




Source: FactSet. 10-year data Dec. 31, 2001 - Dec. 31, 2011; 5-year data Dec. 31, 2006 - Dec. 31, 2011.

Growth at NextEra Energy





[1] Annualized split-adjusted quarterly dividend. Dividend declarations are subject to the discretion of the board of directors of NextEra Energy.

We do the right thing. And we treat people with respect. Integrity and unquestioned ethics are at the very foundation of who we are, what we do, and how we do it. We expect all representatives of our company and our subsidiaries to act with the highest standards of personal and professional integrity, and to comply with all applicable laws, regulations and company policies.

These values are reinforced in numerous ways.

The NextEra Energy Code of Business Conduct & Ethics applies to all representatives of our company, including directors, officers and employees, temporary employees and all others who work with or represent us, directly or indirectly. Senior executive and financial leaders are also subject to a separate Code of Ethics for Senior Executive and Financial Officers. Both documents are available at **www.NextEraEnergy.com**, under Our Company, then Governance.

Every new employee is required to read the Code, and employees are regularly reminded of its importance. A training course on the Code is mandatory for all non-bargaining employees. Every year NextEra Energy's compliance department sends a mandatory electronic questionnaire to all non-bargaining employees certifying understanding and adherence to our Code of Business Conduct & Ethics, including disclosing any conflicts of interest as well as any gifts, meals and entertainment received from vendors during the prior year. Any employee who discloses any type of information receives a follow-up communication to better understand the nature of the issue so that the proper actions can be taken in compliance with all applicable laws.

The decisions made by our government have a tremendous impact on how NextEra Energy operates as a public company and competes in the marketplace. Accordingly, it is important that the company maintain a presence in the public policy arena to express viewpoints to legislators and regulators on key matters that impact how we operate as a business.

NextEra Energy operates a political action committee (PAC), the NextEra Energy PAC, according to all applicable federal

and state laws to assist our company in educating candidates on issues that directly impact our business, employees, customers and shareholders. The PAC is funded entirely by voluntary employee contributions and used solely for political purposes to support candidates, PACs and party committees. The PAC is governed by a Board of Trustees composed of employees from various areas of our business. NextEra Energy also operates a Florida state PAC known as a committee of continuous existence (CCE).

NextEra Energy PAC discloses activity to the Federal Election Commission at **www.fec.gov** and to the Florida Division of Elections at **http://election.dos.state.fl.us/**. Questions about the PAC may be directed to **NextEra-Energy-PAC@nexteraenergy.com**.

NextEra Energy also maintains a written Supplier Code of Conduct, which is designed to serve as a statement of policy and intent for prospective suppliers. The key provisions of the Supplier Code of Conduct have been incorporated and are invoked through the company's standard terms and conditions for enforceability. The Supplier Code of Conduct is available online at **www.FPL.com/suppliercode**.

The company has made available to employees many ways to report any actual or suspected violations of applicable laws or regulations, any actual or suspected fraud and any other violation or suspected violation of the Code of Business Conduct & Ethics. One option is via a 24-hour hotline administered by a leading third-party global provider of employee hotline services. Employees may also contact either a compliance officer or any member of the Audit Committee of the NextEra Energy Board of Directors.

The company prohibits any retaliatory action against any individual for raising in good faith concerns or questions regarding compliance with laws, regulations, our Code of Business Conduct & Ethics or other ethics matters.

Managing Risk Carefully and Thoroughly

In addition to doing the right thing, we believe that being successful requires careful and thorough attention to risk in its many forms. Being disciplined in managing risk plays a major role in our financial success.

At NextEra Energy, our chief executive officer also serves as our chief risk officer. In addition, many analytical and monitoring functions are conducted under the direction of our chief financial officer, senior vice president of internal audit and compliance, and general counsel. On a quarterly basis, our company's Corporate Risk Management Committee, comprising a broad range of officers and managers, meets to reach consensus on the top risks our company faces and discuss the appropriateness of any mitigation. The assistant controller serves as the committee chair and meets with our Risk Lead Team (composed of our chief executive officer, chief financial officer, corporate compliance officer and general counsel) on a semi-annual basis to discuss the findings of the Corporate Risk Management Committee. Also, on a semi-annual basis, our Corporate Risk Management Committee chair provides the Board of Directors' Audit Committee with a high-level assessment of company risks.

To us, good risk management means understanding all the things that can go wrong and their potential impact on our business, then making sensible choices about them. It also means understanding all the things that can go right – better than our base expectations – and making sensible trade-offs. A good risk management culture is one that understands the uncertainties that can affect our results and that takes appropriate actions in response to that knowledge. Our aim is to be prudent and in control, not to avoid taking risks.

For a more complete list of risks related to our business, please refer to Pages 24-35 of NextEra Energy's Form 10-K for the fiscal year ended Dec. 31, 2011.

More Help for Our Customers

As mentioned on Pages 12 and 15 of this report, we offer a range of programs to help our customers save energy and lower their bills. But our commitment to our customers does not end there. Due to our nation's current economic difficulties,

In 2012 ...

FPL's typical residential bill was the **lowest bill** in the state and



24% below the national average

FPL is proud to deliver better than **99.98% service reliability** to its customers

the number of our customers in need remains high. We believe it is imperative to engage partners, maximize resources, streamline processes and strive to provide the best possible services and assistance to those who need it most. In 2011, through a variety of activities that form FPL's ASSIST program, the company processed more than $49 million in payments to more than 181,000 customers in need. Here are a few of the other helpful programs we offer to make life a little easier for those in need.

Home Energy Makeovers

FPL community relations and customer service volunteers work with local governments, community organizations, conservation contractors and others to provide low-income homeowners with free Home Energy Makeovers, which can help homeowners save up to 25 percent annually on their utility bills. Through this collaborative effort, free energy-efficiency upgrades have been made to the homes of more than 700 low-income families since the program's inception – 150 in 2011 alone.

Non-Profit Energy Makeovers

A similar outreach program using a blended team of FPL and contractor partners helps non-profit organizations save thousands of dollars by making their facilities more energy efficient. In 2011, FPL performed these makeovers for the Boys & Girls Club in Fort Lauderdale, Epiphany Church Food Pantry in Port Orange, New Life Family Shelter in Miami, and the South Florida Science Museum in West Palm Beach.

FPL Care to Share®

Through this program, FPL provides emergency assistance to customers who are unable to pay their electric bills. In 2011, FPL raised more than $1.4 million for customers in need thanks to more than $350,000 in donations from FPL customers, $1 million from NextEra Energy shareholders and $90,000 from more than 1,700 employees. Every dollar donated is given directly to those in need through partner agencies such as The Salvation Army, and no tax-deductible donations are used for fundraising or administrative costs. Since 1994, Care to Share has raised more than $15.7 million to help approximately 68,000 families in need.

Assisting Special Needs Customers

FPL is committed to ensuring that all customers have access to the electricity-related services they need. To do so, FPL employees take numerous steps to address language, cultural, low-literacy and disability-related needs.

Addressing Language and Literacy Barriers

FPL web content (at **www.FPL.com**), as well as informational brochures and customer letters that pertain to safety, efficiency, savings, payment options and hurricane information, are available to customers in both English and Spanish. Additionally, 40 percent of our Customer Care Center staff is bilingual, speaking English and Spanish, while nearly 2 percent can handle inquiries from our Creole-speaking customers. Job aids written in Spanish assist our bilingual agents. Our Care Center's Integrated Voice Response Unit provides account information to customers in both English and Spanish. For the hearing impaired, FPL uses the 711-relay system.

Providing Sustainable Energy Solutions

NextEra Energy entities FPL Services, LLC (FPLS), FPL Energy Services, Inc. (FPLES), and NextEra Energy Solutions have devoted the past 24 years to developing, designing and implementing energy and water conservation solutions for large public and private institutions.

From 1997 to 2012, these companies have helped institutions save more than $107 million, reducing electricity consumption by more than 938,000 MWh and water consumption by more than 2.2 billion gallons – enough energy to power almost 78,200 homes for one year and enough water to fill 3,700 Olympic-size swimming pools. Additionally, the reduced energy consumption avoided emissions equivalent to the annual use of more than 97,600 cars.



FPL employee Rae Dowling (seated in foreground) joined a larger FPL team that performed a Home Energy Makeover for a customer in Sarasota, Fla. The money-saving, energy-conserving improvements can save customers as much as 25 percent on their utility bills each year.



FPL employees decorate a home in Ft. Pierce, Fla., as part of a Forgotten Soldiers Outreach holiday makeover.

Volunteering Our Time

At NextEra Energy, we take great pride in serving the communities in which we live and work. Our strongest link to the community is in our own employees, who donate thousands of hours annually to a wide range of projects that are close to their own hearts. In 2011, NextEra Energy employees dedicated more than 20,000 hours of time to various charitable organizations.

Power to Care Week

For the fourth year in a row, NextEra Energy employees, their friends and families fanned out throughout FPL's service territory for this massive community volunteer project. This year, more than 900 volunteers participated in 22 events in 10 Florida counties during the week of March 26-31, helping clean up beaches, landscape gardens, spruce up parks, paint homes and more.

Dollars for Doers

Company employees who volunteer at least 20 hours during a calendar year with a qualified 501(c)(3) organization can earn grants for the same organization thanks to NextEra Energy's Dollars for Doers program. Since 2009, more than 260 Dollars for Doers grants have helped to make a difference in our communities. Recipient organizations range from local Boys & Girls Clubs to other youth athletic associations and organizations like the Florida Highway Patrol Auxiliary Foundation.

Record-Setting United Way Campaign

Since 2000, NextEra Energy and its employees have donated more than $36 million and countless hours of volunteer work to United Way to improve lives and build stronger communities. In 2011, our record-setting campaign raised more than $3 million in pledges, and employees used a new giving system that made it easier for them to target where their dollars are directed as well as to keep track and log their volunteer efforts. Each year, donations support programs that

Making a Difference in Our Communities



assist youth in gaining skills to achieve their full potential in school and life, help those in crisis meet basic needs for food, shelter and clothing, prepare individuals and their families to become financially stable, and connect residents to available and affordable health services.

Race for the Cure

In 2011, FPL was a presenting sponsor for the Susan G. Komen Race for the Cure in West Palm Beach, for the 14th consecutive year. The race, which raises funds to fight against breast cancer, has one of the highest levels of FPL participation of any single event in Florida. In 2010 and 2011, more than 1,500 NextEra Energy employees united to raise nearly $150,000 in West Palm Beach, Orlando, Fort Myers and Miami.

Supporting Seniors

Community Care for the Elderly provides assistance to qualifying seniors aged 60 and over so they can remain in their homes or with their caregivers rather than relocating to institutional care living facilities. In 2011, FPL supported the Florida Council on Aging (FCOA) with funding from NextEra Energy shareholders. That assistance was matched by donations from partner organizations and individuals across the state. Together, these sponsorships enabled FCOA to conduct a grassroots advocacy campaign that helped increase funding for the program from the Florida Legislature.

Other Community Initiatives

NextEra Energy's charitable foundation donated $1.7 million in 2011 to projects and programs that contribute to the health and well-being of the people who live in the 35 counties FPL serves. FPL hosted Kettle Drives in several offices for the sixth straight year and we extended our support to many other groups, including: 211 Information and Referral Services, Alliance For Aging, Alzheimer's Association, American Red Cross, Children's Home Societies, Consumer Credit Counseling, Meals on Wheels, Retired Senior Volunteer Programs, and Senior Resource Alliance.

Education is Key to Our Future Success

Renewed Commitment to Science, Technology, Engineering and Math (STEM)

At NextEra Energy, we remain committed to doing our share to ensure students are prepared for the 21st century global marketplace. Here are a few examples of how we are helping.

Solar Education in Schools: Given that we are the U.S. leader in solar energy generation, we're using solar education as a platform to help open young students' minds to the many benefits of this clean, abundant energy source. We've already trained nearly 250 teachers on the importance of utilizing a diversity of fuels, the use of math and science in the real world, and how innovative technologies and approaches to problems can help solve complex challenges such as energy independence. FPL has also donated solar installations or made grants to more than 100 schools to give students hands-on learning tools that help spark their interest in solar energy and promote creative thinking.

School Shows and Programs: Our employees visit schools and classrooms across the country to involve students in new learning experiences. One example is the "Kid Wind" program, which educates teachers on wind energy so they can help their students better understand the value of renewable energy resources. Additionally, FPL sponsors science shows that visit about 100,000 students a year to help young people understand both how energy is created and why it's important.



Moeti Ncube, senior quantitative analyst at NextEra Energy Resources, is among more than two dozen employees who volunteer to mentor students at H.L. Watkins Middle School in Palm Beach Gardens, Fla. The program is being expanded in 2012.

Mentoring in Middle Schools: In 2011, FPL launched a pilot mentoring program at a middle school in Palm Beach Gardens, Fla. Twenty-eight NextEra Energy employees delivered motivational talks to 900 students. The program was so well received that it will be expanded to reach an additional four schools in 2012.

Adopt-a-Classroom: In 2011, FPL launched a new partnership with Adopt-a-Classroom that enables NextEra Energy employees to help STEM teachers purchase much needed supplies for the classroom. More than 900 gifts were matched in 2011 with plans to expand the program for the upcoming school year.

On-Site Energy Education: Near three of our nuclear power plants, NextEra Energy operates very successful energy education centers. Thousands of students, teachers and interested parties visit these sites each year.

Spurring Competition in the Classroom: NextEra Energy Resources employees helped sponsor and judge a competition at William T. Dwyer High School in Florida. Students made their business case for constructing a hypothetical wind farm, based on analytic and other tools used in the actual business.

Educational Resources: Some of our programs are more broad-based, such as the kid-friendly web pages on the company website that provides games, activities and general energy information (**NextEraEnergy.apogee.net/kids**).

Matching Gifts: Through NextEra Energy's Education Matching Gift program, full-time employees can donate up to $10,000 to any eligible school, and our foundation will match that contribution, dollar for dollar, up to a maximum of $50,000 annually per school.

Wind Technology Training: NextEra Energy Resources maintains partnerships with community colleges in Texas and Iowa to help the colleges develop the kind of training programs that result in qualified wind technicians. Texas State Technical College (Sweetwater) provides basic and intermediate electrical training for our

technicians. North Iowa Area Community College (Mason City) provides hydraulics training to our technicians. We have made numerous hires from these and other community college programs in the last two years.

Foundation Support in Texas: We have also provided educational support in Texas through the Forney Education Leadership Foundation through annual donations amounting to $185,000 over the past eight years.

Skilled Worker Pipeline Program: FPL and the International Brotherhood of Electrical Workers (IBEW) collaborated with Indian River State College (IRSC), located near our St. Lucie nuclear power plant, and Miami Dade College (MDC), near our Turkey Point nuclear power plant. The partnership resulted in an associate's degree program designed to prepare students to become mechanical maintenance, electrical maintenance and instrument and control technicians. To date, 200 program graduates received employment or promotion with FPL.

Commitment to Diversity: MDC is ranked first nationally for number of degrees awarded to Hispanics and African-Americans. The Nuclear Regulatory Commission recognizes the program's commitment to diversity and recently awarded a scholarship grant that will fund approximately 30 students' program tuition. The program ensures the requisite skilled workforce to support new reactors at our Turkey Point site, allows FPL to "grow its own" source of new and diverse workers, and supports our local community.

Dynamic Flow-Loop Simulator Project: With the support of the U.S. Department of Energy, vendors and the IBEW, FPL and IRSC are building a dynamic flow-loop simulator that includes pumps, valves, instruments and controls to illustrate the basic principles of thermodynamics, pressure and fluid flow, allowing the next generation of energy technicians to train on a fully functional device. FPL/IRSC STEM Summer Camps for middle and high school students will also use the simulator to capture interest in the energy sector. This device is featured in IRSC's new Brown Center for Innovation and Entrepreneurship, a state-of-the-art facility dedicated to STEM education with an emphasis on the energy sector.

Regional Center for Nuclear Education and Training: IRSC, with the support of FPL, received a significant National Science Grant to become a Regional Center for Nuclear Education and Training (RCNET). The RCNET ensures the demand for skilled nuclear technicians is met in a unified, systematic way in the Southeastern United States. RCNET will accomplish this by creating a comprehensive turnkey curriculum for technician tracks, developing or enhancing training programs at the regional colleges, providing STEM career paths to higher education and undergraduate research, and providing remote access to expensive and unique training components.

In 2011 ...



Awarded $230 million in contracts to small, minority- and women-owned businesses

Paid approximately $400 million in property taxes for the benefit of our communities



Record-setting United Way campaign **raised $3 million**

Serving FPL Customers from a College Campus

In a unique partnership with Florida International University (FIU), FPL opened a university-based Customer Care Center in 2011. The student-staffed center is the first of its kind and will help support FPL's efforts to strengthen its talent pipeline for the future.

After on-campus information sessions and a rigorous interview process, 21 FIU students were selected to join FPL's team of 475 customer service representatives responsible for handling 30,000 calls on any given day. The student employees handle calls from FPL customers on topics including account balance, bill payment options and service inquiries.

NextEra Energy employs more than 670 FIU alumni, making the school one of its top suppliers of graduates.

Piloting Renewable Energy and Smart Grid Curricula

FPL has received a $5 million grant to help develop educational curricula to train college and university students in the growing fields of renewable energy and the Smart Grid. NextEra Energy employees, along with Smart Energy Grid Associates and various college

and university partners, are working to develop the program, which is scheduled for completion in mid-2013.

Creating Economic Benefits for our Communities and Suppliers

Being a large and successful company enables us to benefit our communities in a variety of ways. These benefits include tax payments to localities, direct jobs, capital expenditures, and opportunities for countless suppliers large and small.

In Florida, NextEra Energy was the No. 1 taxpayer in 2011, paying more than $1 billion in taxes and business-related fees, including property taxes, use taxes, gross receipts taxes, and franchise fees. We were also the largest investor in Florida with $3.5 billion in spending on capital projects.

In property taxes alone, NextEra Energy paid $296 million to Florida governments in 2011. Property taxes are administered at the county level with all funds going directly into the communities the company serves. A breakdown of 2011 payments is as follows:

- 45.61 percent, or $135 million, went to local government in the form of support for county fire, police and other government services;
- 40.2 percent, or $119 million, went directly to schools;
- 11.15 percent, or $33 million, went to city governments; and
- 3.04 percent, or $9 million, went to other organizations such as water management districts.

Nationwide, NextEra Energy paid approximately $402 million in property taxes in 2011.

NextEra Energy also creates positive value in our communities by embracing a diverse business environment and promoting partnerships with qualified small businesses and minority- and women-owned businesses. From Oct. 1, 2010, through Sept. 30, 2011, small firms in Florida benefited from more than $138 million in contracts, minority-owned businesses nearly $52 million, and women-owned businesses $44 million. Moreover, on certain major construction projects we encourage prime suppliers to exercise reasonable efforts to seek and use local labor and other resources, whenever possible and cost effective.

Helping Grow Florida Jobs with Discounted Electric Service for New and Expanding Businesses

FPL launched a new Economic Development office in 2011 to work with state and local economic development organizations to encourage job creation within our service territory and help boost our state's economy. To that end, and with the support of our



NextEra Energy employees gather to support the Susan G. Komen Race for the Cure in West Palm Beach, Fla.

regulators, FPL now offers a special "Economic Development Rate" for FPL business customers that commit to bringing jobs to the state. For more information on this new rate for new and expanding businesses, please go to: **www.FPL.com/poweringflorida**.

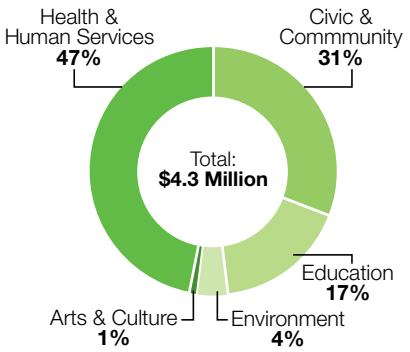
Engaging Our Customers and Other Stakeholders

Stakeholder engagement is a core activity across NextEra Energy. For decades, FPL has conducted community outreach to take into consideration the thoughts and concerns of citizens and community leaders. The company uses a variety of methods to gather and consider the input of interested parties prior to doing business in a community, and it continues these efforts as the projects transition from development to operation. Traditionally, these stakeholder groups have included residential and business customers, community organizations, government accounts, associations and non-profit organizations and, of course, our own employees.

This year, FPL created the Public Engagement Program (PEP). PEP's goal is to achieve stakeholder satisfaction and civic leadership by recruiting executives and employees of NextEra Energy and our subsidiaries to become involved in our communities. The program provides speakers from various areas of our company who make informative presentations to community organizations on issues facing our industry and impacting local communities. Through these speaking engagements, employees and executives build relationships and trust with our communities.

At the company's Nuclear Division and at NextEra Energy Resources, a comprehensive public affairs program reaches a wide range of stakeholders including legislators, regulators, opinion leaders, environmental organizations, academics, media and neighbors. Programs activities range from site tours and speakers bureau appearances to collateral materials, community newsletters and targeted web content. Also at NextEra Energy Resources, a variety of methods is used to gather and consider the input of local residents and community leaders prior to doing business in a community for the first time. These efforts then continue as the projects transition from development to construction and operation.

NextEra Energy Charitable Giving - 2011







Karine Hoffman, associate engineer, at FPL's Conservation substation in Sunrise, Fla.

Investing in Our Employees

At NextEra Energy, we take pride in providing our employees with a positive and engaging work environment, and we actively promote a culture of health, safety, continued learning and diversity. We believe an investment in our employees is a direct investment in our company's success.

Creating an Environmentally Friendly Workplace

We are committed to making environmental improvements at company work locations.

In Juno Beach, Fla., home to FPL, NextEra Energy Resources and other NextEra Energy subsidiaries, we achieved the prestigious Gold-level Leadership in Energy and Environmental Design (LEED) certification in 2011.

Developed by the U.S. Green Building Council, LEED is the nationally accepted benchmark for the design, construction and operation of high-performance "green" buildings.

A Comprehensive Wellness Program for Employees and Their Families

The NextEra Health & Well-Being program provides information, motivation and on-site facilities to help employees better care for themselves and their families.

The program consists of five distinct, but integrated, areas to help employees improve and maintain their health and well-being, including: fitness centers, health centers, health promotion, nutrition services, and an Employee Assistance Program (EAP), which helps employees and their families proactively address psychological concerns.

In 2011 ...

Employees completed nearly

150,000

corporate training courses, investing

357,240

hours

Corporate headquarters

received prestigious

LEED

environmental design certification

On-site

fitness centers

offered at

66

company locations

- Fitness Centers: On-site fitness centers are offered at 66 company locations, and 62 percent of eligible employees are enrolled, with 48 percent of those enrolled as active users. Sites with no fitness center have access to NextEra Energy's team of fitness professionals, who are available to design and send personalized workout information to any employee.
- Health Centers: With more than 21,000 visits to our on-site health centers in 2011, our employees and their family members received high-quality primary care and other services such as nutritional counseling, blood work, physical therapy and radiology services.
- Health Promotion, Weight Management and Nutrition Services: NextEra Health & Well-Being staff professionals made 422 on-site presentations to more than 12,000 employees in 2011 on topics ranging from healthy eating to back health and physical activity. In 2011, at 115 locations countrywide, more than 5,300 employees participated in on-site health screenings, an 11 percent increase over 2010. In an effort to keep families healthy during flu season, we also provide, at no cost, the annual flu shot vaccine to the majority of our locations for employees and their families. In 2011, we had 4,189 participants receive flu shots at more than 70 locations countrywide.
- Employee Assistance Program: More than 2,900 employees received some type of EAP counseling services in 2011, while the company provided 141 on-site educational presentations to more than 2,000 employees.

Helping Employees Stay Safe

NextEra Energy is working on many fronts to keep its more than 15,000 employees safe.

ZERO *Today!* – It's More than a Motto

NextEra Energy's ZERO *Today!* safety vision is intended to help the company achieve a zero-injury record across its operations. Under ZERO *Today!*:

- We promote an expectation of safe working practices, personal and peer-to-peer accountability for safety.
- We celebrate safe behavior and recognize those work groups and individual employees that have worked injury free.
- We continue to further refine our Safety Information Management System, which helps to drive a heightened level of safety responsibility among employees, supervisors and managers. Additionally, the system further prompts a higher level of analysis and loss prevention.
- The company has rolled out a comprehensive education program aimed at employees and management to ensure that "near misses" are appropriately reported and investigated, and that effective countermeasures are put into place. The act of identifying near misses serves as an early warning system for failures that can lead to injuries.
- Safety culture is an extremely important element of the success of a safety program. Therefore, the company recently administered a safety culture survey of our employees in field operations. The survey questions were carefully selected to assess our employees' perspectives on our safety culture and to help identify areas of opportunity.
- Many areas of the company have added additional safety training to their curricula, focusing on areas such as safety leadership, driver safety, and enhanced technical training.
- Our company-wide safety communications place a special emphasis on hazard recognition for field and office employees. The "What could go wrong" theme further supports our ZERO *Today!* goal.
- Our incident investigation processes have been further strengthened to better identify and understand root causes, leading to more effective countermeasures. Additionally, we are training our employees on advanced incident investigation techniques.

ZERO *Today!* stresses that safety is everybody's job. All managers ask every employee to include at least one safety goal as part of their annual performance objectives.

Safety in Collective Bargaining Agreements and Supplier Contracts

NextEra Energy's safety focus permeates all 10 collective bargaining agreements with its family of companies. Specific provisions address safety equipment, hazardous working conditions, and joint company-union involvement in the development of safety standards. For example, the agreement between FPL and the International Brotherhood of Electrical Workers System Council U-4 has a detailed company-union program including Local Joint Safety Advisory Committees, Business Unit Joint Safety Committees and a Corporate Joint Safety Committee. It also includes a comprehensive program for serious incident investigations using a specially trained union-management team.

NextEra Energy is committed to maintaining a safe working environment, including using suppliers with a demonstrated commitment to safety. In general, suppliers who have a presence on company premises of 30 or more cumulative person-days within 12 months are required to comply with the requirements of NextEra Energy's Supplier Safe and Secure Workplace policy whereby suppliers are expected to demonstrate an Experience Modification Rate (EMR) for safety purposes that is equal to or better than average for their industry. An EMR is a ratio that indicates how a company's Workers' Compensation losses compare to those of other companies with similar classifications. NextEra Energy maintains specific guidelines for the implementation of these goals and invokes them as requirements within supplier contractual agreements.

Enhancing Learning and Development Opportunities

NextEra University

NextEra University coordinates and delivers strategically aligned, enterprise-wide and business-unit-specific training and development.

It plays a key role in employee development with more than 1,500 classroom and online offerings in the following areas: Career Development, Commercial Skills, Corporate Culture,

OSHA Injury Rates, OSHA Illness Rates, Lost-Time Injury Rates and Number of Work-Related Fatalities for Each Region - 2011

Location	Hours Worked	Fatalities	All OSHA Cases	Lost-Time Cases	Illness Cases	Injury Cases	Lost-Time Rate	Illness Rate	Injury Rate	OSHA Rate
Fla. Region	22,307,500	0	106	36	3	103	0.32	0.03	0.92	0.95
Non-Fla. Region	7,961,400	1	32	10	0	32	0.25	0.0	0.80	0.80
Totals	**30,268,900**	**1**	**138**	**46**	**3**	**135**				

Lost-Time Rate = no. of lost-time cases x 200,000 divided by actual hours worked; Illness Rate = no. of OSHA illness cases x 200,000 divided by actual hours worked;
Injury Rate = no. of OSHA injury cases x 200,000 divided by actual hours worked; OSHA Rate = no. of OSHA injury cases + no. of OSHA illness cases x 200,000 divided by actual hours worked.

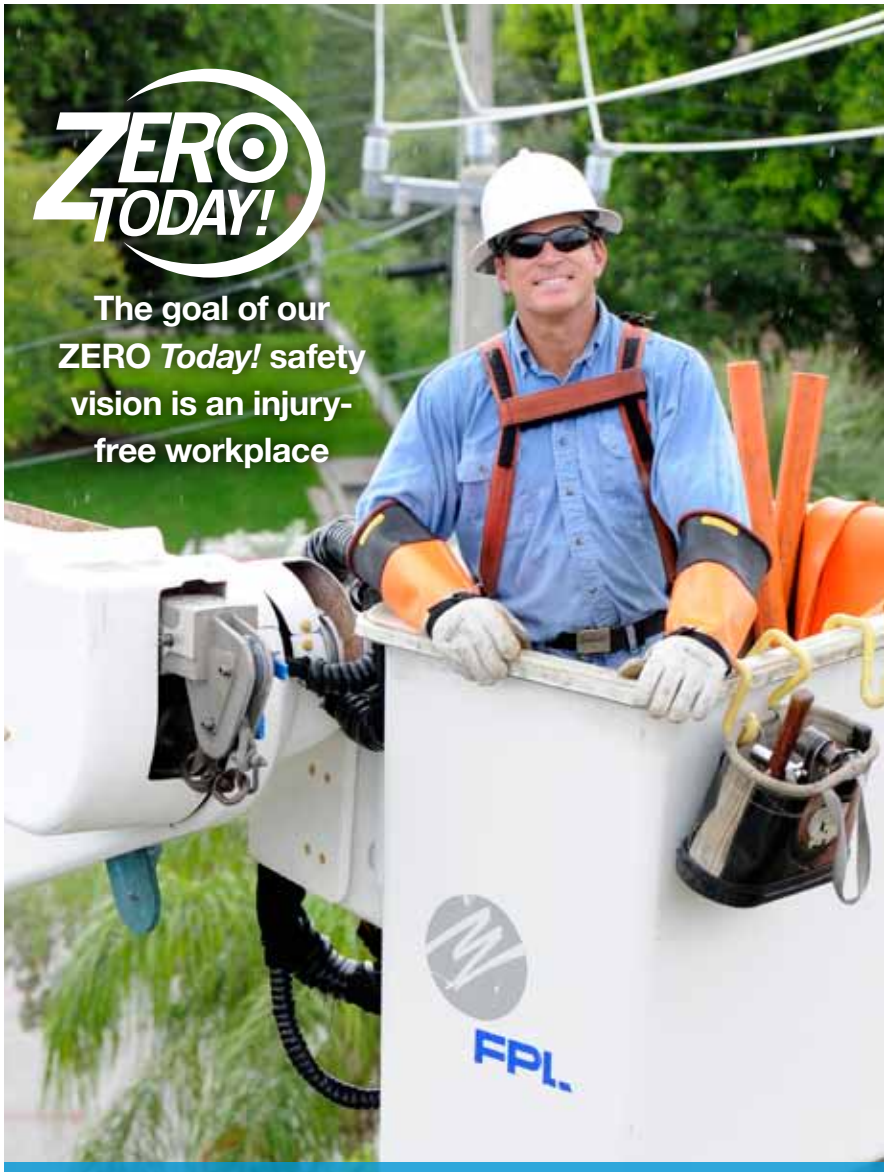
Leadership Development, Personal & Professional Effectiveness, Process & Project Management.

Our colleges represent the major sectors of our business: College of Customer Service, College of Information Management, College of Nuclear Power, College of Power Generation, College of Distribution and College of Transmission/ Substation. These provide employees of specific business units the knowledge and skills necessary to thrive at their jobs.

In 2011, our employees completed 146,951 corporate training courses, including online and instructor-led courses, investing a total of 357,240 hours in training.

Education Assistance Program

For more than 30 years, our Education Assistance program has helped employees pursue formal education in areas that align with the needs of our business by covering a portion of their tuition expenses and enrollment fees. Employees are eligible for assistance benefits immediately upon hire and may pursue undergraduate degrees, graduate degrees or individual college courses in areas such as business administration, computer science, engineering, finance, human resources and marketing.



FPL senior line specialist Nick Amuso is among the 15,000 NextEra Energy employees committed to safe work practices. The company's ZERO *Today!* safety vision includes components such as training, communications, incident reporting and investigation, and recognition.

Valuing Talent and Performance

In addition to enhancing talent through education, NextEra Energy applies a rigorous methodology to ensure employee engagement initiatives continuously assess and address employee needs.

Valuing Employee Engagement

At NextEra Energy, we value employees who are committed to the work we do. After all, it's been shown that when employees are engaged, they do their best work and their companies achieve exemplary business performance.

As we have regularly surveyed NextEra Energy employees to gain insight into the aspects of engagement that are most important to them, four areas of special focus have emerged: career development, leadership and trust, work-life balance, and rewards and recognition. To address these areas, the company initiated senior executive outreach sessions, a career discovery workshop, an enhanced onboarding experience for new employees, and career mapping to help employees better plan and manage their opportunities for advancement.

In 2011, we completed preparations to incorporate corporate values into the 2012 employee performance appraisal process. To reinforce the role everyone plays in employee engagement, all employees received an Employee Engagement Game Plan that they could use as a tool to identify actions to improve their personal engagement. Sharing of best practices occurred through the distribution of an Initiative Resource Guide. In addition, two pulse surveys were conducted with randomly selected employees to monitor progress and the results indicated positive progress was occurring.

In January 2012, we conducted our fourth corporate-wide survey. Eighty-one percent or 12,024 of our employees participated, with bargaining employee participation nearly doubling from 2010. We found that 64 percent of NextEra Energy employees are engaged – that's above the Aon Hewitt U.S. norm and on the cusp of their "best employer" range, which begins at 65 percent.

At NextEra Energy, through our engagement strategy we want to attract and retain the right people to achieve our business goals and objectives. As well, we want to create a culture that fosters the willingness of employees to voluntarily commit themselves to NextEra Energy and that inspires their loyalty to work for us.

Enforcing Equal Employment Opportunity and Non-Discrimination

At NextEra Energy, we adhere strictly to U.S. equal opportunity and non-discrimination laws. Even as our operations outside the United States are very limited, we support global efforts to oppose child labor, forced compulsory labor and violations of indigenous peoples. Our equal employment opportunity policy requires employees and supervisors to promptly report any harassing conduct or discriminatory practice they experience, witness or of which they have knowledge. We provide multiple reporting avenues. Employees are encouraged to report concerns to their supervisors, a company human resources representative, or our equal employment opportunity office via a toll-free hotline where they can raise their concerns confidentially.

All complaints of discrimination are thoroughly investigated, and appropriate remedial action is taken where warranted. No employee is subject to retaliation for good-faith reporting of harassing or discriminatory conduct. Each allegation is handled promptly and confidentially.



Michael McLaughlin, FPL's director of talent, acquisition and compliance, talks to summer interns gathered at the company's corporate headquarters. The students, who were placed within almost every functional area of the business, received valuable work experience in the ever-changing energy industry.

Embracing Diversity and Inclusion

By leading respectfully, promoting teamwork, building a diverse and inclusive team, and investing in development, we strengthen and engage our greatest asset – our people.

A Core Belief in Strength Through Differences

NextEra Energy is committed to fostering an inclusive business environment that values and leverages the diverse talents, perspectives and ideas of all employees. We believe that a focus on diversity and inclusion can directly impact our bottom line. Our customer base is very diverse, and we believe it is important to have a workforce whose diverse perspectives and experience enable it to be responsive to the varied needs of our customers.

Through the Office of Diversity and Inclusion, in partnership with the Corporate Diversity Council, we have integrated the standards of diversity and inclusion into our corporate culture. We have also created a variety of mechanisms to ensure the company is maximizing the power of diversity, including:

- **Employee Network Groups (ENGs):** At NextEra Energy, more than 700 employees are actively engaged in 10 ENGs: African-American Professionals; Asian Professionals in Energy; Disability Awareness and Support; Lesbian, Gay, Bisexual, Transgender and Allies; Military/Veterans; Next Generation in Nuclear; Toastmasters Club (two groups); Women in Energy; and Young Aspiring Professionals in Energy. These groups promote an inclusive business environment and enhance employee engagement through information sharing, career development, team building and networking opportunities.
- **Soliciting Employee Feedback:** We included a set of diversity and inclusion questions on the company's employee engagement survey.
- **Workforce Training:** Online and classroom resources are available to help employees embrace our commitment to diversity and

inclusion. The diversity and inclusion training is a part of the core training curriculum for leaders.

» **Community Outreach:** NextEra Energy actively supports various local and national partnerships, including the Urban League of Palm Beach County, Catalyst, American Association of Blacks in Energy, Executive Women of the Palm Beaches and more.

Diversity Through Recruiting Practices

Our internal recruiting team leverages a suite of recruiting tools and practices to ensure a diverse candidate pool. We use print media, advanced Internet searches, candidate referrals, college recruiting, third-party staffing and executive search firms, and posting to targeted websites. Our recruiters regularly attend events of diverse organizations, professional associations, military and veterans groups, and individuals with disabilities across the country. Here are some examples of these efforts:

» **Professional Diversity Organizations and Events:** In 2011, we attended career fairs for organizations such as the American Association of Blacks in Energy, the Society of Women Engineers, the National Society of Black Engineers, the 10th Annual Asian Diversity Career Expo, Asian MBA Expo & Career Fair, Careers and the Disabled Career Expo for People with Disabilities, Women for Hire Career Fairs, National Urban League Conference & Career Fair, Kappa Alpha Psi National Conference, and many others.

» **Military Recruiting and Partnerships:** In partnership with the Non-Commissioned Officers Association (NCOA) and **Military.com**, our recruiting team is scheduled to attend at least 10 military career fairs during 2012. We partner with military transition offices and local veterans employment representatives seeking advance notice of exiting military personnel, and we are continuing NextEra Energy's relationship with the U.S. Army's Partnership for Youth Success (PaYS) program. PaYS provides youth with an opportunity to serve their country and then interview for a job with our company after completing a one-term enlistment.

College Internships

NextEra Energy has revitalized the college intern program for 2012 by standardizing a corporate platform and has doubled the number of interns. The purpose of the internship program is to provide a meaningful and productive learning experience for each student employed with NextEra Energy while building a talented and diverse pipeline of future employees.

NextEra Energy offers a range of opportunities for qualified individuals. The goal is to develop new talent and test candidates for a right fit for future, full-time employment by offering relevant work experience on challenging projects and assignments. Interns must have a GPA of 3.0 or higher and be enrolled currently as full-time students in a bachelor's degree or higher in the appropriate course of study. Most internships will last eight to 12 weeks. Once the internship is completed, students will be evaluated for possible rehire the following summer or full-time employment.

We're looking for the best and the brightest college students to help shape the future of clean, renewable energy.



Employees celebrate NextEra Energy being named No. 1 in its sector for the sixth straight year in *Fortune* magazine's "Most Admired Companies" rankings.

Awards and Recognition

Dow Jones Sustainability Index

NextEra Energy was named in 2012, 2011, 2010 and 2009 to the Dow Jones Sustainability Index (DJSI) of the leading companies in North America for corporate sustainability. The DJSI North America selects the top 20 percent of companies in sustainability performance from the 600 largest companies in North America.

EEI National Key Accounts Award

The nation's leading chain and multi-site businesses recognized FPL with the Edison Electric Institute's 2011 National Key Accounts Award for Outstanding Customer Service. The award is given to companies that provide service to national account organizations above and beyond normal expectations by truly recognizing and responding to the account's "uniqueness." More than 700 companies voted in the awards program, including national brands such as Best Buy, HealthSouth, Staples, Starwood Hotels, The Limited and Walmart.

Fortune World's Most Admired Companies

In 2012, NextEra Energy was named No. 1 in its sector for the sixth straight year on *Fortune* magazine's "Most Admired Companies" rankings. In the 2011 *Fortune* ranking, the company was named one of the top 10 most socially responsible companies in the world.

Computerworld 100 Best Places to Work in Information Technology (IT)

NextEra Energy has been selected as one of *Computerworld*'s "100 Best Places to Work in IT" for 2012. *Computerworld*'s list is based on an evaluation of companies' offerings in categories such as benefits, diversity, career development, training and retention. In addition, a company's IT employees are surveyed by *Computerworld*, and their responses factor heavily in determining the rankings. Topics covered in the survey included satisfaction with training and development, compensation, benefits and work/life balance.

Ethisphere Honors for Compliance and Ethics

Ethisphere magazine, which provides third-party verification of compliance programs and ethical cultures, has conducted a review of NextEra Energy's compliance program against federal guidelines and has notified us that we have received a Compliance Leader Verification designation through Dec. 31, 2013. According to *Ethisphere*, this designation recognizes companies with "best-in-industry compliance programs," and those that "proactively invest resources in compliance, sending a clear signal to key stakeholders that your company takes compliance and ethics seriously."

In addition, for the fifth straight year NextEra Energy in 2011 was named one of the World's Most Ethical Companies by *Ethisphere*. Of the 110 firms named to the World's Most Ethical Companies list last year, only two were from the U.S. energy and utility sector.

ServiceOne Award for Exceptional Customer Service

In 2011, FPL again earned the ServiceOne Award for exceptional customer service, which is presented annually to utility companies by the worldwide consulting firm PA Consulting Group. FPL is the only utility to win this award eight consecutive years. The company achieved first quartile performance based on 27 objective measures of excellence. FPL also received ServiceOne Balanced Scorecard Achievement Awards for its customer care, billing, meter reading and field meters departments. These awards recognize excellence in specific areas of customer service.

A Best Employer for Healthy Lifestyles

NextEra Energy was honored in 2012 by the National Business Group on Health for its commitment and dedication to promoting a healthy workplace and encouraging its workers and families to support and maintain healthy lifestyles. The company was the only one in its industry sector and one of just 13 U.S. employers outside the health care industry to receive the 2012 Best Employers for Healthy Lifestyles Award in the prestigious Platinum category. That designation honors companies for their "established healthy weight, healthy lifestyles programs with measurable success and documented outcomes." This marks the sixth year NextEra Energy has received a Best Employers for Healthy Lifestyles Award.

E SOURCE Honors for Large Business Customer Satisfaction

FPL earned first place in the national 2011 E SOURCE Gap and Priority Benchmark survey for value provided to its large business customers. FPL received high scores in all categories, including satisfaction with account representatives and value provided relative to the price paid for energy.

TreeLine USA

For nine consecutive years through 2011, FPL has been recognized as a Tree Line USA utility. Sponsored by the Arbor Day Foundation in cooperation with the National Association of State Foresters, the recognition is afforded utilities that demonstrate quality tree care practices, annual worker training, and public education programs such as FPL's Right Tree, Right Place campaign.

A U.S. Leader in Diversity

NextEra Energy was named by Hispanic Business Media in 2012, 2011 and 2010 as one of the nation's leading companies for diversity practices. To assemble the list, the organization analyzed data on companies' boards of directors and leadership, recruitment, retention and promotion, marketing and community outreach, and supplier diversity.

Electrical Engineering and Solar Power Awards

In July 2012, retired FPL President and Chief Executive Officer Armando Olivera received the Leadership in Power Award from the Power & Energy Society of the Institute of Electrical and Electronics Engineers, the world's largest association for the advancement of technology. The recognition honors those who have supported the electric power engineering profession. Prior to his retirement, in October 2011, Armando was named Utility CEO of the Year by the Solar Electric Power Association.

Company Profile

NextEra Energy, Inc. (NYSE: NEE), through its subsidiaries, is a leading clean energy company with revenues of more than $15.3 billion, more than 41,000 megawatts of generating capacity, and approximately 15,000 employees in 24 states and Canada as of year-end 2011. Headquartered in Juno Beach, Fla., NextEra Energy's principal subsidiaries are Florida Power & Light Company, which serves approximately 4.6 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country, and NextEra Energy Resources, LLC, which together with its affiliated entities is the largest generator in the United States of renewable energy from the wind and sun. Through its subsidiaries, NextEra Energy generates clean, emissions-free electricity from eight commercial nuclear power units in Florida, New Hampshire, Iowa and Wisconsin. For more information about NextEra Energy companies, visit these websites: **www.NextEraEnergy.com, www.FPL.com, www.NextEraEnergyResources.com**.

Board of Directors – Composition by Classification

- Executive directors: 2 (Executive Chairman; President and CEO)
- Independent directors: 12
- Total: 14

NextEra Energy's executive chairman serves as Chairman of the company's Board of Directors, and the Board also has an independent Lead Director. The Governance & Nominating Committee is responsible for recommending to the Board the selection and nomination of Board members. The company's Corporate Governance Principles & Guidelines, a copy of which is available in the Governance section of NextEra Energy's website at **www.NextEraEnergy.com/corporategovernance**, contains Board membership qualifications, including experience, skills and attributes that are considered by the Governance & Nominating Committee in recommending non-employee nominees for a position on the Board. The selection of top management is a Board function, with remuneration set by the Compensation Committee.

All corporate governance documents comply with applicable New York Stock Exchange and U.S. Securities and Exchange Commission requirements. Non-executive directors are required to own shares valued at five times their annual retainer within three years of Board election. The full Board and each Committee perform annual self-assessments. A variety of processes are also in place for the Board to ensure that conflicts of interest (COI) and even the appearance of conflicts are avoided. NextEra Energy has implemented a variety of methods for preventing and reporting COIs in the workplace, including



Members of the NextEra Energy Board of Directors tour FPL's St. Lucie Nuclear Power Plant, July 27, 2012. In 2011, FPL began the process of upgrading the St. Lucie and Turkey Point nuclear plants to produce additional needed electricity, without expanding the footprint of the plants. These upgrades will save FPL customers billions of dollars in fossil fuel costs over the plants' lifetimes.

processes for disclosing potential COIs, auditing mechanisms to detect conflicts, and employee communications and training to promote compliance.

Environmental, Sustainability and Corporate Responsibility Reporting History

FPL was one of the first electric utilities in the United States to form an environmental department. Starting in the mid-1970s, FPL began reporting on its environmental performance on a regular basis in the form of environmental reports. Over time, these reports have become broader and more detailed. Today, FPL's parent company, NextEra Energy, produces a regular corporate responsibility report. This is the company's sixth such report. The first covered mainly 2006 activities, the second covered the company's 2007 environmental and social initiatives, and the three most recent reports, published annually since 2009, summarized our activities related to environmental excellence, social involvement and economic performance.

This 2012 edition of the report includes mainly 2011 activities and covers operations in the United States, Canada and Spain for NextEra Energy's businesses and subsidiaries – including FPL and NextEra Energy Resources – in addition to certain aspects of supplier relationships.

Over time, NextEra Energy has made a significant effort to ensure the report reaches a wide variety of stakeholders. In 2010, a cross-functional team determined that these reports should contain more information on the company's environmental, economic and social performance, and reach a more comprehensive audience than ever before, including investors, community leaders, state and local government leaders, and environmental and social-interest groups. Much of the information contained within the report is also reported to state and federal regulatory agencies such as state public service commissions, the U.S. Securities and Exchange Commission, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and other agencies.

In producing the 2012 report, NextEra Energy has used generally accepted reporting measures in the electric utility industry. In addition, we use the Global Reporting Initiative's (GRI) Electric Utility Sector Specific Guidelines. GRI is the most widely used sustainability reporting framework. We currently assess our GRI application level to be at level B, based on a self-evaluation of our report's contents. A GRI Index is available at **www.NextEraEnergy.com/CorporateResponsibility**. For more information on GRI, you can visit **www.globalreporting.org**.

We intend to continue to produce these reports annually. Feedback on our corporate responsibility initiatives is welcome and encouraged. Please contact NextEra Energy at 561-691-2655 or via email at **corporateresponsibility@NextEraEnergy.com**.

NextEra Energy Governance Structure

Below is a list of members of the Board of Directors and the committees on which they serve, effective July 27, 2012. For a description of each committee charter, please go to **www.NextEraEnergy.com/investors/governance.shtml.**
C = Chairperson / M = Member

Director	Audit	Compensation	Executive	Finance & Investment	Governance & Nominating	Nuclear
Sherry S. Barrat	M		M		C	
Robert M. Beall, II		M		M		
James L. Camaren	M				M	
Kenneth B. Dunn		M		M		
J. Brian Ferguson		C	M		M	
Lewis Hay, III			C			
Toni Jennings		M		M		
Oliver D. Kingsley, Jr	M					M
James L. Robo			M			
Rudy E. Schupp		M	M	C		
John D. Skolds						M
William H. Swanson	M				M	
Michael H. Thaman	C		M			
Hansel E. Tookes, II		M			M	

Cautionary Statements and Risk Factors that May Affect Future Results

This report contains "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are not statements of historical facts, but instead represent the current expectations of NextEra Energy, Inc. (NextEra Energy) and Florida Power & Light Company (FPL) regarding future operating results and other future events, many of which, by their nature, are inherently uncertain and outside of NextEra Energy's and FPL's control. In some cases, you can identify the forward-looking statements by words or phrases such as "will," "will likely result," "expect," "anticipate," "believe," "intend," "plan," "seek," "aim," "potential," "projection," "forecast," "predict," "goals," "target," "outlook," "should," "would" or similar words or expressions. You should not place undue reliance on these forward-looking statements, which are not a guarantee of future performance. The future results of NextEra Energy and FPL are subject to risks and uncertainties that could cause their actual results to differ materially from those expressed or implied in the forward-looking statements. These risks and uncertainties include, but are not limited to, the following: effects of extensive regulation of NextEra Energy's and FPL's business operations; inability of NextEra Energy and FPL to recover in a timely manner any significant amount of costs, a return on certain assets or an appropriate return on capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise; impact of political, regulatory and economic factors on regulatory decisions important to NextEra Energy and FPL; risks of disallowance of cost recovery by FPL based on a finding of imprudent use of derivative instruments; effect of any reductions to or elimination of governmental incentives that support renewable energy projects of NextEra Energy Resources, LLC and its affiliated entities (NextEra Energy Resources); impact of new or revised laws, regulations or interpretations or other regulatory initiatives on NextEra Energy and FPL; effect on NextEra Energy and FPL of potential regulatory action to broaden the scope of regulation of OTC financial derivatives and to apply such regulation to NextEra Energy and FPL; capital expenditures, increased cost of operations and exposure to liabilities attributable to environmental laws and regulations applicable to NextEra Energy and FPL; effects on NextEra Energy and FPL of federal or state laws or regulations mandating new or additional limits on the production of greenhouse gas emissions; exposure of NextEra Energy and FPL to significant and increasing compliance costs and substantial monetary penalties and other sanctions as a result of extensive federal regulation of their operations; effect on NextEra Energy and FPL of changes in tax laws and in judgments and estimates used to determine tax-related asset and liability amounts; impact on NextEra Energy and FPL of adverse results of litigation; effect on NextEra Energy and FPL of failure to proceed with projects under development or inability to complete the construction of (or capital improvements to) electric generation, transmission and distribution facilities, gas infrastructure facilities or other facilities on schedule or within budget; impact on development and operating activities of NextEra Energy and FPL resulting from risks related to project siting, financing, construction, permitting, governmental approvals and the negotiation of project development agreements; risks involved in the operation and maintenance of electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities; effect on NextEra Energy and FPL of a lack of growth or slower growth in the number of customers or in customer usage; impact on NextEra Energy and FPL of severe weather and other weather conditions; risks associated with threats of terrorism and catastrophic events that could result from terrorism, cyber attacks or other attempts to disrupt NextEra Energy's and FPL's business or the businesses of third parties; risk of lack of availability of adequate insurance coverage for protection of NextEra Energy and FPL against significant losses; risk to NextEra Energy Resources of increased operating costs resulting from unfavorable supply costs necessary to provide NextEra Energy Resources' full energy and capacity requirement services; inability or failure by NextEra Energy Resources to hedge effectively its assets or positions against changes in commodity prices, volumes, interest rates, counterparty credit risk or other risk measures; potential volatility of NextEra Energy's results of operations caused by sales of power on the spot market or on a short-term contractual basis; effect of reductions in the liquidity of energy markets on NextEra Energy's ability to manage operational risks; effectiveness of NextEra Energy's and FPL's hedging and trading procedures and associated risk management tools to protect against significant losses; impact of unavailability or disruption of power transmission or commodity transportation facilities on sale and delivery of power or natural gas by FPL and NextEra Energy Resources; exposure of NextEra Energy and FPL to credit and performance risk from customers, hedging counterparties and vendors; risks to NextEra Energy and FPL of failure of counterparties to perform under derivative contracts or of requirement for NextEra Energy and FPL to post margin cash collateral under derivative contracts; failure or breach of NextEra Energy's and FPL's information technology systems; risks to NextEra Energy and FPL's retail businesses of compromise of sensitive customer data; risks to NextEra Energy and FPL of volatility in the market values of derivative instruments and limited liquidity in OTC markets; impact of negative publicity; inability of NextEra Energy and FPL to maintain, negotiate or renegotiate acceptable franchise agreements with municipalities and counties in Florida; increasing costs of health care plans; lack of a qualified workforce or the loss or retirement of key employees; occurrence of work strikes or stoppages and increasing personnel costs; NextEra Energy's ability to successfully identify, complete and integrate acquisitions; environmental, health and financial risks associated with NextEra Energy's and FPL's ownership of nuclear generation facilities; liability of NextEra Energy and FPL for significant retrospective assessments and/or retrospective insurance premiums in the event of an incident at certain nuclear generation facilities; increased operating and capital expenditures at nuclear generation facilities of NextEra Energy or FPL resulting from orders or new regulations of the Nuclear Regulatory Commission; inability to operate any of NextEra Energy Resources' or FPL's owned nuclear generation units through the end of their respective operating licenses; liability of NextEra Energy and FPL for increased nuclear licensing or compliance costs resulting from hazards posed to their owned nuclear generation facilities; risks associated with outages of NextEra Energy's and FPL's owned nuclear units; effect of disruptions, uncertainty or volatility in the credit and capital markets on NextEra Energy's and FPL's ability to fund their liquidity and capital needs and meet their growth objectives; inability of NextEra Energy, FPL and NextEra Energy Capital Holdings, Inc., to maintain their current credit ratings; risk of impairment of NextEra Energy's and FPL's liquidity from inability of creditors to fund their credit commitments or to maintain their current credit ratings; poor market performance and other economic factors that could affect NextEra Energy's and FPL's defined benefit pension plan's funded status; poor market performance and other risks to the asset values of NextEra Energy's and FPL's nuclear decommissioning funds; changes in market value and other risks to certain of NextEra Energy's investments; effect of inability of NextEra Energy subsidiaries to upstream dividends or repay funds to NextEra Energy or of NextEra Energy's performance under guarantees of subsidiary obligations on NextEra Energy's ability to meet its financial obligations and to pay dividends on its common stock; and effect of disruptions, uncertainty or volatility in the credit and capital markets of the market price of NextEra Energy's common stock. NextEra Energy and FPL discuss these and other risks and uncertainties in their annual report on Form 10-K for the year ended Dec. 31, 2011, and other SEC filings, and this report should be read in conjunction with such SEC filings made through the date of this report. The forward-looking statements made in this report are made only as of the date of this report and NextEra Energy and FPL undertake no obligation to update any forward-looking statements.

NextEra Energy, Inc., Reconciliation of Adjusted Earnings Per Share to Earnings Per Share

	2011
Earnings Per Share (assuming dilution)	$ 4.59
Adjustments:	
Net unrealized mark-to-market (gains) losses associated with non-qualifying hedges	(0.45)
Other than temporary impairment losses, net	0.01
Loss on sale of natural gas-fired generating assets	0.24
Adjusted Earnings Per Share	**$ 4.39**

Environmental Attributes

The environmental or green attributes attributable to the electric generation from NextEra Energy Resources facilities have been or likely will be sold or transferred to third parties, who are solely entitled to the reporting rights to all renewable energy credits, emissions reductions, offsets, allowances and the avoided emission of greenhouse gas pollutants that contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere (collectively, "Environmental Attributes"). In disclosing the information herein, NextEra Energy, Inc., is not claiming ownership of any Environmental Attributes for any purpose, including compliance with any federal or state law or reporting to any federal or state agency, or for any other present or future federal, state, local, international, foreign, or voluntary emissions trading program.



NextEra Energy, Inc.
700 Universe Boulevard
Juno Beach, Florida 33408

For more information on NextEra Energy companies, visit:
www.NextEraEnergy.com
www.FPL.com
www.NextEraEnergyResources.com

For more on NextEra Energy's corporate responsibility initiatives, visit www.NextEraEnergy.com/CorporateResponsibility

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Enbridge 2011 Annual Report

TAB A1c

2011 ANNUAL REPORT



Energy matters

ENBRIDGE INC.



Forward-Looking Information: This Annual Report includes references to forward-looking information. By its nature this information applies certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect every business, including ours. The more significant factors and risks that might affect future outcomes for Enbridge are listed and discussed in the "Forward-Looking Information" section on page 36 of this annual report and also in the risk sections of our public disclosure filings, including Management's Discussion and Analysis, available on both the SEDAR and EDGAR systems at www.sedar.com and www.sec.gov/edgar.shtml.

There is a growing dialogue around energy issues. It's an important discussion for us all to be a part of.

PAT DANIEL
Chief Executive Officer



Most North Americans enjoy easy access to affordable energy, but many take for granted the vast infrastructure that enables this access.

Society needs a secure and reliable supply of energy. We need energy to heat and light our homes, businesses, schools and hospitals. We need energy to move people, goods and information. Energy literally drives economies around the world.

As North America moves towards energy self-sufficiency, through growing production of oil, gas and renewable energy, there is a need to develop new infrastructure to deliver the energy to where people need it.

This is where Enbridge fits into the discussion.



We recognize there's a range of perspectives on energy matters—about everything from security of supply and diversity of markets, to the overall environmental impact of energy production and consumption.

These are important issues—not just for Enbridge shareholders, but for all our stakeholders, including employees, partners, customers, governments, Aboriginal groups, communities in which we operate and the general public, all of whom are inextricably linked to our business.

Enbridge's number one social responsibility is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible.


While we can't promise to have all the answers, we can promise an openness to discussing energy matters with you.
So let's start the discussion.



Energy supply and demand

"WHY DO WE NEED MORE PIPELINES?"

People need energy for nearly everything we do, and with new sources of supply emerging, we need new infrastructure to meet growing demand.

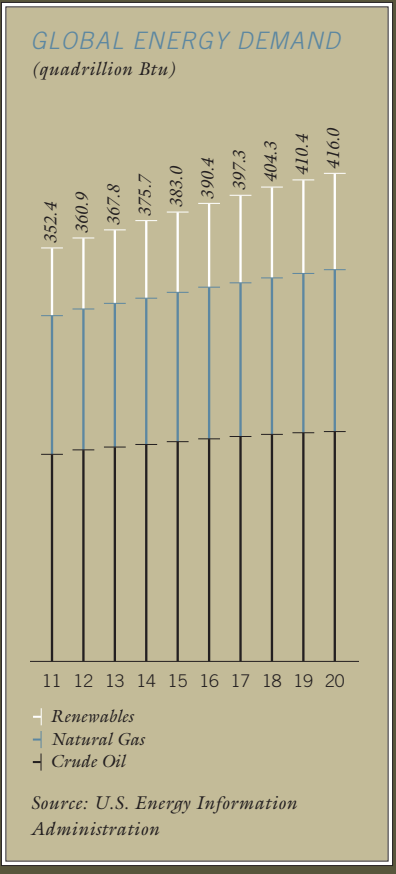
Even as society moves towards a lower impact energy future, the supply of and demand for oil and gas are growing.

Evolving technology has opened up vast new energy resources in North America.

At the same time, demand for crude oil is rising globally, and there are tremendous opportunities to deliver domestically produced crude oil into existing and developing markets.

Demand for natural gas is also growing, driven by an increasing number of gas-fired power plants and consumers' demand for this cleaner burning fuel.

Whether it's crude oil or natural gas, pipelines are the safest and most efficient way to deliver the energy society needs.



STEVE WUORI

President, Liquids Pipelines

Steve is responsible for all of Enbridge's crude oil and liquids pipeline operations in North America, and oversees Enbridge's many opportunities for new pipelines to transport growing crude oil production. Steve is also responsible for the Major Projects unit at Enbridge, which manages the engineering, procurement and construction of growth projects across the Company.

"We are on the cusp of the next wave of crude oil pipeline development in North America. Our already expansive network positions us well for these new market extension opportunities."



"WHAT'S ENBRIDGE DOING TO KEEP PACE WITH EVOLVING ENERGY SUPPLY AND DEMAND?"

We're continually monitoring changes in supply and demand, optimizing our existing systems and identifying new opportunities on an ongoing basis.

From the Alberta oil sands and the Bakken formation, to unconventional gas and renewable energy, Enbridge's existing systems and operations position us well to offer new and innovative solutions to connect these growing and developing sources of energy supply to the places where energy is needed. We work closely with our customers to understand their needs and develop solutions that meet the changing supply and demand landscape. In doing so, we're playing a key role in the delivery of secure and reliable energy that supports economic stability and growth.

Exiting 2011, we had over $13 billion in commercially secured projects, all of which are expected to be in service by the end of 2015. We've so far identified $48 billion in individual projects for development between 2011 and 2020.

We have enormous opportunities in front of us. Here's what we're doing today.

CRUDE OIL

North American crude oil supply is growing at a rapid pace and producers need greater access to new and existing markets. We're providing that access.

CONNECTING CANADA'S OIL SANDS: We have an extensive pipeline network in the oil sands region, one of the largest proven oil resources in the world. To connect growing oil sands production to upgraders and

Energy matters

60% OF THE U.S.-BOUND CRUDE OIL THAT COMES FROM WESTERN CANADA IS TRANSPORTED BY ENBRIDGE, DELIVERING APPROXIMATELY **13%** OF THE UNITED STATES' DAILY CRUDE OIL IMPORTS.



JANET HOLDER

Executive Vice President, Western Access

Janet provides overall leadership for the Northern Gateway Pipeline Project, providing oversight as the project advances through the regulatory phase. Previously, Janet was President, Gas Distribution, a role she held since January 2008.

"Gateway is the link between the third-largest petroleum reserves and the fastest-growing markets for energy in the world and it will have a truly transformative positive impact on Canada's economy."

refineries, we're expanding our Alberta regional infrastructure, including a $1.2-billion twinning of our Athabasca Pipeline, which will add approximately 450,000 barrels per day (bpd) of capacity by 2015.

GROWING IN THE BAKKEN: The Bakken region of southern Saskatchewan and northern North Dakota is one of the most prolific new resource plays in North America. We're expanding our crude oil transportation systems there to provide producers greater access out of the region.

ENABLING MARKET ACCESS: We're extending our network off our mainline system to provide Canadian and U.S. crude oil producers access to new markets, including the U.S. Gulf Coast (in 2011, we acquired 50% of the Seaway Pipeline System and announced the twinning of our Spearhead Pipeline), as well as refineries in Ontario and potentially Quebec (through our Line 5 expansion and Line 9 reversal projects). Moreover, to help Canadian producers meet growing Asian demand, we're also proposing to build the Enbridge Northern Gateway Project, a crude oil export pipeline and condensate import pipeline between Edmonton, Alberta, and a proposed new marine terminal in Kitimat, British Columbia. Public hearings on Northern Gateway began in January 2012.

NATURAL GAS

Large unconventional gas resource plays in both Canada and the United States are providing a major new source of natural gas supply. We're helping to link these new sources of supply to consumers and capturing new natural gas transportation and processing opportunities—from northeast British Columbia to offshore Gulf of Mexico.

ONSHORE PIPELINES: Alliance Pipeline is expanding its infrastructure in northeast British Columbia and the Bakken region to facilitate movement of those regions' high-energy, liquids-rich natural gas to the Aux Sable natural gas liquids (NGL) processing facilities in Illinois. Also, Enbridge Energy Partners (EEP) is participating in a joint venture to build the 280,000-bpd Texas Express Pipeline to enhance access for mid-continent NGL to the Gulf Coast market.

OFFSHORE PIPELINES: We're expanding our footprint in the Gulf of Mexico with the $400-million Walker Ridge Gas Gathering System, $200-million Big Foot Oil Pipeline and $150-million Venice expansion, all of which are scheduled to be in service for our customers by 2014.

AL MONACO
President, Enbridge Inc.

Prior to his appointment as President of Enbridge Inc. on February 27, 2012, Al served as President, Gas Pipelines, Green Energy & International, which included responsibility for the growth and operations of Enbridge's gas pipelines and gas gathering and processing operations.

"With the explosive growth in unconventional resource development, producers require new energy infrastructure to capitalize on the value of natural gas liquids. Our strong position in some of the most prolific shale gas plays in North America allows us to capture these opportunities."



PROCESSING: Enbridge took an important initial step into the Canadian Midstream natural gas business in 2011 with our $1.1-billion investment in the development of the Cabin Gas Plant, a natural gas processing facility in the prolific Horn River Basin natural gas play in northeast British Columbia. Also in 2011, EEP, which is already one of the largest gas processors in Texas, placed a new gas plant into service, upgraded two others and started construction of a 150-million-cubic-feet-per-day (mmcf/d) cryogenic processing plant.

GAS DISTRIBUTION

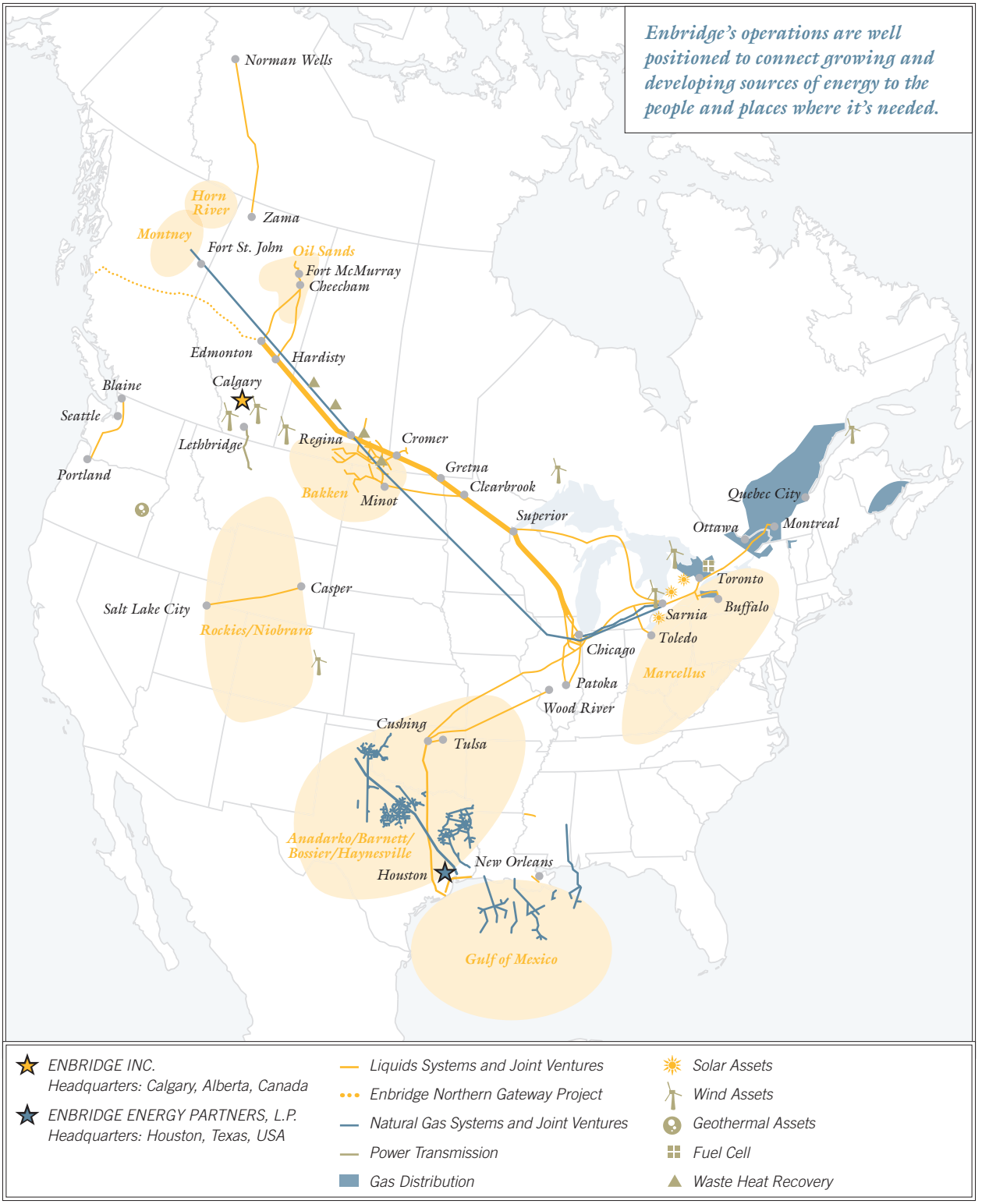
Enbridge Gas Distribution (EGD), which has been delivering clean-burning natural gas to consumers for over 160 years, expects to welcome its two millionth customer in Ontario in 2012. EGD is the largest gas distribution franchise in Canada and one of the fastest growing in North America, adding about 35,000 new customers each year. Enbridge's gas distribution business also includes Enbridge Gas New Brunswick and interests in natural gas utilities in Quebec and upstate New York.

GREEN ENERGY

We're continuing our substantial investment in renewable energy and alternative technologies to support society's desire for a lower impact energy future. In 2011, we placed into service approximately 370 megawatts (MW) of new wind and solar generating capacity, including our first U.S. wind farm, the 250-MW Cedar Point Wind Energy Project in Colorado. We also entered the large and growing Quebec wind energy market through our $330-million investment in the 300-MW Lac Alfred Wind Project. As a result, we now have interests in close to 1,000 MW of renewable and alternative energy projects—including eight wind farms, three solar farms, a geothermal facility, four waste heat recovery facilities, and a fuel cell power plant. These have enough capacity to supply the power needs of over 270,000 homes and avoid approximately 1.4 million tonnes of greenhouse gas emissions each year.

POWER TRANSMISSION

We successfully entered the power transmission business in 2011 with our acquisition of the 300-MW Montana-Alberta Tie-Line (MATL) project, a 345-kilometre transmission line that will connect the prolific wind energy resource regime of Montana with the growing demand centre of Alberta.


Enbridge's operations are well positioned to connect growing and developing sources of energy to the people and places where it's needed.
Norman Wells
Horn River
Zama
Montney
Fort St. John
Oil Sands
Fort McMurray
Cheecham
Edmonton
Hardisty
Calgary
Blaine
Seattle
Portland
Lethbridge
Regina
Cromer
Gretna
Clearbrook
Bakken
Minot
Superior
Quebec City
Ottawa
Montreal
Toronto
Buffalo
Sarnia
Toledo
Chicago
Marcellus
Patoka
Wood River
Casper
Salt Lake City
Rockies/Niobrara
Cushing
Tulsa
Anadarko/Barnett/
Bossier/Haynesville
Houston
New Orleans
Gulf of Mexico
ENBRIDGE INC.
Headquarters: Calgary, Alberta, Canada
ENBRIDGE ENERGY PARTNERS, L.P.
Headquarters: Houston, Texas, USA
Liquids Systems and Joint Ventures
Enbridge Northern Gateway Project
Natural Gas Systems and Joint Ventures
Power Transmission
Gas Distribution
Solar Assets
Wind Assets
Geothermal Assets
Fuel Cell
Waste Heat Recovery

Responsible energy development

"HOW ARE YOU ADDRESSING DIFFERING VIEWS ABOUT ENERGY PROJECTS?"

Public concerns are a valid part of the conversation, and we're committed to transparent and open consultation about our projects.

We fully understand there are alternate points of view about energy development. We also understand that energy is essential for our society and our economy.

Energy at any cost isn't energy worth having—or delivering. That's why we consult openly and communicate frequently with communities located near our planned projects to build public awareness and understanding, gather comments and suggestions, and answer questions. It's also why we build and operate our infrastructure the way we do—with safety and integrity as our first priority and with respect for the people and the environment that our infrastructure impacts.

We're confident that we can continue to deliver the energy that powers our lives safely, reliably and efficiently—just as we've done for decades.

Energy matters

BY THE 2010 INVENTORY YEAR, WE HAD REDUCED OUR DIRECT GREENHOUSE GAS EMISSIONS BY

21%

BELOW 1990 LEVELS, WHILE INCREASING PIPELINE THROUGHPUT BY

47%

LEON ZUPAN
President, Gas Pipelines

Leon is responsible for the overall leadership of Enbridge's gas pipelines and processing businesses in Canada and the U.S., and prior to that was Senior Vice President, Operations overseeing Enbridge's Canadian and U.S. liquids pipelines.

"Public awareness of our buried facilities and maintenance activities is a vital element of pipeline safety. We're committed to open, transparent and ongoing consultation with the people who live along our pipeline rights-of-way and those who may become neighbours as our pipeline network grows."



"WHAT ARE YOU DOING ABOUT PIPELINE SAFETY?"

We'll never compromise on the safety and reliability of our pipelines and facilities. Safety is our top priority—for people, communities, the environment—and we're aiming to be the best.

In July 2010, Enbridge experienced the worst spill in our history near Marshall, Michigan. That incident has only strengthened our resolve to achieve our goal of zero spill incidents. We have and will continue to apply our learnings from that experience to our operations, and to share those learnings with industry to enhance pipeline safety for all.

Our ability to consistently provide safe and reliable operations and service is of paramount importance to us, our customers and the communities we serve. It's also a prerequisite for us in maintaining our social license to build and operate our infrastructure within the communities along our rights-of-way. In other words, it provides us with the foundation for our future growth.

Even though pipelines have been proven to be by far the safest and most efficient way of transporting oil and gas, we're working constantly to ensure safety by increasing the reliability of our pipelines and facilities.

We're reinforcing a high level of safety and operational integrity across the Company by investing in six program areas:

- integrity management;
- third-party damage avoidance and detection;
- leak detection capability and control systems;
- incident response capacity;
- worker and contractor occupational safety; and
- public safety and environmental protection.

We will strive to remain at or attain at least top-quartile performance in all of these critical program areas in the near term, with being best in class as our ultimate objective.



DAVID ROBOTTOM

Executive Vice President & Chief Legal Officer

David is responsible for Enbridge's legal teams, supporting the Company's businesses, growth initiatives and financial transactions.

"Building energy infrastructure involves thorough regulatory review processes that touch on all aspects of a project—from stakeholder consultation to economic benefits to engineering and construction. Enbridge has the in-house expertise to ensure we provide regulators—and our stakeholders—all of the information they need to make decisions on our projects."

"HOW CAN YOU DELIVER HYDROCARBONS AND STILL BE ENVIRONMENTALLY RESPONSIBLE?"

We recognize that our relationship with hydrocarbons comes with great responsibilities. These include reducing our own use of these fuels, minimizing their environmental impact, and investing in the development of alternative energy technologies for the future.

Just as we take great pride in meeting our primary social responsibility of safely and reliably delivering energy to people, we're also committed to conducting our business in an environmentally sustainable way.

For example, we set targets to lower our Canadian direct greenhouse gas (GHG) emissions. For the 2010 inventory year, we had reduced GHG emissions by 21% below 1990 levels, primarily through upgrading facilities and equipment. We achieved these reductions at the same time as increasing pipeline throughput by 47%. EGD in Ontario has also undertaken many initiatives to reduce GHG emissions, including the operation of 550 natural gas vehicles—the largest fleet in Canada.

Enbridge has formally committed to stabilizing its environmental footprint through our Neutral Footprint initiative. As of 2009, we're counteracting our environmental impacts within five years of their occurrence—planting a tree for every tree we remove; conserving an acre of natural habitat for every acre we permanently impact; and generating a kilowatt of renewable energy for every kilowatt of power our operations consume.

Energy matters

FOR THE FOURTH CONSECUTIVE YEAR, ENBRIDGE HAS BEEN RECOGNIZED AS ONE OF THE GLOBAL 100 MOST SUSTAINABLE CORPORATIONS IN THE WORLD. AMONG CANADIAN COMPANIES IN 2012, WE'RE RANKED

No. 2

GUY JARVIS
President, Enbridge Gas Distribution

Guy is responsible for the overall leadership and operations of Enbridge Gas Distribution, Canada's largest natural gas utility, as well as Enbridge Gas New Brunswick, Gazifère and St. Lawrence Gas.

"Through our demand-side management programs and our incentive regulation sharing model, we're helping consumers make informed decisions about energy use and helping them get good value for every energy dollar they spend."



Between January 2009 and the end of 2011, we had made significant progress on these commitments. We had removed 589,850 trees and planted approximately 250,000. Over the same time period, we had disturbed almost 1,600 acres of natural habitat and through our work with the Nature Conservancy of Canada had conserved approximately 3,950 acres. Regarding our kilowatt-for-a-kilowatt commitment, we forecast our electricity consumption will increase in the future as new projects come on stream. However, at the same time Enbridge's electricity generation from renewable sources will also increase over time and we're on track to honour this commitment as well.

We're investing in a wide array of low-environmental-impact energy sources—both renewables (wind, solar and geothermal) and alternative technologies (fuel cell and waste heat recovery). These investments complement our core operations today and may one day form part of a sustainable energy future.

We're also helping our customers use energy wisely. EGD has a broad portfolio of demand-side management (DSM) programs that encourage our residential, commercial and industrial customers to adopt energy-saving equipment and reduce consumption of natural gas. Since 1995, EGD's DSM programs have cumulatively delivered approximately 6.1 billion cubic metres of natural gas savings (the equivalent of enough gas to supply approximately 1.9 million homes for one year) and net savings to customers of about $1.9 billion. Through these DSM activities, EGD has helped its customers avoid cumulatively approximately 11.5 million tonnes of carbon dioxide emissions.

Energy *matters*

WE NOW HAVE INTERESTS IN NEARLY

1,000 *megawatts*

OF RENEWABLE AND ALTERNATIVE ENERGY PROJECTS, WHICH HAVE THE CAPACITY TO POWER OVER 270,000 HOMES.



KAREN RADFORD
Executive Vice President, People & Partners

Karen leads Enbridge's Human Resources and Public & Government Affairs teams.

"We're passionate about supporting initiatives that deliver real, tangible benefits to the communities where we operate. For example, 11,000 riders made a commitment toward a cancer-free future by participating in our 2011 Enbridge Ride to Conquer Cancer in British Columbia, Alberta, Ontario and Quebec, which raised nearly $44 million to support cancer research, treatment and care."

"WHAT IMPACT DO YOU HAVE ON THE COMMUNITIES WHERE YOU OPERATE?"

Along with delivering the energy people count on, we deliver significant economic and social benefits to communities across North America.

We believe our success is rooted in treating people well, and we work hard every day to demonstrate to all of our stakeholders that we'll always live up to our core values of integrity, safety, and respect.

Across Canada and the United States, our business operations provide thousands of jobs and contracting opportunities. Over the years, we've also paid hundreds of millions of dollars in taxes that have ultimately been used in part to fund and operate public services and infrastructure, both locally and nationally.

We work with Aboriginal communities to ensure they achieve sustainable benefits from our projects and operations, including opportunities in equity partnership, training and education, employment, procurement, business development and community investment.

We also invest significantly in hundreds of charitable, non-profit and community organizations every year to help make communities better places to live. Through our dollars, partnerships and employees' initiatives, we support organizations that contribute to the economic and social development of communities near the Company's operations. We believe that these investments are essential to being a good neighbour and are a contributing factor in maintaining the Company's social license to operate.

Energy *matters*

ENBRIDGE'S SCHOOL PLUS PROGRAM PROVIDES FUNDING FOR EXTRACURRICULAR PROGRAMMING AT FIRST NATIONS SCHOOLS. SINCE 2009, THE PROGRAM HAS ENRICHED THE EDUCATION OF OVER

8,500

youth in over 50 schools.

Reliable energy investments

"IN THESE GLOBAL ECONOMIC CONDITIONS, WHY SHOULD I INVEST IN ENBRIDGE?"

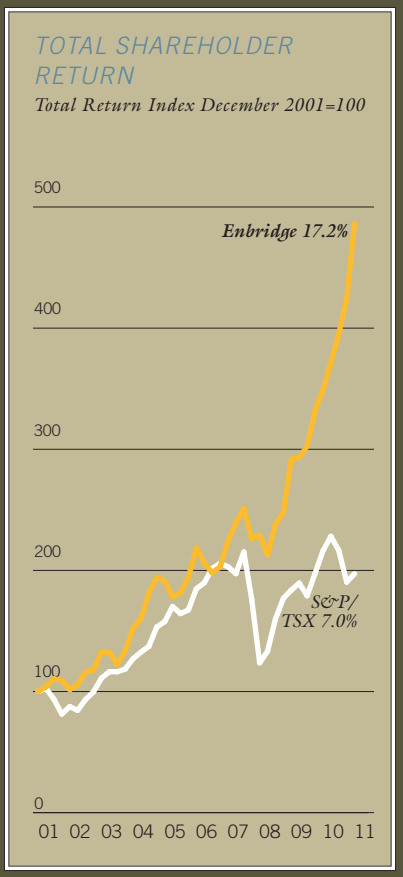
Our unique combination of growth, dividends and reliability has delivered consistently great returns for our shareholders over the long term.

Enbridge's growth has been strong and steady over the long term, and has been based on a wide range of business opportunities which have provided highly predictable earnings and cash flows.

The demand for new energy infrastructure that continues to fuel Enbridge's growth has also resulted in significant value creation for our shareholders.

In 2011 alone, our total shareholder return (TSR) reached 40% and we were the single largest positive contributor to the S&P/TSX Composite Index.

Looking back 10 years, Enbridge's TSR has increased on average 17% per year, significantly outperforming the TSX Composite Index. While historical performance is not necessarily an indicator of future results, our formula for success remains unchanged going forward.



RICHARD BIRD

Executive Vice President, Chief Financial Officer & Corporate Development

Richard is responsible for all financial affairs of the Company as well as corporate planning, mergers, acquisitions and corporate development. Richard is also responsible for Enbridge's green energy, international and energy services businesses.

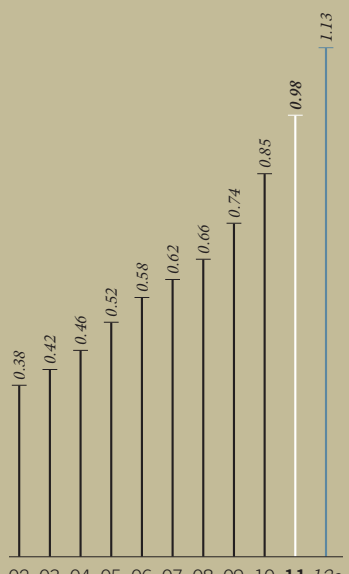
"To support our growth plans, we place a very high priority on financial strength and flexibility, ensuring that we have access to capital when we need it and at the lowest possible cost."



DIVIDENDS

(Canadian dollars per share)

We have increased the dividend in each of the last 17 years and grown it by about 11% a year over the past decade.



VISIBLE GROWTH

Enbridge's growth is fueled by the ongoing need for new energy infrastructure development. In 2011 alone, we secured $8 billion in new growth projects across all of our business segments. As a result, by year-end we had $13 billion in secured growth projects, all of which we expect will be in service by 2015. These form part of the $48 billion in new opportunities that we have identified for development between 2011 and 2020.

We've achieved close to 10% average annual adjusted earnings per share (EPS) growth over the past decade, grew EPS 11% in 2011, and we're confident in achieving 10% average annual EPS growth from 2010 through the middle of this decade.

RELIABLE BUSINESS MODEL

Enbridge's business model produces adjusted earnings you can count on. That's because a substantial amount of Enbridge's earnings come from fees paid by customers for essential energy delivery services.

GROWING INCOME STREAM

Our shareholders place a great deal of value on the growing dividend that we provide, especially in the current low-interest rate environment. We've increased the dividend in each of the last 17 years, grown the dividend by more than 11% a year over the past decade, and we've never cut the dividend in our almost 60-year history as a publicly traded company. In 2010, 2011 and again in 2012, we increased the dividend by 15%. Looking ahead, we expect dividend growth will continue to track or exceed our strong EPS growth rate.

Whether it's delivering energy or delivering returns for our investors, we hold ourselves to very high standards.

FINANCIAL HIGHLIGHTS

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings per common share [1]	**1.32**	1.30	2.13
Adjusted earnings per common share [1]	**1.48**	1.33	1.17
Dividends paid per common share [1]	**0.98**	0.85	0.74
Common share dividends declared	**759**	648	555
Return on average shareholders' equity	**12.0%**	12.9%	22.2%
Debt to debt plus shareholders' equity	**64.6%**	66.7%	66.2%

OPERATING HIGHLIGHTS

Liquids Pipelines – Average deliveries *(thousands of barrels per day)*			
Canadian Mainline [2]	**1,554**	1,537	1,562
Regional Oil Sands System [3]	**329**	291	259
Spearhead Pipeline	**82**	144	121
Gas Pipelines, Processing and Energy Services – Average throughput volume *(millions of cubic feet per day)*			
Alliance Pipeline US	**1,564**	1,600	1,601
Vector Pipeline	**1,525**	1,456	1,334
Enbridge Offshore Pipelines	**1,595**	1,962	2,037
Gas Distribution – Enbridge Gas Distribution			
Volumes *(billions of cubic feet)*	**426**	409	408
Number of active customers *(thousands)* [4]	**1,997**	1,963	1,937

1 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

2 Canadian Mainline includes deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.

3 Volumes are for the Athabasca mainline and the Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.

4 Number of active customers is the number of natural gas consuming EGD customers at the end of the period.

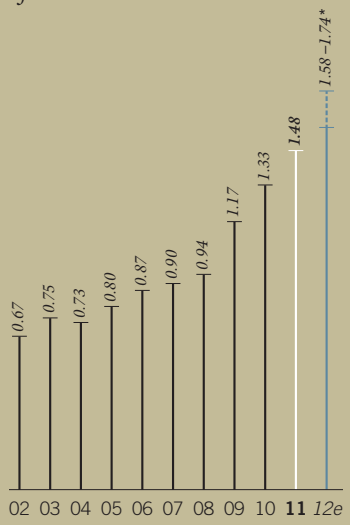


PAT DANIEL
Chief Executive Officer

DAVID ARLEDGE
Chair of the Board

ADJUSTED EARNINGS PER SHARE
(Canadian dollars per share)

We're confident we can achieve 10% in average annual EPS growth through the middle of the decade.



** 2012 earnings guidance announced December 7, 2011 of $1.58 to $1.74.*

Because energy matters to North Americans, Enbridge is constantly growing and expanding, all of which is translating into significant value creation for our shareholders.

Enbridge made tremendous progress on many fronts in 2011, with new projects continuing to be the main driver of our very impressive growth story.

We achieved significant cash flow growth in 2011 as we reaped the benefits of the many energy infrastructure projects we completed and placed into service over the past year.

Adjusted earnings per share rose 11% in 2011 to $1.48 per common share, building on a 14% increase in 2010.

Enbridge has outperformed the stock market over the last 50+ years. And while many investors may not be looking at an investment of 50 years, we run the Company as if they are.

Strides taken in 2011 will have a positive impact on Enbridge's future growth. We reached agreement with our Liquids Pipelines shippers on a 10-year Competitive Toll Settlement (CTS). We secured over $8 billion in attractive new growth projects across our existing businesses, including liquids pipelines, gas pipelines and distribution, green energy, and our new platforms of power transmission and the Canadian midstream gas sector.

On that basis, we are confident we can deliver a 10% average annual growth rate in adjusted earnings per share through the middle of this decade, based on conservative assumptions about throughput on our crude oil mainline system and future growth investments.

$48 BILLION IN OPPORTUNITIES

Enbridge today has a much larger and more broadly based suite of opportunities than we have ever had. Over $48 billion worth of individually identified opportunities are before us over the next 10 years. We plan to have invested $20 billion of this amount by the middle of the decade, $13 billion of which is already commercially secured.

Underpinning our growth story is our strong balance sheet and financial flexibility, together with an uncompromising focus on operational safety and integrity across all of our operations and assets.

The Board has increased the 2012 dividend by 15%. This follows similar increases in 2010 and 2011. Enbridge has increased its dividend by an average of 11% per year over the past decade, and we have never reduced the dividend to shareholders in our almost 60 years as a publicly traded company.

Looking ahead, our ability to continue to grow the dividend is supported by our ongoing success in securing new business development projects. All of our projects—whether they are within our liquids pipelines, gas pipelines and processing, green energy or gas distribution businesses—are aligned with our reliable business model, with long-term contracts or regulatory structures that allow us to be confident in our earnings and cash-flow growth targets into the future.

LIQUIDS PIPELINES

The new CTS on our mainline system that went into effect in 2011 is a win-win, providing shippers a competitive, stable and predictable toll while also providing the opportunity for better returns for Enbridge. Already, CTS is acting as a catalyst for advancing Enbridge's business development opportunities to extend our traditional market reach.



Enbridge's network is hard-wired into one of the largest reserves of crude oil in the world—Canada's oil sands—and we deliver into one the best markets for crude oil in the world—the U.S. Midwest. Those two anchors make our Liquids Pipelines business segment one of the strongest utility franchises in the world, and, as a strategic priority, we are moving ahead with expanding and extending our network to make it even stronger.

To connect growing oil sands production to upgraders and refineries, we are expanding our Alberta regional infrastructure, including a $1.2-billion twinning of our Athabasca Pipeline, which will add approximately 450,000 bpd of capacity to that line by 2015.

Simultaneously, we are broadening market access to the U.S. Gulf Coast for Canadian and U.S. crude oil production through two major initiatives:

- our acquisition in 2011 of a 50% interest in the Seaway Pipeline System and the reversal and twinning of that system, which will provide U.S. and Canadian producers new and timely options to transport crude oil from the oversupplied hub in Cushing, Oklahoma, to the U.S. Gulf Coast; and
- our program to twin our Spearhead Pipeline from Flanagan, Illinois, to Cushing, from where crude oil will move to Houston and Port Arthur, Texas, on the Seaway Pipeline System.

And we are continuing to expand our already extensive crude oil transportation systems in the Bakken region of southern Saskatchewan and northern North Dakota, which is one of the most prolific energy plays in North America. Our significant investments there are enabling Bakken producers to access multiple markets.

We are also working to broaden western Canadian shippers' access to markets by extending our network both east and west.

We are providing shippers of light crude oil produced in western Canada and the U.S. access to eastern refiners through the expansion of EEP's Line 5 light crude oil pipeline between Superior, Wisconsin, and Sarnia, Ontario, and by reversing a portion of Enbridge's Line 9 in western Ontario to permit crude oil movements eastbound to refineries in central Ontario and potentially to Montreal.

In the west, community hearings got underway in January 2012 for the Enbridge Northern Gateway Pipeline Project, a proposed crude oil export pipeline and condensate import

EXECUTIVE LEADERSHIP TEAM

(left to right)

D. GUY JARVIS
President, Enbridge Gas Distribution

LEON A. ZUPAN
President, Gas Pipelines

DAVID T. ROBOTTOM
Executive Vice President & Chief Legal Officer

JANET A. HOLDER
Executive Vice President, Western Access

J. RICHARD BIRD
Executive Vice President, Chief Financial Officer & Corporate Development

KAREN L. RADFORD
Executive Vice President, People & Partners

AL MONACO
President

STEPHEN J. WUORI
President, Liquids Pipelines

PATRICK D. DANIEL
Chief Executive Officer

pipeline running between Edmonton, Alberta and a proposed new marine terminal in Kitimat, British Columbia. This will be a very thorough and extensive regulatory process, conducted by the National Energy Board and the Canadian Environmental Assessment Agency.

We believe strongly that Northern Gateway is a tremendous opportunity for Canada. It will contribute significantly to Canada's national prosperity, and the strong commercial support we have received for the project from both Canadian oil producers and Asian markets reinforces the international importance of the project for Canada. There may never have been an energy project more in Canada's national interest than Northern Gateway, and we believe the sooner we are able to get the project in service, the better it will be for Canada and its trading partners.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

The strategic positioning of our natural gas assets is excellent, with exposure to many of the major North American gas plays—from northeast British Columbia to offshore Gulf of Mexico.

In 2011, we took a substantial initial step in the execution of our strategy to establish a strong position in the Canadian Midstream natural gas business with our $1.1-billion investment in the development of the Cabin Gas Plant, a natural gas processing facility in the prolific Horn River Basin natural gas play in northeast British Columbia. Midstream gas infrastructure in western Canada is an area of excellent growth potential. The Cabin investment aligns very well with Enbridge's reliable business model. The investment also comes with growth potential from future development.

In the United States, EEP is participating in a joint venture to build the 280,000-bpd Texas Express Pipeline. This pipeline will help producers in west and central Texas, the Rocky Mountains, southern Oklahoma and the mid-continent maximize the value of their natural gas production by providing additional NGL takeaway capacity and enhanced access to the Gulf Coast market.

In 2011, EEP further strengthened its competitive position in the prolific, liquids-rich Granite Wash area, which is primarily located in the Texas Panhandle region, placing its 150-mmcf/d Allison Gas Plant into service, upgrading its Sweetwater and Nine Mile gas plants, and starting construction of the 150-mmcf/d Ajax cryogenic processing plant.

Alliance Pipeline bolstered its strong position in the Bakken region in 2011, developing a natural gas pipeline lateral and associated facilities to facilitate movement of the region's high-energy, liquids-rich natural gas to the Aux Sable NGL processing facilities in Illinois. In addition, an affiliate of Aux Sable acquired two key assets in the Bakken region—the Palermo Conditioning Plant and the Prairie Rose Pipeline.

In the Gulf of Mexico, we have several very good new projects underway, with the $400-million Walker Ridge Gas Gathering System, $200-million Big Foot Oil Pipeline and $150-million Venice expansion all scheduled to be in service by 2014. Our strategy going forward is to optimize and grow our offshore business.

GAS DISTRIBUTION

EGD's customer base continues to grow solidly. Already the largest gas distribution franchise in Canada and one of the fastest growing in North America, EGD is adding approximately 35,000 new customers each year and expects to welcome its two millionth customer in Ontario this year. 2012 is the final year of EGD's current Incentive Regulation (IR) settlement and we expect to file our next generation IR plan for 2014 through 2018 later this year.

In 2011, Enbridge invested $144 million to acquire an additional interest in Noverco, bringing its total

interest to 38.9%. Noverco holds a majority interest in Gaz Métro Limited Partnership, which owns gas distribution and gas pipelines assets in Quebec and gas and electric power distribution and transmission assets in Vermont.

GREEN ENERGY

In 2011, we advanced our strategy to invest in renewable energy sources that complement our core operations, generate solid returns and stable cash flow, and benefit the environment.

We celebrated the opening, ahead of schedule and under budget, of the Company's first U.S. wind farm, the 250-MW Cedar Point Wind Energy Project in Colorado. In Ontario, we placed into operation the 99-MW Greenwich Wind Project and the 5-MW Tilbury and 15-MW Amherstburg II solar projects.

In November, Enbridge announced it will invest $330 million in a 50% interest in the development of the 300-MW Lac Alfred Wind Project, marking our entry into the growing Quebec wind energy market, which is the second largest in Canada.

We also transferred a portfolio of Enbridge's renewable energy assets to Enbridge Income Fund (the Fund) for $1.2 billion, which both enhanced the distributable cash flow of the Fund and provided Enbridge with additional capital to reinvest into new growth opportunities.

The Company's interests in renewable and alternative generating capacity now total close to 1,000 MW.

POWER TRANSMISSION

Power transmission represents an attractive opportunity for Enbridge, with strong industry fundamentals and growth potential, and our acquisition in 2011 of the 300-MW MATL project was an excellent entry point for us.

The 345-kilometre transmission line from Great Falls, Montana, to Lethbridge, Alberta, is designed to take advantage of a growing supply of electric power in Montana, including green power production, and the buoyant power demand of Alberta. MATL has great fundamentals in terms of the Montana-to-Alberta power price differential, is fully contracted and has low-cost expansion potential.

We plan to build on this initial base to continue to grow within the power transmission sector, as well as potentially expanding into other electric platforms such as gas-fired power generation.

INTERNATIONAL

We continue to be very interested in international opportunities to support the Company's long-term growth.

We are currently evaluating a liquids pipeline project in Colombia, and while this will be a main focus for our international activities in 2012, we are also examining other opportunities elsewhere in the world that would fit within the Company's reliable business model.

SAFETY AND PIPELINE INTEGRITY

We made good progress in 2011 in further reinforcing the safety and operational integrity across all our business units, including the implementation of an Operations and Integrity Committee as the most senior committee in the Company.

Our Operational Risk Management Plan, which is a companion to our strategic business plan, focuses on six program areas—integrity management; third-party damage avoidance and detection; leak detection capability and control systems; incident response capacity; worker and contractor occupational safety; and public safety and environmental protection. Our ultimate objective is to be best in class in each of these six areas.

The safety and reliability of our existing assets provides us with the foundation for our future growth.

MANAGEMENT CHANGES

On February 27, 2012, the Board of Directors announced that Pat Daniel will retire on or before the end of 2012. The Board also announced the appointment of Al Monaco to the Board of Directors and to the position of President effective immediately. Pat will continue as CEO and a member of the Board until his retirement.

The Board wishes to recognize Pat's tremendous contribution to Enbridge over his tenure with the Company. Under his leadership, Enbridge's share price has grown by 250% and

the average annual total shareholder return has been 15.8%. The market capitalization of the Company has grown from $6.8 billion in January 2001 to over $30 billion today. Enbridge's success is testament to Pat's keen sense of the needs of Enbridge's many stakeholders, his ability to successfully navigate through challenges, and his consistent, thorough and disciplined leadership style.

The Board places very high priority on succession planning and on developing people to ensure the Company's continuing success. Over his 30 years of experience in the energy industry, Al Monaco has demonstrated exceptional leadership capabilities across the range of Enbridge's businesses. The Board looks forward to working with both Al and Pat over the coming months as they transition leadership responsibilities.

With Al's appointment as President and our ongoing focus on broadening the experience of our senior management talent pool, the Company also announced several organizational changes. Leon Zupan has been appointed President, Gas Pipelines. Richard Bird has broadened his responsibilities to include Enbridge's green energy, international and energy services businesses. Steve Wuori has expanded his responsibilities to include the major projects group.

Also, in 2011, Janet Holder, who previously ran EGD, relocated to Prince George, British Columbia, as Executive Vice President, Western Access, with primary responsibility for the Northern Gateway Project. Guy Jarvis joined the executive management team as President of EGD. We also welcomed Karen Radford to the team as Executive Vice President, People and Partners, a new title that highlights our strong commitment to our employees and the communities in which we work.

Enbridge has an outstanding management team, and it will remain focused on the sustainability of profitable growth, on adding value for our customers, and on safe operations, the environment and our people.

Behind our many successes in 2011 and our continuing growth story are our 6,900 employees. We wish to thank each of them for their exceptional efforts in helping to establish Enbridge as a North American leader in the safe and reliable delivery of energy.

IN CONCLUSION

Few major corporations in North America have had the quarter-over-quarter, year-over-year success that Enbridge has achieved.

Our success is based on our ability to create strong and respectful relationships by adhering to our core values of safety, integrity, and respect for every single stakeholder who is linked to our business.

Energy matters to all of us. Across North America, we will continue to deliver the energy people count on every day, and we are fully committed to doing so safely and reliably well into the future.



DAVID A. ARLEDGE
Chair of the Board of Directors



PATRICK D. DANIEL
Chief Executive Officer

March 2, 2012

Corporate Governance

BOARD OF DIRECTORS

(left to right)

DAVID A. LESLIE
Corporate Director,
Toronto, Ontario

CHARLES W. FISCHER
Corporate Director,
Calgary, Alberta

PATRICK D. DANIEL
Chief Executive Officer,
Enbridge Inc.,
Calgary, Alberta

CHARLES E. SHULTZ
Chair & Chief Executive Officer,
Dauntless Energy Inc.,
Calgary, Alberta

J. HERB ENGLAND
Chairman & Chief Executive Officer,
Stahlman-England Irrigation Inc.,
Naples, Florida

CATHERINE L. WILLIAMS
Corporate Director,
Calgary, Alberta

GEORGE K. PETTY
Corporate Director,
San Luis Obispo, California

DAVID A. ARLEDGE
Chair of the Board, Enbridge Inc.,
Naples, Florida

J. LORNE BRAITHWAITE
President & Chief Executive Officer,
Build Toronto,
Thornhill, Ontario

V. MAUREEN KEMPSTON DARKES
Corporate Director,
Lauderdale-by-the-Sea, Florida

DAN C. TUTCHER
Corporate Director,
Houston, Texas

JAMES J. BLANCHARD
Senior Partner, DLA Piper U.S., LLP,
Beverly Hills, Michigan

AL MONACO
President, Enbridge Inc.,
Calgary, Alberta



At Enbridge, corporate governance means that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance with respect to the strategic plan of the Company and monitors implementation.

The Board approves all significant decisions that affect the Company and reviews its results. The Board also oversees identification of the Company's principal risks on an annual basis, monitors risk management programs, reviews succession planning and seeks assurance that internal control systems and management information systems are in place and operating effectively.

2011 Awards and Recognition

By focusing on our core values of Integrity, Safety and Respect, Enbridge has received local and international recognition for the way we run our business.

Listed below are some of the awards and recognition we received in 2011:

Corporate Knights Global 100 Most Sustainable Corporations in the World The Global 100 Most Sustainable Corporations in the World is an annual project initiated by *Corporate Knights* magazine with results announced at the World Economic Forum in Davos, Switzerland. The aim is to highlight the global corporations that have been most proactive in managing environmental, social and governance issues. Enbridge was named to the Global 100 in 2010, 2011, and again in January 2012.

Corporate Knights Best 50 Corporate Citizens in Canada *Corporate Knights* magazine recognized Enbridge as being one of Canada's Best 50 Corporate Citizens, the ninth year in a row the Company has been recognized. Enbridge also made it onto the highly prestigious top 10 list, earning the number 10 spot overall. The ranking is the longest running of its kind and is determined based on a thorough analysis of contenders' environmental, social and governance indicators found in the public domain.

Canada's Top 100 Employers Canada's Top 100 Employers project is a national competition to determine which employers lead their industries in offering exceptional workplaces for their employees. Enbridge was recognized for being an industry leader in attracting and retaining employees. This is the seventh consecutive year Enbridge has been on the list, and tenth since the list's inception 12 years ago.

Canada's Greenest Employers Launched in 2007, this special designation recognizes the employers that lead the nation in creating a culture of environmental awareness in their organizations.

Canada's Top Employers for Young People This special designation recognizes the employers that offer the nation's best benefits for younger workers.

Alberta's Top Employers Alberta's Top Employers is an annual competition organized by the editors of Canada's Top 100 Employers in partnership with the Human Resources Institute of Alberta. The award recognizes companies for best practices in recruitment and retention.

Carbon Disclosure Project The Carbon Disclosure Project (CDP) ranked Enbridge in the top 15% of companies globally for GHG disclosure and management. The CDP is an independent not-for-profit organization working to drive GHG reduction and sustainable water use by business and cities.

Gold Champion Level Reporter (Canadian Standards Association's GHG Registry) The Canadian Standards Association awarded Enbridge Gold Champion Level Reporter status for its GHG emissions reporting.

Canadian Institute of Chartered Accountants Corporate Reporting Award The Corporate Reporting Awards, presented annually by the Canadian Institute of Chartered Accountants, showcase the best reporting models in the country. Enbridge received the 2011 Award of Excellence for Corporate Reporting in the Utilities & Pipelines/Real Estate industry sector and was recognized for both its financial and sustainable development reporting.

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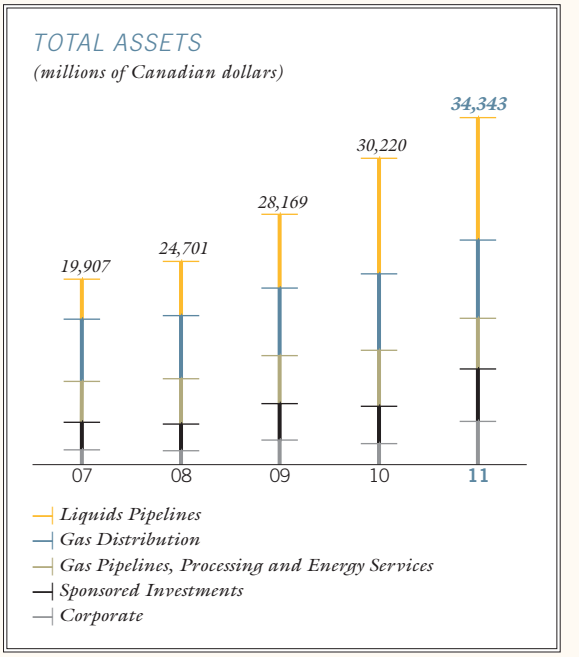
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 21, 2012 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2011, prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

Overview

Enbridge is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has significant involvement in the natural gas transmission and midstream businesses. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a clean energy generator, Enbridge is expanding its interests in renewable and green energy technologies, including wind, solar and geothermal energy, as well as hybrid fuel cells. Enbridge employs approximately 6,900 people, primarily in Canada and the United States.



The Company's activities are carried out through five business segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines and processing facilities, green energy projects, Canadian midstream businesses, the Company's energy services businesses and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business and an interest in the development of Cabin Gas Plant (Cabin) in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico system. The energy services businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, corporate investments and financing costs not allocated to the business segments.

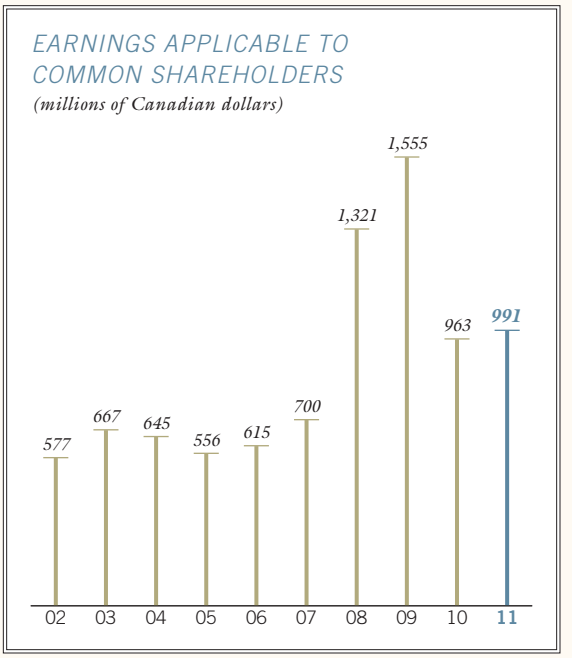
Performance Overview

	Three Months Ended December 31,		Year Ended December 31,		
	2011	2010	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)					
Earnings attributable to common shareholders					
Liquids Pipelines	**203**	117	**505**	512	445
Gas Distribution	**34**	60	**176**	155	186
Gas Pipelines, Processing and Energy Services	**157**	32	**293**	121	428
Sponsored Investments	**159**	56	**344**	137	141
Corporate	**(218)**	61	**(327)**	38	355
	335	326	**991**	963	1,555
Earnings per common share [1]	**0.44**	0.44	**1.32**	1.30	2.14
Diluted earnings per common share [1]	**0.44**	0.43	**1.30**	1.29	2.12
Adjusted earnings [2]					
Liquids Pipelines	**126**	117	**536**	512	454
Gas Distribution	**46**	54	**175**	167	154
Gas Pipelines, Processing and Energy Services	**41**	31	**163**	123	116
Sponsored Investments	**78**	48	**253**	209	151
Corporate	**(16)**	(12)	**(17)**	(27)	(20)
	275	238	**1,110**	984	855
Adjusted earnings per common share [1,2]	**0.37**	0.32	**1.48**	1.33	1.17
Cash flow data					
Cash provided by operating activities	**452**	375	**2,703**	1,851	2,017
Cash used in investing activities	**(2,179)**	(746)	**(4,017)**	(2,674)	(3,306)
Cash provided by financing activities	**1,221**	60	**1,380**	766	1,082
Dividends					
Common share dividends declared	**190**	163	**759**	648	555
Dividends paid per common share [1]	**0.2450**	0.2125	**0.98**	0.85	0.74
Revenues					
Commodity sales	**4,132**	3,280	**15,676**	11,990	9,720
Transportation and other services	**1,304**	863	**3,726**	3,137	2,746
	5,436	4,143	**19,402**	15,127	12,466
Total assets	**34,343**	30,220	**34,343**	30,220	28,169
Total long-term liabilities	**19,796**	18,542	**19,796**	18,542	16,392

1 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

2 Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see pages 37 and 114.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS



Earnings attributable to common shareholders were $991 million, or $1.32 per common share, for the year ended December 31, 2011, compared with $963 million, or $1.30 per common share, for the year ended December 31, 2010. Earnings for 2011 reflected strong earnings growth from substantially all of the Company's business segments and also included the effect of non-cash, unrealized fair value derivative and foreign exchange gains and losses. Earnings for 2011 were also negatively impacted by non-recurring income taxes of $98 million incurred on an intercompany gain on sale to the Fund, not eliminated for accounting purposes.

Significant contributors to increased earnings included, within Liquids Pipelines, the Regional Oil Sands System which realized an increase in earnings in 2011 relative to prior year due to higher shipped volumes, increased tolls, the continued positive impact of terminal infrastructure additions and lower depreciation expense. Similarly, the Canadian Mainline delivered year-over-year growth on increasing volumes and favourable operating performance. Effective July 1, 2011, tolls on the mainline system are governed by the Competitive Toll Settlement (CTS), under which earnings are now subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms.

Within the Gas Pipelines, Processing and Energy Services segment, Energy Services benefited from favourable market conditions, as did Aux Sable which realized stronger fractionation margins compared with prior years. Also within this segment, earnings contributions were realized from newly sanctioned renewable energy projects including the Sarnia Solar and Talbot Wind projects, later transferred to the Fund, within Sponsored Investments, in the fourth quarter of the year, and the Cedar Point and Greenwich wind projects.

EEP earnings, within Sponsored Investments, increased for the year ended December 31, 2011, largely due to higher volumes both within EEP's liquids business and its natural gas business, which was bolstered by the addition of the Elk City Gathering and Processing System (Elk City System) acquired in September 2010, and higher incentive income.

Offsetting these increases in earnings were lower contributions from Southern Lights Pipeline and Spearhead Pipeline, which is experiencing lower volumes due to market pricing dynamics at Cushing, Oklahoma, and higher Corporate costs. Enbridge Offshore Pipelines (Offshore) earnings declined $30 million in 2011 relative to the prior year due to a slower regulatory permitting process and delayed drilling programs by producers in the Gulf of Mexico.

Earnings attributable to common shareholders were $963 million, or $1.30 per common share, for the year ended December 31, 2010, compared with $1,555 million, or $2.14 per common share, for the year ended December 31, 2009. The Company's earnings for 2010 included the positive impacts of projects coming into service in 2010, including Alberta Clipper, Southern Lights Pipeline and the Sarnia Solar Project. Compared with 2009, earnings have increased further due to customer growth in Gas Distribution and improved contributions from green energy, partially offset by less favourable weather conditions in the Company's gas distribution franchise areas. In 2009, significant one-time favourable items impacted earnings, including a $329 million gain on the disposal of Oleoducto Central S.A. (OCENSA) and unrealized derivative and intercompany foreign exchange gains.

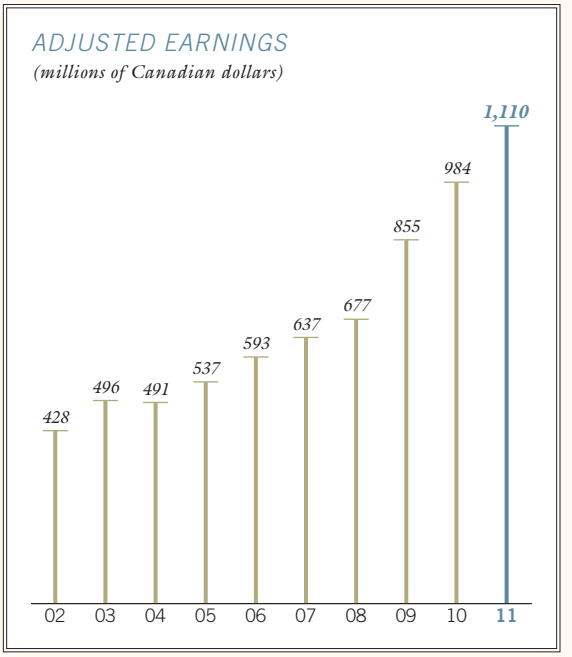
Additionally, 2011 and 2010 results were impacted by the 2010 Line 6A and 6B crude oil releases. Earnings for the year ended December 31, 2011 and 2010 included the Company's share of EEP's costs, before insurance recoveries and excluding fines and penalties, of $33 million and $103 million, respectively, related to these incidents. Lost revenue associated with downtime on both Line 6A and 6B of $3 million (net to Enbridge) further contributed to the decrease in earnings in 2010 compared with 2009. Earnings for the year ended December 31, 2011 included insurance recoveries of $50 million (net to Enbridge) related to the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners – EEP Lakehead System Line 6A and 6B Crude Oil Releases.*

Comparability of earnings attributable to common shareholders for the year ended December 31, 2011 with the prior years is impacted by the effect of unrealized derivative and intercompany foreign exchange gains and losses which totaled a loss of $132 million in 2011, a gain of $59 million in 2010 and a gain of $305 million in 2009. Further, earnings for the year ended December 31, 2009 reflected gains on the disposition of investments, including OCENSA, of $354 million, whereas no dispositions occurred in 2010 or 2011.

Earnings attributable to common shareholders for the three months ended December 31, 2011 were $335 million compared with $326 million for the fourth quarter of 2010. Fourth quarter earnings drivers are largely consistent with year-to-date trends and continued to include non-cash, unrealized fair value derivative and foreign exchange gains and losses. Unique to the fourth quarter of 2011 are reduced earnings from Gas Distribution due to warmer than normal weather, leak insurance recoveries of $29 million (net to Enbridge) and $98 million of income taxes on the intercompany gain on sale to the Fund not eliminated for accounting purposes.

ADJUSTED EARNINGS

Adjusted earnings for the year ended December 31, 2011 were $1,110 million, or $1.48 per common share, compared with $984 million, or $1.33 per common share, for the year ended December 31, 2010, an increase of 11% in adjusted earnings per common share. Adjusted earnings, which excludes the impact of non-recurring or non-operating items, for the year ended December 31, 2011 surpassed $1.0 billion for the first time in the Company's history, with higher contributions from substantially all of the Company's business segments driving strong overall earnings growth in the year. Significant drivers of the increase in adjusted earnings included increased volumes on the Company's liquids pipelines assets both in Canada and the United States, supported by robust activity in the oil sands region of Alberta, favourable fractionation margins and market conditions benefiting the Aux Sable and Energy Services businesses and increased contributions from a growing portfolio of renewable power generation assets. Areas of the Company's operations which realized year-over-year declines in adjusted earnings included Offshore, due to a slower regulatory permitting process and delayed drilling programs by producers in the Gulf of Mexico, and Spearhead Pipeline, which experienced lower volumes due to market pricing dynamics at Cushing, Oklahoma.



Adjusted earnings were $984 million, or $1.33 per common share, for the year ended December 31, 2010, compared with $855 million, or $1.17 per common share, for the year ended December 31, 2009. The increase in adjusted earnings primarily reflected contributions from projects coming into service, including the Alberta Clipper Project, the Southern Lights Pipeline and the Sarnia Solar Project, as well as strong performance from the Company's existing liquids and natural gas assets. The Company also realized improved adjusted earnings from Gas Distribution due to customer growth and favourable operating performance. Sponsored Investments further contributed to year-over-year increases in adjusted earnings, benefiting from higher contributions from EEP as a result of expansions and the acquisition of the Elk City System completed in 2010.

Adjusted earnings were $275 million, or $0.37 per common share, for the three months ended December 31, 2011, compared with $238 million, or $0.32 per common share, for the three months ended December 31, 2010. Positive contributors to increased adjusted earnings in the quarter included Gas Pipelines, Processing and Energy Services, whose Aux Sable and Energy Services businesses continued to benefit from favourable margins in the period, and Regional Oil Sands System which realized higher shipped volumes. Adjusted earnings from Sponsored Investments increased in the fourth quarter of 2011 due to strong results from EEP's natural gas business and higher general partner incentive income. Partially offsetting these items are lower adjusted earnings from Gas Distribution owing to lower other income. Commencing the fourth quarter of 2011, adjusted earnings from the Ontario Wind, Sarnia Solar and Talbot Wind projects are included within Sponsored Investments following the transfer of these assets to the Fund. These assets were previously reported under Gas Pipelines, Processing and Energy Services.

CASH FLOWS

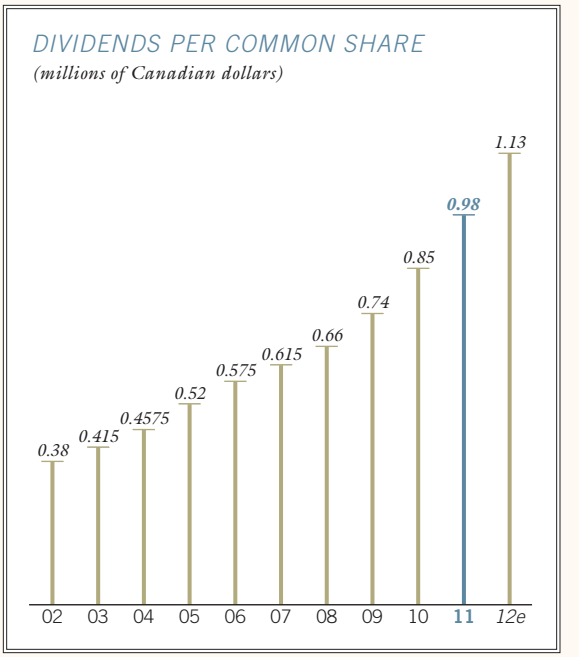
The Company's strong operating results from its core assets and stable cash flow generation from growth projects placed into service in recent years resulted in cash provided by operating activities of $2,703 million for the year ended December 31, 2011, an increase over $1,851 million generated in the prior year. Operating cash flow, together with cash provided by financing activities, funded the Company's ongoing growth initiatives in 2011, including capital expenditures of $2,516 million and the strategic acquisition of a 50% interest in the Seaway Pipeline for $1.2 billion.

Financing activities for 2011 included normal course short-term borrowings and term note issuances, as well as the issuance of $926 million of preference shares. The partial monetization of Enbridge's interest in several renewable power generation assets through a transfer to the Fund generated net cash proceeds of $210 million that will be reinvested in further growth projects. These transactions are in keeping with the Company's strategy to diversify its funding sources and derive greater value for its investors through maintaining a low cost of capital.

DIVIDENDS

The Company has paid common share dividends since its public inception in 1953. Based on estimated 2012 dividends, the annual rate of increase has averaged 11.5% since 2002 and 10.2% since inception. In December 2011, the Company announced a 15% increase in its quarterly dividend to $0.2825 per common share, or $1.13 annualized, effective March 1, 2012. The Company continues to target a payout of approximately 60% to 70% of adjusted earnings as dividends and, with the most recent dividend increase, the 2012 payout is expected to be near the upper end of the range. In 2011, dividends paid per share were 66% of adjusted earnings per share (2010 – 64%; 2009 – 63%).

The chart shows dividends per common share for the last 10 years, as well as estimated dividends for 2012, based on the quarterly dividend of $0.2825 per common share declared by the Board of Directors on December 7, 2011.



REVENUES

The Company generates revenue from two primary sources: commodity sales and transportation and other services.

Commodity sales revenue of $15,676 million (2010 – $11,990 million; 2009 – $9,720 million) is earned through the Company's natural gas distribution and energy services activities. While revenues generated by the natural gas distribution business vary with the price of natural gas, earnings are not affected due to the pass through nature of these costs. Similarly, the impact of commodity prices on revenues derived from the Company's energy services activities do not directly impact earnings since such earnings reflect a margin or percentage of revenue which depends more on differences in commodity prices between locations and points in time than on the absolute level of prices. The period-over-period variances in commodity sales are primarily driven by natural gas and crude oil commodity prices and similar trends were experienced in commodity costs over these periods.

Transportation services revenue has increased from $2,746 million in 2009 to $3,137 million in 2010 and $3,726 million in 2011. This increasing trend reflects contributions from the Company's growth projects placed into service in recent years as well as increasing volumes within the Company's core liquids and natural gas businesses. Significant growth projects placed in service over this time period include the initial phase of the Sarnia Solar Project in December 2009 followed by an expansion in 2010, Alberta Clipper in April 2010 and the Southern Lights Pipeline in July 2010. The Talbot Wind Energy Project commenced operations near the end of 2010, as did several Bakken-area expansion projects completed by the Company's Sponsored Investments.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected costs related to projects under construction; expected in-service dates for projects under construction; expected tariffs for pipelines; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and NGLs; prices of crude oil, natural gas and NGLs; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas and NGLs, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by Canadian GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

Corporate Vision

Enbridge's vision is to be the leading energy delivery company in North America. The Company transports, generates and distributes energy. By doing so, we deliver value to shareholders. The Company's objective is to generate superior economic value for shareholders through securing, constructing and operating energy infrastructure projects that are consistent with its investment value proposition: visible growth, a reliable business model and a growing income stream. Consistently applied, such stewardship should continue to generate attractive returns on invested capital and, in turn, provide for growing dividend distributions and capital appreciation to its shareholders.

At Enbridge, we integrate our core values into our daily activities, helping us work toward achieving our collective vision. Our values include integrity, safety and respect.

Corporate Strategy

In support of its long-term vision, the Company employs six key strategies that guide decision making across the enterprise:

1. Focusing on Operations and System Integrity;
2. Strengthening Our Core Businesses;
3. Developing New Platforms for Growth and Diversification;
4. Developing People;
5. Responding to Environmental Priorities; and
6. Preserving Financial Strength and Flexibility.

Enbridge's strategies are reviewed annually with direction from its Board of Directors and incorporate perspectives on macroeconomic conditions in North America and globally, evolving energy supply and demand fundamentals, changing customer demands, stakeholder expectations and competitor behaviors.

1. FOCUSING ON OPERATIONS AND SYSTEM INTEGRITY

Effective management of operations and project execution is the foundation of Enbridge's strategic plan. The overarching objective and priority of the business is to ensure the safety and reliability of our delivery systems for our customers, the public and our employees. To support this objective and to emphasize the operational focus of our business, the Company has organized its operations along functional lines and has substantially increased the amount of capital that will be directed towards maintenance and integrity programs.

Timely and cost-effective execution of an existing slate of $13 billion commercially secured projects continues to be a key priority for Enbridge. Project execution is a core competency at Enbridge and the Company continues to build upon its project management skills and processes, primarily through the Major Projects support team which was established in early 2008. Major Projects focuses on project execution success factors such as cost estimation, regulatory permitting, material and labour sourcing and project governance.

2. STRENGTHENING OUR CORE BUSINESSES

The Company has an established history of serving the transportation needs of key North American crude oil and natural gas markets and our Liquids Pipelines and natural gas segments will continue to be central to delivering our value proposition to investors. However, faced with evolving supply and demand fundamentals and increased competition, strategies to strengthen the Company's core businesses and to expand and extend our asset base in these areas are critical to meet the Company's long-term objectives.

Within the Liquids Pipelines segment, strategies are focused on maintaining the competitiveness of mainline assets, pursuing new market access opportunities and strengthening the Company's position in the Alberta oil sands and Bakken regions. The 10-year CTS reached with shippers in 2011 was an important first step in executing this broader strategy. The CTS provides a stable and competitive toll to shippers and preserves and enhances throughput on the Canadian mainline system for Enbridge. The CTS provides the foundation to support further extensions off the mainline system and the Company continues to pursue opportunities to provide its customers broader market access for Canadian bitumen and synthetic crude oil, including expansion initiatives to the Texas Gulf Coast. In late 2011, the Company announced it had acquired a 50% interest in the Seaway Pipeline system and that it was proceeding with the Gulf Coast Access initiative, which will offer shippers access to the Gulf Coast refining complex. The Company's efforts to expand market access and provide the highest netback for producers also include eastern market access opportunities and development of the proposed Northern Gateway pipeline, which would provide access to markets off the Pacific coast of Canada.

Regional liquids pipeline development involves projects which connect new oil sands production to existing hubs on the Canadian mainline. Enbridge, the largest pipeline operator in the oil sands region of Alberta, is currently is developing close to $3.4 billion in commercially secured regional oil sands transportation facilities that are being placed into service between 2011 and 2015. The Company also has $0.8 billion of secured system expansion projects in Saskatchewan and North Dakota where the Company is strategically located to capture increased production from the Bakken play.

The fundamentals of the natural gas market in North America have been altered significantly in recent years with the emergence of unconventional shale gas plays. The Company's natural gas strategies include leveraging the competitive advantages of existing assets and expanding its footprint in these emerging areas, including establishment of a Canadian midstream position. Alliance Pipeline is well positioned to service developing regions in northeast British Columbia and the Bakken play, and is continuously evaluating opportunities to expand its service offerings in those areas as well as strategies to attract liquids rich gas onto the system. Development of the Montney and Horn River shale plays is also creating the need for additional Canadian midstream infrastructure; an opportunity which fits with the Company's investment value proposition and which can leverage existing operational expertise. The Company made a significant investment in the Canadian midstream business in October 2011 with the acquisition of a majority stake in Cabin in the Horn River basin. Within the United States, strategic priorities include expanding gathering and processing capacity, particularly in the Granite Wash area, and seeking opportunities to expand its service offerings, including NGL transportation. In addition to these onshore strategies, the Company continues to pursue crude oil and natural gas gathering expansion opportunities for ultra-deep projects in the Gulf of Mexico.

3. DEVELOPING NEW PLATFORMS FOR GROWTH AND DIVERSIFICATION

The development of new platforms to diversify and sustain long-term growth is an important strategy for Enbridge. Renewable energy is a source of new growth as government initiatives and changing social beliefs focused on lower carbon emissions are creating opportunities to deliver green energy solutions with risk and return characteristics consistent with Enbridge's investment value proposition. Renewable energy is also an important part of Enbridge's environmental and corporate social responsibility (CSR) strategies. Enbridge has advanced its green energy strategy over the last several years and has interests in a renewable energy portfolio of close to 1,000-megawatts (MW). Near term priorities will focus on expansion of existing sites and pursuit of relationships with existing developers that have a suite of development projects. The Company is also assessing opportunities to invest in gas-fired generation which is projected to grow significantly over the long-term based on natural gas supply fundamentals.

Power transmission is also an attractive growth opportunity for the Company and a complement to its renewable energy strategy. Substantial transmission needs exist in North America with risk and return profiles that fit Enbridge's investment value proposition. The Company's strategy in this area is to establish an initial base of assets and an experienced management team. Enbridge's first step in this regard was achieved in late 2011 with the acquisition of the Montana-Alberta Tie-Line (MATL) transmission project and integration of the project development management team into Enbridge.

Internationally, there is a growing need for energy infrastructure which provides further opportunities for Enbridge to grow and diversify. Enbridge's international business development strategy focuses on select regions with strong supply and demand fundamentals and favourable investment climates.

Enbridge's Alternative and Emerging Technology program continues to identaqify early stage energy technologies that complement the Company's core businesses and provide potential for further growth.

4. DEVELOPING PEOPLE

Attracting, developing and retaining high performing and effective employees and leaders continue to be strategic priorities for Enbridge. Key priorities related to building and improving Enbridge's organizational and workforce capabilities include:

- Developing workforce optimization strategies and determining optimal staffing models;
- Ensuring leadership continuity and readiness with an increased focus on succession management, leadership development and mentorship;
- Refreshing Enbridge's core values and embedding them within all talent management practices;
- Implementing an enterprise wide change management approach and building change management capability within the organization; and
- Standardizing processes and systems.

5. RESPONDING TO ENVIRONMENTAL PRIORITIES

Enbridge believes it must have effective strategies to respond to environmental and other corporate responsibilities. Enbridge adheres to a strong set of corporate values, has adopted a number of corporate responsibility policies and practices and has made significant investments in renewable and alternative energy technologies.

Enbridge defines CSR as conducting business in an ethical and responsible manner, protecting the environment and the safety of people, providing economic and other benefits to the communities in which we operate, supporting universal human rights and employing a variety of policies, programs and practices to manage corporate governance and ensure fair, full and timely disclosure. Enbridge's 2011 CSR Report can be found at *http://csr.enbridge.com/*. None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.

The Company's Neutral Footprint plan includes commitments to counteract the environmental impact of Enbridge's operations since January 2009 within five years of their occurrence. Enbridge Neutral Footprint commitments include:

- planting a tree for every tree we remove to build new facilities;
- conserving an acre of land for every acre of wilderness we permanently impact; and
- generating a kilowatt of renewable energy for every kilowatt our operations consume.

To achieve its Neutral Footprint goal, Enbridge is working with the Nature Conservancy of Canada, The Conservation Fund in the United States and others. As reported in Enbridge's 2011 CSR Report, progress on the Company's Neutral Footprint initiatives (which are subject to change based on changes in the Company's operations) includes:

- 589,850 trees removed; 246,000 tree seedlings planted;
- 1,598 acres disturbed; 3,955 acres conserved through the Nature Conservancy of Canada;
- forecasted growth in power consumption (from 2008 to 2015) is 1,852 gigawatts per hour (GWh); power currently generated from renewable sources is approximately 1,900 GWh.

6. PRESERVING FINANCIAL STRENGTH AND FLEXIBILITY

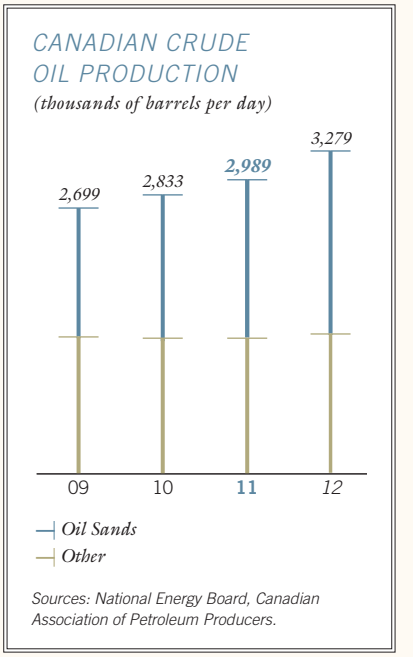
The maintenance of adequate financial strength and flexibility is fundamental to Enbridge's growth strategy. Enbridge's financial strategies are designed to ensure the Company has sufficient liquidity to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain or improve Enbridge's credit ratings, diversify its funding sources and maintain substantial bank credit facilities and ready access to capital markets in both Canada and the United States.

A key tenet of the Company's reliable business model is mitigation of exposure to market price risks. The Company has robust risk management processes which ensure earnings volatility from market price risk is managed within the parameters of its earnings-at-risk policy. Enbridge will continue to proactively hedge interest rate, foreign exchange and commodity price exposures. Management of counterparty credit risk also remains an ongoing priority.

Enbridge's strategy is reviewed annually with direction from its Board of Directors. The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial benchmarks before being pursued.

Industry Fundamentals

SUPPLY AND DEMAND FOR LIQUIDS



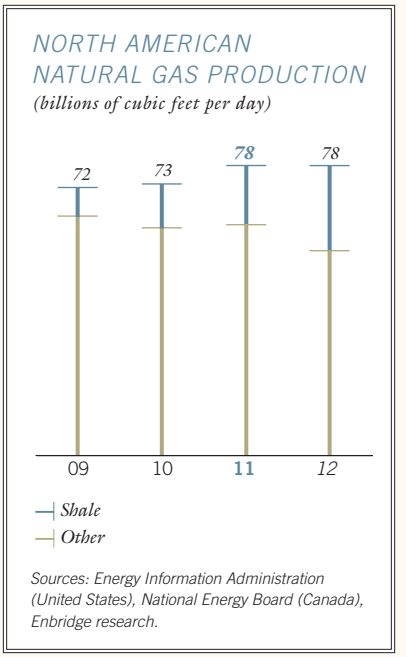
Canadian crude oil exports to the United States continue to grow, further solidifying Canada as its number one supplier. Combined conventional and oil sands established reserves of approximately 173 billion barrels suggest that this trend will continue, albeit against growing concern over the environmental footprint of oil sands crude. The National Energy Board (NEB) estimates that total Western Canadian Sedimentary Basin (WCSB) production averaged approximately 2.8 million barrels per day (bpd) in 2011 (2010 – 2.6 million bpd; 2009 – 2.4 million bpd).

Other than the WCSB, significant growth is forecasted to come from the Bakken Play in North Dakota and eastern Montana. Despite production problems as a result of severe weather in early 2011, production from this area grew from 371 thousand barrels per day (kbpd) in 2010 to an estimated 466 kbpd in 2011. Starting in July 2011, with the reversal of the Portal Link connecting EEP's North Dakota System with the Saskatchewan System, the Canadian Mainline began to receive up to 25 kbpd of United States Bakken crude at Cromer, Manitoba. This volume will increase to a maximum of 145 kbpd with the completion of the Bakken Expansion program in 2013.

Sustained oil prices have led to a resurgence in oil sands project announcements that had slowed during the economic downturn. These announcements provide optimism for oil sands production growth in the medium term. The question remains whether industry can avoid the capital cost inflation which overwhelmed projects during the most recent boom as companies competed for resources. The Canadian Association of Petroleum Producers' June 2011 growth case estimates indicate that future WCSB production is expected to steadily increase by 5.3% annually to approximately 4.6 million bpd by 2025. This forecasted growth is largely attributed to increased oil sands production in Alberta.

World crude oil demand was approximately 700 kbpd higher in 2011 relative to 2010, with China being the major contributor of demand growth. Although North American demand growth remains relatively flat, and is projected to remain that way in the near future, Canadian crude exports to the United States Midwest are growing while United States overall crude imports from other countries have declined relative to past years. Planned reconfiguration of refineries in the Midwest will increase the demand for Canadian crude in one of Enbridge's key markets. Further, the Company's planned incremental pipeline capacity into the Texas Gulf Coast refining complex will serve to expand market access and improve netbacks for Canadian producers. While improved Gulf Coast access is an important step to diversify markets for Canadian crude, an industry solution to efficiently access growing Asian markets off the west coast of Canada is needed and is currently under development by Enbridge with industry support.

With the expected increase in heavy oil production in western Canada, there is an increasing requirement for condensate to be used as a blending agent in order to transport these high viscosity volumes to market. Condensate is a light hydrocarbon which is conventionally a byproduct of natural gas production. Production of this commodity is decreasing in western Canada but, with the increasing demand for diluents from heavy oil producers, there is an increasing need to import condensate. Currently, volumes are transported via Enbridge's Southern Lights condensate pipeline, via rail to Alberta from the United States and from international sources via tankers and rail from the West Coast.



Sources: Energy Information Administration (United States), National Energy Board (Canada), Enbridge research.

SUPPLY AND DEMAND FOR NATURAL GAS

Evolving drilling and completion technologies have unlocked vast gas resources from unconventional reservoirs, primarily shale plays, and have led to oversupplied markets in North America. Recent estimates of gas resources for the United States and Canada total approximately 2,600 trillion cubic feet (tcf). With current combined annual gas production of approximately 27 tcf, the United States and Canada have almost 100 years of gas supply. Moreover, as producers continue to improve well productivity and drilling efficiency for unconventional gas, the average unit cost of developing gas supply has fallen over the past few years. Considering the abundant resource base and lower development costs, North America is expected to experience a relatively low gas price environment for the foreseeable future.

With the expectation of weak gas prices over the near-term, producers are expected to continue their shift in focus away from dry gas to more competitive liquids-rich gas and oil targets. The Marcellus, Eagle Ford and Granite Wash rich-gas plays remain prime targets in the United States. As well, activity is picking up in the offshore Gulf of Mexico as an increasing number of drilling permits are issued focused on oil production, which would lead to additional associated gas production. In Canada, drilling strategies are similar with the focus on liquids-rich gas plays in northeast British Columbia and the Alberta Deep Basin.

Gas supply is expected to continue to outpace demand growth as the North American economy struggles to advance. In contrast to low gas prices, oil prices are expected to be strong, driven by demand growth in developing countries. As such, the wide disparity between gas and oil prices should continue to support the extraction of NGL with favorable fractionation spreads.

Growth in industrial gas demand has been sluggish as the economic recovery has been slow. While economic growth is expected to continue to be weak over the next few years, low gas prices should enable a larger amount of coal-fired generation to be displaced by more competitive gas units. Further, proposed environmental regulations in the Lower 48 would cause the retirement of some older, less efficient coal generators and potentially increase gas-fired generation's share of the overall power production portfolio. Growth in gas-fired generation is expected to lead overall gas demand in North America. Canadian gas demand will also be driven by the development of oil sands projects. The United States Energy Information Administration (EIA) and the NEB estimate North American gas demand to be approximately 31 tcf in 2035; a 15% increase from 2010.

The prospect of relatively low domestic gas prices continuing over the longer-term have spurred the progress of multiple projects to export liquefied natural gas from North America to higher-priced global markets, which are primarily linked to oil prices. Export authorization has been granted to several Canadian and United States projects with first deliveries occurring as early as mid-decade.

SUPPLY AND DEMAND FOR GREEN ENERGY

Traditional forms of energy are expected to represent the major source of future North American energy supply; however, a shift to a lower carbon intensive economy, prompted mainly by government policy, exists. As overall North American energy needs continue to grow, particularly the need for electricity to meet industrial and residential demand, opportunities arise for renewable energy projects to capture a significant portion of incremental and replacement generation capacity over the next 25 years.

Growth in North American electricity demand is expected to average approximately 1% annually. The EIA forecasts that new United States generating capacity of over 200 gigawatts (GW) will be required by 2035, with renewable sources playing an increasing role. Growth in nuclear and coal-fired generation is expected to be limited due to permitting challenges, long lead times, capital cost and uncertainty of environmental regulations, leaving opportunity for renewable sources to meet a critical portion of the incremental demand.

The United States National Renewable Energy Laboratory reports that North America has significant wind and solar resources, with wind alone having the potential for over 10,000 GW of power generation. Solar resources in south western states such as Arizona, California, Colorado and Nevada are the best in the world for large-scale solar plants. In Canada, Environment Canada reports an abundance of wind resources, particularly in the north eastern regions.

Expanding renewable energy infrastructure in North America is not without challenges. Projects are typically capital intensive and renewable technology is in the early stages relative to mature energy sources. Further, renewable projects must balance the benefit of reduced carbon emissions with land disturbances and project aesthetics. High quality wind and solar resources are often found in regions at long distances from high demand markets, introducing the need for new transmission capacity.

Many factors will impact the pace of future development in renewable energy, including, but not limited to, the pace of economic recovery; technological advances; future energy or climate change regulations; and continued government support. The forecasted increase in power generation arising from renewable sources is in part supported by government incentives. The continuing ability to obtain tax or other government incentives and the ability to secure long-term power purchase agreements through government or investor-owned power authorities is required to support project economics, based on current costs and technologies. Alternative energy sources are expected to play an increasingly important role in meeting future North American energy demand with a continued drive to develop and promote green energy.

Growth Projects

In 2010, Enbridge was successful in placing almost $7 billion of new growth projects into service, including the $3.5 billion Alberta Clipper project, the largest liquids pipeline project in the Company's history, as well as the $2.3 billion Southern Lights Pipeline. In 2011, the Company was very successful in re-stocking its growth project inventory by securing close to $8 billion in new infrastructure growth projects across many of its businesses, including Liquids Pipelines, Canadian gas midstream, Texas gathering and processing, offshore Gulf of Mexico gas processing, renewable power generation and power transmission. The Company now has approximately $13 billion in commercially secured growth projects that have or are expected to come into service between 2011 and 2015. Further, the Company has identified an additional $35 billion of potential opportunities for development over the 2011 – 2020 time horizon.

The table below summarizes the current status of the Company's commercially secured projects, separated into the Company's business segments. This inventory of growth projects provides confidence to Enbridge management that the Company will be able to achieve an average annual earnings per share growth of 10% through the middle of this decade, based on conservative assumptions.

	Actual/Estimated Capital Cost [1]	Expenditures to Date	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
Liquids Pipelines				
1. Christina Lake Lateral Project	$0.2 billion	$0.2 billion	2011	Substantially complete
2. Edmonton Terminal Expansion	$0.3 billion	$0.1 billion	2012	Under construction
3. Woodland Pipeline	$0.3 billion	$0.2 billion	2012	Under construction
4. Wood Buffalo Pipeline	$0.4 billion	$0.2 billion	2012	Under construction
5. Seaway Crude Pipeline System (including reversal and extension)	US$1.5 billion	US$1.2 billion	2012 – 2013 (in phases)	Pre-construction
6. Waupisoo Pipeline Capacity Expansion	$0.4 billion	$0.1 billion	2012 – 2013 (in phases)	Under construction
7. Norealis Pipeline	$0.5 billion	No significant expenditures to date	2013	Under construction
8. Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.1 billion	2013 – 2014 (in phases)	Pre-construction
9. Flanagan South Pipeline Project	US$1.9 billion	No significant expenditures to date	2014	Pre-construction
10. Athabasca Pipeline Twinning	$1.2 billion	No significant expenditures to date	2015	Pre-construction
Gas Pipelines, Processing and Energy Services				
11. Amherstburg Solar Project	$0.1 billion	$0.1 billion	2011	Complete
12. Cedar Point Wind Energy Project [2]	US$0.5 billion	US$0.5 billion	2011	Complete
13. Greenwich Wind Energy Project	$0.3 billion	$0.3 billion	2011	Complete
14. Prairie Rose Pipeline and Palermo Conditioning Plant	US$0.1 billion	US$0.1 billion	2011	Complete
15. Lac Alfred Wind Project	$0.3 billion	$0.1 billion	2012 – 2013 (in phases)	Under construction
16. Cabin Gas Plant	$1.1 billion	$0.4 billion	2012 – 2014 (in phases)	Under construction
17. Tioga Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
18. Venice Condensate Stabilization Facility	US$0.2 billion	No significant expenditures to date	2013	Pre-construction
19. Walker Ridge Gas Gathering System	US$0.4 billion	No significant expenditures to date	2014	Pre-construction
20. Big Foot Oil Pipeline	US$0.2 billion	No significant expenditures to date	2014	Pre-construction

	Actual/Estimated Capital Cost [1]	Expenditures to Date	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
Sponsored Investments				
21. EEP – Bakken Expansion Program	US$0.4 billion	US$0.1 billion	2013	Under construction
22. The Fund – Bakken Expansion Program	$0.2 billion	No significant expenditures to date	2013	Pre-construction
23. EEP – Allison Cryogenic Processing Plant	US$0.1 billion	US$0.1 billion	2011	Complete
24. EEP – Cushing Terminal Storage Expansion Project	US$0.1 billion	No significant expenditures to date	2011 – 2012 (in stages)	Under construction
25. EEP – South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+	Under construction
26. EEP – Eastern Market Expansion	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
27. EEP – Ajax Cryogenic Processing Plant	US$0.2 billion	No significant expenditures to date	2013	Under construction
28. EEP – Bakken Access Program	US$0.1 billion	No significant expenditures to date	2013	Under construction
29. EEP – Berthold Rail Project	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
30. EEP – Texas Express Pipeline	US$0.4 billion	No significant expenditures to date	2013	Pre-construction
31. EEP – Line Replacement Program	US$0.3 billion	No significant expenditures to date	2013	Pre-construction
Corporate				
32. Noverco	$0.1 billion	$0.1 billion	2011	Complete
33. Montana-Alberta Tie-Line	US$0.3 billion	US$0.2 billion	2012 – 2013 (in stages)	Under construction

1 These amounts are estimates only and subject to upward or downward adjustment based on various factors. As appropriate, the amounts reflect Enbridge's share of joint venture projects.

2 Expenditures to date reflected total expenditures before receipt of US$0.1 billion payment from the United States Treasury. See Growth Projects – Gas Pipelines, Processing and Energy Services – Cedar Point Wind Energy Project.

Risks related to the development and completion of growth projects are described under *Risk Management and Financial Instruments.*



△ Liquids Pipelines

1 Christina Lake Lateral Project
2 Edmonton Terminal Expansion
3 Woodland Pipeline
4 Wood Buffalo Pipeline
5 Seaway Crude Pipeline System (including reversal and extension)
6 Waupisoo Pipeline Capacity Expansion
7 Norealis Pipeline
8 Athabasca Pipeline Capacity Expansion
9 Flanagan South Pipeline Project
10 Athabasca Pipeline Twinning

▲ Gas Pipelines, Processing and Energy Services

11 Amherstburg Solar Project
12 Cedar Point Wind Energy Project
13 Greenwich Wind Energy Project
14 Prairie Rose Pipeline and Palermo Conditioning Plant
15 Lac Alfred Wind Project
16 Cabin Gas Plant
17 Tioga Lateral Pipeline
18 Venice Condensate Stabilization Facility
19 Walker Ridge Gas Gathering System
20 Big Foot Oil Pipeline

○ Sponsored Investments

21 EEP – Bakken Expansion Program
22 The Fund – Bakken Expansion Program
23 EEP – Allison Cryogenic Processing Plant
24 EEP – Cushing Terminal Storage Expansion Project
25 EEP – South Haynesville Shale Expansion
26 EEP – Eastern Market Expansion
27 EEP – Ajax Cryogenic Processing Plant
28 EEP – Bakken Access Program
29 EEP – Berthold Rail Project
30 EEP – Texas Express Pipeline
31 EEP – Line Replacement Program

● Corporate

32 Noverco
33 Montana-Alberta Tie-Line

Current Assets
Growth Opportunities

LIQUIDS PIPELINES

CHRISTINA LAKE LATERAL PROJECT

The Christina Lake Lateral Project includes a new pipeline terminal and blended products pipeline, which will allow the Cenovus and ConocoPhillips partnership to deliver increased Christina Lake production volumes directly into the Athabasca Pipeline. Upon substantial completion in August 2011, the expansion project added two 375,000 barrel tanks and 26 kilometres (16 miles) of 30-inch diameter pipeline to the existing Christina Lake lateral and terminal facilities, which include two eight-inch lateral lines and 240,000 barrels of tankage, that connect to the Athabasca Pipeline. The final cost of the additional facilities is approximately $0.2 billion.

EDMONTON TERMINAL EXPANSION

The Edmonton Terminal Expansion Project involves expanding the tankage of the mainline terminal at Edmonton, Alberta by one million barrels at an estimated cost of $0.3 billion, with expenditures to date of approximately $0.1 billion. The expansion is required to accommodate growing oil sands production receipts both from Enbridge's Waupisoo Pipeline and other non-Enbridge pipelines. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of three booster pumps and related infrastructure. Regulatory approval was received in the first quarter of 2011 and, subject to receipt of other approvals, the expansion is expected to be completed in 2012.

WOODLAND PIPELINE

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties to provide for the transportation of blended bitumen from the Kearl oil sands mine to crude oil hubs in the Edmonton, Alberta area. The project will be phased with the mine expansion, with the first phase involving construction of a new 140-kilometre (87-mile) 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on Enbridge's existing Waupisoo Pipeline from Cheecham to the Edmonton area. The new Woodland Pipeline may be extended from Cheecham to Edmonton as part of future industry expansions. Regulatory approval for the Phase I facilities was received in June 2010 and construction is underway. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, with expenditures to date of approximately $0.2 billion. Enbridge expects the pipeline will come into service in late 2012.

WOOD BUFFALO PIPELINE

Enbridge entered into an agreement with Suncor Energy Inc. (Suncor) to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal adjacent to Suncor's oil sands plant to the Cheecham Terminal, which is the origin point of Enbridge's Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to the Edmonton mainline hub. The new Wood Buffalo Pipeline will parallel the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion. With regulatory approval received in the first quarter of 2011, the new pipeline is expected to be in service by late 2012.

SEAWAY CRUDE PIPELINE SYSTEM

In December 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Pipeline system at a cost of approximately US$1.2 billion. The 1,078-kilometre (670-mile) Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter Freeport, Texas to Cushing, Oklahoma long-haul system, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and four import docks at two locations. The other 50% interest in the Seaway Pipeline system is owned by Enterprise Products Partners L.P. (Enterprise).

Enbridge and Enterprise have announced plans to reverse the flow direction of the 805-kilometre (500-mile) 30-inch diameter Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the U.S. Gulf Coast. The initial 150,000 bpd of capacity on the reversed system is expected to be available by the second quarter of 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, capacity would increase to 400,000 bpd assuming a mix of light and heavy grades of crude oil.

In addition, a proposed 137-kilometre (85-mile) pipeline is expected to be built from Enterprise's ECHO crude oil terminal southeast of Houston to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities. This lateral could offer incremental capacity in excess of 400,000 bpd and is expected to be available in early 2014. Enbridge's investment in the joint venture, including its share of reversal expenditures and the Port Arthur lateral, is expected to be approximately US$1.5 billion. Open Seasons were held from January 4, 2012 through February 10, 2012 to solicit capacity commitments from shippers for potential expansion of the Seaway Pipeline through looping or twining, and for service on the Port Arthur lateral.

WAUPISOO PIPELINE CAPACITY EXPANSION

The Waupisoo Pipeline Capacity Expansion, which received regulatory approval in November 2010, is expected to provide 65,000 bpd of additional capacity in the second half of 2012 and an estimated 190,000 bpd of additional capacity in the second half of 2013 when the expansion is fully in service. The project is expected to accommodate additional shipper commitments of 229,000 bpd. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion.

NOREALIS PIPELINE

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company will construct a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Norealis Terminal to the Cheecham Terminal, and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5 billion. With regulatory approval received in the second quarter of 2011, the facilities are expected to be in service in late 2013.

ATHABASCA PIPELINE CAPACITY EXPANSION

The Company will undertake an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including production from the Christina Lake Oilsands Project operated by Cenovus. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on type of crude oil. The estimated cost of full expansion is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion and an expected in service date of 2013 for an initial 430,000 bpd of capacity. The balance of additional capacity is expected to be available by early 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

FLANAGAN SOUTH PIPELINE PROJECT

The Flanagan South Pipeline will transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. The common carrier pipeline is expected to have an initial annual capacity of 350,000 bpd at an expected cost of approximately US$1.9 billion and is designed to be expandable to 540,000 bpd. A binding Open Season that was held in the fourth quarter of 2011 resulted in sufficient customer commitment to move forward with this project. A second Open Season was held concurrent with that for Seaway Pipeline, and commitments from that Open Season will determine the final design scope and capacity. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. Both the Seaway and Flanagan South pipelines are included in the Company's Gulf Coast Access initiative to offer crude oil transportation from its terminal at Flanagan to the United States Gulf Coast.

ATHABASCA PIPELINE TWINNING

In September 2011, Enbridge announced plans to twin the southern section of its Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to accommodate the need for additional capacity to serve Kirby Lake area expected oil sands growth. The expansion project, with an estimated cost of approximately $1.2 billion, will include 345 kilometres (210 miles) of 36-inch pipeline within the existing Athabasca Pipeline right-of-way. The initial annual capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. The line is expected to enter service in 2015.

NORTHERN GATEWAY PROJECT

The Northern Gateway Project involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine and tank terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to import condensate and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

Northern Gateway submitted an application to the NEB on May 27, 2010. The Joint Review Panel (JRP) established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act, has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest. The JRP conducted sessions with the public, including Aboriginal groups, to receive comments on the draft List of Issues, additional information which Northern Gateway should be required to file and locations for the oral hearings. The JRP decided to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. In January 2011, the JRP issued a decision requiring Northern Gateway to provide certain additional information on the design and risk assessment of the pipelines before it would issue a Hearing Order. This information, together with other updates regarding the project, was provided to the JRP in March 2011. The JRP subsequently issued a Hearing Order outlining the procedures to be followed and accordingly, hearings started in January 2012.

In June 2011, Northern Gateway filed additional materials with the JRP including, but not limited to, details of its extensive program of consultation with over 40 Aboriginal communities between December 2009 and March 2011. The update summarized the information provided to Aboriginal groups, the engagement activities that have occurred, the interests and concerns that have been expressed to Northern Gateway, commitments and mitigation measures in response to those concerns and an update on the status of Aboriginal Traditional Knowledge study programs. In August 2011, Northern Gateway filed commercial agreements with the NEB which provide for committed long-term service and capacity on both the proposed crude oil export and condensate import pipelines. Capacity has also been reserved for use by uncommitted shippers.

In a Procedural Direction issued in December 2011, the JRP indicated it expects to hold final hearings in September and October 2012 where Northern Gateway, intervenors, government participants and the JRP will question those who have presented oral or written evidence. Based on this projected schedule, the JRP would anticipate releasing the Environmental Assessment in the fall of 2013 and its final decision on this project near the end of 2013. Subject to continued commercial support, regulatory and other approvals, and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service by 2017 at the earliest, at an estimated cost of $5.5 billion. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.2 billion, including $0.1 billion in funding secured from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

The JRP posts public filings related to Northern Gateway on its website at *http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html* and Enbridge also maintains a Northern Gateway Project website in addition to information available on *www.enbridge.com*. The full regulatory application submitted to the NEB and the 2010 Enbridge Northern Gateway CSR Report are available on *www.northerngateway.ca*. None of the information contained on, or connected to, the JRP website, the Northern Gateway Project website or Enbridge's website is incorporated in or otherwise part of this MD&A.

FORT HILLS PIPELINE SYSTEM

In late 2008, Fort Hills Energy L.P. (FHELP) announced that its final investment decision for the mining portion of its project was being deferred until costs could be reduced, and commodity prices and financial markets strengthened. It also announced that the Fort Hills upgrader was put on hold and that a decision to proceed with the upgrader would be made at a later date. FHELP has now completed its re-evaluation and while it is proceeding with the mining portion of the project, FHELP has decided not to proceed with the original pipeline project. Expenditures incurred to date under the original contractual arrangement of approximately $0.1 billion have been substantially collected from FHELP. Discussions on a new pipeline project to meet the new needs of the mining project are ongoing, with no commitments currently in place.

GAS DISTRIBUTION

NEXUS PROJECT

The Nexus Project is a 4.5 billion cubic feet expansion of EGD's unregulated natural gas storage facility near Sarnia, Ontario. The project, which has received regulatory approval for construction, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and was completed in 2011 at an approximate capital cost of $34 million. Additional remediation and close-out activities are expected to be performed in 2012 to bring the total capital cost to approximately $38 million.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

AMHERSTBURG SOLAR PROJECT

The Amherstburg II Solar Project, located in Amherstburg, Ontario, consists of both a 10-MW facility and a 5-MW facility. First Solar constructed both facilities for Enbridge under fixed price engineering, procurement and construction contracts. The Amherstburg II Solar Project was completed in the third quarter of 2011 at a cost of approximately $0.1 billion, at which time commercial operations commenced. Power output from the facilities is sold to the Ontario Power Authority (OPA) pursuant to 20-year power purchase agreements.

CEDAR POINT WIND ENERGY PROJECT

Enbridge developed the 250-MW Cedar Point Wind Energy Project near Denver, Colorado with Renewable Energy Systems America Inc. (RES Americas), at a cost of approximately US$0.5 billion. RES Americas constructed the wind project under a fixed price, turnkey, engineering, procurement and construction agreement. The project is comprised of 139 Vestas V90 1.8-MW wind turbines on 20,000 acres of leased private land. The Cedar Point Wind Energy Project delivers electricity into the Public Service Company of Colorado grid under a 20-year, fixed price power purchase agreement. Project construction was completed in September 2011 and commercial operation began in November 2011. In December 2011, the Company received a US$0.1 billion payment from the United States Treasury under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property.

GREENWICH WIND ENERGY PROJECT

The Company developed the 99-MW Greenwich Wind Energy Project on the northern shore of Lake Superior in Ontario with Renewable Energy Systems Canada Inc. (RES Canada). Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada constructed the project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens provides operations and maintenance services for the wind turbines. The Greenwich Wind Energy Project delivers energy to the OPA under a 20-year power purchase agreement. The project was completed and commenced commercial operations in October 2011 with expenditures of approximately $0.3 billion.

PRAIRIE ROSE PIPELINE AND PALERMO CONDITIONING PLANT

In July 2011, an affiliate of Aux Sable acquired the Prairie Rose Pipeline and the Palermo Conditioning Plant for US$0.2 billion. The Palermo Conditioning Plant removes condensate and will have a capacity of 80 mmcf/d. The 12-inch diameter, 134-kilometre (83-mile) Prairie Rose Pipeline, with an estimated capacity of 110 mmcf/d, connects the plant to the Alliance Pipeline, which then delivers high energy content gas to Aux Sable's Channahon, Illinois plant for further processing. Enbridge has a 42.7% equity interest in Aux Sable and a 50% interest in Alliance Pipeline US.

LAC ALFRED WIND PROJECT

In December 2011, Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred). The project, located 400 kilometres (250 miles) northeast of Quebec City in Quebec's Bas-Saint-Laurent region, will consist of 150 wind turbines. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1, which began construction in June 2011, is expected to be completed in December 2012; while Phase 2 is expected to be completed in December 2013. Hydro-Quebec will purchase the power under a 20-year power purchase agreement and will construct the 30-kilometre transmission line to connect Lac Alfred to the grid under an interconnection agreement. The Company's total investment in the project is expected to be approximately $0.3 billion.

CABIN GAS PLANT

In December 2011, the Company secured a 71% interest in the development of Cabin, located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. The Company's total investment in phases 1 and 2 of Cabin is expected to be approximately $1.1 billion.

Phase 1 of the development is to have 400 million cubic feet per day (mmcf/d) of processing capacity. The plant is currently under construction and is expected to be in-service in late 2012. Phase 2, which is to provide an additional 400 mmcf/d of capacity, has been sanctioned by the producers and has also received regulatory approval. Phase 2 is expected to be ready for service in the third quarter of 2014. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. These producers can request the Company to expand Cabin up to an additional four phases, under agreed terms.

TIOGA LATERAL PIPELINE

In September 2011, Alliance Pipeline US announced plans to develop a natural gas pipeline lateral and associated facilities to connect production from the Hess Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. Through its 50% ownership interest in Alliance Pipeline US, Enbridge's expected cost related to the project is approximately US$0.1 billion. Alliance Pipeline US has executed a precedent agreement with Hess Corporation (Hess) as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products and Hess have reached a concurrent agreement for the provision of NGL services. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of high-energy, liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of the Alliance mainline system. The pipeline will have an initial design capacity of approximately 120 mmcf/d, which can be expanded based on shipper demand. Subject to regulatory and other required approvals, the pipeline is expected to be in service by the third quarter of 2013.

VENICE CONDENSATE STABILIZATION FACILITY

In January 2011, the Company announced plans for an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within its Offshore business. The expanded condensate processing capacity will be required to accommodate additional natural gas production from the recently sanctioned Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge's onshore facility at Venice via Enbridge's Mississippi Canyon offshore pipeline where it will be processed to separate and stabilize the condensate. The expansion, which is expected to more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

WALKER RIDGE GAS GATHERING SYSTEM

The Company executed definitive agreements in the last quarter of 2010 with Chevron USA, Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deepwater developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 0.1 billion cubic feet per day (bcf/d). WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion.

BIG FOOT OIL PIPELINE

The Company executed definitive agreements in March 2011 with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the proposed Big Foot ultra-deepwater development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline (Big Foot), which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion and it is expected to be in service in 2014.

SPONSORED INVESTMENTS

BAKKEN EXPANSION PROGRAM

A joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. The Bakken Expansion Program is expected to increase takeaway capacity from the Bakken area by an initial 145,000 bpd, which can be expanded to 325,000 bpd. The Bakken Expansion Program will involve United States projects undertaken by EEP at a cost of approximately US$0.4 billion and Canadian projects undertaken by the Fund at a cost of approximately $0.2 billion. Regulatory approval has been received and construction commenced in July 2011 on the United States portion of the project, with expenditures to date of approximately US$0.1 billion. In Canada, NEB approval was secured in December 2011. Subject to other approvals in respect of the Canadian portion, the Bakken Expansion Program is expected to be completed in the first quarter of 2013.

ENBRIDGE ENERGY PARTNERS, L.P.

ALLISON CRYOGENIC PROCESSING PLANT

In April 2010, EEP announced plans to construct a cryogenic processing plant and other facilities on its Anadarko System. The Allison Plant has a capacity of 150 mmcf/d and is intended to accommodate the resurgence of horizontal drilling activity that exists in the Granite Wash formation in the Texas Panhandle, where the Anadarko System is located. The Allison Plant was constructed at an approximate capital cost of US$0.1 billion and placed into service in November 2011. EEP is awaiting the completion of additional third party NGL takeaway capacity to the Allison Plant, expected to be in place during the first quarter of 2012, which will allow EEP to fully utilize its capacity.

CUSHING TERMINAL STORAGE EXPANSION PROJECT

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.2 million barrels. The total estimated cost of the expansion is approximately US$0.1 billion. Five tanks went into service in December 2011 and the remaining tanks are expected to come into service by December 2012.

SOUTH HAYNESVILLE SHALE EXPANSION

EEP is expanding its East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage. The expansion, with an estimated cost of approximately US$0.1 billion, is expected to increase capacity of EEP's East Texas system by 900 mmcf/d once completed in the first quarter of 2012.

In April 2011, EEP announced plans to invest an additional US$0.2 billion to expand its East Texas system, including the construction of gathering and related treating facilities. EEP has signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services. Completion of the additional expansion is dependent on drilling plans of these producers. In light of weak gas prices and lower levels of producer activity, EEP is evaluating deferral of portions of its Haynesville natural gas expansion.

EASTERN MARKET EXPANSION

In October 2011, Enbridge and EEP announced two projects that will provide increased access to refineries in the United States upper mid-west and in Ontario for light crude oil produced in western Canada and the United States. The project involves the expansion of EEP's Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 bpd, at a cost of approximately US$0.1 billion. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of its Line 9 in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a cost of approximately $20 million. Subject to regulatory and other approvals, the Line 5 expansion is targeted to be in service during the first quarter of 2013, while the Line 9 reversal is targeted to be in service in late 2013.

AJAX CRYOGENIC PROCESSING PLANT

EEP is constructing an additional processing plant and other facilities on its Anadarko System at an approximate cost of US$0.2 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013. The Ajax Plant, when operational, in addition to the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

BAKKEN ACCESS PROGRAM

In October 2011, EEP announced the Bakken Access Program, a series of projects totaling approximately US$0.1 billion, which represents an upstream expansion that will further complement its Bakken expansion. This expansion program will enhance gathering capabilities on the North Dakota System by 100,000 bpd. The program, which involves increasing pipeline capacities, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

BERTHOLD RAIL PROJECT

In December 2011, EEP announced that it will be proceeding with the Berthold Rail Project, a US$0.1 billion investment that will provide an interim solution to shipper needs in the Bakken region. The project is expected to expand capacity into the Berthold Terminal by 80,000 bpd and includes the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. Conditional approval was received in early December subject to securing remaining shipper commitments. A regulatory filing is in progress and detailed design is proceeding to enable construction to commence in April 2012 with an expected in-service date by early 2013.

TEXAS EXPRESS PIPELINE

In September 2011, EEP announced a joint venture with Enterprise and Anadarko Petroleum Corporation to design and construct a new NGL pipeline, as well as two new NGL gathering systems which EEP will build and operate. EEP will invest approximately US$0.4 billion in the Texas Express Pipeline (TEP), which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. One of the new NGL gathering systems will connect TEP to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma, while the second will connect TEP to central Texas Barnett Shale processing plants. Subject to regulatory approvals and finalization of commercial terms, the pipeline and portions of the gathering systems are expected to begin service in mid-2013.

LINE REPLACEMENT PROGRAM

In May 2011, EEP announced plans to replace 120 kilometres (75 miles) of non-contiguous sections of Line 6B of its Lakehead System at an estimated cost of US$286 million. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through EEP's tariff surcharge that is part of the system-wide rates of the Lakehead System. EEP subsequently revised the scope of this project to increase the cost by approximately US$30 million, which will bring the total capital for this replacement program to an estimated cost of US$316 million. The US$30 million of additional costs do not currently have recovery under the tariff surcharge.

CORPORATE

MONTANA-ALBERTA TIE-LINE

In October 2011, Enbridge acquired all outstanding common shares of Tonbridge Power Inc. (Tonbridge) for $20 million and assumed long-term debt of $182 million incurred by Tonbridge in the development of the MATL project that was repaid by Enbridge. The Company will also inject further funding to complete the first 300-MW phase of MATL and an expansion between 550-MW and 600-MW. The total expected cost for both phases of MATL is approximately US$0.3 billion, of which approximately half will be funded through a 30-year loan from the Western Area Power Administration of the United States Department of Energy. Expenditures to date are approximately US$0.2 billion.

MATL is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and the buoyant power demand in Alberta. While the permits required for construction have been obtained, the approval in Canada is currently being updated to reflect a number of design modifications which require further consultation with land owners. Subject to these approvals, the system's north-bound capacity, which is fully contracted, is expected to be in-service in the fourth quarter of 2012.

NOVERCO

On June 30, 2011, the Company completed the acquisition of an additional 6.8% interest in Noverco for $144 million. Following the completion of the transaction, Enbridge and Trencap, a partnership managed by the Caisse de Depot et Placement du Quebec, became the sole shareholders of Noverco.

NEAL HOT SPRINGS GEOTHERMAL PROJECT

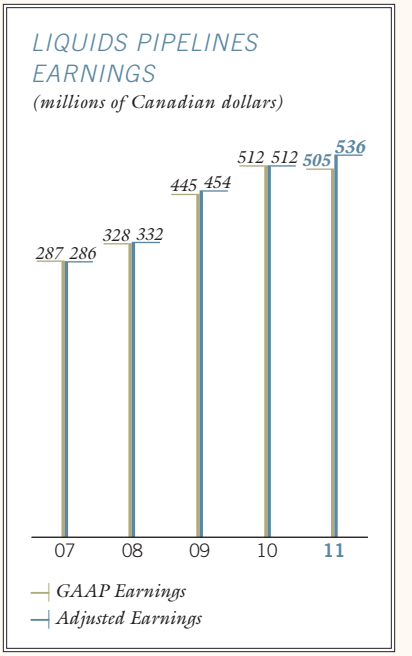
The Company has partnered with U.S. Geothermal Inc. to develop the 35-MW Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. The project is anticipated to be completed in the second quarter of 2012 and will deliver electricity to the Idaho Power grid under a 25-year power purchase agreement. Construction on the project has commenced and Enbridge will invest up to approximately $27 million for a 29% interest in the project.

Liquids Pipelines

EARNINGS

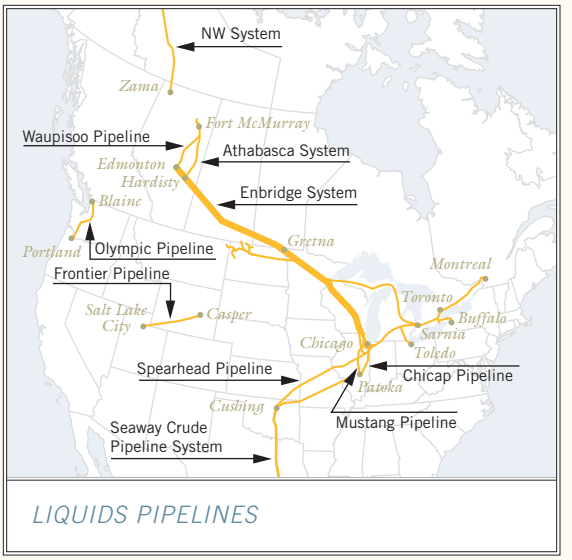
	2011	2010	2009
(millions of Canadian dollars)			
Canadian Mainline	**337**	327	295
Regional Oil Sands System	**110**	73	72
Southern Lights Pipeline	**75**	82	58
Spearhead Pipeline	**17**	29	17
Feeder Pipelines and Other	**(3)**	1	12
Adjusted earnings	**536**	512	454
Canadian Mainline – shipper dispute settlement	**14**	–	–
Canadian Mainline – Line 9 tolling adjustment	**10**	–	–
Canadian Mainline – unrealized derivative fair value loss	**(48)**	–	–
Regional Oil Sands System – asset impairment write-off	**(8)**	–	–
Regional Oil Sands System – leak remediation costs	**–**	–	(9)
Spearhead Pipeline – unrealized derivative fair value gains	**1**	–	–
Earnings	**505**	512	445

Liquids Pipelines adjusted earnings were $536 million in 2011 compared with adjusted earnings of $512 million in 2010 and $454 million in 2009. The Company continued to realize earnings growth on the Canadian Mainline, primarily due to the CTS and the related change in tolling methodology, as well as on the Regional Oil Sands System; however, in 2011 such growth was partially offset by lower contributions from its Southern Lights and Spearhead pipelines as well as Feeder Pipelines and Other.



Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting items.

- Canadian Mainline earnings for 2011 included $14 million from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- Canadian Mainline earnings for 2011 included a Line 9 tolling adjustment related to services provided in prior periods.
- Canadian Mainline earnings for 2011 reflected unrealized fair value losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Regional Oil Sands System earnings for 2011 included the write-off of development expenditures on certain project assets.
- Cleanup and remediation costs related to a valve leak within the Enbridge Cheecham Terminal on the Regional Oil Sands System in January 2009.
- Spearhead Pipeline earnings included unrealized fair value gains on derivative financial instruments used to manage exposures to allowance oil commodity prices.



LIQUIDS PIPELINES

CANADIAN MAINLINE

The mainline system is comprised of Canadian Mainline and Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through six adjacent pipelines with a combined capacity of approximately 2.5 million bpd, the system transports various grades of crude oil and diluted bitumen from western Canada to the midwest region of the United States and eastern Canada. Also included within the Canadian Mainline and located in eastern Canada are two crude oil pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd.

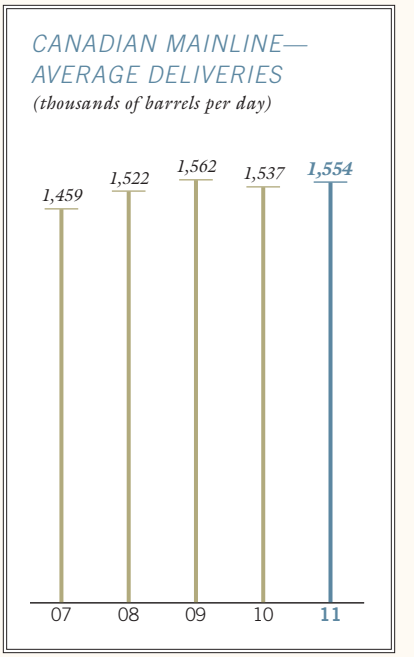
COMPETITIVE TOLL SETTLEMENT

On June 24, 2011, the NEB approved the 10-year CTS reached between Enbridge and shippers on its mainline system. The CTS, which took effect on July 1, 2011, covers local tolls, denominated in United States dollars, to be charged for service on the mainline system (with the exception of Lines 8 and 9). Under the terms of the CTS, the initial Canadian Local Toll (CLT), applicable to deliveries within western Canada, is based on the 2011 Incentive Tolling Settlement (ITS) toll and will be subsequently adjusted by 75% of the Canada Gross Domestic Product at Market Price Index, effective July 1st, for each of the remaining nine years of the settlement. The CTS also provides for an International Joint Tariff (IJT) for crude oil shipments originating in Canada on the mainline system and delivered in the United States off the Lakehead System and into eastern Canada. The IJT, which is based on a fixed toll for the term of the settlement that was negotiated between Enbridge and shippers, will be adjusted annually by the same factor as the CLT. In other limited circumstances the shippers or Enbridge may elect to renegotiate the toll, including a shipper option to renegotiate if TransCanada's Keystone XL pipeline project does not receive the required United States presidential permit by January 1, 2013. If a renegotiation of the toll is triggered, Enbridge and the shippers will meet and use reasonable efforts to agree on how the CTS can be amended to accommodate the event. Local tolls for service on the Lakehead System will not be affected by the CTS and will continue to be established by EEP's existing toll agreements. To the extent the sum of the CLT and the Lakehead System local toll exceeds the IJT, the CLT will be adjusted to ensure the IJT is maintained. The IJT is designed to provide mainline shippers with a stable and competitive long-term toll, preserving and enhancing throughput on both the Canadian Mainline and Lakehead System. Although the Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues and commodity price risk resulting from exposure to variable crude oil and power prices, earnings under the CTS are subject to variability in volume throughput, as well as capital and operating costs.

With NEB approval of the CTS, shippers who initiated the Alberta Clipper hearing request with the NEB formally withdrew their complaints and the hearing proceedings were terminated on July 7, 2011.

INCENTIVE TOLLING

Prior to the CTS taking effect, tolls on Canadian Mainline were governed by various agreements which were subject to NEB approval. These agreements included both the 2011 and 2010 ITS applicable to the Canadian Mainline (excluding Lines 8 and 9), the Terrace agreement, the SEP II Risk Sharing agreement, the Alberta Clipper agreement and the Southern Access Expansion agreement which were recovered via the Mainline Expansion Toll.



RESULTS OF OPERATIONS

Canadian Mainline adjusted earnings were $337 million for the year ended December 31, 2011 compared with $327 million for the year ended December 31, 2010.

As noted previously, effective July 1, 2011, Canadian Mainline earnings are governed by the CTS (with the exception of Lines 8 and 9) whereas earnings for the first six months of 2011 and for the year ended December 31, 2010 were governed by a series of agreements, the most significant being the ITS applicable to the mainline system and the Terrace and Alberta Clipper agreements. Earnings under the CTS are subject to variability in volume throughput and operating costs. Canadian Mainline volumes during the second half of 2011, for which the CTS was in effect, were higher than expected contributing to an increase in full year earnings relative to the prior year. The increased earnings contribution from volumes was partially offset by higher operating costs.

Supplemental information on Canadian Mainline adjusted earnings for the period from July 1, 2011, the date the CTS became effective, to December 31, 2011 is as follows.

	Six months ended December 31, 2011
(millions of Canadian dollars, unless otherwise noted)	
Revenues	**618**
Expenses	
Operating and administrative	**189**
Power	**54**
Depreciation and amortization	**104**
	347
	271
Other income	**5**
Interest expense	**(66)**
	210
Income taxes	**(32)**
Adjusted earnings	**178**
IJT Benchmark Toll [1] *(US dollars per barrel)*	**$ 3.85**
Lakehead System Local Toll [2] *(US dollars per barrel)*	**$ 2.01**
Canadian Mainline IJT Residual Benchmark Toll [3] *(US dollars per barrel)*	**$ 1.84**
Effective United States dollar to Canadian dollar exchange rate [4]	**0.97**

1 *The benchmark toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil.*

2 *Per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois.*

3 *Per barrel of heavy crude oil transported from Hardisty to Gretna. The Canadian Mainline IJT residual toll for any shipment is the difference between the IJT toll for that shipment and the Lakehead System local toll for that shipment.*

4 *Inclusive of realized gains or losses on foreign exchange derivative financial instruments.*

THROUGHPUT VOLUME [1]

2011					2010				
Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Total
1,602	**1,457**	**1,565**	**1,594**	**1,554**	1,515	1,629	1,468	1,537	1,537

1 Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.

Canadian Mainline revenues included the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Line 8 and Line 9 are currently tolled on a separate basis and comprise a relatively small proportion of total Canadian Mainline revenues. CTS revenues include transportation revenues, the largest component, as well as allowance oil and revenues from receipt and delivery charges. Transportation revenues include revenues for volumes delivered off the Canadian Mainline at Gretna and on to the Lakehead System, to which Canadian Mainline IJT residual benchmark tolls apply, and revenues for volumes delivered to other western Canada delivery points, to which the CLT applies. Despite the many factors which affect Canadian Mainline revenues, the primary determinants of those revenues will be throughput volume ex-Gretna, the United States dollar Canadian Mainline IJT residual benchmark toll applicable to those volumes and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. The Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues. The exact relationship between the primary determinants and actual Canadian Mainline revenues will vary somewhat from quarter to quarter but is expected to be relatively stable on average for a year, absent a systematic shift in receipt and delivery point mix or in crude oil type mix.

The largest components of operating and administrative expenses are employee related costs, pipeline integrity, repairs and maintenance, rents and leases and property taxes. Operating and administrative costs are relatively insensitive to throughput volumes. The primary drivers of future increases in operating costs are expected to be normal escalation in wage rates, prices for purchased services and tax rates, addition of new facilities and more extensive integrity and maintenance programs.

Power is the most significant variable operating cost and is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements. However, the primary determinants of power cost are the level of power prices in various jurisdictions and throughput volume. The relationship of power consumption to throughput volume is expected to be roughly proportional over a moderate range of volumes. The Company may utilize derivative financial instruments to hedge power prices.

Depreciation and amortization expense will adjust over time as a result of changes in estimated depreciation rates and of additions to property, plant and equipment due to new facilities, as well as maintenance and integrity capital expenditures.

Canadian Mainline income taxes reflected current income taxes only. Under the CTS the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to future income taxes is recognized as incurred.

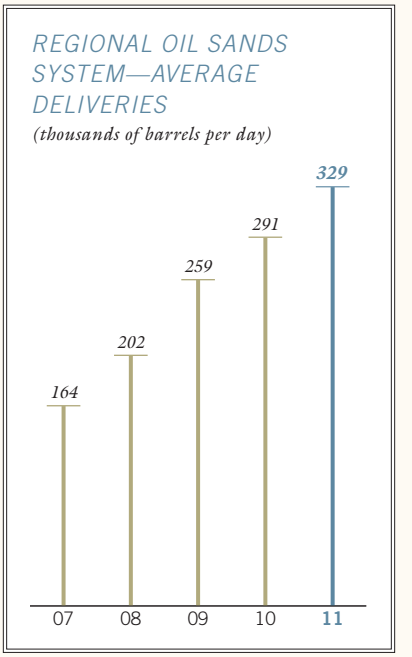
The preceding financial overview includes expectations regarding future events and operating conditions that the Company believes are reasonable based on currently available information; however, such statements are not guarantees of future performance and are subject to change.

Prior to the implementation of the CTS, revenue on the Canadian Mainline was recognized in a manner consistent with the underlying agreements as approved by the regulator, in accordance with rate-regulated accounting. The Company discontinued the application of rate-regulated accounting to its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis commencing July 1, 2011. The regulatory asset balance at the date of discontinuance related to tolling deferrals recognized in prior periods is being recovered through a surcharge to the CLT and IJT. While the CTS is based on previous tolling settlements and cost-of-service principles, earnings are subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset of approximately $470 million related to future income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the date of discontinuance and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred.

Canadian Mainline adjusted earnings were $327 million for the year ended December 31, 2010 compared with $295 million for the year ended December 31, 2009. The increase in adjusted earnings resulted from a higher Alberta Clipper contribution since entering service on April 1, 2010 and favourable operating performance. These positive factors were partially offset by higher taxes in the Terrace component.

REGIONAL OIL SANDS SYSTEM

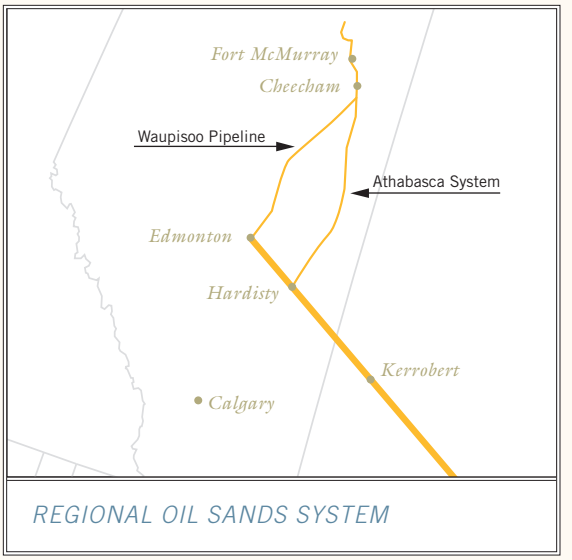
Regional Oil Sands System includes two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline, as well as a variety of other facilities including the MacKay River, Christina Lake, Surmont and Long Lake facilities. It also includes Hardisty Caverns Limited Partnership (Hardisty Caverns), which provides storage service, and two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located 95 kilometres (59 miles) south of Fort McMurray where the Waupisoo Pipeline initiates.



The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline, built in 1999, that links the Athabasca oil sands in the Fort McMurray, Alberta region to a pipeline hub at Hardisty, Alberta. The Athabasca Pipeline has an ultimate design capacity of approximately 570,000 bpd, dependent on the viscosity of crude being shipped. It is currently configured to transport approximately 345,000 bpd.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca Pipeline which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered into service on May 31, 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge's Cheecham Terminal and terminates at its Edmonton Mainline Terminal. The pipeline currently has a design capacity, dependent on crude slate, of up to 350,000 bpd, which can ultimately be expanded to 600,000 bpd.



REGIONAL OIL SANDS SYSTEM

Enbridge has a long-term (25-year) take-or-pay commitment with the four founding shippers on the Waupisoo Pipeline who collectively have contracted for approximately one-third of the initial capacity on the line. The associated revenues provide for a base return on equity (ROE) with significant upside potential as incremental founders and third party volumes are added.

In June 2010, the Company acquired the remaining 50% of Hardisty Caverns previously owned by CCS Corporation for $52 million. The Hardisty Caverns facility, now wholly owned by Enbridge, also includes four salt caverns totaling 3.1 million barrels of capacity. The capacity at the facility is fully subscribed under long-term contracts that generate revenues from storage and terminaling fees.

RESULTS OF OPERATIONS

Adjusted earnings for the year ended December 31, 2011 were $110 million compared with $73 million for the year ended December 31, 2010 and $72 million for the year ended December 31, 2009. The increase in Regional Oil Sands System adjusted earnings reflected higher shipped volumes, increased tolls and the continued positive impact of terminal infrastructure additions. Adjusted earnings for 2011 also reflected lower depreciation expense due to extended estimated useful lives of certain assets reflecting increased probable reservoir supply and commercial viability.

SOUTHERN LIGHTS PIPELINE

The 180,000 bpd, 20-inch diameter Southern Lights Pipeline was placed into service on July 1, 2010 transporting diluent from Chicago, Illinois to Edmonton, Alberta. Enbridge receives tariff revenues under long-term (15-year) contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs plus a ROE of 10%. Uncommitted volumes, up to a specified amount, provide for tariff revenues that are fully credited to all shippers. Enbridge retains 25% of uncommitted tariff revenues on volumes above the specified amount, with the remainder being credited to shippers.

Both the Canadian and United States portions of the 2010, 2011 and 2012 rates for uncommitted shippers on Southern Lights Pipeline have been challenged. The Canadian Southern Lights toll hearing was held before NEB panel members in November 2011. On February 9, 2012, the NEB issued its decision rejecting the challenge from uncommitted shippers stating that tolls in place are just and reasonable. A Federal Energy Regulatory Commission (FERC) hearing was held in January 2012. Briefs will be filed February 27 and March 28, 2012 and an initial decision is expected on or before June 5, 2012. No material financial impact to the Company is anticipated to result from the FERC proceeding.

RESULTS OF OPERATIONS

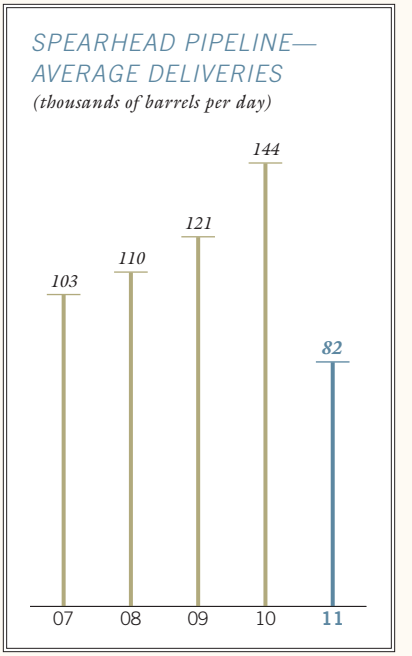
Earnings for the year ended December 31, 2011 were $75 million compared with $82 million for the year ended December 31, 2010. Southern Lights Pipeline earnings for 2011 reflected a full year of in-service earnings. The decrease was primarily due to a decrease in leasing income from a pipeline which was transferred to the mainline system effective May 1, 2010.

Earnings for the year ended December 31, 2010 were $82 million compared with $58 million for the year ended December 31, 2009. Southern Lights Pipeline earnings for 2010 reflected operating earnings from its in-service date of July 1, 2010 in addition to allowance for equity funds used during construction (AEDC) recognized on a growing capital base while the project was under construction during the first six months of the year. The increase in 2010 earnings was partially offset by a decrease in earnings from the new light sour pipeline, which became operational during the first quarter of 2009 and was subsequently transferred to the mainline system effective May 1, 2010.

SPEARHEAD PIPELINE

Spearhead Pipeline delivers crude oil from Chicago, Illinois to Cushing, Oklahoma. The pipeline was originally placed into service in March 2006 and the Spearhead Pipeline Expansion was completed in May 2009. The expansion increased the capacity to Cushing from 125,000 bpd to 193,300 bpd from the new initiating point at Flanagan, Illinois.

Initial committed shippers and expansion shippers currently account for more than 70% of the 193,300 bpd capacity on Spearhead. Both the initial committed shippers and expansion shippers were required to enter into 10-year shipping commitments at negotiated rates that were offered during the open season process. The balance of the capacity is currently available to uncommitted shippers on a spot basis at FERC approved rates.



RESULTS OF OPERATIONS

Spearhead Pipeline adjusted earnings were $17 million for the year ended December 31, 2011 compared with $29 million for the year ended December 31, 2010. The decrease in Spearhead Pipeline adjusted earnings primarily reflected lower throughput volumes as a result of current market pricing dynamics at Cushing, Oklahoma, partially offset by the recognition of make-up rights which expired in the period.

Spearhead Pipeline adjusted earnings were $29 million for the year ended December 31, 2010 compared with $17 million for the year ended December 31, 2009. The earnings increase was due to a full year of higher volumes resulting from the expansion completed in May 2009. Earnings during 2010 were also positively impacted by the recognition of make-up rights which expired in the period, and lower operating costs.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the Company's 85% interest in Olympic Pipe Line Company (Olympic Pipeline), the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. It also includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories (NWT) to Zama, Alberta; interests in a number of liquids pipelines in the United States; contract tankage facilities, including the Hardisty Contract Terminal, which is comprised of 19 tanks with a working capacity of approximately 7.5 million barrels of storage; and business development costs related to Liquids Pipelines activities.

RESULTS OF OPERATIONS

In 2011, Feeder Pipelines and Other incurred a loss of $3 million compared with earnings of $1 million in 2010 and earnings of $12 million in 2009. Earnings in 2011 primarily reflected an increase in business development costs which more than offset a higher contribution from Olympic Pipeline due to the Company's increased ownership interest percentage, as well as a tariff increase and higher volumes.

The decrease in earnings from 2009 to 2010 was due to a number of small factors including a decrease in earnings from Toledo Pipeline due to the Line 6B shutdown and a decrease in earnings from Olympic Pipeline, as well as an increase in business development costs.

NORMAN WELLS PIPELINE CRUDE OIL RELEASE

The Norman Wells Pipeline is a 12-inch, 39,400 bpd line transporting sweet crude oil that stretches 869 kilometres (540 miles) from Norman Wells, NWT to Zama, Alberta. On May 9, 2011, Enbridge reported a crude oil release from the Norman Wells Pipeline approximately 50 kilometres (31 miles) south of the community of Wrigley, NWT. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing necessary repairs. Excavation of all contaminated soils from the spill site was completed in late November 2011. Based on the volume of contaminated materials removed from the site, the current estimate of volume released is approximately 1,600 barrels. Site reclamation work is anticipated to be completed in the summer of 2012. Monitoring of surface water and groundwater at the site will continue until remediation and reclamation goals have been achieved in accordance with plans filed with the regulator. Currently, Management does not believe this incident will have a material impact on the Company's consolidated financial position or result of operations.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

SUPPLY AND DEMAND

The profitability of the Company's liquids pipelines depends to some extent on the volume of products transported on its pipeline systems. The volume of shipments depends primarily on the supply of, and demand for, crude oil and other liquid hydrocarbons from western Canada. Investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, United States demand and availability of markets for produced crude oil. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing levels, alternative energy sources and global supply disruptions. Crude oil prices have been sustained at such levels that oil sands producers have recommenced projects that had been previously cancelled or deferred, creating increased demand in the WCSB for new pipeline infrastructure.

VOLUME RISK

A decrease in volumes transported by certain of the Company's liquids pipelines, including the Company's mainline system and the base Lakehead System owned by EEP, can directly and adversely affect revenues and results of operations. Shippers are not required to enter into long-term shipping commitments on Enbridge's Canadian Mainline; rather, monthly volume nominations are accepted. A decline in volumes transported can be influenced by factors beyond the Company's control, including competition, regulatory action, weather, storage levels, alternative energy sources, decreased demand, fluctuations in commodity prices, economic conditions, supply disruptions, availability of supply connected to the systems and adequacy of infrastructure to move supply into and out of the systems. The Company's existing right-of-way for the Canadian Mainline provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines. In addition, the CTS includes certain minimum threshold volumes to mitigate volume risk.

MARKET PRICE RISK

The replacement of the ITS agreement with the CTS agreement for the Company's Canadian Mainline increases exposure to foreign exchange rates, commodity prices and interest rates. The most significant of these risks is foreign exchange as the Company's International Joint Tolls under the CTS are charged in United States dollars. These risks have been substantially managed through the Company's hedging program by using financial contracts to fix the prices of United States dollars, commodities and interest rates. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, the Company's earnings are exposed to associated mark-to-market valuation changes.

COMPETITION

Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other competing carriers are available to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition also arises from new pipeline proposals that provide access to market areas currently served by the Company's liquids pipelines. One such competing project began commercial operations in early 2010 and serves markets at Wood River, Illinois and Cushing, Oklahoma. This pipeline has an initial capacity of 435,000 bpd and an ultimate stated capacity of 591,000 bpd. Commercial support has also been announced for the construction of additional ex-Alberta capacity of 500,000 bpd to Nederland, Texas, with an in-service date during 2015. Competing alternatives for delivering western Canadian liquid hydrocarbons into the United States or other markets could erode shipper support for current or future expansion. However, the Company believes that its liquids pipelines provide attractive options to producers in the WCSB due to its competitive tolls and multiple delivery and storage points. Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

POTENTIAL PRESSURE RESTRICTIONS

The Company's liquids systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of a pipeline is indefinitely long; however, as pipelines age the level of expenditures required for inspection and maintenance may increase. Pressure restrictions may from time to time be established on the Company's pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. Certain of the Company's liquids pipelines, including the Company's Canadian Mainline, would be adversely affected by any pressure restrictions that do reduce volumes transported. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs.

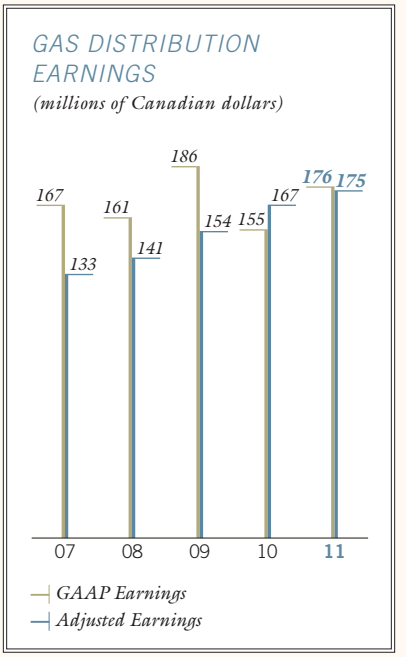
REGULATION

The Canadian Mainline and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from those operations. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the CTS, which govern the majority of the segment's assets.

Gas Distribution

EARNINGS

	2011	2010	2009
(millions of Canadian dollars)			
Enbridge Gas Distribution (EGD)	**137**	135	129
Other Gas Distribution and Storage	**38**	32	25
Adjusted earnings	**175**	167	154
EGD – colder/(warmer) than normal weather	**1**	(12)	17
EGD – impact of tax rate changes	**–**	–	21
EGD – interest income on GST refund	**–**	–	7
Other Gas Distribution and Storage – asset impairment loss	**–**	–	(10)
Other Gas Distribution and Storage – adoption of new accounting standard	**–**	–	(3)
Earnings	**176**	155	186



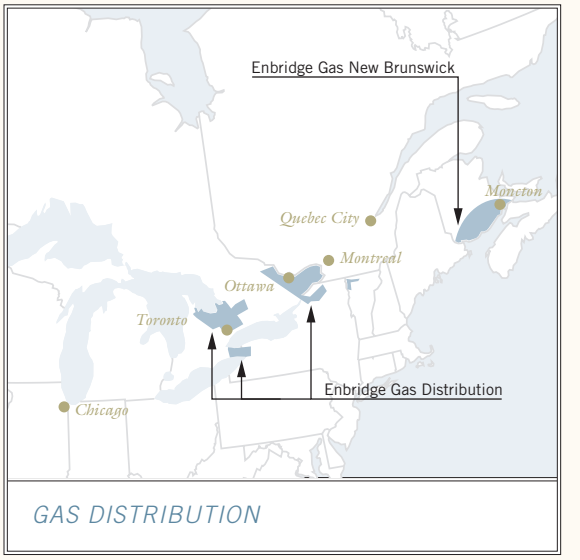
Adjusted earnings from Gas Distribution were $175 million for the year ended December 31, 2011 compared with $167 million for 2010 and $154 million for 2009. The increase in Gas Distribution adjusted earnings primarily resulted from continuing higher contributions from EGD under its Incentive Regulation (IR) arrangement and further growth in the Company's other gas distribution businesses.

Gas Distribution earnings were impacted by the following non-recurring or non-operating adjusting items.

- EGD earnings are adjusted to reflect the impact of weather.
- In 2009, earnings from EGD reflected the impact of favourable tax rate changes.
- Earnings from EGD for 2009 included interest income related to the recovery of excess GST remitted to Canada Revenue Agency.
- Other Gas Distribution and Storage earnings for 2009 were impacted by an asset impairment loss which included goodwill.
- Other Gas Distribution and Storage earnings for 2009 reflected the write-off of deferred development costs as a result of adopting a change in accounting standards, effective January 1, 2009.

ENBRIDGE GAS DISTRIBUTION

EGD is Canada's largest natural gas distribution company and has been in operation for more than 160 years. It serves approximately 2 million customers in central and eastern Ontario and parts of northern New York State. EGD's utility operations are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission.



GAS DISTRIBUTION

INCENTIVE REGULATION

In 2007, the Company filed a rate application with the OEB requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the IR Settlement Agreement (the Settlement) with customer representatives.

The objectives of the Settlement are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to its customers.

Under the Settlement, EGD is allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps must be shared with customers on an equal basis. EGD estimates the customer portion of 2011 earnings over the allowed threshold to be $14 million (2010 – $19 million). In preparation for the conclusion of the current IR term at the end of 2012, EGD filed a 2013 cost of service application, which they expect will be addressed by the OEB in 2012.

RATE ADJUSTMENT APPLICATIONS

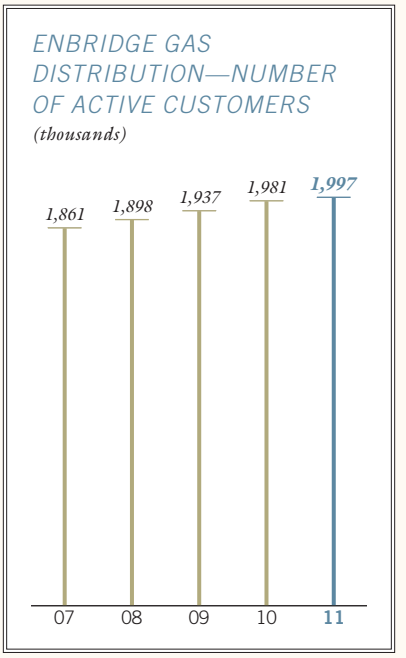
In September of each year, EGD files an application with the OEB to adjust rates for the next calendar year. Each of the 2012, 2011 and 2010 rate applications were filed pursuant to the approved IR formula. Out of the total distribution revenue applied for in the 2012 rate application, 98% was approved for recovery with the rate adjustment being effective January 1, 2012. The hearing with respect to the remaining 2% and related issues was held by the OEB in January 2012 with a decision expected in April 2012.

The total distribution revenue applied for in the 2011 rate application was approved by the OEB and the rate adjustment was effective January 1, 2011. In September 2009, EGD filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Subsequent to filing a settlement agreement with ratepayer groups with the OEB, in March 2010, EGD received approval of a fiscal 2010 final rate order from the OEB. The 2010 final rate order approved the implementation of a rate change effective April 1, 2010, which enabled EGD to recover the approved revenues as if rates were effective January 1, 2010.

RESULTS OF OPERATIONS

Adjusted earnings for the year ended December 31, 2011 were $137 million compared with $135 million for the year ended December 31, 2010. The increase in EGD's adjusted earnings was primarily due to customer growth, lower interest expense and lower taxes. These positive impacts were partially offset by higher customer support costs, as well as an increase in system integrity and employee related expenses. Depreciation expense also increased due to a higher overall asset base.

Adjusted earnings for the year ended December 31, 2010 were $135 million compared with $129 million for the year ended December 31, 2009. The increase in EGD adjusted earnings was primarily a result of continued favourable performance under IR, reflecting customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation expense. Depreciation expense increased due to a higher overall asset base, including the implementation of a new customer billing system in late 2009.



BUSINESS RISKS

The risks identified below are specific to EGD. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

REGULATORY RISK

The utility operations of EGD are regulated by the OEB. To the extent that the Regulator's future actions are different from EGD's current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

The IR Framework permits EGD to recover, with OEB approval, certain costs that are beyond management control, but that are necessary for the maintenance of its services. The IR Framework also includes a mechanism to reassess the IR plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the settlement mitigate EGD's risk to factors beyond management's control. The current IR Framework term expires after the rate year 2012.

NATURAL GAS COST RISK

EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow EGD to recover or refund the natural gas cost differential. EGD has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB. However, the cost of natural gas does affect the amount of EGD's investment in gas in storage.

VOLUME RISK

Since customers are billed on both a fixed charge and volumetric basis, EGD's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current Settlement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. For the years ended December 31, 2011, 2010 and 2009, colder/(warmer) than normal weather resulted in an increase to earnings of $1 million, a reduction to earnings of $12 million and an increase to earnings of $17 million, respectively.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and small commercial sectors account for approximately 80% (2010 – 80%; 2009 – 81%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for customers other than large volume transportation customers is mitigated by the average use true-up variance account that was established under the IR Framework. This variance account enables recovery from or repayment to customers of amounts representing variances in the actual and forecast average use by general service customers. EGD remains at risk from the variability of distribution volumes for large volume contract commercial and industrial customers.

OTHER GAS DISTRIBUTION AND STORAGE

Other Gas Distribution includes natural gas distribution utility operations in Quebec and New Brunswick, the most significant being Enbridge Gas New Brunswick (EGNB) (100% owned and operated by the Company), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 11,000 customers. Approximately 790 kilometres (490 miles) of distribution main has been installed with the capability of attaching approximately 30,000 customers.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The EUB had previously approved the deferral of the shortfall between distribution revenues and the cost of service during the development period for recovery in future rates. The recovery period is expected to commence at the end of the development period in 2013 and end no sooner than 2040. On December 31, 2011, the regulatory deferral asset was $180 million (2010 – $171 million).

ENBRIDGE GAS NEW BRUNSWICK – REGULATORY MATTERS

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 – $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

RESULTS OF OPERATIONS

Other Gas Distribution and Storage adjusted earnings were $38 million for the year ended December 31, 2011 compared with $32 million for the year ended December 31, 2010 and $25 million for the year ended December 31, 2009, primarily due to an increased contribution from Enbridge's Ontario unregulated gas storage business.

Gas Pipelines, Processing and Energy Services

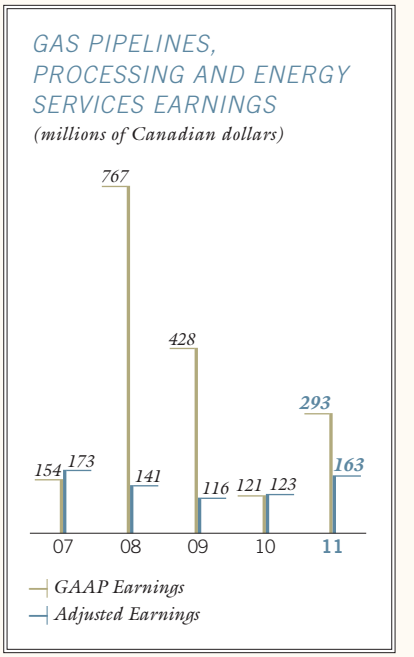
EARNINGS

	2011	2010	2009
(millions of Canadian dollars)			
Enbridge Offshore Pipelines (Offshore)	**(7)**	23	29
Alliance Pipeline US	**26**	25	27
Vector Pipeline	**18**	15	16
Aux Sable	**55**	37	26
Energy Services	**55**	20	29
Other	**16**	3	(11)
Adjusted earnings	**163**	123	116
Offshore – property insurance recoveries from hurricanes	**–**	2	4
Aux Sable – unrealized derivative fair value gains/(loss)	**(7)**	7	(36)
Aux Sable – loan forgiveness	**–**	–	7
Energy Services – unrealized derivative fair value gains/(loss)	**113**	(12)	3
Energy Services – Lehman and SemGroup credit recovery	**–**	1	1
Other – unrealized derivative fair value gains	**24**	–	–
Other – gain on sale of investments	**–**	–	329
Other – impact of tax rate changes	**–**	–	4
Earnings	**293**	121	428

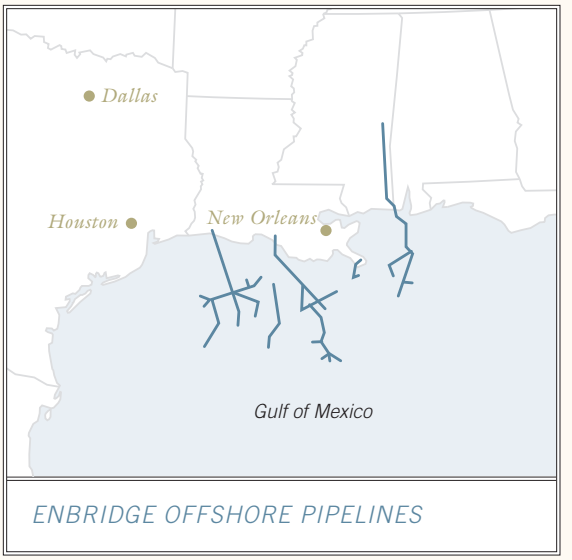
Adjusted earnings from Gas Pipelines, Processing and Energy Services were $163 million for the year ended December 31, 2011 compared with $123 million for the year ended December 31, 2010. The increase was primarily due to higher adjusted earnings from Aux Sable, Energy Services and Other, which includes the Company's green energy projects, partially offset by losses in Offshore.

Adjusted earnings were $123 million for the year ended December 31, 2010 compared with $116 million for the year ended December 31, 2009. The increase resulted from improved contributions from Aux Sable and new green energy investments.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items.



- Offshore earnings for 2010 and 2009 included insurance proceeds related to the replacement of damaged infrastructure as a result of a 2008 hurricane.
- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company's forward gas processing risk management position.
- Earnings for the year ended December 31, 2009 from Aux Sable reflected a gain from a loan forgiveness related to a negotiated settlement with a counterparty in bankruptcy proceedings.
- Energy Services earnings for each period reflected unrealized fair value gains and losses related to the revaluation of inventory and the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions.
- Energy Services earnings for 2010 and 2009 included partial recoveries from the sale of its receivable from Lehman Brothers and from SemGroup.
- Other earnings for 2011 reflected unrealized fair value changes on derivative financial instruments.
- In March 2009, the Company sold its investment in OCENSA, a crude oil export pipeline in Colombia, for proceeds of $512 million, resulting in a gain of $329 million.
- Other earnings for 2009 reflected the impact of favourable tax rate changes.



ENBRIDGE OFFSHORE PIPELINES

ENBRIDGE OFFSHORE PIPELINES

Offshore is comprised of 13 natural gas gathering and FERC-regulated transmission pipelines and one oil pipeline with a capacity of 60,000 bpd, in five major corridors in the Gulf of Mexico, extending to deepwater developments. These pipelines include almost 2,400 kilometres (1,500 miles) of underwater pipe and onshore facilities with total capacity of approximately 7.2 bcf/d. Offshore currently moves approximately 40% of offshore deepwater gas production through its systems in the Gulf of Mexico.

TRANSPORTATION CONTRACTS

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current delivery expectations. The majority of long-term transport rates are market-based, with revenue generation directly tied to actual production deliveries. Some of the systems operate under a cost-of-service methodology while others have minimum take-or-pay obligations.

The business model utilized on a go forward basis and included in the WRGGS, Big Foot and Venice commercially secured projects differs from the historic model. These new projects have a base level return which is locked in through take or pay commitments. If volumes reach producer anticipated levels the return on these projects will increase. In addition, Enbridge has minimal capital cost risk on these projects and commercial agreements continue to contain life-of-lease commitments. The WRGGS and Big Foot project agreements provide for recovery of actual capital costs to complete the project in fees payable by producers over the contract term. The Venice project provides for a capital cost risk sharing mechanism, whereby Enbridge is exposed to a portion of the capital costs in excess of an agreed upon target. Conversely, Enbridge can recover in fees from producers a portion of the capital cost savings below the agreed upon target.

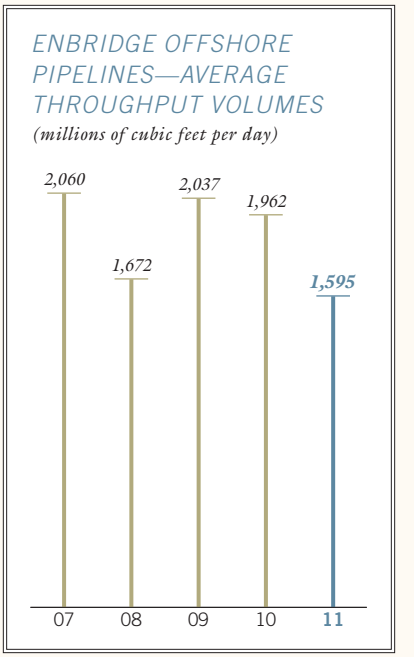
RESULTS OF OPERATIONS

For the year ended December 31, 2011, Offshore incurred a loss of $7 million compared with adjusted earnings of $23 million for the year ended December 31, 2010. The decrease in Offshore adjusted earnings reflected continued volume declines due to the slower regulatory permitting process and delayed drilling programs by producers. Increased operating and administrative costs, including higher insurance premiums and employee benefits, as well as increased depreciation expense also contributed to the decrease in earnings from the prior year.

Adjusted earnings from Offshore for the year ended December 31, 2010 were $23 million compared with $29 million for the year ended December 31, 2009. The Company experienced volume declines due to the slower regulatory permitting process. In July 2010, the Secretary of the Interior suspended deepwater drilling in the Gulf of Mexico. Subsequently, in October 2010, the deepwater drilling suspension was lifted, allowing a return to deepwater drilling, but subject to increased regulation and approval. Other factors contributing to the adjusted earnings decrease were higher operating and administrative costs, including insurance and higher depreciation expense.

BUSINESS RISKS

The risks identified below are specific to Offshore. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*



WEATHER

Adverse weather, such as hurricanes, may impact Offshore's financial performance directly or indirectly. Direct impacts may include damage to Offshore facilities resulting in lower throughput, as well as inspection and repair costs. Indirect impacts may include damage to third party production platforms, onshore processing plants and pipelines that may decrease throughput on Offshore systems. Effective June 2011, Offshore's insurance policy includes specific coverage related to named windstorms, such as hurricanes, for all systems. The occurrence of hurricanes in the United States Gulf Coast increases the cost and availability of insurance coverage, so Enbridge may not be able, or may choose not, to insure against this risk in the future.

COMPETITION

There is competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities, allowing it to more fully utilize existing capacity. Offshore's gas pipelines serve a majority of the strategically located deepwater host platforms, positioning it favourably to make incremental investments for new platform connections and receive additional transportation volumes from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining gas production, as demonstrated with the Neptune crude oil lateral and the planned Big Foot. Given rates of decline, offshore pipelines typically have available capacity, resulting in significant competition for new developments in the Gulf of Mexico.

SUPPLY AND DEMAND

Low natural gas prices, in part due to the prevalence of shale gas, have resulted in reduced investment in exploration activities and producing infrastructure. Offshore diversifies its risk of declining gas production through the construction of crude oil pipelines as noted above.

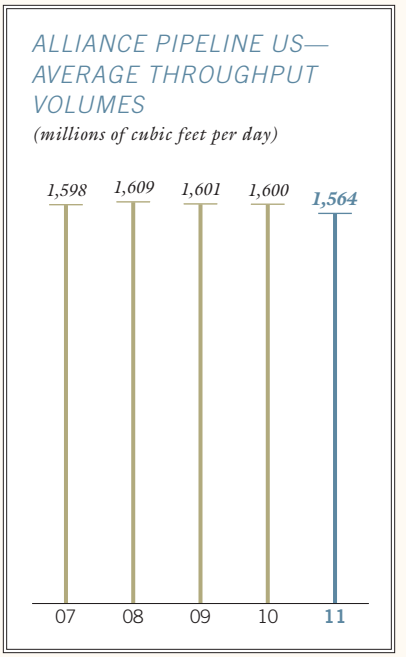
REGULATION

The transportation rates on many of Offshore's transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates are subject to challenge from time-to-time.

The Macondo oil spill in 2010 has altered the offshore regulatory environment. Although the moratorium on deepwater drilling was lifted, future deepwater drilling activity will be subject to heightened regulation and oversight. Increased regulation may impact the levels and timing of future exploration and drilling activity in the region and the resultant production volumes available to ship on the Offshore system. The shifting business environment could result in increases in available capacity, resulting in heightened competition.

OTHER RISKS

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing, changes in plans by shippers and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners or through cost of service tolling arrangements or other pre-arranged terms in commercial agreements. Start-up delays are mitigated by the right to collect stand-by fees.



ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and United States portions of the pipeline system, consists of an approximately 3,000-kilometre (1,864-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (454-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to Channahon, Illinois. Alliance Pipeline US and Alliance Pipeline Canada have firm service shipping contract capacity to deliver 1.405 bcf/d and 1.325 bcf/d, respectively. Enbridge owns 50% of Alliance Pipeline US, while the Fund, described under *Sponsored Investments*, owns 50% of Alliance Pipeline Canada.

Alliance connects with Aux Sable, (of which Enbridge owns 42.7%), an NGL extraction and fractionation facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and northeastern United States and eastern Canada. Alliance Pipeline US is adjacent to the Bakken oil formation in North Dakota which offers new incremental sources of liquids-rich natural gas for delivery to downstream markets. In February 2010, a new receipt point on the pipeline near Towner, North Dakota was placed into service. The receipt point connects to the Prairie Rose Pipeline, which initially provided access to a shipper operating out of the Bakken formation with a firm transportation contract for an initial contract capacity of 40 mmcf/d under a 10-year contract. An additional 40 mmcf/d of firm transportation capacity at this same receipt point became effective February 2011. The Prairie Rose Pipeline was acquired by Aux Sable in 2011.

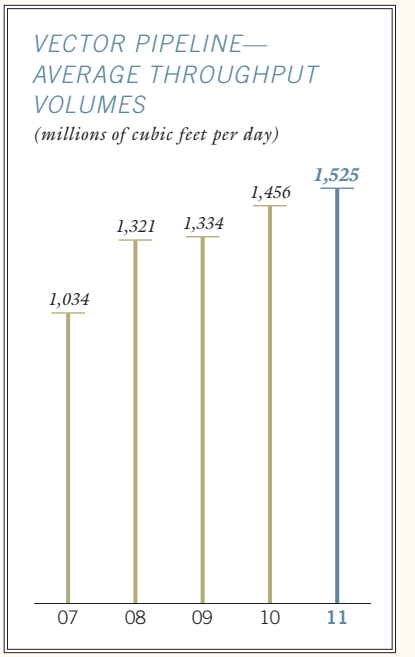
TRANSPORTATION CONTRACTS

Alliance Pipeline US has long-term, take-or-pay contracts to transport substantially all its 1.405 bcf/d of natural gas capacity with terms ending on December 1, 2015. A small percentage of natural gas is being contracted on a short-term basis with an annual renewal option. These contracts permit Alliance Pipeline US, whose operations are regulated by the FERC, to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed ROE of 10.88%.

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense under Canadian GAAP is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the Canadian GAAP amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue, which began being recovered from shippers starting in 2009 for Alliance Pipeline US and in 2012 for Alliance Pipeline Canada. As at December 31, 2011, $103 million (US$101 million) (2010 – $122 million (US$123 million)) was recorded as Enbridge's share of deferred transportation revenue for Alliance Pipeline US.

RESULTS OF OPERATIONS

Alliance Pipeline US earnings were $26 million for the year ended December 31, 2011 comparable with $25 million for the year ended December 31, 2010 and $27 million for the year ended December 31, 2009.



VECTOR PIPELINE

The Vector Pipeline (Vector) system, which includes both the Canadian and United States portions of the pipeline system, consists of 560 kilometres (348 miles) of mainline natural gas transmission pipeline between the Chicago, Illinois hub and the storage complex at Dawn, Ontario. Vector's primary sources of supply are through interconnections with Alliance and the Northern Border Pipeline in Joliet, Illinois. Vector has the capacity to deliver a nominal 1.3 bcf/d and is operating at or near capacity. The Company provides operating services to and holds a 60% joint venture interest in Vector.

TRANSPORTATION CONTRACTS

The total long haul capacity of Vector is approximately 87% committed through 2015. Approximately 55% of the long haul capacity is committed through firm transportation contracts at rates negotiated with the shippers and approved by the FERC, while the remaining committed capacity is sold at market rates. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service. Vector is an interstate natural gas pipeline with FERC and NEB approved tariffs that establish the rates, terms and conditions governing its service to customers. On the United States portion of Vector, tariff rates are determined using a cost of service methodology and tariff changes may only be implemented upon approval by the FERC. For 2011, the FERC approved maximum tariff rates include an underlying weighted average after-tax ROE component of 11.18% (2010 – 11.18%; 2009 – 11.07%). On the Canadian portion, Vector is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2011, maximum tariff tolls include a ROE component of 10.48% after-tax.

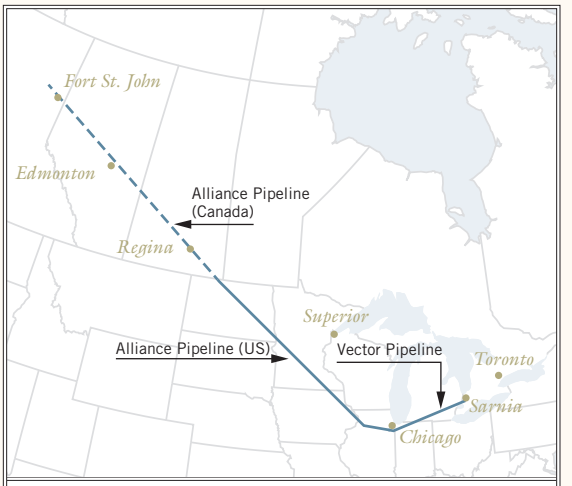
Depreciation expense prescribed in the negotiated transportation contracts is different than the depreciation expense used for financial statement purposes. Negotiated depreciation expense is less than the financial statement amount at the beginning of the contract and higher than the financial statement amount in the later years of the negotiated transportation contracts. This difference results in the recognition of a long-term receivable, referred to as unbilled transportation revenue, which began to be recovered from shippers in 2008 for Vector US and 2006 for Vector Canada. As at December 31, 2011 $21 million (US$21 million) (2010 – $27 million (US$27 million)) was recorded as Enbridge's share of unbilled transportation revenue for Vector.

RESULTS OF OPERATIONS

Vector Pipeline earnings were $18 million for the year ended December 31, 2011 comparable with $15 million for the year ended December 31, 2010 and $16 million for the year ended December 31, 2009.

BUSINESS RISKS

The risks identified below are specific to both Alliance Pipeline US and Vector. General risks that affect the entire Company are described under *Risk Management and Financial Instruments.*



NATURAL GAS PIPELINES

SUPPLY AND DEMAND

Currently, natural gas pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending primarily to 2015; however, excess capacity could negatively impact re-contracting beyond this term. Re-contracting risk is mitigated to some extent as Alliance Pipeline US is well positioned to deliver incremental liquids-rich gas production from new developments in the Montney and Bakken regions. Alliance Pipeline US is also engaged with market participants in developing new receipt facilities and services to expand its reach in transporting liquids-rich gas to premium markets. In addition, Aux Sable, through its participation in midstream businesses upstream of Alliance Pipeline US, attracts liquids-rich gas to Alliance Pipeline US by offering incremental value for producers' NGL. Vector's interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago, Illinois and Dawn, Ontario relative to the transportation toll.

COMPETITION

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB and the Bakken to natural gas markets in the midwestern United States. In addition, there are several proposals to upgrade existing pipelines or to build new pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by Alliance Pipeline US because of location, facilities or other factors. In addition, these pipelines could charge rates or provide transportation services to locations that result in greater net profit for shippers, with the effect of forcing Alliance Pipeline US to realize lower revenues and cash flows. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance the competitive position of Alliance Pipeline US.

Vector faces competition for pipeline transportation services to its delivery points from new supply sources and traditional low cost pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector has mitigated this risk by entering into long-term firm transportation contracts, which expire starting in November 2015, for approximately 87% of its capacity. The remaining contracts expire at various times starting in April 2012. Certain long-term firm contracts (55% of capacity) provide for additional compensation to Vector if shippers do not extend their contracts beyond the initial term ending November 2015. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Vector and Alliance pipelines also face potential competition from new sources of natural gas such as the Marcellus shale formation, which is among the largest gas play in North America. The Marcellus shale formation is in close proximity to the Chicago Hub. The development of the Marcellus shale formation could provide an alternate source of gas to the Chicago Hub as well as decrease the northeastern region of the United States' reliance on natural gas imports from Canada.

REGULATION

Both the United States portion of Vector and Alliance Pipeline US operations are subject to regulation by the FERC. If tariff rates are protested, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position could be different from the amounts that are eventually recovered or refunded. In addition, future profitability of the entities could be negatively impacted. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

FERC has intensified its oversight of financial reporting, risk standards and affiliate rules and has issued new standards on managing gas pipeline integrity. The Company continues ongoing dialogue with regulatory agencies and participates in industry lobby groups to ensure it is informed of emerging issues in a timely manner.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, an NGL extraction and fractionation business, which owns and operates a plant near Chicago, Illinois at the terminus of Alliance. The plant extracts NGLs from the liquids-rich natural gas transported on Alliance, as necessary to meet gas quality specifications of downstream transmission and distribution companies and to take advantage of positive fractionation spreads.

Aux Sable sells its NGL production to BP under a long-term contract. BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel gas requirements of the Aux Sable plant and pays market rates for the capacity on the Alliance Pipeline held by an Aux Sable affiliate. The BP agreement is for an initial term of 20 years, expiring March 31, 2026, and may be extended by mutual agreement for 10-year terms.

Aux Sable also owns and operates facilities upstream of the Alliance Pipeline that deliver liquids-rich gas volumes into the pipeline for further processing at the Aux Sable plant. These facilities include the Prairie Rose Pipeline and the Palermo Conditioning Plant in the Bakken area of North Dakota and the Septimus Gas Plant and the Septimus Pipeline in the Montney area of British Columbia.

RESULTS OF OPERATIONS

Aux Sable adjusted earnings were $55 million for the year ended December 31, 2011 compared with $37 million for the year ended December 31, 2010. Aux Sable adjusted earnings increased primarily due to stronger realized fractionation margins which resulted in higher contributions from the upside sharing mechanism in its production sales agreement, as well as increased earnings contribution from new assets including Septimus Pipeline and Gas Plant, Prairie Rose Pipeline and Palermo Conditioning Plant.

Aux Sable adjusted earnings increased from $26 million in 2009 to $37 million in 2010 primarily due to enhanced plant performance and stronger fractionation margins.

ENERGY SERVICES

Energy Services provides energy supply and marketing services to North American refiners, producers and other customers. Crude oil and NGL marketing services are provided by Tidal Energy. This business transacts at many North American market hubs and provides its customers with various services, including transportation, storage, supply management, flexible pricing, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities can create commodity exposures. Any residual open positions created from this physical business are closely monitored and must comply with the Company's formal risk management policies.

Natural gas marketing services are provided by Tidal Energy and Gas Services. Tidal Energy markets natural gas to optimize Enbridge's commitments on the Alliance and Vector pipelines. Capacity commitments at December 31, 2011 and 2010 were 30 mmcf/d on Alliance and 156 mmcf/d on Vector. Earnings from these commitments are dependent upon the basis (location) differentials between Alberta and Chicago, Illinois for Alliance, and between Chicago and Dawn, Ontario for Vector. To the extent transportation costs exceed the basis (location) differential, earnings will be negatively affected. Tidal Energy also provides fee-for-service arrangements for third parties, leveraging its natural gas marketing expertise and access to transportation capacity. Gas Services markets natural gas to commercial and industrial customers in the upper mid-west area of the United States.

RESULTS OF OPERATIONS

Energy Services adjusted earnings were $55 million for the year ended December 31, 2011 compared with $20 million for the year ended December 31, 2010. This increase was primarily attributable to crude oil marketing strategies designed to capture basis (location) differentials and tank management revenue when opportunities arise. Energy Services employs such strategies in compliance with and under the oversight of the Company's formal risk management policies and procedures. Partially offsetting positive earnings contributions from crude oil services were declines in natural gas marketing due to narrower natural gas basis (location) spreads, which impact the Company's merchant capacity on certain natural gas pipelines. Earnings from Energy Services are dependent on market conditions, including, but not limited to, location and grade basis spreads, and may not be indicative of results to be achieved in future periods.

Energy Services adjusted earnings decreased to $20 million for the year ended December 31, 2010 from $29 million in 2009 as a result of reduced volume and margin opportunities in liquids marketing.

OTHER

Other includes operating results from the Company's investments in green energy projects, net of business development expenses associated with international and Canadian gas activities.

In October 2011, ownership of the Sarnia Solar, Ontario Wind and Talbot Wind energy projects was transferred to the Fund. Effective October 21, 2011, earnings contributions from these assets, net of noncontrolling interest, will be reflected within the Sponsored Investments segment. Green energy projects remaining in the Gas Pipelines, Processing and Energy Services segment include Greenwich Wind Energy, Cedar Point Wind Energy, Amherstburg Solar and Tilbury Solar.

In 2009, the Company sold its 24.7% interest in OCENSA, a crude oil export pipeline in Colombia. This investment was sold at a very attractive price and proceeds were utilized in the funding of the North American expansion projects discussed earlier. There are currently minimal operations in International; however, Enbridge continues to actively monitor the international business environment to identify potential new investment opportunities.

RESULTS OF OPERATIONS

Other adjusted earnings for the year ended December 31, 2011 were $16 million compared with $3 million for the year ended December 31, 2010 and an adjusted loss of $11 million for the year ended December 31, 2009. The increase reflected strong contributions primarily from the Sarnia Solar expansion and Talbot Wind Energy Project, both of which were completed in the latter part of 2010. In addition, adjusted earnings from 2011 reflected several newly constructed green energy projects, including Cedar Point Wind Energy, Greenwich Wind Energy and Amherstburg Solar.

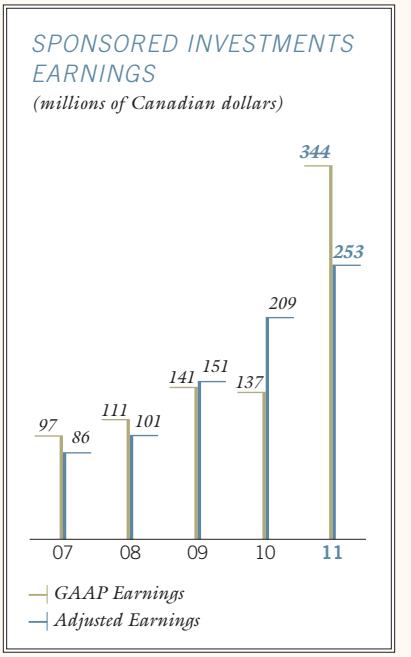
Sponsored Investments

EARNINGS

(millions of Canadian dollars)	2011	2010	2009
Enbridge Energy Partners (EEP)	**152**	122	99
Enbridge Energy, Limited Partnership – Alberta Clipper US (EELP)	**42**	42	7
Enbridge Income Fund (the Fund)	**59**	45	45
Adjusted earnings	**253**	209	151
EEP – leak insurance recoveries	**50**	–	–
EEP – leak remediation costs and lost revenue	**(33)**	(106)	–
EEP – unrealized derivative fair value gains/(loss)	**3**	(1)	(2)
EEP – NGL trucking and marketing prior period adjustment	**(3)**	–	–
EEP – shipper dispute settlement	**8**	–	–
EEP – lawsuit settlement	**1**	–	–
EEP – impact of unusual weather conditions	**(1)**	–	–
EEP – Lakehead System billing correction	**–**	1	4
EEP – dilution gain on Class A unit issuance	**66**	36	–
EEP – asset impairment loss	**–**	(2)	(12)
Earnings	**344**	137	141

Adjusted earnings from Sponsored Investments were $253 million for the year ended December 31, 2011 compared with $209 million for the year ended December 31, 2010. The increase in adjusted earnings resulted from increased contributions from both EEP and the Fund.

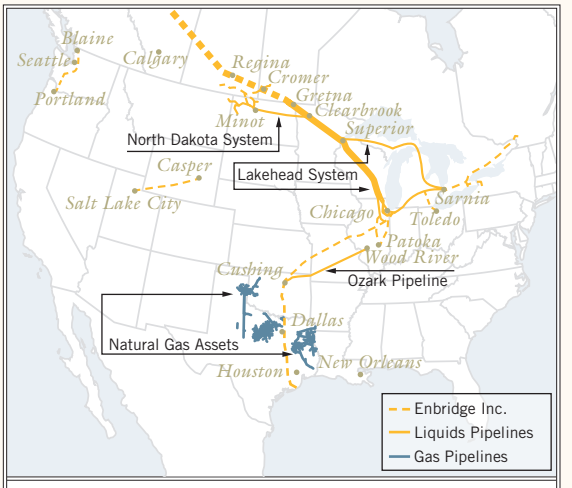
Adjusted earnings from Sponsored Investments were $209 million for the year ended December 31, 2010 compared with $151 million in 2009. The increase in adjusted earnings resulted primarily from increased contributions from EEP as a result of positive operating factors, including growth projects, as well as the Company's investment in EELP.



Sponsored Investments earnings were impacted by the following non-recurring or non-operating adjusting items.

- EEP 2011 earnings included insurance recoveries associated with the Line 6B crude oil release. See *EEP Lakehead System Line 6A and 6B Crude Oil Releases.*
- Earnings from EEP for 2011 and 2010 included a charge related to estimated costs, before insurance recoveries, associated with the Line 6A and 6B crude oil releases. EEP earnings from 2010 also included a charge of $3 million (net to Enbridge) related to lost revenue as a result of the crude oil releases. See *EEP Lakehead System Line 6A and 6B Crude Oil Releases.*
- Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.
- Earnings from EEP included an unfavourable prior period adjustment related to NGL trucking and marketing.
- EEP earnings for 2011 included proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- EEP earnings for 2011 included proceeds related to the settlement of a lawsuit during the first quarter.

- EEP earnings for 2011 included an unfavourable effect related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations.
- EEP earnings for 2010 and 2009 included Lakehead System billing corrections.
- EEP 2011 and 2010 earnings included dilution gains (after tax and noncontrolling interest) as Enbridge did not fully participate in EEP's issuances of Class A units.
- EEP earnings for 2010 and 2009 included charges related to asset impairment losses.



ENBRIDGE ENERGY PARTNERS

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transportation and storage assets and natural gas and NGL gathering, treating, processing, transportation and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Canadian Mainline in the United States, the Mid-Continent crude oil system consisting of an interstate crude oil pipeline and storage facilities, a crude oil gathering system and interstate pipeline system in North Dakota and natural gas assets located primarily in Texas. Subsidiaries of Enbridge provide services to EEP in connection with the operation of its liquids assets, including the Lakehead System.

In September 2010, EEP acquired the entities that comprise the Elk City System from Atlas Pipeline Partners for US$686 million. The Elk City System extends from southwestern Oklahoma to Hemphill County in the Texas Panhandle and consists of approximately 1,290 kilometres (800 miles) of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 mmcf/d and a combined NGL production capability of 20,000 bpd. The acquisition of the Elk City System complements EEP's existing Anadarko natural gas system by providing additional processing capacity and expansion capability.

OWNERSHIP INTEREST

Enbridge's ownership interest in EEP is impacted by EEP's issuance and sale of its Class A common units. To the extent Enbridge does not fully participate in these offerings, the Company's ownership interest in EEP is reduced. At December 31, 2011, Enbridge's ownership interest in EEP was 23.0% (2010 – 25.5%; 2009 – 27.0%). The Company's average ownership interest in EEP during 2011 was 24.4% (2010 – 26.7%; 2009 – 27.0%).

DISTRIBUTIONS

EEP makes quarterly distributions of its available cash to its common unitholders. Under the Partnership Agreement, Enbridge Energy Company, Inc. (EECI), a wholly owned subsidiary of Enbridge, as general partner (GP), receives incremental incentive cash distributions, which represent incentive income on the portion of cash distributions (on a per unit basis) that exceed certain target thresholds as follows.

	Unitholders including Enbridge	GP Interest
Quarterly cash distributions per unit [1]		
Up to $0.295 per unit	98%	2%
First target – $0.295 per unit up to $0.350 per unit	85%	15%
Second target – $0.350 per unit up to $0.495 per unit	75%	25%
Over second target – cash distributions greater than $0.495 per unit	50%	50%

1 Distributions restated to reflect EEP's two-for-one stock split which was effective April 2011.

In 2009, EEP paid a quarterly distribution of $0.495 per unit to its common unitholders. This quarterly distribution remained in effect through the first quarter of 2010 when, effective April 2010, EEP increased it to $0.50125 per unit. In July 2010, EEP further increased its quarterly distribution to $0.51375 per unit and in July 2011 the quarterly distribution was increased to $0.5325. Of the $152 million Enbridge recognized as adjusted earnings from EEP during 2011, $46 million (2010 – $33 million; 2009 – $27 million) were GP incentive earnings, while the remainder was Enbridge's limited partner share of EEP's earnings.

RESULTS OF OPERATIONS

After adjusting EEP earnings for non-recurring or non-operating items, including the impact of the 2010 Line 6A and Line 6B crude oil releases, EEP adjusted earnings increased to $152 million for the year ended December 31, 2011 compared with $122 million for the year ended December 31, 2010. The increase was primarily attributable to strong results from its natural gas business as a result of higher natural gas and NGL volumes, including those associated with the acquisition of the Elk City System in September 2010, as well as higher general partner incentive income. Increased volumes in liquids pipelines and a full year contribution from Alberta Clipper also drove higher earnings in 2011. These positive factors were partially offset by an increase in operating and administrative costs and higher financing costs.

EEP adjusted earnings were $122 million for the year ended December 31, 2010 compared with $99 million for the year ended December 31, 2009. The increase was largely attributable to strong results from the liquids business as well as higher incentive income. The liquids improvement was generated largely from higher delivered volumes and increased average transportation rates, partially offset by increased operating costs.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

LINE 6B CRUDE OIL RELEASE

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas—a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The change in estimate was primarily based on a review of costs and commitments incurred, and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations, and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

LINE 6A CRUDE OIL RELEASE

A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

INSURANCE RECOVERIES

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) in insurance recoveries for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

LINE 6B PIPELINE INTEGRITY PLAN

In connection with the restart of Line 6B, EEP committed to accelerate a process initiated prior to the crude oil release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), EEP completed remediation of those pipeline anomalies it identified between 2007 and 2009 that were scheduled for refurbishment, and anomalies identified for action in a July 2010 PHMSA notification, on schedule within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, EEP also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

In February 2011, EEP filed a tariff supplement with the FERC, which became effective on April 1, 2011, for recovery of US$175 million of capital costs and US$5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30-year period, while operating costs will be recovered through EEP's annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

LEGAL AND REGULATORY PROCEEDINGS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP – ALBERTA CLIPPER US

In July 2009, the Company committed to fund 66.7% of the cost to construct the United States segment of the Alberta Clipper Project. The Company funded 66.7% of the project's equity requirements through EELP, while 66.7% of the debt funding was made through EEP. EELP – Alberta Clipper US earnings are the Company's earnings from its investment in EELP which undertook the project. The Alberta Clipper Project was placed into service on April 1, 2010.

RESULTS OF OPERATIONS

Adjusted earnings from EELP – Alberta Clipper US were $42 million for the year ended December 31, 2011 compared with $42 million for the year ended December 31, 2010 and $7 million for the year ended December 31, 2009. These earnings represent the Company's earnings from its 66.7% investment in a series of equity within EELP which owns the United States segment of Alberta Clipper. In 2010, earnings were favourably impacted by lower operating costs, predominantly property tax rates applicable during the construction phase relative to the deemed recovery permitted in tolls. Earnings for 2009 and for the first quarter of 2010, in advance of the in service date of April 1, 2010, were attributable to AEDC recognized while the project was under construction.

BUSINESS RISKS

The risks identified below are specific to EEP and EELP. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

COMPETITION

EEP's Lakehead System, the United States portion of the Liquids Pipelines mainline, is a major crude oil export conduit from the WCSB. Other existing competing carriers and pipeline proposals to ship western Canadian liquids hydrocarbons to markets in the United States represent competition for the Lakehead System. Further details on such competing projects are described within Business Risks under *Liquids Pipelines.* EEP's Mid-Continent and North Dakota systems also face competition from existing competing pipelines, proposed future pipelines and alternative gathering facilities (being predominately rail), available to producers or the ability of the producers to build such gathering facilities. Competition for EEP's storage facilities includes large integrated oil companies and other midstream energy partnerships.

Other interstate and intrastate natural gas pipelines (or their affiliates) and other midstream businesses that gather, treat, process and market natural gas or NGLs represent competition to EEP's natural gas segment. The level of competition varies depending on the location of the gathering, treating and processing facilities. However, most natural gas producers and owners have alternate gathering, treating and processing facilities available to them, including those owned by competitors that are substantially larger than EEP.

EEP's marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and natural gas producers, independent aggregators and regional marketing companies.

SUPPLY AND DEMAND

The profitability of EEP depends to some extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and eastern Canada. Investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, United States demand and availability of markets for produced crude oil. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing levels, alternative energy sources and global supply disruptions. Crude oil prices have been sustained at such levels that oil sands producers have recommenced projects that had been previously cancelled or deferred, creating increased demand in the WCSB for new pipeline infrastructure.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Supply for the marketing segment depends to a large extent on the natural gas reserves and rate of drilling within the areas served by the natural gas business. Demand is typically driven by weather-related factors, with respect to power plant and utility customers, and industrial demand. EEP's marketing business uses third party storage to balance supply and demand factors.

VOLUME RISK

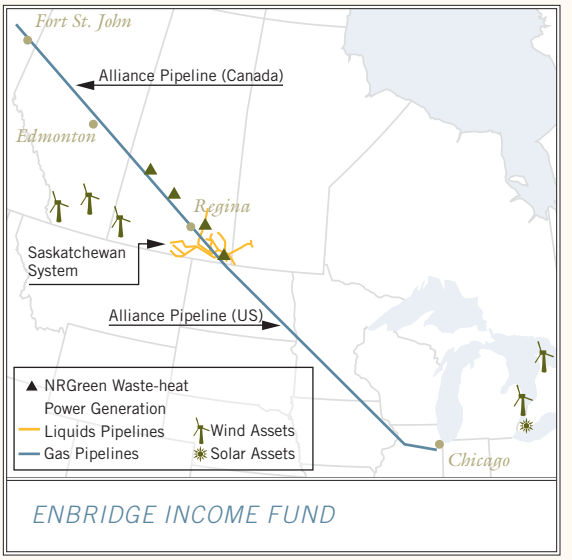
A decrease in volumes transported by EEP's systems can directly and adversely affect revenues and results of operations. A decline in volumes transported can be influenced by factors beyond EEP's control including competition, regulatory actions, government actions, weather, storage levels, alternative energy sources, decreased demand, fluctuations in commodity prices, economic conditions, supply disruptions, availability of supply connected to the systems and adequacy of infrastructure to move supply into and out of the systems.

REGULATION

In the United States, the interstate oil pipelines owned and operated by EEP and certain activities of EEP's intrastate natural gas pipelines are subject to regulation by the FERC or state regulators and its financial condition and results of operations could worsen if tariff rates were protested. While gas gathering pipelines are not currently subject to active rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

MARKET PRICE RISK

EEP's gas processing business is subject to commodity price risk arising from movements in natural gas and NGL prices and differentials. These risks have been managed by using physical and financial contracts to fix the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, EEP's earnings are exposed to associated mark-to-market valuation changes.



ENBRIDGE INCOME FUND

The Fund is involved in the generation and transportation of energy through its 50% interest in Alliance Pipeline Canada, its crude oil and liquids pipelines business in Saskatchewan (the Saskatchewan System) and interests in more than 400 MW of renewable power generation capacity. The Saskatchewan System operates a crude oil gathering system and trunkline pipeline in southern Saskatchewan and southwestern Manitoba, connecting to Enbridge's mainline pipeline to the United States. The Fund's renewable power portfolio includes the 190-MW Ontario Wind Project, the 99-MW Talbot Wind Project and the 80-MW Sarnia Solar Project, which were acquired from a wholly-owned subsidiary of Enbridge in October 2011, as well as interests in three wind power joint ventures and a business that operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

CORPORATE RESTRUCTURING

On December 17, 2010, a plan of arrangement (the Plan) to restructure the Fund took effect. Under the Plan all publicly held trust units and five million units held by Enbridge were exchanged on a one-for-one basis for shares of a taxable Canadian corporation, ENF. The business of ENF is generally limited to investment in the Fund. Following completion of the Plan, the Company retained its overall 72% economic interest in the Fund and remained the primary beneficiary of the Fund both before and after the Plan through a combined direct and indirect investment in the Fund voting units and a non-voting preferred unit investment. As such, Enbridge continues to consolidate the Fund under variable interest entity accounting rules.

RENEWABLE ENERGY ASSETS TRANSFER

In October 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for an aggregate price of approximately $1.2 billion. The transaction was financed by the Fund through a combination of debt and equity, including the issuance of additional ordinary trust units of the Fund to ENF and preferred units to Enbridge. ENF in turn issued additional common shares to the public and to Enbridge. Enbridge's overall economic interest in the Fund was reduced from 72% to 69% upon completion of the transaction and associated financing.

As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer has been eliminated from the consolidated financial statements of Enbridge, although cash income taxes incurred of $98 million remain as a charge to consolidated earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.

Through this transaction, which essentially resulted in a partial monetization of these assets by Enbridge through sale to non-controlling interests (being ENF's public shareholders), Enbridge realized a source of funds of $210 million, as presented within Financing Activities on the Consolidated Statement of Cash Flows for the year ended December 31, 2011.

SASKATCHEWAN SYSTEM SHIPPER COMPLAINT

On December 17, 2010, the Saskatchewan System filed amended Westspur tariffs with the NEB with an effective date of February 1, 2011. In January 2011, a shipper on the Westspur System requested the NEB make the tolls "interim" effective February 1, 2011 pending discussions between the shipper and the Saskatchewan System on information requests put forward by the shipper. Subsequently, the shipper filed a complaint with the NEB on the basis the information provided by the Fund was not adequate to allow an assessment to be made of the reasonableness of the tolls. Six parties have filed letters with the NEB supporting the shipper's complaint. The NEB directed additional discussion among the parties and, as of February 6, 2012, the Fund continues to discuss the reasonableness of its Westspur tolls with shippers.

INCENTIVE AND MANAGEMENT FEES

Enbridge receives an annual base management fee for administrative and management services it provides to the Fund, plus incentive fees. Incentive fees are paid to Enbridge based on cash distributions by the Fund that exceed a base distribution amount. In 2011, the Company received intercompany incentive fees of $10 million (2010 – $8 million; 2009 – $8 million) before income taxes. Enbridge also provides management services to ENF. No additional fee is charged to ENF for these services provided the Fund is paying a fee to Enbridge.

RESULTS OF OPERATIONS

Earnings from the Fund totaled $59 million for the year ended December 31, 2011 compared with $45 million for the year ended December 31, 2010. The increased earnings from the Fund reflected continued increased contributions from the Saskatchewan System following substantial completion of its Phase II expansion project in December 2010, as well as contribution from the renewable assets acquired by the Fund in October 2011. These positive impacts were partially offset by higher operating and administrative costs as a result of the asset acquisition and an increase in interest expense and taxes.

Earnings from the Fund were $45 million for both the years ended December 31, 2010 and 2009. Earnings for both years reflected growth attributable to Phase II of the Saskatchewan System Capacity Expansion, which was placed into service in December 2010, offset by a reduced contribution from the wind power assets and increased corporate costs related to the corporate restructuring completed in December 2010. The Fund's interest in Alliance Pipeline Canada continued to contribute stable adjusted earnings in both 2010 and 2009.

BUSINESS RISKS

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Gas Pipelines, Processing and Energy Services segment. The following risks generally relate to the Saskatchewan System and the wind and solar business, as indicated. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

COMPETITION

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably trucking. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers and thereby potentially reduce shipping on the Saskatchewan System or result in possible toll reductions. The Saskatchewan System manages exposure to loss of shippers by ensuring the shipping rates are competitive and by providing a high level of service. Furthermore, the Saskatchewan System's right-of-way and expansion efforts have created a competitive advantage. The Saskatchewan System will continue to focus on increasing efficiencies through its expansion projects in order to meet its shippers' growing demand.

REGULATION

The Fund's 50% interest in Alliance Pipeline Canada and certain pipelines within the Saskatchewan System are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays. Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of the Fund.

VOLUME RISK

Operations and tolls for the Saskatchewan Gathering and the Westspur Systems are, in general, based on volumes transported and are on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

WIND AND SOLAR RESOURCES

There is risk that the wind or solar resource at specific locations is lower than expected leading to lower than expected power generation revenue. Extensive long term wind studies were completed prior to committing capital to the selected sites in order to mitigate this risk.

Corporate

EARNINGS

	2011	2010	2009
(millions of Canadian dollars)			
Noverco	**24**	21	19
Other Corporate	**(41)**	(48)	(39)
Adjusted loss	**(17)**	(27)	(20)
Noverco – impact of tax rate changes	**–**	–	6
Other Corporate – unrealized derivative fair value gains/(loss)	**(87)**	25	207
Other Corporate – unrealized foreign exchange gains/(loss) on translation of intercompany balances, net	**(131)**	40	133
Other Corporate – impact of tax rate changes	**6**	–	4
Other Corporate – gain on sale of investment in NetThruPut (NTP)	**–**	–	25
Other Corporate – tax on intercompany gain on sale	**(98)**	–	–
Earnings/(loss)	**(327)**	38	355

Total adjusted loss from Corporate was $17 million for the year ended December 31, 2011 compared with $27 million for the year ended December 31, 2010. The decrease in adjusted loss was due to both an increase in adjusted earnings from the Company's investment in Noverco and a decrease in adjusted loss from Other Corporate.

Total adjusted loss from Corporate was $27 million for the year ended December 31, 2010 compared with $20 million for the year ended December 31, 2009. The increase in adjusted loss was primarily due to the Company recording foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances in 2009, whereas no similar gains occurred in 2010. Other factors contributing to the increased adjusted loss included higher administrative costs and higher interest costs, partially offset by an increased corporate income tax recovery.

Corporate earnings/(loss) was impacted by the following non-recurring or non-operating adjusting items.

- Noverco earnings for 2009 included a benefit related to favourable tax rate changes.
- Earnings/(loss) for each year included a change in the unrealized fair value gains and losses on derivative financial instruments related to forward foreign exchange risk management positions.
- Earnings/(loss) included net unrealized foreign exchange gains or losses on the translation of foreign-denominated intercompany balances.
- Earnings/(loss) for the 2011 and 2009 were impacted by tax rate changes.
- In May 2009, the Company sold its investment in NTP, an internet-based crude oil trading and clearing platform, for proceeds of $32 million, resulting in a gain of $25 million.
- Earnings/(loss) for 2011 were impacted by tax on an intercompany gain on sale.

NOVERCO

At December 31, 2011, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2010 – 32.1%; 2009 – 32.1%) of its common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71% of Gaz Metro Limited Partnership (Gaz Metro), a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the state of Vermont. Effective September 2010, Gaz Metro became a privately held limited partnership as a result of a reorganization of its publicly held partnership units, which were exchanged on a one-for-one basis for common shares in Valener Inc., a new publicly listed corporation.

Noverco also holds, directly and indirectly, an investment in Enbridge common shares aggregating 69.4 million shares. The substantial increase in the value of these shares over the last decade has resulted in a significant shift in the balance of Noverco's asset mix. The board of directors of Noverco has authorized the Caisse De Depot et Placement de Quebec, as manager of Noverco, to rebalance Noverco's asset mix through the sale of up to 22.5 million Enbridge shares, by way of private placement, secondary offering or stock market sales, from time to time as market conditions permit, and to distribute the proceeds to shareholders, subject to compliance with restrictions under applicable law and credit facilities. Enbridge's share of such proceeds would be up to approximately $300 million, which would be applied to the funding of Enbridge's growth program.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investments which are based on the yield of 10-year Government of Canada bonds plus a weighted average spread of approximately 4.38%.

RESULTS OF OPERATIONS

Noverco adjusted earnings were $24 million for the year ended December 31, 2011 compared with $21 million for the year ended December 31, 2010 and $19 million for the year ended December 31, 2009. Noverco earnings for each year reflected contributions from the Company's increased preferred share investment and Noverco's underlying gas distribution investments.

OTHER CORPORATE

Corporate also consists of the new business development activities, general corporate investments and financing costs not allocated to the business segments.

Other Corporate adjusted loss was $41 million for the year ended December 31, 2011 compared with $48 million for the year ended December 31, 2010. The decreased adjusted loss reflected an increase in preference share dividends following the issuance of 38 million preference shares during the year and higher tax expense, which were more than offset by lower interest expense.

Adjusted loss from Corporate was $48 million for the year ended December 31, 2010 compared with $39 million for the year ended December 31, 2009. The increase was primarily due to the Company recording foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances in 2009, whereas no similar gains occurred in 2010. Other factors contributing to the increase included higher administrative costs and higher interest costs, partially offset by an increased income tax recovery.

Liquidity and Capital Resources

The Company expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. At December 31, 2011, excluding the Southern Lights project financing, the Company had $7,170 million of committed credit facilities of which $3,682 million were drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $77 million, the Company had net available liquidity at December 31, 2011 of $3,565 million. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2011.

	Maturity Dates [1]	Total Facilities	Credit Facility Draws [2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012 – 2013	**717**	**556**	**161**
Sponsored Investments	2013	**500**	**268**	**232**
Corporate [4]	2012 – 2016	**5,653**	**2,832**	**2,821**
		7,170	**3,682**	**3,488**
Southern Lights project financing [3]	2013 – 2014	**1,576**	**1,466**	**110**
Total credit facilities		**8,746**	**5,148**	**3,598**

1 *Total facilities include $30 million in demand facilities with no maturity date.*

2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

3 *Total facilities inclusive of $61 million for debt service reserve letters of credit.*

4 *In January 2012, the Company secured additional revolving facilities of US$1.3 billion with a maturity date of 2015.*

The Company's credit facility agreements include standard default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As in prior years, the Company expects to continue to comply with these provisions and therefore not trigger any early repayments. As at December 31, 2011, the Company was in compliance with all debt covenants.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The Company's debt to capitalization ratio at December 31, 2011, including short-term borrowings but excluding non-recourse debt, was 63.2%, compared with 65.1% at the end of 2010. Including all debt, the debt to capitalization ratio was 64.7% at December 31, 2011 compared with 66.9% at December 31, 2010.

The Company invests its surplus cash in short-term investment grade instruments with credit worthy counterparties. Short-term investments were $77 million at December 31, 2011 (2010 – $99 million).

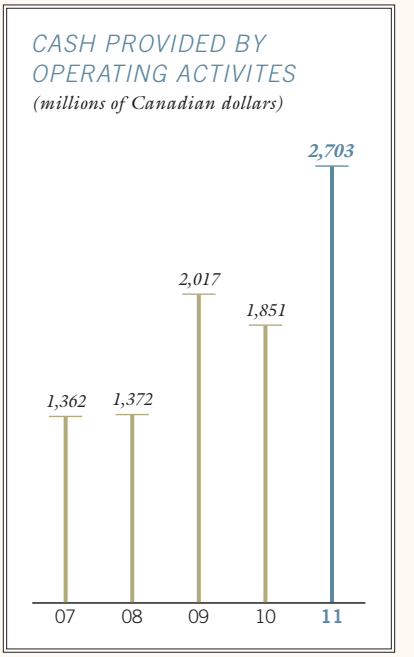
Excluding current maturities of long-term debt, the Company has a negative working capital position, compared with a positive position at December 31, 2010. Working capital includes the current portion of unrealized fair value derivative gains and losses related to the Company's risk management activities. Of the $821 million change in working capital in 2011 compared with the prior year, $573 million relates to an increase in current derivative liabilities. Actual cash outflows to be incurred to settle these liabilities depend on foreign exchange rates, interest rates or commodity prices in effect when derivative contracts outstanding mature; therefore, working capital at a point in time may not be representative of actual future cash flows. The Company maintains adequate liquidity at all times, through committed credit facilities and other sources, to fund liabilities as they come due. Further, working capital will fluctuate from time to time due to changes in natural gas inventory and borrowing levels at EGD, as well as activity levels within, among others, the Company's Energy Services businesses.

	2011	2010
(millions of Canadian dollars)		
Cash and cash equivalents [1]	**420**	342
Accounts receivable and other	**3,136**	2,706
Inventory	**739**	813
Bank indebtedness	**(102)**	(100)
Short-term borrowings	**(548)**	(326)
Accounts payable and other	**(3,722)**	(2,688)
Interest payable	**(114)**	(117)
Working capital	**(191)**	630

1 Includes short-term investments, restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

Changes in commodity prices impact accounts receivable and other, inventory and accounts payable and other within Energy Services and EGD.

OPERATING ACTIVITIES



Cash provided by operating activities for the year ended December 31, 2011 was $2,703 million compared with $1,851 million for the year ended December 31, 2010. The growth in cash from operating activities represented favourable operating performance from the Company's core liquids and natural gas assets, increased contributions from a growing portfolio of renewable power generation assets and increased cash flow generated by the Energy Services and Aux Sable business. Also contributing to the increase in cash from operating activities was a variance of $544 million in changes in operating assets and liabilities due to increased transaction volume in the Energy Services business.

Cash provided by operating activities for the year ended December 31, 2010 was $1,851 million compared with $2,017 million for the year ended December 31, 2009. Cash from operating activities was positively impacted in 2010 by contributions from growth projects placed in service, including Alberta Clipper and Southern Lights Pipeline. Alberta Clipper includes contributions from both the Canadian portion as well as cash distributions received on the Company's 66.7% equity investment in EELP which owns the United States segment of Alberta Clipper. Variances in working capital balances, primarily due to changes in commodity prices and sales volumes within Energy Services, as well as changes in natural gas prices at EGD, resulted in the decline in cash from operating activities in 2010 compared with 2009.

There are no material restrictions on the Company's cash with the exception of proportionately consolidated joint venture cash of $224 million, which cannot be accessed until distributed to the Company, restricted cash of $7 million related to Southern Lights project financing and cash in trust of $10 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities was $4,017 million for the year ended December 31, 2011 compared with $2,674 million for 2010, an increase of $1,343 million. Cash used in investing activities included $2,516 million (2010 – $2,357 million) of additions to property, plant and equipment for the year ended December 31, 2011. Capital expenditures on growth projects included Cabin, Athabasca Pipeline Capacity Expansion and Cedar Point Wind Energy Project, as well as a number of other projects under construction. Investing activities also includes several acquisitions, including a 50% interest in Seaway Pipeline for $1.2 billion (US$1.2 billion).

In 2010, cash used for investing activities was $2,674 million compared with $3,306 million in 2009, a decrease of $632 million. Cash used in investing activities included $2,357 million of additions to property, plant and equipment for the year ended December 31, 2010 and $3,225 million of additions to property, plant and equipment for the year ended December 31, 2009. Additions to property, plant and equipment declined compared with 2009 given the completion of several significant projects – Alberta Clipper, Southern Lights Pipeline and Hardisty Contract Terminal, among others. The Company also completed three acquisitions in 2010 resulting in a use of cash of $116 million.

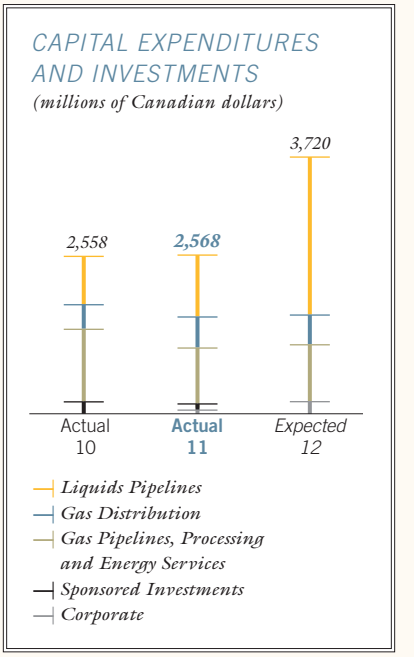
Investing activities also include long-term investments and affiliate lending, which in 2009 and 2010 consisted primarily of the Company's investing in and funding of EELP which holds the Company's interest in the United States segment of Alberta Clipper. The higher use of cash used in investing activities reported in 2009 was partially offset by proceeds received on the sale of the Company's investments in OCENSA and NTP.

CAPITAL EXPENDITURES AND INVESTMENTS

	Expected 2012	**Actual 2011**	Actual 2010
(millions of Canadian dollars)			
Liquids Pipelines	2,080	**977**	765
Gas Distribution	480	**483**	387
Gas Pipelines, Processing and Energy Services	910	**953**	1,153
Sponsored Investments [1]	–	**122**	253
Corporate	250	**33**	–
	3,720	**2,568**	2,558

1 Includes the Company's investment in sponsored vehicles.

The Company's capital expansion initiatives are described in *Growth Projects*. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $3,720 million during 2012 on maintenance and growth capital projects which are substantially secured, including increased spending on integrity programs. The Company expects to finance these expenditures through cash from operating activities and available liquidity. The Company may also raise capital through the monetization or disposition of selected assets, or through accessing capital markets as required.



The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued by the Company to finance business acquisitions, investments in subsidiaries and long-term investments. Funds for debt retirements are generated through cash provided from operating activities as well as through the issuance of replacement debt.

FINANCING ACTIVITIES

In 2011, cash provided by financing activities was $1,380 million compared with $766 million and $1,082 million in 2010 and 2009, respectively. Significant financing activities included an increase in short term borrowings, issuances and repayment of debentures and term notes, and issuances of preference shares.

Short-term borrowings are primarily used to finance near term working capital requirements, including gas inventories at EGD. In 2011, short-term borrowings increased to also fund long-term debt repayments and increased investing activities. In 2010, EGD had lower net repayments of short-term borrowings compared with 2009.

Medium-term note issuances included the following:

- Enbridge – $600 million (2010 – $800 million; 2009 – $1,000 million)
- Enbridge Pipelines Inc. – nil (2010 – $900 million; 2009 – $500 million)
- EGD – $100 million (2010 – $400 million; 2009 – nil)
- The Fund – $125 million (2010 – $200 million; 2009 – nil)

Contributions from noncontrolling interests increased to $214 million in 2011 compared with distributions of $1 million in 2010 and $33 million in 2009. The increase of contributions from noncontrolling interests was primarily a result of the share issuances at ENF and EEM. In 2011, Enbridge transferred three renewable energy assets to the Fund at an aggregate price of $1.2 billion. To acquire those assets, the Fund issued additional trust units to ENF, which in turn issued equity of $220 million to public shareholders.

In 2011, the proceeds from these term note issuances were used in part to fund term note repayments of $203 million (2010 – $600 million; 2009 – $616 million). In 2010, the proceeds from the issuance of term notes were also used to fund the repayment of commercial paper and credit facility of $347 million.

In 2011, the Company issued redeemable preference shares. Net proceeds from the issuance of Series B and Series D preference shares were $926 million (2010 and 2009 – nil).

In 2008, the Company secured financing that is non-recourse to the Company specific to the Canadian and United States segments of the Southern Lights Pipeline. In 2011, the repayment of Southern Lights Pipeline project financing was $62 million. For the years ended December 31, 2010 and 2009, the net proceeds on Southern Lights financing were $14 million and $343 million, respectively.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the year ended December 31, 2011, dividends declared were $759 million (2010 – $648 million), of which $530 million (2010 – $426 million) were paid in cash and reflected in financing activities. The remaining $229 million of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the years ended December 31, 2011 and 2010, 30% and 34%, respectively, of total dividends declared were reinvested.

OUTSTANDING SHARE DATA [1]

	Number
Preference Shares, Series A (non-voting equity shares)	5,000,000
Preference Shares, Series B (non-voting equity shares) [2]	20,000,000
Preference Shares, Series D (non-voting equity shares) [3]	18,000,000
Preference Shares, Series F (non-voting equity shares) [4]	20,000,000
Common Shares – issued and outstanding (voting equity shares)	782,270,762
Total issued and outstanding stock options (18,269,393 vested)	30,973,891

1 Outstanding share data information is provided as at February 15, 2012.

2 On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series B will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series B into an equal number of Cumulative Redeemable Preference Shares, Series C.

3 On March 1, 2018, and on March 1 every five years thereafter, the holders of Preference Shares, Series D will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series D into an equal number of Cumulative Redeemable Preference Shares, Series E.

4 On June 1, 2018, and on June 1 every five years thereafter, the holders of Preference Shares, Series F will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series F into an equal number of Cumulative Redeemable Preference Shares, Series G.

Effective May 25, 2011, a two-for-one stock split of the Company's common shares was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, adjusted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,120 million which are expected to be paid over the next five years.

CONTRACTUAL OBLIGATIONS

Payments due for contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1 – 3 years	3 – 5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt [1]	14,495	251	1,347	1,615	11,282
Non-recourse long-term debt [1]	1,048	120	154	143	631
Capital and operating leases	147	20	37	37	53
Long-term contracts [2,3]	4,318	2,247	1,515	361	195
Pension obligations [4]	105	105	–	–	–
Total contractual obligations	20,113	2,743	3,053	2,156	12,161

1 *Excludes interest. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements.*

2 *Approximately $2,776 million of these contracts are commitments for materials related to the construction of growth projects. Changes to the planned funding requirements, including cancellation, are dependent on changes to the related projects.*

3 *Contracts totaling $62 million are within proportionately consolidated joint venture entities and contracts totaling $125 million are between the Company and proportionately consolidated joint venture entities.*

4 *Assumes only required payments will be made into the pension plans in 2012. Contributions are made in accordance with the independent actuarial valuations as at December 31, 2011. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

UNITED STATES LEGAL AND REGULATORY PROCEEDINGS – LINE 6A AND 6B INCIDENTS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases; however, currently no penalties or fines have been assessed against EEP in connection with the incidents. In addition, a number of actions or claims have been filed against Enbridge, EEP or their affiliates in the United States federal and state courts in connection with these incidents. See *Sponsored Investments – Enbridge Energy Partners – EEP Lakehead System Line A and 6B Crude Oil Releases.*

ENBRIDGE GAS DISTRIBUTION INC.

BLOOR STREET INCIDENT

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

ENBRIDGE GAS NEW BRUNSWICK INC.

REGULATORY MATTERS

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 – $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LEGAL AND REGULATORY PROCEEDINGS

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

Quarterly Financial Information [1]

2011	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**4,713**	**4,981**	**4,272**	**5,436**	**19,402**
Earnings attributable to common shareholders	**393**	**259**	**4**	**335**	**991**
Earnings per common share [2]	**0.52**	**0.35**	**0.01**	**0.44**	**1.32**
Diluted earnings per common share [2]	**0.52**	**0.34**	**0.01**	**0.44**	**1.30**
Dividends per common share [2]	**0.2450**	**0.2450**	**0.2450**	**0.2450**	**0.98**
EGD – warmer/(colder) than normal weather	**(11)**	**(2)**	**–**	**12**	**(1)**
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	**(43)**	**27**	**235**	**(87)**	**132**

2010	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	3,977	3,505	3,502	4,143	15,127
Earnings attributable to common shareholders	342	138	157	326	963
Earnings per common share [2]	0.47	0.19	0.21	0.44	1.30
Diluted earnings per common share [2]	0.46	0.18	0.21	0.43	1.29
Dividends per common share [2]	0.2125	0.2125	0.2125	0.2125	0.85
EGD – warmer/(colder) than normal weather	8	10	–	(6)	12
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	(30)	87	(45)	(71)	(59)

1 Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.

2 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

Several factors impact comparability of the Company's financial results on a quarterly basis, including, but not limited to, seasonality in the Company's gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company's other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market price risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, unrealized fair value gains and losses on these instruments will impact earnings. In 2011, Corporate earnings were impacted by unrealized derivative fair value changes of a $16 million gain, a $65 million loss, $83 million loss and a $45 million gain in the first, second, third and fourth quarters, respectively. Most comparably, earnings were positively impacted by unrealized derivative fair value gains of $26 million, $39 million and $48 million in the first, third and fourth quarters of 2010, respectively, and negatively impacted by an unrealized derivative fair value loss of $88 million in the second quarter of 2010. The revaluation of foreign-denominated intercompany loans impacts earnings each quarter, with most notable impacts being the recognition of gains of $68 million and $50 million in the second and third quarters of 2009.

Reflected in 2011 earnings are the Company's share of leak remediation costs and lost revenue associated with the Line 6A and Line 6B crude oil releases in the amounts of $6 million, $21 million (2010 – $85 million) and $6 million (2010 – $21 million) in the second, third and fourth quarters, respectively. Earnings for 2011 also reflected insurance recoveries associated with the Line 6B crude oil release of $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters, respectively.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company's capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects*.

Related Party Transactions

All related party transactions are undertaken in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, for the year ended December 31, 2011 are $380 million (2010 – $332 million; 2009 – $342 million) to EEP and $6 million (2010 – $7 million; 2009 – $6 million) to Vector. At December 31, 2011, the Company has accounts receivable of $35 million (2010 – $29 million) from EEP and nil (2010 – nil) from Vector.

The Company had previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty.

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance and Vector. EGD is charged market prices for these services. For the year ended December 31, 2011, EGD was charged $42 million (2010 – $42 million; 2009 – $42 million) for services from Alliance and $25 million (2010 – $28 million; 2009 – $29 million) from Vector.

Tidal Energy Marketing (US) L.L.C., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. For the year ended December 31, 2011, amounts purchased were $1 million (2010 – $2 million; 2009 – $16 million) and sales were nil (2010 – nil; 2009 – $6 million).

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C, subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector. For the year ended December 31, 2011, amounts paid to Alliance Pipeline Canada were $17 million (2010 – $13 million; 2009 – $9 million), amounts paid to Alliance Pipeline US were $11 million (2010 – $9 million; 2009 – $7 million) and amounts paid to Vector were $11 million (2010 – $10 million; 2009 – $16 million).

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP. For the year ended December 31, 2011, amounts purchased were $122 million (2010 – $151 million; 2009 – $80 million) and sales were $4 million (2010 – $3 million; 2009 – $7 million).

ALBERTA CLIPPER PROJECT

The Company funded 66.7% of the United States segment of Alberta Clipper's equity requirements through EELP, an equity investee. The Company also provided a $348 million (US$342 million) (2010 – $346 million (US$347 million) loan to EEP for debt financing related to the construction. At December 31, 2011, $336 million (2010 – $334 million) is included in Deferred amounts and other assets with the remaining $12 million (2010 – $12 million) included in Accounts receivable and other. The loan, denominated in United States dollars, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. Semi-annual payments of principal and accrued interest are required. Semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period.

During the year the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $74 million (US$76 million) (2010 – $40 million (US$39 million)) payable to the Company relating to its Series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE

In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which was effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 – $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE

An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million.

LAKEHEAD LINE 6B CRUDE OIL RELEASE

In connection with the Lakehead Line 6B crude oil release, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $6 million for the year ended December 31, 2011 (2010 – $18 million).

Risk Management and Financial Instruments

Enbridge's proven investment value proposition is based on maintaining a reliable business model. More than 90% of the Company's revenues come from investment grade customers. Other risks, such as capital cost and inflation, are generally transferred to customers through contractual arrangements. In addition to contractually reducing the majority of its business risk, the Company has formal risk management policies, procedures and systems designed to mitigate any residual risks, such as market price risk, credit risk and operational risk. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

MARKET PRICE RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Market Price Risk Management Policy which outlines a risk management governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its businesses will exceed a defined tolerance.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk sensitivity at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The philosophy behind this metric is to identify the potential risk to the Company's annual earnings target, taking into account the illiquidity of certain exposure positions. The Company's policy is to limit EaR to a maximum of 5% of the next 12 months of forecasted earnings. Earnings exposure to market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with the EaR limits are reported to the CFRMC and variances are remediated as necessary.

Various hedging programs have been put into place to help ensure that the residual market price risks remain within policy limits, and thus help provide the Company with a general stability of earnings over a short and medium term horizon. The following section summarizes the primary types of market price risks to which the Company is exposed, and outlines the financial derivative hedging programs implemented.

The following table summarizes the EaR as a percentage of forecast earnings from the main groups of market price risk after impact of the Company's hedging programs. These EaR numbers are based on business conditions and hedging programs as of December 31, 2011 and may not be applicable to other periods.

Risk	EaR
(% of forecast 12 month forward earnings)	
Foreign exchange	0.8%
Interest rate	0.2%
Commodity	1.5%
Total EaR	2.5%

FOREIGN EXCHANGE RISK

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from the performance of its United States dollar denominated subsidiaries and investments, and certain revenues and expenses denominated in United States dollars. The Company has implemented a policy where it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company currently has economically hedged over 85% of its forecast adjusted earnings through 2016 at an average rate of approximately $1.05C$/US$. The Company may also use foreign exchange forward contracts to hedge anticipated foreign currency denominated purchases or sales and foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

INTEREST RATE RISK

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate the volatility to variable rate interest expense through 2016 at an average swap rate of 2.27%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates on future fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2015. A total of $5,200 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure the consolidated portfolio of debt stays within the Board of Directors' approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

COMMODITY PRICE RISK

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGLs. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arises from physical transactions involving these commodities.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and its indirect ownership of the gathering and processing business held by EEP.

EQUITY PRICE RISK

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, Restricted Share Units.

CREDIT RISK

The Company's earnings and cash flows could be exposed to the risk of payment default by its shippers or other counterparties. Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Counterparty Credit Risk Policy outlining a governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arise from counterparty defaults across any of its businesses.

Further initiatives to mitigate credit exposure include ensuring that all counterparties shipping on the regulated oil pipelines that have credit ratings below investment grade provide the carrier with a form of credit assurance, for example, a creditworthy parental guarantee, letter of credit or cash.

Credit risk in the Gas Distribution segment is mitigated by its large and diversified customer base and its ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due. The Company minimizes credit risk applicable to derivatives counterparties by entering into risk management transactions only with institutions that possess investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company's credit criteria to provide collateral. During 2010 and 2011, despite challenging market conditions, the Company did not suffer any material credit losses.

FINANCING RISK

The Company's financing risk relates to the price volatility and availability of debt to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and United States financial market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian and United States public capital markets by maintaining current shelf prospectuses with the securities regulators.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as access to capital markets. The Company maintains current shelf prospectuses with the securities regulators, which enable, subject to market conditions, ready access to either the Canadian or United States public capital markets.

MATURITIES OF DERIVATIVE FINANCIAL INSTRUMENTS

For the years ending December 31, 2012 through 2016, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its derivative instruments based on the valuations at the balance sheet date:

	2012	2013	2014	2015	2016	Thereafter
(millions of Canadian dollars)						
Cash inflows	440	213	180	69	74	105
Cash outflows	(401)	(133)	(124)	(77)	(65)	(610)
Net cash flows	39	80	56	(8)	9	(505)

The maturity profile of non-derivative financial liabilities is presented in *Liquidity and Capital Resources.*

FINANCIAL INSTRUMENTS

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**420**	–	–	–	–	–	–	**420**	**420**
Accounts receivable and other	**443**	–	**2,392**	–	–	**22**	**279**	**3,136**	**2,857**
Long-term investments	–	**56**	–	**285**	–	–	**2,199**	**2,540**	**285**
Deferred amounts and other assets	**450**	–	**4**	–	–	**99**	**2,667**	**3,220**	**553**
Liabilities									
Bank indebtedness	**102**	–	–	–	–	–	–	**102**	**102**
Short-term borrowings	–	–	–	–	**548**	–	–	**548**	**548**
Accounts payable and other	**365**	–	–	–	**2,728**	**346**	**283**	**3,722**	**3,439**
Interest payable	–	–	–	–	**114**	–	–	**114**	**114**
Long-term debt	–	–	–	–	**14,509**	–	–	**14,509**	**16,772**
Non-recourse long-term debt	–	–	–	–	**1,073**	–	–	**1,073**	**1,248**
Other long-term liabilities	**88**	–	–	–	–	**345**	**1,459**	**1,892**	**433**

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	342	–	–	–	–	–	–	342	342
Accounts receivable and other	145	–	2,113	–	–	25	423	2,706	2,283
Long-term investments	–	54	339	181	–	–	1,624	2,198	520
Deferred amounts and other assets	277	–	334	–	–	185	2,090	2,886	462
Liabilities									
Bank indebtedness	100	–	–	–	–	–	–	100	100
Short-term borrowings	–	–	–	–	326	–	–	326	326
Accounts payable and other	62	–	–	–	2,393	76	157	2,688	2,531
Interest payable	–	–	–	–	117	–	–	117	117
Long-term debt	–	–	–	–	13,715	–	–	13,715	14,770
Non-recourse long-term debt	–	–	–	–	1,131	–	–	1,131	1,298
Other long-term liabilities	6	–	–	–	–	127	1,340	1,473	133

1 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating interest rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

DERIVATIVE INSTRUMENTS

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

	2011		2010	
December 31,	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards – purchase *(millions of United States dollars)*	2012 – 2020	**1,281**	2011 – 2020	1,185
U.S. dollar forwards – sell *(millions of United States dollars)*	2012 – 2020	**10,866**	2011 – 2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	2012 – 2029	**16,540**	2011 – 2029	10,772
Commodity contracts – energy *(bcfe)*	2012 – 2013	**2**	2011 – 2013	41
Commodity contracts – power *(MW/H)*	2012 – 2024	**53**	2011 – 2024	2
Equity contracts *(millions of shares)*	2011 – 2013	**2**	2011 – 2012	1

The Company has also designated a US$300 million (2010 – US$300 million) medium-term note and US$15 million (2010 – US$15 million) of commercial paper as hedges of certain United States dollar investments.

The following table summarizes the fair value of the Company's derivative instruments.

December 31, 2011	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other				
Foreign exchange contracts	**4**	**15**	**315**	**334**
Interest rate contracts	**–**	**–**	**7**	**7**
Commodity contracts	**–**	**–**	**114**	**114**
Equity contracts	**3**	**–**	**7**	**10**
	7	**15**	**443**	**465**
Deferred amounts and other				
Foreign exchange contracts	**15**	**79**	**203**	**297**
Interest rate contracts	**1**	**–**	**22**	**23**
Commodity contracts	**1**	**–**	**223**	**224**
Equity contracts	**3**	**–**	**2**	**5**
	20	**79**	**450**	**549**
Accounts payable and other				
Foreign exchange contracts	**(4)**	**–**	**(275)**	**(279)**
Interest rate contracts	**(341)**	**–**	**(3)**	**(344)**
Commodity contracts	**(1)**	**–**	**(87)**	**(88)**
	(346)	**–**	**(365)**	**(711)**
Other long-term liabilities				
Foreign exchange contracts	**(35)**	**(5)**	**(51)**	**(91)**
Interest rate contracts	**(303)**	**–**	**(18)**	**(321)**
Commodity contracts	**(2)**	**–**	**(19)**	**(21)**
	(340)	**(5)**	**(88)**	**(433)**
Total net derivative asset/(liability)				
Foreign exchange contracts	**(20)**	**89**	**192**	**261**
Interest rate contracts	**(643)**	**–**	**8**	**(635)**
Commodity contracts	**(2)**	**–**	**231**	**229**
Equity contracts	**6**	**–**	**9**	**15**
	(659)	**89**	**440**	**(130)**

December 31, 2010	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other				
Foreign exchange contracts	4	15	111	130
Interest rate contracts	6	–	–	6
Commodity contracts	–	–	33	33
Equity contracts	–	–	1	1
	10	15	145	170
Deferred amounts and other				
Foreign exchange contracts	18	100	275	393
Interest rate contracts	67	–	–	67
Commodity contracts	–	–	2	2
	85	100	277	462
Accounts payable and other				
Foreign exchange contracts	(4)	–	(11)	(15)
Interest rate contracts	(72)	–	–	(72)
Commodity contracts	–	–	(51)	(51)
	(76)	–	(62)	(138)
Other long-term liabilities				
Foreign exchange contracts	(47)	–	(3)	(50)
Interest rate contracts	(80)	–	–	(80)
Commodity contracts	–	–	(3)	(3)
	(127)	–	(6)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	(29)	115	372	458
Interest rate contracts	(79)	–	–	(79)
Commodity contracts	–	–	(19)	(19)
Equity contracts	–	–	1	1
	(108)	115	354	361

The fair value of derivative instruments has primarily been estimated using models or other industry standard valuation techniques derived from observable market information. This market information includes published market prices for commodities, interest rate yield curves, foreign exchange rates and equity prices. When possible, financial instruments are valued using quoted market prices.

An unrealized fair value loss of $593 million (2010 – $82 million) related to derivative instruments used as cash flow and net investment hedges was recognized in OCI for the year ended December 31, 2011. An unrealized fair value gain related to non-qualifying derivative instruments of $78 million (2010 – $26 million) was recognized in transportation revenues, commodity costs, other investment income and interest expense for the year ended December 31, 2011.

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 23 and 24 of the 2011 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

STRATEGY AND EXECUTION RISKS

PROJECT EXECUTION

The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, inadequate resources and in-service delays (collectively, Execution Risk). Customer trends are toward expecting the Company to assume more risk and accept lower returns. Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation and environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to regulatory delays, contractor or supplier non-performance and weather conditions may impact project development.

The Company has a centralized and clearly defined governance structure and process for all major projects with dedicated resources organized to lead and execute each major project. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. Early stage project risks are mitigated by early assessment of stakeholder issues to develop proactive relationships and specific action plans. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors.

INVESTMENT ANALYSIS

The Company evaluates the value proposition for expansion projects, new acquisitions or divestitures on an ongoing basis. Investment analysis may be ineffective in terms of earnings projections, cost estimates, project scoping, and risk assessment resulting in a loss in profits for the Company. Large scale acquisitions may involve significant pricing and integration risk.

A centralized corporate development group which is appropriately staffed rigorously evaluates all major investment proposals with consistent due diligence processes including a thorough review of the asset quality, systems and financial performance of the assets being assessed.

REPUTATION RISK

The Company's reputation is one of its most valuable assets. Reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action, increased regulatory oversight and costs.

Reputation risk often arises as a consequence of some other risk event, such as in connection with operational, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;

- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's CSR Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company's commitment to Green Energy).

OPERATIONAL RISKS

SYSTEM INTEGRITY

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating and insuring the Company's assets or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required and are supported by operating and capital budgets directed to pipeline integrity. Emergency response plans, operator training and landowner education programs are included in the Company's response preparedness. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company feels the level of insurance is adequate, it may not be sufficient to cover all potential losses.

ENVIRONMENTAL, HEALTH AND SAFETY RISK

The Company's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment and the investigation and remediation of contamination. The Company's facilities, or facilities to which it provides operating services, could experience incidents, malfunctions or other unplanned events that result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company's upstream customers' ability to produce crude oil and natural gas. The Company could be targeted, along with the oil sands industry, by environmental groups attempting to draw attention to GHG emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Ongoing training is provided to ensure employee and contractor competency as well as to enhance the safety culture at Enbridge. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

INFORMATION SYSTEMS

The Company's infrastructure, applications and data are becoming more integrated, creating increased risk that a failure in one system could lead to a failure of another system. Major systems development involves project management risks including implementation delays, scope creep, cost overruns or failure of systems to meet original project requirements. Disruption to business operations due to inadequate information security safeguards is also a risk.

The Company has a centralized information office which supports the development of standardized systems, use of industry proven packages where feasible, use of an information security risk management strategy and disaster recovery plans for critical operations. Back-up computers are installed in business units for enterprise-wide fail protection. Project management risks are mitigated through both a strict value proposition evaluation and a robust pre-implementation testing process with high quality requirements.

BUSINESS ENVIRONMENT RISKS

ABORIGINAL RELATIONS

Canadian judicial decisions have recognized that Aboriginal rights and treaty rights exist in proximity to the Company's operations and future project developments. The courts have also confirmed that the Crown has a duty to consult with Aboriginal peoples when its decisions or actions may adversely affect Aboriginal rights and interests or treaty rights. Crown consultation has the potential to delay regulatory approval processes and construction, which may affect project economics. In some cases, respecting Aboriginal rights may mean regulatory approval is denied or made economically challenging.

Given this environment and the breadth of relationships across the Company's geographic span, Enbridge has implemented the Aboriginal and Native American Policy. This Policy promotes the achievement of participative and mutually beneficial relationships with Aboriginal and Native American groups affected by the Company's projects and operations. Specifically, the Policy sets out principles governing the Company's relationships with Aboriginal and Native American peoples and makes commitments to work with Aboriginal peoples and Native Americans so they may realize benefits from the Company's projects and operations. Notwithstanding the Company's efforts to this end, the issues are complex and the impact of Aboriginal relations on Enbridge's operations and development initiatives is uncertain.

SPECIAL INTEREST GROUPS INCLUDING NON-GOVERNMENTAL ORGANIZATIONS

The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups, including non-governmental organizations. Recent Supreme Court decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, the Company and others in the energy and pipeline businesses are facing opposition from organizations opposed to oil sands development and shipment of production from oil sands regions.

The Company works proactively with special interest groups and non-governmental organizations to identify and develop appropriate responses to their concerns regarding its projects. The Company is investing significant resources in these areas. Its CSR program also reports on the Company's responsiveness to environmental and community issues. Please see Enbridge's annual CSR report, available online at csr.enbridge.com for further details regarding the CSR program. None of the information contained on, or connected to, Enbridge's website is incorporated in or otherwise part of this MD&A.

REGULATORY AND COMPLIANCE RISKS

UNFAVOURABLE RULINGS

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers. Recently shippers have challenged toll increases on various pipelines owned by Enbridge and some of Enbridge's competitors. Enbridge retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

CLIMATE CHANGE LEGISLATION

Uncertainty continues with respect to GHG regulations in Canada and the United States. The federal governments of both countries have signaled their intention to develop sector specific carbon related regulations but are reluctant to implement measures that might slow economic recovery. As a result, it is uncertain how climate legislation could affect the industry.

Enbridge has voluntarily reported its GHG emissions for over ten years. The Company is on track to deploy a new emissions data management system to ensure compliance with reporting requirements mandated in Canada and the United States. The Company will continue to monitor GHG regulatory developments and publicly report its GHG emissions as well as develop internal procedures to reduce these emissions.

RENEWABLE ENERGY

Enbridge has significant interests in wind, solar and geothermal power generation and is well positioned to expand this portfolio. Many programs to encourage and advance renewable energy exist in Canada and the United States as well as individual provinces and states. Enbridge continues to assess and advance renewable energy opportunities and monitor potential changes to government policies and incentives that may positively or negatively impact existing or future renewable energy projects.

Critical Accounting Estimates

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2011 of $22,623 million (2010 – $20,332 million), or 66% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the Energy Resources Conservation Board and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2011, the Company's significant regulatory assets totaled $1,337 million (2010 – $1,368 million) and significant regulatory liabilities totaled $931 million (2010 – $1,014 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. See *Gas Distribution – Other Gas Distribution and Storage – Enbridge Gas New Brunswick Regulatory Matters.*

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and post-employment benefits other than pensions (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the universal method. This method involves complex actuarial calculations using several assumptions including discount rates which were determined using the discount rate curve developed by the Canadian Institute of Actuaries, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The Company remains able to pay the current benefit obligations using cash from operations, reflecting strong capital market performance recovery. The shortfall from expected return on plan assets was $76 million for the year ended December 31, 2011 (2010 – $47 million excess) as disclosed in Note 27 to the 2011 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2011 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	126	14	18	1
Decrease in expected return on assets	–	6	–	–
Decrease in rate of salary increase	(25)	(5)	–	–

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments, including EGD and EECI, are detailed in the *Commitments and Contingencies* section of this report and are disclosed in Note 31 of the 2011 Annual Consolidated Financial Statements. In addition, any unasserted claims that later may become evident could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin setting aside funds for abandonment no later than January 1, 2015. Since then, the NEB has issued several revised "base case assumptions" based on feedback from member companies. Companies have the option to follow the base case assumptions or to submit pipeline specific applications.

On November 29, 2011, as required by NEB, the Company filed the applications for its regulated pipelines systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc., and Vector Pipelines Limited Partnership (Group 2 companies). The Company is seeking NEB approval of its preliminary calculations, which were largely based on the base case assumptions issued by NEB specifically for the purpose of this filing. The NEB is also requiring regulated pipeline companies to file a proposed process for collecting and setting aside the funds for abandonment by November 30, 2012 for Group 1 companies and by March 31, 2013 for Group 2 companies.

Both of the required submissions will require NEB approval and will result in increases to transportation tolls and regulatory liabilities, the amount of which is uncertain at this time. Currently, for certain of the Company's assets, there is insufficient data or information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation (ARO). In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

Changes in Accounting Policies

BUSINESS COMBINATIONS

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The application of this standard decreased Earnings attributable to Enbridge Inc. by $37 million, net of income taxes of $5 million for dilution gains for subsidiaries, which are now recognized in equity for the year ended December 31, 2011. The application of this standard had no material impact to the Company's cash flows for the year ended December 31, 2011.

CONSOLIDATED FINANCIAL STATEMENTS AND NONCONTROLLING INTERESTS

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only there was no impact to the Company's earnings or cash flows for the current or prior periods presented.

FUTURE ACCOUNTING POLICIES

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (U.S. GAAP)

First-time adoption of Part I – International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and presented its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

As a rate regulated accounting standard model has not been finalized by the International Accounting Standards Board, the Company does not intend to adopt IFRS in 2012 but rather U.S. GAAP. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

In preparation for the U.S. GAAP conversion, Enbridge has formed a U.S. GAAP project team and developed a transition plan and governance structure to monitor the progress of the transition. The Company has engaged a public accounting firm to assist with the project and to provide technical accounting advice on the interpretation and application of U.S. GAAP to its primary financial statements. Management reports regularly to the Audit, Finance and Risk Committee of the Board of Directors on the advancement of the conversion to U.S. GAAP.

ACCOUNTING AND REPORTING

The Company is in the process of integrating known U.S. GAAP differences into its primary financial statements. The most significant U.S. GAAP differences impact the following areas:

- consolidation of EEP;
- equity accounting treatment of joint ventures;
- inventory valuation;
- common control transactions;
- classification and valuation of redeemable noncontrolling interests;
- pensions and OPEB; and
- presentation differences, including the presentation of deferred financing costs.

Under U.S. GAAP the Company is deemed to control EEP and will therefore consolidate its interest in the partnership. The Company will commence reporting using U.S. GAAP as its primary basis of accounting in the first quarter of 2012. To facilitate users understanding of the transition, subsequent to filing its Canadian GAAP financial statements for the year ended December 31, 2011 and before filing its first interim report under U.S. GAAP, the Company will provide, for information purposes, its 2011 financial statements restated under U.S. GAAP along with comparative periods and related note disclosures.

TRAINING

As an SEC registrant, the Company has experience reporting under U.S. GAAP and has reconciled its financial statements to U.S. GAAP for many years. Further, two of the Company's affiliates, EEM and EEP are also registered with the SEC and currently prepare and file U.S. GAAP financial statements. The Company has provided supplemental U.S. GAAP training to internal personnel impacted by the conversion. U.S. GAAP training will continue into and beyond 2012 as a regular business activity.

INFORMATION SYSTEMS AND BUSINESS PROCESSES

The Company has completed testing system changes necessary to support the conversion to U.S. GAAP and to sustain U.S. GAAP reporting in 2012 and beyond. Implementation of these changes will take place in the first quarter of 2012. Impacts to internal controls over financial reporting and disclosures have been evaluated and no significant impacts were noted.

BUSINESS ACTIVITIES

The Company has reviewed the effect of the U.S. GAAP conversion on its debt covenants, compensation agreements and hedging activities and does not expect the conversion to U.S. GAAP to significantly impact these activities or requirements.

The detailed project plan and the expected timing of key activities identified above may change prior to the U.S. GAAP conversion date due to economic conditions or other factors.

FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2012. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

FAIR VALUE MEASUREMENT

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on fair value measurement under U.S. GAAP as part of the FASB's joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

STATEMENT OF COMPREHENSIVE INCOME

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of net income and OCI either in one continuous statement, referred to as the Statement of Comprehensive Income, or in two separate but consecutive statements of net income and OCI. The adoption of this pronouncement does not affect the Company's presentation of comprehensive income, and will not have an impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

GOODWILL IMPAIRMENT

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

BALANCE SHEET OFFSETTING

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As of the year ended December 31, 2011, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Enbridge is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with Canadian GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2011.

During the year ended December 31, 2011, there has been no material change in the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

Non-GAAP Reconciliations

	2011	2010	2009
(millions of Canadian dollars)			
GAAP earnings as reported	**991**	963	1,555
Significant after-tax non-recurring or non-operating factors and variances:			
Liquids Pipelines			
Canadian Mainline – shipper dispute settlement	**(14)**	–	–
Canadian Mainline – Line 9 tolling adjustment	**(10)**	–	–
Canadian Mainline – unrealized derivative fair value loss	**48**	–	–
Regional Oil Sands System – asset impairment loss	**8**	–	–
Regional Oil Sands System – leak remediation costs	**–**	–	9
Spearhead Pipeline – unrealized derivative fair value gains	**(1)**	–	–
Gas Distribution			
EGD – warmer/(colder) than normal weather	**(1)**	12	(17)
EGD – impact of tax rate changes	**–**	–	(21)
EGD – interest income on GST refund	**–**	–	(7)
Other Gas Distribution and Storage – asset impairment loss	**–**	–	10
Other Gas Distribution and Storage – adoption of new accounting standard	**–**	–	3
Gas Pipelines, Processing and Energy Services			
Offshore – property insurance recovery from hurricanes	**–**	(2)	(4)
Aux Sable – unrealized derivative fair value (gains)/loss	**7**	(7)	36
Aux Sable – loan forgiveness	**–**	–	(7)
Energy Services – unrealized derivative fair value (gains)/loss	**(113)**	12	(3)
Energy Services – Lehman and SemGroup credit recovery	**–**	(1)	(1)
Other – unrealized derivative fair value gains	**(24)**	–	–
Other – gain on sale of investments	**–**	–	(329)
Other – impact of tax rate changes	**–**	–	(4)
Sponsored Investments			
EEP – leak insurance recoveries	**(50)**	–	–
EEP – leak remediation costs and lost revenue	**33**	106	–
EEP – unrealized derivative fair value (gains)/loss	**(3)**	1	2
EEP – NGL trucking and marketing prior period adjustment	**3**	–	–
EEP – shipper dispute settlement	**(8)**	–	–
EEP – lawsuit settlement	**(1)**	–	–
EEP – impact of unusual weather conditions	**1**	–	–
EEP – Lakehead System billing correction	**–**	(1)	(4)
EEP – dilution gain on Class A unit issuance	**(66)**	(36)	–
EEP – asset impairment loss	**–**	2	12
Corporate			
Noverco – impact of tax rate changes	**–**	–	(6)
Other Corporate – unrealized derivative fair value (gains)/loss	**87**	(25)	(207)
Other Corporate – unrealized foreign exchange (gains)/loss on translation of intercompany balances, net	**131**	(40)	(133)
Other Corporate – impact of tax rate changes	**(6)**	–	(4)
Other Corporate – tax on intercompany gain on sale	**98**	–	–
Other Corporate – gain on sale of investment in NTP	**–**	–	(25)
Adjusted earnings	**1,110**	984	855

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

FINANCIAL REPORTING

Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

INTERNAL CONTROL OVER FINANCIAL REPORTING

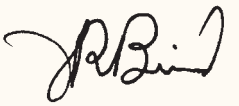
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States).



PATRICK D. DANIEL
President & Chief Executive Officer



J. RICHARD BIRD
Executive Vice President & Chief Financial Officer

February 21, 2012

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2011, 2010 and 2009 consolidated financial statements and its internal control over financial reporting as at December 31, 2011. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2011 and December 31, 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in accordance with Canadian generally accepted accounting principles.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2011, based on the criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

DEFINITION OF INTERNAL CONTROL OVER FINANCIAL REPORTING

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

INHERENT LIMITATIONS

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

OPINION

In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2011 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 21, 2012

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**15,676**	11,990	9,720
Transportation and other services	**3,726**	3,137	2,746
	19,402	15,127	12,466
Expenses			
Commodity costs	**14,854**	11,291	9,011
Operating and administrative	**1,720**	1,466	1,430
Depreciation and amortization	**937**	864	764
	17,511	13,621	11,205
	1,891	1,506	1,261
Income from equity investments	**336**	38	198
Other income *(Note 28)*	**112**	374	678
Interest expense *(Note 16)*	**(711)**	(687)	(597)
Gain on sale of investments *(Note 6)*	**–**	–	365
	1,628	1,231	1,905
Income taxes *(Note 26)*	**(568)**	(251)	(306)
Earnings	**1,060**	980	1,599
Earnings attributable to noncontrolling interests	**(56)**	(10)	(37)
Earnings attributable to Enbridge Inc.	**1,004**	970	1,562
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	**991**	963	1,555
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*	**1.32**	1.30	2.14
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*	**1.30**	1.29	2.12

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings	**1,060**	980	1,599
Other comprehensive income/(loss)			
Change in unrealized loss on cash flow hedges, net of tax	**(427)**	(113)	(54)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**(19)**	51	151
Reclassification to earnings of realized cash flow hedges, net of tax	**32**	(25)	114
Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 23)*	**8**	–	(20)
Other comprehensive loss from equity investees, net of tax	**(61)**	(11)	(24)
Change in foreign currency translation adjustment	**242**	(274)	(815)
Other comprehensive loss	**(225)**	(372)	(648)
Comprehensive income	**835**	608	951
Comprehensive (income)/loss attributable to noncontrolling interests	**(43)**	23	35
Comprehensive income attributable to Enbridge Inc.	**792**	631	986
Preference share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders	**779**	624	979

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**125**	125	125
Preference shares issued	**931**	–	–
Balance at end of year	**1,056**	125	125
Common shares *(Note 20)*			
Balance at beginning of year	**3,683**	3,379	3,194
Common shares issued	**–**	–	4
Dividend reinvestment and share purchase plan	**229**	224	143
Shares issued on exercise of stock options	**57**	80	38
Balance at end of year	**3,969**	3,683	3,379
Contributed surplus			
Balance at beginning of year	**59**	54	38
Stock-based compensation	**18**	13	19
Options exercised	**(7)**	(8)	(3)
Dilution gains and other *(Note 19)*	**36**	–	–
Balance at end of year	**106**	59	54
Retained earnings			
Balance at beginning of year	**4,734**	4,400	3,383
Earnings attributable to Enbridge Inc. common shareholders	**991**	963	1,555
Common share dividends declared	**(759)**	(648)	(555)
Dividends paid to reciprocal shareholder	**25**	19	17
Balance at end of year	**4,991**	4,734	4,400
Accumulated other comprehensive income/(loss) *(Note 22)*			
Balance at beginning of year	**(882)**	(543)	33
Other comprehensive loss	**(212)**	(339)	(576)
Balance at end of year	**(1,094)**	(882)	(543)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(154)**	(154)	(154)
Acquisition of equity investment	**(33)**	–	–
Balance at end of year	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	7,565	7,261
Noncontrolling interests			
Balance at beginning of year	**658**	727	797
Earnings attributable to noncontrolling interests	**56**	10	37
Other comprehensive income/(loss) attributable to noncontrolling interests			
Change in unrealized income/(loss) on cash flow hedges, net of tax	**(7)**	(9)	4
Other comprehensive loss from equity investees, net of tax	**(15)**	(3)	(5)
Change in foreign currency translation adjustment	**9**	(21)	(71)
	(13)	(33)	(72)
Comprehensive income/(loss) attributable to noncontrolling interests	**43**	(23)	(35)
Distributions	**(37)**	(30)	(33)
Contributions *(Note 19)*	**208**	29	–
Acquisitions *(Notes 10 and 19)*	**(27)**	(45)	–
Other	**1**	–	(2)
Balance at end of year	**846**	658	727
Total shareholders' equity	**9,687**	8,223	7,988
Dividends paid per common share	**0.98**	0.85	0.74

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Operating activities			
Earnings attributable to Enbridge Inc.	**1,004**	970	1,562
Depreciation and amortization	**937**	864	764
Unrealized gains on derivative instruments	**(13)**	(10)	(204)
Allowance for equity funds used during construction	**(3)**	(80)	(135)
Cash distributions (less than)/in excess of equity earnings	**(42)**	214	(9)
Gain on reduction of ownership interest	**(141)**	(81)	–
Gain on sale of investments *(Note 6)*	**–**	–	(365)
Future income taxes *(Note 26)*	**415**	238	218
Goodwill and asset impairment losses	**11**	–	11
Noncontrolling interests	**56**	10	37
Other	**150**	(11)	(105)
Changes in regulatory assets and liabilities	**78**	30	11
Changes in operating assets and liabilities *(Note 29)*	**251**	(293)	232
	2,703	1,851	2,017
Investing activities			
Additions to property, plant and equipment	**(2,516)**	(2,357)	(3,225)
Government grant	**145**	–	–
Additions to intangible assets	**(165)**	(50)	(95)
Change in construction payable	**(66)**	27	(110)
Long-term investments	**(217)**	(121)	(359)
Affiliate loans, net	**10**	(80)	(145)
Acquisitions *(Notes 6 and 19)*	**(1,208)**	(116)	–
Proceeds on sale of investments *(Note 6)*	**–**	23	535
Sale of property, plant and equipment	**–**	–	87
Settlement of hedges *(Note 6)*	**–**	–	6
	(4,017)	(2,674)	(3,306)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**224**	(165)	(393)
Net change in commercial paper and credit facility draws	**11**	(347)	736
Debenture and term note issues	**825**	2,300	1,500
Debenture and term note repayments	**(203)**	(600)	(616)
Net change in Southern Lights project financing	**(62)**	14	343
Non-recourse debt issues	**17**	5	60
Non-recourse debt repayments	**(81)**	(73)	(130)
Contributions from/(distributions to) noncontrolling interests, net	**214**	(1)	(33)
Preference shares issued	**926**	–	–
Common shares issued	**46**	66	36
Preference share dividends	**(7)**	(7)	(7)
Common share dividends	**(530)**	(426)	(414)
	1,380	766	1,082
Effect of translation of foreign denominated cash and cash equivalents	**12**	(11)	(35)
Increase/(decrease) in cash and cash equivalents	**78**	(68)	(242)
Cash and cash equivalents at beginning of year	**342**	410	652
Cash and cash equivalents at end of year [1]	**420**	342	410
Supplementary cash flow information			
Income taxes paid/(received) *(Note 26)*	**(35)**	108	205
Interest paid *(Note 16)*	**749**	711	656

The accompanying notes are an integral part of these consolidated financial statements.

1 *Cash and cash equivalents consists of $343 million (2010 – $243 million; 2009 – $267 million) of cash and $77 million (2010 – $99 million; 2009 – $143 million) of short-term investments and includes restricted cash of $17 million (2010 – $12 million; 2009 – $7 million), and joint-venture cash which is not readily accessible by the Company of $224 million (2010 – $48 million; 2009 – $52 million).*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	2011	2010
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**420**	342
Accounts receivable and other *(Note 7)*	**3,136**	2,706
Inventory *(Note 8)*	**739**	813
	4,295	3,861
Property, plant and equipment, net *(Note 9)*	**22,623**	20,332
Long-term investments *(Note 11)*	**2,540**	2,198
Deferred amounts and other assets *(Note 12)*	**3,220**	2,886
Intangible assets *(Note 13)*	**600**	478
Goodwill *(Note 14)*	**1,024**	385
Future income taxes *(Note 26)*	**41**	80
	34,343	30,220
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**102**	100
Short-term borrowings *(Note 16)*	**548**	326
Accounts payable and other *(Note 15)*	**3,722**	2,688
Interest payable	**114**	117
Current maturities of long-term debt *(Note 16)*	**252**	154
Current maturities of non-recourse long-term debt *(Note 17)*	**122**	70
	4,860	3,455
Long-term debt *(Note 16)*	**14,257**	13,561
Non-recourse long-term debt *(Note 17)*	**951**	1,061
Other long-term liabilities *(Note 18)*	**1,892**	1,473
Future income taxes *(Note 26)*	**2,696**	2,447
	24,656	21,997
Equity		
Share capital		
Preference shares *(Note 20)*	**1,056**	125
Common shares *(Note 20)*	**3,969**	3,683
Contributed surplus	**106**	59
Retained earnings	**4,991**	4,734
Accumulated other comprehensive loss *(Note 22)*	**(1,094)**	(882)
Reciprocal shareholding *(Note 11)*	**(187)**	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	7,565
Noncontrolling interests *(Note 19)*	**846**	658
	9,687	8,223
Commitments and contingencies *(Note 31)*		
	34,343	30,220

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:



DAVID A. ARLEDGE
Chair



DAVID A. LESLIE
Director

1. General Business Description

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including the Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines and processing facilities, green energy projects, Canadian midstream businesses, the Company's energy services businesses and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business, an interest in the development of Cabin Gas Plant in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico System. The energy services businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, corporate investments and financing costs not allocated to the business segments.

2. Summary of Significant Accounting Policies

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post-employment benefits *(Note 27)*; commitments and contingencies *(Note 31)*; and fair value of asset retirement obligations (AROs). Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and its proportionate share of the accounts of various joint ventures. The Fund is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of the Fund through the combination of a total direct and indirect 35.4% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as Held to maturity, Loans and receivables or Available for sale (see *Financial Instruments*).

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing and the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue was recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Effective July 1, 2011, Canadian Mainline earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective July 1, 2011, the Company discontinued the application of rate-regulated accounting for its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis, with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

For rate-regulated operations in Sponsored Investments and rate-regulated operations in natural gas pipelines included in Gas Pipelines, Processing and Energy Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

FINANCIAL INSTRUMENTS

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the Consolidated Statements of Financial Position. Subsequent measurement of the financial instrument is based on its classification.

HELD FOR TRADING

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenue, Commodity costs, Other income and Interest expense. The Company has classified Cash and cash equivalents, bank indebtedness and its non-qualifying derivative instruments as held for trading.

AVAILABLE FOR SALE

Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other comprehensive income/(loss) (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from available for sale financial assets are recognized in earnings when the right to receive payment is established.

LOANS AND RECEIVABLES

Loans and receivables, which include Accounts receivable and other and affiliate long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

HELD TO MATURITY

The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

OTHER FINANCIAL LIABILITIES

Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Interest payable, Long-term debt and Non-recourse long-term debt.

DERIVATIVES IN QUALIFYING HEDGING RELATIONSHIPS

The Company uses derivative financial instruments to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

CASH FLOW HEDGES

The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

FAIR VALUE HEDGES

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges outstanding at December 31, 2011 or December 31, 2010.

NET INVESTMENT HEDGES

The Company uses net investment hedges to manage the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated other comprehensive income/(loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment.

CLASSIFICATION OF DERIVATIVES

The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current or long-term depending on the timing of the settlements and the resulting cash flows associated with the instruments. The fair value related to cash flows occurring beyond one year are classified as non-current.

BALANCE SHEET OFFSET

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

TRANSACTION COSTS

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

EQUITY INVESTMENTS

Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees.

NONCONTROLLING INTERESTS

Noncontrolling interests represent the outstanding ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and variable interest entities. The portion of the entities not owned by the Company is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a future income tax liability is recognized with a corresponding regulatory asset. Any interest and/or penalty incurred related to tax is reflected in income taxes.

FOREIGN CURRENCY TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates. Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The Company's foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these operations are included in the cumulative translation adjustment component of AOCI and are recognized in earnings when there is a disposal of all or part of the foreign operation.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

The Company uses the group method of depreciation for all property, plant and equipment, except for the non rate-regulated assets in Canada, which are depreciated on a single asset basis. Depreciation is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. Under the group method, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system, is sold, a gain or loss is recognized in the Consolidated Statements of Earnings for the difference between the cash received and the net book value of the assets sold.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including future income taxes, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts, long-term power purchase agreements and certain software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangibles are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually in the fourth quarter of each year, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

IMPAIRMENT

The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

ASSET RETIREMENT OBLIGATIONS

AROs associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the initial net transitional asset, prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses, in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

Certain regulated operations of the Company recover pension and OPEB expense based on amounts paid in accordance with the methodology accepted by the regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. In the absence of rate regulation, these balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Contributed surplus. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Bloomberg barrier option valuation model and is recognized on a straight-line basis with a corresponding credit to Contributed surplus. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

3. Changes in Accounting Policies

BUSINESS COMBINATIONS

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The application of this standard decreased Earnings attributable to Enbridge Inc. by $37 million, net of income taxes of $5 million for dilution gains for subsidiaries, which are now recognized in equity for the year ended December 31, 2011. The application of this standard had no material impact to the Company's cash flows for the year ended December 31, 2011.

CONSOLIDATED FINANCIAL STATEMENTS AND NONCONTROLLING INTERESTS

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements* and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there was no impact to the Company's earnings or cash flow for the current or prior periods presented.

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

First-time adoption of Part I – International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and presented its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

As a rate regulated accounting standard model has not been finalized by the International Accounting Standards Board, the Company does not intend to adopt IFRS in 2012 but rather U.S. GAAP. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

4. Segmented Information

Year ended December 31, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**1,959**	**2,574**	**14,476**	**393**	**–**	**19,402**
Commodity costs	**–**	**(1,354)**	**(13,500)**	**–**	**–**	**(14,854)**
Operating and administrative	**(760)**	**(492)**	**(295)**	**(137)**	**(36)**	**(1,720)**
Depreciation and amortization	**(327)**	**(320)**	**(167)**	**(111)**	**(12)**	**(937)**
	872	**408**	**514**	**145**	**(48)**	**1,891**
Income/(loss) from equity investments	**–**	**–**	**–**	**342**	**(6)**	**336**
Other income/(expense)	**31**	**(11)**	**38**	**202**	**(148)**	**112**
Interest expense	**(256)**	**(166)**	**(97)**	**(74)**	**(118)**	**(711)**
Income taxes recovery/(expense)	**(139)**	**(55)**	**(161)**	**(219)**	**6**	**(568)**
Earnings/(loss)	**508**	**176**	**294**	**396**	**(314)**	**1,060**
Earnings attributable to noncontrolling interests	**(3)**	**–**	**(1)**	**(52)**	**–**	**(56)**
Preference share dividends	**–**	**–**	**–**	**–**	**(13)**	**(13)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**505**	**176**	**293**	**344**	**(327)**	**991**
Additions to property, plant and equipment [1]	**977**	**483**	**953**	**73**	**33**	**2,519**
Total assets	**12,366**	**7,713**	**4,968**	**5,245**	**4,051**	**34,343**

Year ended December 31, 2010	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,672	2,611	10,518	326	–	15,127
Commodity costs	–	(1,384)	(9,907)	–	–	(11,291)
Operating and administrative	(603)	(497)	(215)	(120)	(31)	(1,466)
Depreciation and amortization	(312)	(310)	(144)	(88)	(10)	(864)
	757	420	252	118	(41)	1,506
Income from equity investments	–	–	–	32	6	38
Other income/(expense)	115	(17)	30	114	132	374
Interest expense	(223)	(179)	(96)	(58)	(131)	(687)
Income taxes recovery/(expense)	(135)	(64)	(65)	(66)	79	(251)
Earnings	514	160	121	140	45	980
Earnings attributable to noncontrolling interests	(2)	(5)	–	(3)	–	(10)
Preference share dividends	–	–	–	–	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	512	155	121	137	38	963
Additions to property, plant and equipment [1]	765	387	1,153	132	–	2,437
Total assets	11,508	7,594	5,536	3,833	1,749	30,220

Year ended December 31, 2009	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,333	2,992	7,823	313	5	12,466
Commodity costs	–	(1,757)	(7,254)	–	–	(9,011)
Operating and administrative	(565)	(495)	(226)	(113)	(31)	(1,430)
Depreciation and amortization	(230)	(298)	(140)	(88)	(8)	(764)
	538	442	203	112	(34)	1,261
Income from equity investments	–	–	–	188	10	198
Other income/(expense) and gain on sale of investments	161	(12)	366	13	515	1,043
Interest expense	(144)	(188)	(87)	(56)	(122)	(597)
Income taxes	(108)	(50)	(54)	(88)	(6)	(306)
Earnings	447	192	428	169	363	1,599
Earnings attributable to noncontrolling interests	(2)	(6)	–	(28)	(1)	(37)
Preference share dividends	–	–	–	–	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	445	186	428	141	355	1,555
Additions to property, plant and equipment [1]	2,662	326	321	41	10	3,360

1 Includes allowance for equity funds used during construction (AEDC).

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

GEOGRAPHIC INFORMATION

REVENUES [1]

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Canada	**12,591**	9,876	9,503
United States	**6,811**	5,251	2,963
	19,402	15,127	12,466

1 Revenues are based on the country of origin of the product or services sold.

PROPERTY, PLANT AND EQUIPMENT

December 31,	**2011**	2010
(millions of Canadian dollars)		
Canada	**17,843**	16,095
United States	**4,780**	4,237
	22,623	20,332

5. Financial Statement Effects of Rate Regulation

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation whereby the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

CANADIAN MAINLINE

The Canadian Mainline includes the Canadian portion of the mainline system. The primary business activities of the Canadian Mainline are subject to regulation by the NEB. Prior to July 1, 2011, the incentive tolling settlement (ITS) defined the methodology for calculation of tolls and the revenue requirement on the core component of the Canadian Mainline. Toll adjustments, for variances from requirements defined in the ITS, were filed annually with the regulator for approval. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

Effective July 1, 2011, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the ten year term of the CTS. As a result, the Company discontinued the application of rate-regulated accounting to its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost of service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment.

The regulatory asset of approximately $470 million related to future income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the discontinuance of rate-regulated accounting, and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred. The regulatory asset of approximately $70 million related to tolling deferrals recorded at the date of discontinuance is being recovered through a toll surcharge over a period of two years.

SOUTHERN LIGHTS

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

ENBRIDGE GAS DISTRIBUTION

EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD's after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2011, 2010 and 2009 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

ENBRIDGE GAS NEW BRUNSWICK

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB's after-tax ROE for the year ended December 31, 2011 was 10.90% (2010 – 13.00%; 2009 – 13.00%) based on equity which is capped at 45%.

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

VECTOR PIPELINE

Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2011 included an after-tax ROE component of 11.18% (2010 – 11.18%; 2009 – 11.07%).

ALLIANCE PIPELINE

The Alliance Pipeline US is regulated by the FERC and Alliance Pipeline Canada is regulated by the NEB. Transportation service agreements with shippers are in place for substantially all of the pipeline capacity until December 2015 under a cost of service methodology. Toll adjustments are filed annually with the regulators. Tolls for the years ended December 31, 2011, 2010 and 2009 included an after-tax ROE component of 10.88% for Alliance Pipeline US and 11.26% (2010 – 11.26%; 2009 – 11.26%) for Alliance Pipeline Canada. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	2011	2010	Estimated Settlement Period *(years)*	Earnings Impact [1] 2011	2010	2009
(millions of Canadian dollars)						
Regulatory assets/(liabilities)						
Liquids Pipelines						
Future income taxes [2]	**527**	479	–	**36**	55	49
Tolling deferrals [3]	**14**	132	1	**(3)**	19	(16)
Deferred transportation revenue [8]	**84**	32	29	**34**	21	–
Gas Distribution						
Future income taxes [2]	**224**	211	–	**9**	(12)	(11)
EGNB regulatory deferral [4]	**180**	171	30	**9**	18	15
Future removal and site restoration reserves [5]	**(836)**	(773)	–	**–**	–	6
Purchased gas variance [6]	**–**	(144)	1	**–**	–	–
Pension plans and OPEB, net [7]	**(95)**	(97)	–	**(2)**	–	(2)
Gas Pipelines, Processing and Energy Services						
Future income taxes [2]	**1**	1	–	**–**	–	–
Deferred transportation revenue [8]	**124**	150	13 – 15	**(18)**	(17)	(6)
Sponsored Investments						
Future income taxes [2]	**83**	94	–	**(8)**	(3)	(11)
Deferred transportation revenue [8]	**100**	98	15	**1**	5	5

1 *The effect of a number of the Company's businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.*

2 *The asset represents the regulatory offset to future income tax liabilities to the extent that future income taxes are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3 *Tolls for regulated pipelines under a cost of service methodology are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline result in an under or over collection of the annual revenue requirement, a regulatory asset or liability is recognized and incorporated into tolls in the subsequent year or in accordance with the related agreement.*

4 *A regulatory deferral account captures the cumulative difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2013 and end no sooner than 2040. The impact of legislative changes passed by the Government of New Brunswick in December 2011 (the specific details of which remain dependent upon regulations which have not yet been published) is not determinable as of February 21, 2012.*

5 *The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company's businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

6 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.*

7 *The pension plan balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement periods for these balances are not determinable. EGD continues to record and recover pension and OPEB expenditures through rates on a cash basis. In the absence of rate regulation, these regulatory balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

8 *Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Southern Lights, Alliance and Vector Pipelines and the negotiated depreciation rates included in the regulated transportation tolls. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Southern Lights after 2020, for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2012 and for Vector Pipeline beginning in 2008. This regulatory asset is not included in the rate base.*

OTHER ITEMS AFFECTED BY RATE REGULATION

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AND OTHER CAPITALIZED COSTS

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

OPERATING COST CAPITALIZATION

With the approval of regulators, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, cumulative costs relating to this consulting contract of $133 million (2010 – $124 million) were included in property plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. Acquisitions and Dispositions

ACQUISITIONS

SEAWAY CRUDE PIPELINE COMPANY

On December 20, 2011, Enbridge acquired 50% of the outstanding common units in Seaway Pipeline, a partnership engaged in the crude oil pipeline business in Texas, for cash consideration of $1.2 billion (US$1.2 billion). The Company's investment in Seaway Pipeline is accounted for as a joint venture interest *(Note 10)*.

December 20,	2011
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**536**
Goodwill	**638**
Current liabilities	**(4)**
	1,175
Purchase Price:	
Cash (net of $9 million cash acquired)	**1,175**

A net loss of $1 million related to transaction costs was recognized in Earnings for the year ended December 31, 2011. Had the acquisition occurred on January 1, 2011, an unaudited proforma net loss of $2 million, including $1 million of transaction costs, would have been recognized as earnings. The entire amount of acquired goodwill is expected to be tax deductible for United States income tax purposes.

TONBRIDGE POWER INC.

On October 13, 2011, Enbridge acquired 100% of the 36 million outstanding common shares of Tonbridge Power Inc. (Tonbridge), an independent company engaged in constructing an electric transmission line between Montana and Alberta, for $20 million in cash at a price of $0.54 per share.

October 13,	**2011**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Working capital deficiency	**(5)**
Property, plant and equipment	**196**
Intangible assets	**17**
Long-term debt	**(182)**
Other long-term liabilities	**(21)**
	5
Purchase Price:	
Cash (net of $15 million cash acquired)	**5**

No revenue from Tonbridge was recognized in 2011 as the transmission line is not yet in service. A net loss of $1 million was recognized in income for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expenses. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in income in 2011 had the acquisition occurred on January 1, 2011.

DISPOSITIONS

GAIN ON SALE OF INVESTMENTS

December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
NetThruPut (NTP)	**–**	–	29
Oleoducto Central S.A. (OCENSA)	**–**	–	336
	–	–	365

NTP

On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million and were included in the Corporate operating segment.

OCENSA

On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million. Earnings from the OCENSA investment were included in the Gas Pipelines, Processing and Energy Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

7. Accounts Receivable and Other

December 31,	2011	2010
(millions of Canadian dollars)		
Unbilled revenues	**1,535**	1,284
Trade receivables	**699**	740
Taxes receivable	**157**	205
Regulatory assets	**80**	182
Current derivative assets *(Note 23)*	**465**	170
Due from affiliates *(Note 30)*	**69**	63
Prepaid expenses and deposits	**42**	36
Dividends receivable	**32**	16
Other	**113**	72
Allowance for doubtful accounts *(Note 23)*	**(56)**	(62)
	3,136	2,706

8. Inventory

December 31,	2011	2010
(millions of Canadian dollars)		
Natural gas	**488**	537
Other commodities	**251**	276
	739	813

9. Property, Plant and Equipment

December 31, 2011	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.8%	**7,482**	**1,811**	**5,671**
Pumping equipment, buildings, tanks and other	3.5%	**5,098**	**1,367**	**3,731**
Land and right-of-way	3.0%	**232**	**38**	**194**
Under construction	–	**1,718**	**–**	**1,718**
		14,530	**3,216**	**11,314**
Gas Distribution				
Gas mains, services and other	4.0%	**6,961**	**1,401**	**5,560**
Land and right-of-way	2.5%	**79**	**30**	**49**
Under construction	–	**137**	**–**	**137**
		7,177	**1,431**	**5,746**
Gas Pipelines, Processing and Energy Services				
Pipeline	3.6%	**2,171**	**814**	**1,357**
Wind turbines, solar panels and other [1]	5.8%	**1,208**	**125**	**1,083**
Land and right-of-way	2.6%	**50**	**14**	**36**
Under construction	–	**567**	**–**	**567**
		3,996	**953**	**3,043**
Sponsored Investments				
Pipeline	4.0%	**1,105**	**398**	**707**
Wind turbines, solar panels and other [1]	3.4%	**1,744**	**225**	**1,519**
Under construction	–	**23**	**–**	**23**
		2,872	**623**	**2,249**
Corporate				
Other	2.9%	**270**	**30**	**240**
Under construction	–	**31**	**–**	**31**
		301	**30**	**271**
		28,876	**6,253**	**22,623**

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.7%	7,295	1,618	5,677
Pumping equipment, buildings, tanks and other	3.6%	4,728	1,221	3,507
Land and right-of-way	1.8%	232	29	203
Under construction	–	728	–	728
		12,983	2,868	10,115
Gas Distribution				
Gas mains, services and other	3.6%	6,605	1,272	5,333
Land and right-of-way	2.6%	68	15	53
Under construction	–	103	–	103
		6,776	1,287	5,489
Gas Pipelines, Processing and Energy Services				
Pipeline	3.4%	2,121	706	1,415
Wind turbines, solar panels and other [1]	3.1%	1,527	142	1,385
Land and right-of-way	2.4%	62	13	49
Under construction	–	622	–	622
		4,332	861	3,471
Sponsored Investments				
Pipeline	4.0%	1,598	484	1,114
Wind turbines, solar panels and other [1]	8.5%	108	29	79
Under construction	–	17	–	17
		1,723	513	1,210
Corporate				
Other	11.3%	67	20	47
		67	20	47
		25,881	5,549	20,332

1 *In October 2011, Enbridge Pipelines Inc. (EPI) sold three renewable energy assets to the Fund. As a result, at December 31, 2011, $1,087 million of property, plant and equipment was reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The December 31, 2010 balance of $1,103 million has not been reclassified for presentation purposes.*

10. Joint Ventures

The impact of the Company's joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

		Net Assets	
December 31,	Ownership Interest	**2011**	2010
(millions of Canadian dollars)			
Liquids Pipelines			
Chicap Pipeline	43.8%	**27**	27
Mustang Pipeline	30.0%	**27**	26
Woodland Pipeline	50.0%	**79**	23
Seaway Pipeline *(Note 6)*	50.0%	**1,186**	–
Gas Pipelines, Processing and Energy Services			
Enbridge Offshore Pipelines – various joint ventures	22.0% – 74.3%	**420**	433
Alliance Pipeline US	50.0%	**293**	318
Vector Pipeline	60.0%	**347**	349
Aux Sable [1]	42.7% – 50.0%	**217**	86
Lac Alfred Wind Project (Lac Alfred) [2]	50.0%	**130**	–
Other	33.3% – 70.0%	**21**	27
Sponsored Investments			
Alliance Pipeline Canada	50.0%	**642**	660
Other	33.0% – 50.0%	**58**	56
		3,447	2,005

1 In July 2011, the Company, through its affiliate Aux Sable, acquired a 42.7% interest in the Palermo Conditioning Plant and the Prairie Rose Pipeline for $76 million.

2 In December 2011, the Company acquired a 50% interest in Lac Alfred for $128 million.

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings			
Revenues	**804**	771	781
Commodity costs	**(138)**	(92)	(74)
Operating and administrative	**(200)**	(203)	(226)
Depreciation and amortization	**(163)**	(163)	(171)
Interest expense	**(75)**	(82)	(99)
Other income/(expense)	**(2)**	(1)	10
Proportionate share of earnings	**226**	230	221
Cash flows			
Cash provided by operating activities	**392**	349	342
Cash used in investing activities	**(196)**	(57)	(49)
Cash used in financing activities	**(71)**	(78)	(133)
Proportionate share of increase in cash and cash equivalents	**125**	214	160

December 31,	2011	2010
(millions of Canadian dollars)		
Financial position		
Current assets	**229**	171
Property, plant and equipment, net	**3,019**	2,331
Intangible assets	**210**	166
Goodwill	**959**	321
Deferred amounts and other assets	**267**	270
Current liabilities	**(239)**	(150)
Non-recourse long-term debt	**(951)**	(1,061)
Other long-term liabilities	**(47)**	(43)
Proportionate share of net assets	**3,447**	2,005

During the year ended December 31, 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline) for $28 million (US$27 million), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

11. Long-Term Investments

December 31,	Ownership Interest	2011	2010
(millions of Canadian dollars)			
Equity investments			
Sponsored Investments			
The Partnership	23.0%	**1,711**	1,473
Enbridge Energy, Limited Partnership – Series AC	66.7%	**453**	463
Corporate			
Noverco Common Shares	38.9%	**–**	14
Other	5.0% – 20.0%	**35**	13
Other investments			
Corporate			
Noverco Preferred Shares		**285**	181
Value Creation Inc.		**29**	29
Fuel Cell Energy Ltd.		**11**	25
Other		**16**	–
		2,540	2,198

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $120 million at December 31, 2011 (2010 – $123 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets.

THE PARTNERSHIP

The Partnership includes the Company's investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 23.0% ownership in EEP, through a 2.0% general partner interest, a 16.0% interest in Class A units, a 2.7% interest in Class B units and a 2.3% interest in EEP as a result of a 16.8% investment in EEM, which owns 13.3% of EEP through its 100% interest in EEP's i-units.

The Company recorded investment income inclusive of incentive earnings, before tax, of $296 million (2010 – $51 million; 2009 – $175 million) for the year ended December 31, 2011.

During the year ended December 31, 2011, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $66 million net of income taxes of $53 million and noncontrolling interests of $22 million, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 25.5% to 23.0%.

During the year ended December 31, 2010, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $81 million before tax and noncontrolling interest, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 27.0% to 25.5%.

Although 83.2% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP

The Company has a 66.7% interest in the series AC units of EELP, which constructed the United States segment of the Alberta Clipper project *(Note 30)*. The Company recorded investment income from EELP of $53 million for the year ended December 31, 2011 (2010 – $63 million; 2009 – $12 million).

During 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 – $40 million (US$39 million)) payable to the Company relating to its series AC interest in the Alberta Clipper project.

NOVERCO

During the year ended December 31, 2011, the Company invested $144 million in cash and $255 million in a dividend received from Noverco to increase its common share investment from 32.1% to 38.9%. In addition, the Company received $399 million of preferred shares which are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.40%. There has been no change in the accounting for the Company's common or preferred share investments in Noverco as a result of the restructuring. The Company's interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

The Company adjusted its preferred share investments in Noverco which are entitled to cumulative preferred dividends based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40% to $285 million at December 31, 2011 (2010 – $181 million) due to the restructure of Noverco in 2011.

The Company also reduced its equity investment in Noverco common shares to nil at December 31, 2011 (2010 – $14 million) due to the restructure. Noverco owns an approximate 8.9% (2010 – 9.0%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.5% (2010 – 2.9%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $187 million at December 31, 2011 (2010 – $154 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2011, the Company recorded an equity investment loss of $6 million (2010 – $6 million of earnings; 2009 – $10 million of earnings) related to its interest in Noverco.

12. Deferred Amounts and Other Assets

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory assets	**1,434**	1,419
Long-term portion of derivative assets *(Note 23)*	**549**	462
Affiliate long-term note receivable *(Note 30)*	**336**	334
Pension asset *(Note 27)*	**320**	301
Contractual receivables	**288**	277
Other	**293**	93
	3,220	2,886

At December 31, 2011, deferred amounts of $63 million (2010 – $66 million) were subject to amortization and are presented net of accumulated amortization of $43 million (2010 – $39 million). Amortization expense in 2011 was $6 million (2010 – $9 million; 2009 – $7 million).

13. Intangible Assets

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.4%	**521**	**199**	**322**
Transportation agreements	4.2%	**241**	**79**	**162**
Power purchase agreements and other	10.4%	**122**	**6**	**116**
		884	**284**	**600**

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.4%	457	172	285
Transportation agreements	4.2%	231	66	165
Power purchase agreements and other	5.0%	33	5	28
		721	243	478

Total amortization expense for intangible assets was $61 million for the year ended December 31, 2011 (2010 – $60 million; 2009 – $44 million). Assuming no asset additions or impairments, the Company expects aggregate amortization expense for the years ending December 31, 2012 through 2016 of $62 million, $55 million, $48 million, $43 million and $38 million, respectively.

14. Goodwill

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at December 31, 2009	19	–	45	308	–	372
Foreign exchange and other	(1)	–	(3)	–	–	(4)
Business acquisition	17	–	–	–	–	17
Balance at December 31, 2010	35	–	42	308	–	385
Foreign exchange and other	**–**	**–**	**1**	**–**	**–**	**1**
Acquired *(Note 6)*	**638**	**–**	**–**	**–**	**–**	**638**
Balance at December 31, 2011	**673**	**–**	**43**	**308**	**–**	**1,024**

In 2011, the Company recognized $638 million of goodwill on the acquisition of a 50% interest in Seaway Pipeline. In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty Caverns.

15. Accounts Payable and Other

December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating accrued liabilities	**2,068**	1,677
Trade payables	**153**	232
Construction payables	**224**	253
Taxes payable	**283**	156
Current derivative liabilities *(Note 23)*	**711**	138
Security deposits	**84**	78
Contractor holdbacks	**40**	78
Other	**159**	76
	3,722	2,688

16. Debt

December 31,	Weighted Average Interest Rate	Maturity	2011	2010
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.20%	2024	**200**	200
Medium-term notes	5.05%	2012 – 2040	**2,435**	2,435
Southern Lights project financing [1]	2.52%	2013 – 2014	**1,449**	1,488
Commercial paper and credit facility draws, net			**26**	26
Other [2]			**13**	15
Gas Distribution				
Debentures	9.85%	2024	**85**	235
Medium-term notes	5.51%	2014 – 2050	**2,295**	2,195
Commercial paper and credit facility draws, net			**556**	334
Sponsored Investments				
Medium-term notes	4.72%	2014 – 2020	**415**	290
Credit facility draws, net			**260**	130
Corporate				
U.S. dollar term notes [3]	5.48%	2014 – 2017	**1,119**	1,094
Medium-term notes	4.74%	2013 – 2040	**3,518**	2,918
Commercial paper and credit facility draws, net [4]			**2,785**	2,776
Deferred debt issue costs and other			**(99)**	(95)
Total debt			**15,057**	14,041
Current maturities			**(252)**	(154)
Short-term borrowings	1.07%		**(548)**	(326)
Long-term debt			**14,257**	13,561

1 2011 – $360 million and US$1,071 million (2010 – $388 million and US$1,106 million).

2 Primarily capital lease obligations.

3 2011 – US$1,100 million (2010 – US$1,100 million).

4 2011 – $987 million and US$1,780 million (2010 – $2,515 million and US$265 million).

Debenture and term note maturities for the years ending December 31, 2012 through 2016 are $252 million, $451 million, $898 million, $916 million and $701 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $557 million, $536 million, $515 million, $475 million and $450 million, respectively.

INTEREST EXPENSE

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Debentures and medium-term notes	**598**	578	494
Non-recourse long-term debt *(Note 17)*	**65**	75	83
Commercial paper and credit facility draws	**71**	63	71
Southern Lights project financing	**38**	37	45
Capitalized	**(61)**	(66)	(96)
	711	687	597

CREDIT FACILITIES

December 31, 2011	Maturity Dates [2]	Total Facilities	Credit Facility Draws [3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012 – 2013	**717**	**556**	**161**
Sponsored Investments	2013	**500**	**268**	**232**
Corporate	2012 – 2016	**5,653**	**2,832**	**2,821**
		7,170	**3,682**	**3,488**
Southern Lights project financing [1]	2013 – 2014	**1,576**	**1,466**	**110**
Total credit facilities		**8,746**	**5,148**	**3,598**

1 Total facilities inclusive of $61 million for debt service reserve letters of credit.

2 Total facilities include $30 million in demand facilities with no maturity date.

3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

Credit facilities carry a weighted average standby fee of 0.17% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,079 million (2010 – $2,940 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. Non-Recourse Debt

December 31,	Weighted Average Interest Rate	Maturity	2011	2010
(millions of Canadian dollars)				
Gas Pipelines, Processing and Energy Services				
Long-term credit facilities [1]		2015	**5**	1
Senior notes [2]	6.78%	2015 – 2025	**325**	347
Term debt [3]	3.54%	2012 – 2019	**31**	29
Capital lease obligations	10.60%	2020	**31**	32
Sponsored Investments				
Credit facilities		2012 – 2015	**23**	23
Senior notes	6.67%	2015 – 2025	**638**	675
Fair value increment on senior notes acquired			**25**	29
Deferred debt issue costs and other			**(5)**	(5)
Total non-recourse debt			**1,073**	1,131
Current maturities			**(122)**	(70)
Non-recourse long-term debt			**951**	1,061

1 2011 – US$5 million (2010 – US$1 million).

2 2011 – US$319 million (2010 – US$349 million).

3 2011 – US$26 million (2010 – US$24 million).

Maturities on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $122 million, $78 million, $81 million, $86 million and $64 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $67 million, $62 million, $56 million, $51 million and $46 million, respectively.

Certain assets of Alliance Pipeline Canada and Alliance Pipeline US, with a carrying value of $959 million and $693 million, respectively, are pledged as collateral to Alliance Pipeline Canada and to Alliance Pipeline US lenders.

18. Other Long-Term Liabilities

December 31,	2011	2010
(millions of Canadian dollars)		
Future removal and site restoration reserves *(Note 5)*	**836**	773
Regulatory liabilities	**189**	198
Derivative liabilities *(Note 23)*	**433**	133
OPEB liabilities *(Note 27)*	**127**	118
Other	**307**	251
	1,892	1,473

19. Noncontrolling Interests

December 31,	2011	2010
(millions of Canadian dollars)		
Enbridge Energy Management, L.L.C. (EEM)	**475**	394
Enbridge Income Fund (the Fund)	**227**	109
Enbridge Gas Distribution Inc. (EGD) Preferred Shares	**100**	100
Talbot Windfarm, LP (Talbot)	**–**	26
Greenwich Windfarm, LP (Greenwich)	**26**	12
Other	**18**	17
	846	658

Noncontrolling interests in EEM represents the 83.2% of the listed shares of EEM not held by the Company. During the year ended December 31, 2011, EEM completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests.

Noncontrolling interests in the Fund at December 31, 2011 represents 64.6% of interests that are held by third parties. During the year ended December 31, 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly owned subsidiary of Enbridge for proceeds of $1.2 billion. Ordinary trust units were issued by the Fund to partially finance the acquisition, resulting in an increase in interests held by third parties. Contributions from noncontrolling interests for the year ended December 31, 2011 included $168 million attributable to the Fund's common trust unit issuance.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2011, no preferred shares have been redeemed.

Noncontrolling interests in both Talbot and Greenwich represent 10% of partnership units held by a third party. During the year ended December 31, 2011, the Company acquired the remaining 10% interest in Talbot for $28 million, increasing its ownership interest to 100%. Effective October 21, 2011, ownership of Talbot was transferred to the Fund.

20. Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

December 31,	2011 Number of Shares	2011 Amount	2010 Number of Shares	2010 Amount	2009 Number of Shares	2009 Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**770**	**3,683**	756	3,379	746	3,194
Common shares issued	**–**	**–**	–	–	–	4
Shares issued on exercise of stock options	**4**	**57**	6	80	2	38
Dividend Reinvestment and Share Purchase Plan (DRIP)	**7**	**229**	8	224	8	143
Balance at end of year	**781**	**3,969**	770	3,683	756	3,379

PREFERENCE SHARES

December 31,	2011 Number of Shares	2011 Amount	2010 Number of Shares	2010 Amount	2009 Number of Shares	2009 Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference shares, Series A	**5**	**125**	5	125	5	125
Preference shares, Series B issued [1]	**20**	**490**	–	–	–	–
Preference shares, Series D issued [2]	**18**	**441**	–	–	–	–
Balance at end of year		**1,056**		125		125

1 Gross proceeds – $500 million; net issuance costs – $10 million.

2 Gross proceeds – $450 million; net issuance costs – $9 million.

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend [1]	Per Share Cash Dividend Declared	Per share Base Redemption Value [2]	Redemption and Conversion Option Date [2,3]	Right to Convert [3,4]
(Canadian dollars unless otherwise stated)						
Preference shares, Series A	5.5%	1.3750	1.3750	25	–	–
Preference shares, Series B	4.0%	1.0000	0.4192	25	June 1, 2017	Series C
Preference shares, Series D	4.0%	1.0000	0.2705	25	March 1, 2018	Series E

1 Fixed, cumulative, quarterly preferential dividend per share per year.

2 The Company may at its option, redeem all or a portion of the outstanding preference shares for the base redemption value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified Series on the Conversion Option Date and every fifth anniversary thereafter.

4 Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C) or 2.37% (Series E)).

Subsequent to year end, on January 18, 2012, the Company issued 20 million Series F Preference Shares for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to the same dividends, redemption and conversion terms as the Series B and Series D Preference Shares. Redemption of Series F Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series G can occur on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Series G Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada treasury bill rate plus 2.51%.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 25 million (2010 – 22 million; 2009 – 22 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

December 31,	**2011**	2010	2009
(number of common shares in millions)			
Weighted average shares outstanding	**751**	741	728
Effect of dilutive options	**10**	7	5
Diluted weighted average shares outstanding	**761**	748	733

For the year ended December 31, 2011, 48,000 anti-dilutive stock options (2010 – 92,000; 2009 – 1,113,000) with a weighted average exercise price of $32.02 (2010 – $27.84; 2009 – $20.49) were excluded from the diluted earnings per share calculation.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. Stock Option and Stock Unit Plans

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 43 million have been issued to date. In 2007, a new reserve of 33 million common shares was approved and established and in 2011 an increase of 19 million to the reserved common shares was approved, resulting in a total of 52 million shares being available for the 2007 ISO and PBSO plans, of which 1 million have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2011 for ISOs is $16 million (2010 – $11 million; 2009 – $17 million).

OUTSTANDING INCENTIVE STOCK OPTIONS

	2011		2010		2009	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**25,460**	**18.34**	24,932	17.01	21,300	15.53
Options granted	**6,041**	**28.78**	4,000	22.70	6,056	19.81
Options exercised	**(3,926)**	**14.23**	(3,436)	14.52	(2,374)	11.01
Options cancelled or expired	**(110)**	**25.87**	(36)	12.45	(50)	20.33
Options at end of year	**27,465**	**21.19**	25,460	18.34	24,932	17.01
Options vested	**14,214**	**17.93**	13,764	16.01	13,100	14.48

The total intrinsic value of ISOs exercised during the year ended December 31, 2011 was $68 million (2010 – $38 million; 2009 – $22 million) and cash received on exercise was $56 million (2010 – $50 million; 2009 – $26 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2011 was $285 million (2010 – $182 million) and $194 million (2010 – $131 million), respectively.

INCENTIVE STOCK OPTION CHARACTERISTICS

December 31, 2011	Options Outstanding			Options Vested		
Exercise Price Range	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
10.00 – 12.49	**1,195**	**1.0**	**10.45**	**1,195**	**1.0**	**10.45**
12.50 – 14.99	**1,440**	**2.1**	**12.86**	**1,440**	**2.1**	**12.86**
15.00 – 17.49	**2,578**	**4.7**	**15.99**	**1,963**	**4.0**	**15.94**
17.50 – 19.99	**7,877**	**6.0**	**19.30**	**5,486**	**5.5**	**19.08**
20.00 – 22.49	**5,202**	**6.4**	**20.55**	**3,390**	**6.2**	**20.37**
22.50 – 24.99	**3,102**	**8.1**	**23.30**	**717**	**8.1**	**23.30**
27.50 – 29.99	**6,023**	**9.1**	**28.90**	**23**	**8.9**	**27.84**
30.00 – 32.49	**48**	**9.7**	**32.02**	**–**	**–**	**–**
	27,465	**6.5**	**21.08**	**14,214**	**4.9**	**17.83**

The total fair value of options vested under the ISO Plan during the year ended December 31, 2011 was $17 million (2010 – $14 million; 2009 – $13 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	**2011**	2010	2009
Fair value per option *(Canadian dollars)* [1]	**4.19**	3.44	3.56
Valuation assumptions			
Expected option term *(years)* [2]	**6**	6	6
Expected volatility [3]	**18.63%**	19.72%	28.08%
Expected dividend yield [4]	**3.40%**	3.64%	3.87%
Risk-free interest rate [5]	**2.85%**	2.70%	2.24%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States options and the Canadian options. The fair value per option was $4.01 (2010 – $3.28; 2009 – $3.37) for Canadian employees and US$5.11 (2010 – US$4.00; 2009 – US$3.43) for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility. Beginning in 2010, implied volatility observable in call option values near the grant date is also considered in determining the expected volatility.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and United States Treasury Bond Yields.*

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $24 million. The cost is expected to be fully recognized by December 31, 2014.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2011 for PBSOs was $2 million (2010 – $2 million; 2009 – $2 million).

OUTSTANDING PERFORMANCE BASED STOCK OPTIONS

	2011		2010		2009	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**4,294**	**18.51**	6,790	16.85	7,476	16.36
Options exercised	**(167)**	**18.29**	(2,078)	13.12	(686)	11.58
Options cancelled	**–**	**–**	(418)	18.29	–	–
Options at end of year	**4,127**	**18.52**	4,294	18.51	6,790	16.85
Options vested	**3,191**	**18.47**	2,524	18.44	1,600	11.58

The total intrinsic value of PBSOs exercised during the year ended December 31, 2011 was $2 million (2010 – $26 million; 2009 – $6 million) and cash received on exercise was $3 million (2010 – $27 million; 2009 – $8 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2011 is $54 million (2010 – $30 million) and $42 million (2010 – $18 million), respectively.

PERFORMANCE BASED STOCK OPTION CHARACTERISTICS

December 31, 2011	Options Outstanding			Options Vested		
Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
18.29	**3,627**	**3.6**	**18.29**	**2,891**	**3.6**	**18.29**
20.21	**500**	**3.6**	**20.21**	**300**	**3.6**	**20.21**
	4,127	**3.6**	**18.52**	**3,191**	**3.6**	**18.47**

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2011 was $2 million (2010 – $2 million; 2009 – $2 million).

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $1 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2009, 2010 and 2011 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2011 for PSUs was $42 million (2010 – $27 million; 2009 – $20 million). To calculate the 2011 expense, multipliers of two, based upon multiplier estimates at December 31, 2011, were used for each of the 2009, 2010 and 2011 PSU grants.

OUTSTANDING PERFORMANCE STOCK UNITS

December 31,	**2011**	2010	2009
Units at beginning of year	**955,894**	660,832	590,856
Units granted	**317,000**	572,400	339,200
Units matured	**(375,190)**	(319,634)	(303,764)
Dividend reinvestment	**39,453**	42,296	34,540
Units at end of year	**937,157**	955,894	660,832

Of the PSUs outstanding at December 31, 2011, 610,459 units have a performance period ending December 31, 2012 and 326,698 have a performance period ending December 31, 2013. The total intrinsic value of PSUs outstanding at December 31, 2011 is $71 million (2010 – $54 million; 2009 – $31 million). The total amount paid during the year ended December 31, 2011 for PSUs was $17 million (2010 – $14 million; 2009 – $9 million).

RESTRICTED STOCK UNITS

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2011 for RSUs was $31 million (2010 – $29 million; 2009 – $23 million).

OUTSTANDING RESTRICTED STOCK UNITS

December 31,	**2011**	2010	2009
Units at beginning of year	**2,095,970**	1,975,754	1,400,068
Units granted	**938,100**	937,200	1,087,000
Units cancelled	**(92,276)**	(60,908)	(36,858)
Units matured	**(1,132,674)**	(855,504)	(565,312)
Notional dividend reinvestment	**92,865**	99,428	90,856
Units at end of year	**1,901,985**	2,095,970	1,975,754

The total intrinsic value of RSUs outstanding at December 31, 2011 is $72 million (2010 – $59 million; 2009 – $47 million). The total liability paid during the year ended December 31, 2011 for RSUs was $39 million (2010 – $24 million; 2009 – $12 million).

As of December 31, 2011, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $68 million and is expected to be fully recognized by December 31, 2013.

22. Components of Accumulated Other Comprehensive Income/(Loss)

	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Noncontrolling Interests	Cash Flow Hedges	Total
(millions of Canadian dollars)						
Balance at January 1, 2009	278	(275)	(8)	17	21	33
Changes during the year	181	(815)	(38)	72	71	(529)
Tax impact	(30)	–	14	–	(31)	(47)
	151	(815)	(24)	72	40	(576)
Balance at December 31, 2009	429	(1,090)	(32)	89	61	(543)
Changes during the year	61	(274)	(18)	33	(133)	(331)
Tax impact	(10)	–	7	–	(5)	(8)
	51	(274)	(11)	33	(138)	(339)
Balance at December 31, 2010	480	(1,364)	(43)	122	(77)	(882)
Changes during the year	**(21)**	**242** [1]	**(91)**	**13**	**(513)**	**(370)**
Tax impact	**2**	**–**	**30**	**–**	**126**	**158**
	(19)	**242**	**(61)**	**13**	**(387)**	**(212)**
Balance at December 31, 2011	**461**	**(1,122)**	**(104)**	**135**	**(464)**	**(1,094)**

1 Changes in the Cumulative Translation Adjustment balance during the year included the release of a $155 million loss to earnings following the partial liquidation of an investment in a foreign subsidiary.

23. Risk Management and Financial Instruments

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company's policy is to operate within a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with EaR limits is reported to the CFRMC and variances, if any, are remediated as necessary.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

FOREIGN EXCHANGE RISK

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues and expenses denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues and expenses denominated in United States dollars.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2011 would have resulted in a $310 million increase (2010 – $81 million) to earnings. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to non-consolidated foreign operations within the Company that are not denominated in the Company's functional currency and are not considered a net investment. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company's United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

INTEREST RATE RISK

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.27%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2015. A total of $5,200 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 – nil) in earnings and a $457 million increase (2010 – $178 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011. A 1% increase across the interest rate yield curve, with all other variables constant, would have caused a $23 million decrease (2010 – $22 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

COMMODITY PRICE RISK

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGLs. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and its indirect ownership of the gathering and process business held by EEP.

The Company uses EaR as a metric to monitor certain commodity price risk exposures, principally those associated with its ownership of Aux Sable, its ownership of EEP and the activities of its energy services subsidiaries. The EaR metric measures the price exposures, net of the impact of financial derivatives used to manage such exposures. The Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from such commodity price risk over a one month period.

	2011	2010
(millions of Canadian dollars)		
Average EaR during the year	**23**	22
High EaR during the year	**27**	29
Low EaR during the year	**18**	16
Closing EaR at year end	**20**	25

EQUITY PRICE RISK

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, RSUs *(Note 21)*.

Due to revaluation of the equity derivative contracts at December 31, 2011, the impact of a $4 increase in the Company's share price would have been a $3 million increase in earnings (2010 – $2 million) and a $2 million increase in OCI (2010 – $1 million). The earnings impact of non-qualifying equity derivatives partially offsets earnings impacts due to the revaluation of liabilities associated with the Company's RSUs.

TOTAL DERIVATIVE INSTRUMENTS

The following tables summarize the balance sheet location and fair value of the Company's derivative instruments. The Company had no outstanding fair value hedges as at December 31, 2011 or 2010.

December 31, 2011	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	**4**	**15**	**315**	**334**
Interest rate contracts	**–**	**–**	**7**	**7**
Commodity contracts	**–**	**–**	**114**	**114**
Equity contracts	**3**	**–**	**7**	**10**
	7	**15**	**443**	**465**
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	**15**	**79**	**203**	**297**
Interest rate contracts	**1**	**–**	**22**	**23**
Commodity contracts	**1**	**–**	**223**	**224**
Equity contracts	**3**	**–**	**2**	**5**
	20	**79**	**450**	**549**
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	**(4)**	**–**	**(275)**	**(279)**
Interest rate contracts	**(341)**	**–**	**(3)**	**(344)**
Commodity contracts	**(1)**	**–**	**(87)**	**(88)**
	(346)	**–**	**(365)**	**(711)**
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	**(35)**	**(5)**	**(51)**	**(91)**
Interest rate contracts	**(303)**	**–**	**(18)**	**(321)**
Commodity contracts	**(2)**	**–**	**(19)**	**(21)**
	(340)	**(5)**	**(88)**	**(433)**
Total net derivative asset/(liability)				
Foreign exchange contracts	**(20)**	**89**	**192**	**261**
Interest rate contracts	**(643)**	**–**	**8**	**(635)**
Commodity contracts	**(2)**	**–**	**231**	**229**
Equity contracts	**6**	**–**	**9**	**15**
	(659)	**89**	**440**	**(130)**

December 31, 2010	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	4	15	111	130
Interest rate contracts	6	–	–	6
Commodity contracts	–	–	33	33
Equity contracts	–	–	1	1
	10	15	145	170
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	18	100	275	393
Interest rate contracts	67	–	–	67
Commodity contracts	–	–	2	2
	85	100	277	462
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	(4)	–	(11)	(15)
Interest rate contracts	(72)	–	–	(72)
Commodity contracts	–	–	(51)	(51)
	(76)	–	(62)	(138)
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	(47)	–	(3)	(50)
Interest rate contracts	(80)	–	–	(80)
Commodity contracts	–	–	(3)	(3)
	(127)	–	(6)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	(29)	115	372	458
Interest rate contracts	(79)	–	–	(79)
Commodity contracts	–	–	(19)	(19)
Equity contracts	–	–	1	1
	(108)	115	354	361

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

	2011		2010	
December 31,	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards – purchase *(millions of United States dollars)*	2012 – 2020	**1,281**	2011 – 2020	1,185
U.S. dollar forwards – sell *(millions of United States dollars)*	2012 – 2020	**10,866**	2011 – 2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	2012 – 2029	**16,540**	2011 – 2029	10,772
Commodity contracts – energy *(billions of cubic feet equivalent)*	2012 – 2013	**2**	2011 – 2013	41
Commodity contracts – power *(megawatts per hour)*	2012 – 2024	**53**	2011 – 2024	2
Equity contracts *(millions of shares)*	2011 – 2013	**2**	2011 – 2012	1

THE EFFECT OF DERIVATIVE INSTRUMENTS ON THE STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**(22)**	(25)
Interest rate contracts	**(545)**	(172)
Commodity contracts	**(6)**	97
Equity contracts	**6**	(1)
Net investment hedges		
Foreign exchange contracts	**(26)**	19
Total unrealized loss recognized in OCI	**(593)**	(82)
Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)*		
Cash flow hedges		
Foreign exchange contracts [1]	**1**	(7)
Interest rate contracts [2]	**18**	68
Commodity contracts [3]	**5**	(95)
Equity contracts [4]	**(2)**	1
Total gain/(loss) reclassified from AOCI to earnings *(effective portion)*	**22**	(33)
Amount of ineffectiveness reclassified from AOCI to earnings		
Cash flow hedges		
Interest rate contracts [2]	**11**	–
Total ineffectiveness reclassified from AOCI to earnings	**11**	–

1 *(Gain)/loss reported within Other income in the Consolidated Statements of Earnings.*

2 *(Gain)/loss reported within Interest expense in the Consolidated Statements of Earnings.*

3 *(Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

4 *(Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $33 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all significant forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months at December 31, 2011.

NON-QUALIFYING DERIVATIVES

The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Foreign exchange contracts [1]	**(179)**	33	232
Interest rate contracts [2]	**9**	(2)	2
Commodity contracts [3]	**244**	(5)	(88)
Equity contracts [4]	**4**	–	–
Total unrealized derivative fair value gain	**78**	26	146

1 *Gain/(loss) reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*

2 *Gain/(loss) reported within Interest expense in the Consolidated Statements of Earnings.*

3 *Gain/(loss) reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*

4 *Gain reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

Additional information regarding the Company's derivative instruments is included in Note 24, *Fair Value of Financial Instruments.*

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as access to capital markets. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

MATURITIES OF FINANCIAL INSTRUMENTS

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17)*.

For the years ending December 31, 2012 through 2016, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

	2012	2013	2014	2015	2016	Thereafter
(millions of Canadian dollars)						
Cash inflows	440	213	180	69	74	105
Cash outflows	(401)	(133)	(124)	(77)	(65)	(610)
Net cash flows	39	80	56	(8)	9	(505)

CREDIT RISK

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and industry standard netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011 and 2010, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments.

December 31,	2011	2010
(millions of Canadian dollars)		
Canadian financial institutions	**426**	451
Non-Canadian financial institutions	**509**	125
Other	**73**	50
	1,008	626

Credit risk also arises from trade and other long-term receivables and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, *Fair Value of Financial Instruments.*

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Balance at beginning of year	**(62)**	(74)
Additional allowance	**(26)**	(23)
Amounts used	**32**	35
Balance at end of year	**(56)**	(62)

24. Fair Value of Financial Instruments

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2011	Held for Trading	Available for Sale [1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**420**	**–**	**–**	**–**	**–**	**–**	**–**	**420**	**420**
Accounts receivable and other	**443**	**–**	**2,392**	**–**	**–**	**22**	**279**	**3,136**	**2,857**
Long-term investments	**–**	**56**	**–**	**285**	**–**	**–**	**2,199**	**2,540**	**285**
Deferred amounts and other assets	**450**	**–**	**4**	**–**	**–**	**99**	**2,667**	**3,220**	**553**
Liabilities									
Bank indebtedness	**102**	**–**	**–**	**–**	**–**	**–**	**–**	**102**	**102**
Short-term borrowings	**–**	**–**	**–**	**–**	**548**	**–**	**–**	**548**	**548**
Accounts payable and other	**365**	**–**	**–**	**–**	**2,728**	**346**	**283**	**3,722**	**3,439**
Interest payable	**–**	**–**	**–**	**–**	**114**	**–**	**–**	**114**	**114**
Long-term debt	**–**	**–**	**–**	**–**	**14,509**	**–**	**–**	**14,509**	**16,772**
Non-recourse long-term debt	**–**	**–**	**–**	**–**	**1,073**	**–**	**–**	**1,073**	**1,248**
Other long-term liabilities	**88**	**–**	**–**	**–**	**–**	**345**	**1,459**	**1,892**	**433**

December 31, 2010	Held for Trading	Available for Sale [1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	342	–	–	–	–	–	–	342	342
Accounts receivable and other	145	–	2,113	–	–	25	423	2,706	2,283
Long-term investments	–	54	339	181	–	–	1,624	2,198	520
Deferred amounts and other assets	277	–	334	–	–	185	2,090	2,886	462
Liabilities									
Bank indebtedness	100	–	–	–	–	–	–	100	100
Short-term borrowings	–	–	–	–	326	–	–	326	326
Accounts payable and other	62	–	–	–	2,393	76	157	2,688	2,531
Interest payable	–	–	–	–	117	–	–	117	117
Long-term debt	–	–	–	–	13,715	–	–	13,715	14,770
Non-recourse long-term debt	–	–	–	–	1,131	–	–	1,131	1,298
Other long-term liabilities	6	–	–	–	–	127	1,340	1,473	133

1 Classified as Other investments carried at cost under U.S. GAAP.

2 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of financial assets carried as long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

LEVEL 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations in the Gas Pipelines, Processing and Energy Services segment.

LEVEL 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts as well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services and Corporate segments.

LEVEL 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services segment.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2011	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	–	**334**	–	**334**
Interest rate contracts	–	**7**	–	**7**
Commodity contracts	**1**	**59**	**54**	**114**
Equity contracts	–	**10**	–	**10**
	1	**410**	**54**	**465**
Long-term derivative assets				
Foreign exchange contracts	–	**297**	–	**297**
Interest rate contracts	–	**23**	–	**23**
Commodity contracts	–	**193**	**31**	**224**
Equity contracts	–	**5**	–	**5**
	–	**518**	**31**	**549**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	–	**(279)**	–	**(279)**
Interest rate contracts	–	**(344)**	–	**(344)**
Commodity contracts	–	**(42)**	**(46)**	**(88)**
	–	**(665)**	**(46)**	**(711)**
Long-term derivative liabilities				
Foreign exchange contracts	–	**(91)**	–	**(91)**
Interest rate contracts	–	**(321)**	–	**(321)**
Commodity contracts	–	**(16)**	**(5)**	**(21)**
	–	**(428)**	**(5)**	**(433)**
Total net derivative asset/(liability)				
Foreign exchange contracts	–	**261**	–	**261**
Interest rate contracts	–	**(635)**	–	**(635)**
Commodity contracts	**1**	**194**	**34**	**229**
Equity contracts	–	**15**	–	**15**
	1	**(165)**	**34**	**(130)**

December 31, 2010	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	–	130	–	130
Interest rate contracts	–	6	–	6
Commodity contracts	–	5	28	33
Other contracts	–	–	1	1
	–	141	29	170
Long-term derivative assets				
Foreign exchange contracts	–	393	–	393
Interest rate contracts	–	67	–	67
Commodity contracts	–	–	2	2
	–	460	2	462
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	–	(15)	–	(15)
Interest rate contracts	–	(72)	–	(72)
Commodity contracts	(9)	(2)	(40)	(51)
	(9)	(89)	(40)	(138)
Long-term derivative liabilities				
Foreign exchange contracts	–	(50)	–	(50)
Interest rate contracts	–	(80)	–	(80)
Commodity contracts	–	(1)	(2)	(3)
	–	(131)	(2)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	–	458	–	458
Interest rate contracts	–	(79)	–	(79)
Commodity contracts	(9)	2	(12)	(19)
Other contracts	–	–	1	1
	(9)	381	(11)	361

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of year	**(11)**	(28)
Total gains/(losses), unrealized		
Included in earnings [1]	**46**	19
Included in OCI	**(4)**	3
Settlements	**3**	(5)
Level 3 net derivative asset/(liability) at end of year	**34**	(11)

1 Gain reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense.

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as of December 31, 2011 and December 31, 2010.

25. Capital Disclosures

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and noncontrolling interests less cash and cash equivalents (excluding restricted cash of amounts in trust and proportionately consolidated cash from joint ventures, net of bank indebtedness). Non-recourse debt, including debt proportionately consolidated from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows.

December 31,	**2011**	2010
(millions of Canadian dollars)		
Short-term borrowings	**548**	326
Long-term debt (includes current portion)	**14,608**	13,810
Noncontrolling interests	**846**	658
Shareholders' equity	**10,122**	8,601
Cash and cash equivalents	**(77)**	(282)
	26,047	23,113

The Company seeks to balance a number of objectives when managing capital, including enabling its businesses to operate at the highest efficiency while maintaining safety and reliability; ensuring liquidity for growth opportunities; and minimizing cost of capital. These objectives are primarily met through maintenance of an investment grade credit rating, disciplined investment criteria and sufficient committed credit facilities. Capital is available generally through the issuance of both short and long-term debt and various forms of equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2011, including short-term borrowings but excluding non-recourse short and long-term debt, was 58.0% compared with 60.4% at the end of 2010.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. This covenant also applies to the Company's credit facilities that are used to backstop its commercial paper program. Total consolidated capitalization consists of shareholders' equity, long-term debt, noncontrolling interests and future income taxes.

During the year ended December 31, 2011, the Company was in compliance with externally imposed capital requirements.

26. Income Taxes

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings attributable to Enbridge Inc. before income taxes	**1,572**	1,221	1,868
Combined statutory income tax rate	**27.3%**	28.9%	30.5%
Income taxes at statutory rate	**429**	353	570
Increase/(decrease) resulting from:			
Future income taxes related to regulated operations	**(35)**	(62)	(68)
Higher/(lower) foreign tax rates	**84**	(22)	(61)
Tax rates and legislated tax changes	**2**	(23)	(58)
Non-taxable items, net	**1**	(2)	11
Intercompany sale of investments [1]	**98**	–	(99)
Other	**(11)**	7	11
Income taxes	**568**	251	306
Effective income tax rate	**36.1%**	20.6%	16.4%

1 *In October 2011, EPI sold three renewable energy assets to the Fund. As the transaction occurred between entities under common control of the Company, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $98 million remain as a charge to earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.*

COMPONENTS OF FUTURE INCOME TAXES

December 31,	**2011**	2010
(millions of Canadian dollars)		
Net future income tax liabilities/(assets)		
Differences in accounting and tax bases of property, plant and equipment	**1,831**	1,468
Differences in accounting and tax bases of investments	**603**	479
Regulatory assets/(liabilities)	**308**	340
Financial instruments	**(24)**	105
Loss carryforwards	**(126)**	(81)
Other	**63**	56
Net future income tax liability	**2,655**	2,367

Net future income tax liability of $2,655 million (2010 – $2,367 million) is comprised of future income tax liabilities of $2,696 million (2010 – $2,447 million) net of future income tax assets of $41 million (2010 – $80 million).

At December 31, 2011, the Company had recognized the benefit of unused tax loss carryforwards of $401 million (2010 – $248 million) which start to expire in 2020 and beyond.

GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**600**	711	954
United States	**839**	379	334
Other	**133**	131	580
	1,572	1,221	1,868
Current income taxes			
Canada	**207**	(29)	49
United States	**(48)**	37	35
Other	**(6)**	5	4
	153	13	88
Future income taxes			
Canada	**31**	134	117
United States	**384**	104	101
	415	238	218
Current and future income taxes	**568**	251	306

27. Post-Employment Benefits

PENSION PLANS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation for the Canadian and United States Plans.

DEFINED BENEFIT PLANS

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2010	December 31, 2011
Gas Distribution	December 31, 2009	December 31, 2012
United States Plan	December 31, 2010	December 31, 2011

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

DEFINED CONTRIBUTION PLANS

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

POST-EMPLOYMENT BENEFITS OTHER THAN PENSIONS

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,323**	1,119	**195**	170
Service cost	**61**	48	**6**	5
Interest cost	**73**	72	**11**	11
Amendments	**–**	–	**–**	6
Employees' contributions	**–**	–	**1**	1
Actuarial loss [1]	**270**	145	**28**	12
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**8**	–	**7**	–
Effect of foreign exchange rate changes	**5**	(9)	**2**	(3)
Benefit obligation at end of year	**1,686**	1,323	**243**	195
Change in plan assets				
Fair value of plan assets at beginning of year	**1,324**	1,167	**41**	38
Actual return on plan assets [1]	**16**	127	**1**	2
Employer's contributions	**72**	89	**13**	9
Employees' contributions	**–**	–	**1**	1
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**4**	(1)	**4**	–
Effect of foreign exchange rate changes	**3**	(6)	**1**	(2)
Fair value of plan assets at end of year	**1,365**	1,324	**54**	41
Funded status				
Benefit obligation	**(1,686)**	(1,323)	**(243)**	(195)
Fair value of plan assets	**1,365**	1,324	**54**	41
Overfunded/(underfunded) status at end of year	**(321)**	1	**(189)**	(154)
Unamortized prior service cost	**2**	4	**5**	6
Unamortized transitional obligation/(asset)	**(9)**	(11)	**7**	8
Unamortized net loss	**648**	307	**50**	22
Net amount recognized in the Consolidated Statements of Financial Position at end of year	**320**	301	**(127)**	(118)
Presented as follows:				
Deferred amounts and other assets *(Note 12)*	**320**	301	**–**	–
Other long-term liabilities *(Note 18)*	**–**	–	**(127)**	(118)

1 *Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**4.46%**	5.64%	6.46%	**4.44%**	5.55%	6.28%
Average rate of salary increases	**3.50%**	3.50%	3.73%			

NET BENEFIT COSTS RECOGNIZED

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
(millions of Canadian dollars)						
Benefits earned during the year	**61**	48	53	**6**	5	4
Interest cost on projected benefit obligations	**73**	72	71	**11**	11	11
Actual return on plan assets	**(16)**	(127)	(51)	**(1)**	(2)	(6)
Difference between actual and expected return on plan assets	**(76)**	47	(27)	**(2)**	–	3
Amortization of prior service costs	**2**	2	2	**1**	–	–
Amortization of transitional obligation	**(2)**	(2)	(2)	**1**	1	1
Amortization of actuarial loss	**25**	19	21	**1**	1	1
Amount charged to EEP [1]	**(15)**	(15)	(20)	**(6)**	(5)	(5)
Net defined benefit costs on an accrual basis	**52**	44	47	**11**	11	9
Defined contribution benefit costs	**4**	5	4	**–**	–	–
Net benefit cost recognized in the Consolidated Statements of Earnings	**56**	49	51	**11**	11	9

1 EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.

For certain gas distribution businesses, regulatory adjustments are recorded in the Consolidated Statement of Earnings and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Differences arise since accounting is based on an accrual basis whereas ratemaking is based on a cash basis or funding approach. Regulatory assets or liabilities recognized in the Consolidated Statements of Financial Position are disclosed in Note 5.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows.

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.64%**	6.47%	6.59%	**5.55%**	6.31%	6.42%
Average rate of return on pension plan assets	**7.30%**	7.30%	7.30%	**6.00%**	6.00%	6.09%
Average rate of salary increases	**3.50%**	3.73%	5.00%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows.

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.4%	4.5%	2029
Other Medical and Dental	4.5%	4.5%	2029
United States Plan	7.8%	4.5%	2030

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $36 million in the accumulated post-employment benefit obligations and an increase of $3 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $29 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its defined benefit pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

TARGET MIX FOR PLAN ASSETS

	Liquids Pipelines Pension Plan	Gas Distribution Pension Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

EXPECTED RATE OF RETURN ON PLAN ASSETS

	Pension Benefits		OPEB	
Years ended December 31,	**2011**	2010	**2011**	2010
Canadian Plans	**7.0%**	7.25%		
United States Plan	**7.5%**	7.75%	**6.0%**	6.00%

MAJOR CATEGORIES OF PLAN ASSETS

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

As at December 31, 2011, assets securing pension benefits were invested 56.6% (2010 – 60.2%) in equity securities, 36.5% (2010 – 33.8%) in fixed income securities and 6.9% (2010 – 6.0%) in other. OPEB assets securing OPEB benefits were invested 55.3% (2010 – 51.2%) in equity securities, 40.3% (2010 – 48.8%) in fixed income securities and 4.3% (2010 – nil) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $82 million (2010 – $69 million) have been excluded from the table below.

	2011				2010			
December 31,	Level 1 [1]	Level 2 [2]	Level 3 [3]	Total	Level 1 [1]	Level 2 [2]	Level 3 [3]	Total
(millions of Canadian dollars)								
Pension benefits								
Cash and cash equivalents	**14**	**–**	**–**	**14**	10	–	–	10
Fixed income securities								
Canadian government bonds	**–**	**115**	**–**	**115**	–	97	–	97
Corporate bonds and debentures	**–**	**4**	**–**	**4**	4	–	–	4
Canadian corporate bond index fund	**158**	**–**	**–**	**158**	151	–	–	151
Canadian government bond index fund	**157**	**–**	**–**	**157**	149	–	–	149
United States debt index fund	**62**	**–**	**–**	**62**	47	–	–	47
Equity								
Canadian equity securities	**148**	**–**	**–**	**148**	163	–	–	163
Canadian equity funds	**23**	**74**	**–**	**97**	26	80	–	106
United States equity funds	**172**	**89**	**–**	**261**	147	76	–	223
Global equity funds	**192**	**7**	**–**	**199**	221	19	–	240
Private equity investment [4]	**–**	**–**	**68**	**68**	–	–	65	65
OPEB								
Cash and cash equivalents	**3**	**–**	**–**	**3**	–	–	–	–
Fixed income securities								
United States government and government agency bonds	**22**	**–**	**–**	**22**	20	–	–	20
Equity								
United States equity funds	**15**	**14**	**–**	**29**	9	–	–	9
Global equity funds	**–**	**–**	**–**	**–**	–	12	–	12

1 *Level 1 assets include assets with quoted prices in active markets for identical assets.*

2 *Level 2 assets include assets with significant observable inputs.*

3 *Level 3 assets include assets with significant unobservable inputs.*

4 *The fair value of the investment in United States Limited Partnership – Global Infrastructure Fund is established through the use of valuation models.*

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows.

	Private Equity Investment
Balance at beginning of year	65
Total gains, unrealized	8
Purchases, issuances, settlements, net	(5)
Balance at end of year	68

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Total contributions	**72**	89	**13**	9
Contributions expected to be paid in 2012	**94**		**11**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2012	2013	2014	2015	2016	2017 – 2021
(millions of Canadian dollars)						
Expected future benefit payments	66	68	72	76	80	466

28. Other Income

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	**(109)**	132	444
Gain on reduction of EEP ownership interest	**141**	81	–
AEDC	**3**	80	135
Interest income on affiliate loans	**38**	37	38
Noverco preferred dividends income	**30**	15	15
Hurricane insurance recoveries	**–**	5	13
OCENSA investment income	**–**	–	6
Other	**9**	24	27
	112	374	678

29. Changes in Operating Assets and Liabilities

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Accounts receivable and other	**(94)**	(480)	99
Inventory	**54**	(42)	99
Deferred amounts and other assets	**(253)**	(98)	(354)
Accounts payable and other	**504**	254	105
Interest payable	**(3)**	13	2
Other long-term liabilities	**43**	60	281
	251	(293)	232

30. Related Party Transactions

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
EEP	**380**	332	342
Vector Pipeline	**6**	7	6
	386	339	348

At December 31, 2011, the Company had accounts receivable of $35 million (2010 – $29 million) from EEP and nil (2010 – nil) from Vector Pipeline.

The Company previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principal amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty.

EGD, a subsidiary of the Company, has contracts for gas transportation services with Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**25**	25	24
Alliance Pipeline US	**17**	17	18
Vector Pipeline	**25**	28	29
	67	70	71

Tidal Energy Marketing (US) L.L.C., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Purchases	**1**	2	16
Sales	**–**	–	(6)
	1	2	10

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. Amounts charged are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**17**	13	9
Alliance Pipeline US	**11**	9	7
Vector Pipeline	**11**	10	16
	39	32	32

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Purchases	**122**	151	80
Sales	**(4)**	(3)	(7)
	118	148	73

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. As at December 31, 2011, the Company had met all funding commitments. The Company funded 66.7% of the project's equity requirements through EELP, an equity investee.

The Company also provided a $348 million (US$342 million) (2010 – $346 million (US$347 million)) loan to EEP for debt financing related to the construction. At December 31, 2011, $336 million (2010 – $334 million) is included in Deferred amounts and other assets with the remaining $12 million (2010 – $12 million) included in Accounts receivable and other. The loan, denominated in United States dollars, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. Semi-annual payments of principal and accrued interest are required. Semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period.

During the year ended December 31, 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 – $40 million (US$39 million)) payable to the Company relating to its series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE

In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which became effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 – $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE

An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million.

LAKEHEAD LINE 6B CRUDE OIL RELEASE

In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $6 million (2010 – $18 million) for the year ended December 31, 2011.

31. Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation totaling $4,120 million which are expected to be paid within the next five years.

ENBRIDGE GAS DISTRIBUTION INC.

BLOOR STREET INCIDENT

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

ENBRIDGE GAS NEW BRUNSWICK INC.

REGULATORY MATTERS

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 – $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

ENBRIDGE ENERGY PARTNERS, L.P.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

Enbridge holds an approximate 23.0% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

LINE 6B CRUDE OIL RELEASE

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas—a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The change in estimate was primarily based on a review of costs and commitments incurred, and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the EPA directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

LINE 6A CRUDE OIL RELEASE

A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

INSURANCE RECOVERIES

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

LEGAL AND REGULATORY PROCEEDINGS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LEGAL AND REGULATORY PROCEEDINGS

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

32. Guarantees

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The above-noted indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. United States Accounting Principles

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to Enbridge Inc. common shareholders under Canadian GAAP	**991**	963	1,555
Earnings attributable to Enbridge Inc. under Canadian GAAP	**1,004**	970	1,562
Dilution gains, net of tax [4]	**(88)**	(52)	–
Gain on acquisition, net of tax [1]	**–**	20	–
Inventory valuation adjustment, net of tax [2]	**13**	4	(24)
Amortization of underfunded pension adjustment [3]	**(7)**	(7)	(7)
Unrealized foreign exchange loss adjustment [12]	**155**	**–**	**–**
Earnings/(loss) attributable to noncontrolling interests			
EEP	**351**	(172)	177
Other	**56**	25	37
Earnings under U.S. GAAP	**1,484**	788	1,745
(Earnings)/loss attributable to noncontrolling interests	**(407)**	147	(214)
Earnings attributable to Enbridge Inc. under U.S. GAAP	**1,077**	935	1,531
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders under U.S. GAAP	**1,064**	928	1,524
Earnings per common share attributable to Enbridge Inc. common shareholders	**1.42**	1.25	2.09
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	**1.40**	1.24	2.08

COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings under U.S. GAAP	**1,484**	788	1,745
Other comprehensive loss including noncontrolling interests under Canadian GAAP	**(225)**	(372)	(648)
Underfunded pension adjustment [3]	**(145)**	(38)	11
Unrealized foreign exchange loss adjustment [12]	**(155)**	–	–
Other comprehensive loss attributable to noncontrolling interests in EEP under U.S. GAAP [4]	**(124)**	(29)	(62)
Other comprehensive loss including noncontrolling interests under U.S. GAAP	**(649)**	(439)	(699)
Comprehensive income	**835**	349	1,046
Comprehensive (income)/loss attributable to noncontrolling interests	**(270)**	224	(80)
Comprehensive income attributable to Enbridge Inc. under U.S. GAAP	**565**	573	966
Preference share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders under U.S. GAAP	**552**	566	959

FINANCIAL POSITION

December 31,	2011 Canada	2011 United States	2010 Canada	2010 United States
(millions of Canadian dollars)				
Assets				
Current assets				
Cash and cash equivalents [4,6]	**420**	**811**	342	456
Accounts receivable and other [4,6,9]	**3,136**	**3,990**	2,706	3,582
Inventory [2,4,6]	**739**	**714**	813	915
	4,295	**5,515**	3,861	4,953
Property, plant and equipment, net [4,6,8,9]	**22,623**	**31,833**	20,332	28,562
Long-term investments [4,6]	**2,540**	**510**	2,198	367
Deferred amounts and other assets [3,4,6,7,9]	**3,220**	**2,615**	2,886	2,212
Intangible assets [4,8]	**600**	**798**	478	676
Goodwill [4,8]	**1,024**	**1,091**	385	445
Future income taxes [1]	**41**	**40**	80	79
	34,343	**42,402**	30,220	37,294
Liabilities and shareholders' equity				
Current liabilities				
Bank indebtedness	**102**	**102**	100	100
Short-term borrowings	**548**	**548**	326	326
Accounts payable and other [4,6,9]	**3,722**	**4,904**	2,688	3,811
Interest payable [4]	**114**	**185**	117	177
Current maturities of long-term debt [4]	**252**	**354**	154	185
Current maturities of non-recourse long-term debt [6]	**122**	**103**	70	68
	4,860	**6,196**	3,455	4,667
Long-term debt [4,7,8]	**14,257**	**19,222**	13,561	18,374
Non-recourse long-term debt [6]	**951**	**606**	1,061	701
Other long-term liabilities [3,4,6,9]	**1,892**	**2,306**	1,473	1,658
Future income taxes [1,2,3,6,8]	**2,696**	**2,574**	2,447	2,370
	24,656	**30,904**	21,997	27,770
Redeemable noncontrolling interests [5]	**–**	**640**	–	364
Shareholders' equity				
Share capital				
Preference shares	**1,056**	**1,056**	125	125
Common shares	**3,969**	**3,969**	3,683	3,683
Contributed surplus	**106**	**–**	59	–
Retained earnings [1,2,3,5,8,9,12]	**4,991**	**4,172**	4,734	3,977
Additional paid-in capital [4]	**–**	**244**	–	131
Accumulated other comprehensive loss [3,12]	**(1,094)**	**(1,536)**	(882)	(1,026)
Reciprocal shareholding	**(187)**	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	**7,718**	7,565	6,736
Noncontrolling interests [4,5]	**846**	**3,140**	658	2,424
	9,687	**10,858**	8,223	9,160
	34,343	**42,402**	30,220	37,294

1 ***Gain on Acquisition*** *At December 31, 2010 under Canadian GAAP, the original equity interest in a step acquisition continued to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and noncontrolling interest in a step acquisition were re-measured to fair value on the date control was obtained. Under Canadian GAAP, the original equity interest and noncontrolling interest were not re-measured to fair value. At December 31, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists.*

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in Hardisty Caverns was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of Hardisty Caverns, a $20 million gain, net of tax, was recorded in earnings for the year ended December 31, 2010 under U.S. GAAP.

2 **Commodity Inventories Valuation** Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the year ended December 31, 2011, lower of cost or market adjustments resulted in a $11 million (2010 – $32 million) decrease to inventory, a $4 million increase (2010 – $6 million decrease) to the future income tax liability and a $13 million increase (2010 – $4 million increase; 2009 – $24 million decrease) to earnings.

3 **Pension Accounting** U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through OCI while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status. Pension funding status adjustments resulted in a decrease in the net pension asset of $704 million (2010 – $337 million) for the underfunded status of the plans, a decrease in regulatory liabilities of $304 million (2010 – $138 million), a decrease in future tax liability of $114 million (2010 – $58 million) and a decrease in AOCI of $286 million (2010 – $141 million) at December 31, 2011.

Under Canadian GAAP, an unrecognized net transitional asset was recognized as part of the net pension asset on the adoption of CICA Handbook Section 3461, Employee Future Benefits. There is no corresponding asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $2 million (2010 – $3 million) increase to the net pension asset with an offset to retained earnings, and a $1 million decrease to earnings (2010 – $1 million; 2009 – $1 million).

Under Canadian GAAP, a regulatory asset is recorded in relation to recoverable costs associated with OPEB plans. There is no corresponding regulatory asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $88 million (2010 – $85 million) decrease to regulatory assets with a corresponding decrease to retained earnings, and a $6 million decrease to earnings (2010 – $6 million; 2009 – $6 million).

Amounts removed from OCI and recognized as components of the net pension and OPEB costs in the year are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Prior service cost	**–**	1	–
Net loss	**10**	7	5
	10	8	5

Amounts included in AOCI that have not yet been recognized as a component of net periodic benefit cost are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Prior service cost	**3**	4	1
Accumulated net loss	**283**	137	102
	286	141	103

Net amounts reflected in OCI for the year are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Unamortized prior service cost	**(1)**	3	–
Net loss/(gain)	**146**	35	(10)
	145	38	(10)

The Company estimates that approximately $25 million related to pension and OPEB plans at December 31, 2011 will be reclassified into earnings in the next twelve months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	–	1	1
Loss	22	2	24
	22	3	25

4 **Consolidation of a Limited Partnership** Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 23.0 % interest in the partnership, resulting in an increase to assets of $8,920 million (2010 – $7,972 million), an increase in liabilities of $6,398 million (2010 – $6,098 million) and an increase in noncontrolling interests of $2,519 million (2010 – $1,871 million) at December 31, 2011. During the year ended December 31, 2011, dilution gains of $88 million, net of tax of $53 million (2010 – $52 million, net of tax of $30 million) were reclassified from earnings to equity as a result of the consolidation of EEP.

5 **Redeemable Noncontrolling Interests** Under Canadian GAAP, a subsidiary's redeemable units classified as equity are eliminated on consolidation when held by the parent, or presented by the parent in the Consolidated Statements of Financial Position as noncontrolling interest in equity. Under U.S. GAAP, noncontrolling interest in a redeemable equity security is classified outside of permanent equity. Further, under U.S. GAAP, noncontrolling interest in a redeemable equity security is required to be presented at its redemption value with changes in value recognized in retained earnings. At December 31, 2011, this difference resulted in an increase to noncontrolling interests, with a corresponding decrease to retained earnings, of $411 million (2010 – $255 million).

6 **Accounting for Joint Ventures** Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the SEC, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity.

7 **Transaction Costs** Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in Long-term debt. For U.S. GAAP, these costs are reclassified to Deferred amounts and other assets. As at December 31, 2011, $92 million (2010 – $89 million) of transaction costs were reclassified.

8 Common Control Transactions *U.S. GAAP requires common control transactions to be measured at the carrying amount, with any difference between the carrying value and consideration reflected as a charge or credit to equity. At December 31, 2011, a decrease in assets of $408 million (2010 – $414 million), a decrease in liabilities of $54 million (2010 – $61 million), and a decrease in retained earnings of $354 million (2010 – $353 million), related to a historic transaction with the Fund were retroactively reflected in the U.S. GAAP Statement of Financial Position. There was a $1 million decrease to earnings (2010 – $1 million; 2009 – $1 million).*

9 Accounting for Leases *The criteria for determining whether an arrangement contains a lease are consistent under both Canadian and U.S. GAAP; however, the U.S. GAAP guidance was effective prior to the Canadian GAAP guidance. As a result, one of the Company's pipeline transportation agreements is considered a lease under U.S. GAAP, resulting in an increase in assets of $122 million (2010 – $129 million), an increase in liabilities of $114 million (2010 – $122 million), an increase in retained earnings of $8 million (2010 – $7 million) and an increase in earnings of $1 million (2010 – $1 million; 2009 – $1 million).*

10 Unrecognized Tax Benefits

	2011	2010
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**17**	22
Gross increases for tax positions of current year	**3**	2
Gross increases for tax positions of prior years	**–**	–
Gross decreases for tax positions of prior years	**(1)**	(2)
Reduction for lapse of statute of limitations	**(1)**	(2)
Changes in translation of foreign currency	**–**	–
Decreases relating to settlements with taxing authority	**–**	(3)
Unrecognized tax benefits at end of year	**18**	17

The unrecognized tax benefits at December 31, 2011, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2011 includes a $1 million expense (2010 – $2 million recovery; 2009 – $1 million expense) of interest and penalties. As at December 31, 2011, interest and penalties of $9 million (2010 – $8 million; 2009 – $10 million) have been accrued.

The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, United States federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2007 and all returns are generally closed through 2006. Generally, all United States federal income tax returns and state and local income tax returns are closed through 2007.

11 Indefinite Reversal Rule *The Company has not provided future taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2011 were approximately $524 million (2010 – $491 million; 2009 – $406 million).*

12 Unrealized Foreign Exchange Loss *Under Canadian GAAP, an unrealized foreign exchange loss in AOCI was recognized in earnings during the year ended December 31, 2011 due to a dividend paid by a subsidiary. Under U.S. GAAP, this foreign exchange loss should remain in AOCI until the subsidiary is sold. At December 31, 2011, this difference resulted in an increase to earnings of $155 million with a corresponding decrease in OCI. This difference did not result in an adjustment at December 31, 2010 or December 31, 2009.*

FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2012. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

FAIR VALUE MEASUREMENT

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on fair value measurement under U.S. GAAP as part of the FASB's joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

STATEMENT OF COMPREHENSIVE INCOME

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of net income and OCI either in one continuous statement, referred to as the Statement of Comprehensive Income, or in two separate but consecutive statements of net income and OCI. The adoption of this pronouncement does not affect the Company's presentation of comprehensive income, and will not have an impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

GOODWILL IMPAIRMENT

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

BALANCE SHEET OFFSETTING

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim reporting periods beginning on or after January 1, 2013.

GLOSSARY

AEDC	allowance for equity funds used during construction
AFUDC	allowance for funds used during construction
Alliance	Alliance System
AOCI	accumulated other comprehensive income/loss
ASU	Accounting Standards Update of the FASB
bcf/d	billion cubic feet per day
bcfe	billions of cubic feet equivalent
bpd	barrels per day
Canadian GAAP	Part V – Pre-changeover Accounting Standards of the CICA
CICA	Canadian Institute of Chartered Accountants
CLT	Canadian Local Toll
CSR	corporate social responsibility
CTS	Competitive Toll Settlement
EaR	earnings at risk
EECI	Enbridge Energy Company, Inc.
EELP	Enbridge Energy, Limited Partnership
EEM	Enbridge Energy Management, L.L.C.
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick Inc.
Enbridge	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
EUB	New Brunswick Energy and Utilities Board
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fund	Enbridge Income Fund
GHG	greenhouse gas emissions
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IJT	International Joint Tariff
IR	incentive regulation
ISO	incentive stock options
ITS	incentive tolling settlement
JRP	Joint Review Panel
kbpd	thousand barrels per day
mmcf/d	million cubic feet per day
MW	megawatts
NEB	National Energy Board
NGL/NGLs	natural gas liquids
OCI	other comprehensive income/loss
OEB	Ontario Energy Board
Offshore	Enbridge Offshore Pipelines
OPA	Ontario Power Authority
OPEB	post-employment benefits other than pensions
Part V	Part V – Pre-changeover Accounting Standards of the CICA
PBSO	performance based stock options
PSU	performance stock units
ROE	return on equity
RSU	restricted stock units
SEC	United States Securities and Exchange Commission
tcf	trillion cubic feet
the Company	Enbridge Inc.
U.S. GAAP	United States Generally Accepted Accounting Principles
WCSB	Western Canadian Sedimentary Basin

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2011	2010	2009	2008	2007
(millions of Canadian dollars; per share amounts in Canadian dollars)					
Earnings attributable to common shareholders					
Liquids Pipelines	**505**	512	445	328	287
Gas Distribution	**176**	155	186	161	167
Gas Pipelines, Processing and Energy Services	**293**	121	428	767	154
Sponsored Investments	**344**	137	141	111	97
Corporate	**(327)**	38	355	(46)	(5)
	991	963	1,555	1,321	700
Earnings per common share [1]	**1.32**	1.30	2.13	1.84	0.99
Diluted earnings per common share [1]	**1.30**	1.29	2.12	1.82	0.98
Adjusted earnings [2]					
Liquids Pipelines	**536**	512	454	332	286
Gas Distribution	**175**	167	154	141	133
Gas Pipelines, Processing and Energy Services	**163**	123	116	141	173
Sponsored Investments	**253**	209	151	101	86
Corporate	**(17)**	(27)	(20)	(38)	(41)
	1,110	984	855	677	637
Adjusted earnings per common share [1,2]	**1.48**	1.33	1.17	0.94	0.90
Cash flow data					
Cash provided by operating activities	**2,703**	1,851	2,017	1,372	1,362
Cash used in investing activities	**(4,017)**	(2,674)	(3,306)	(2,853)	(2,229)
Cash provided by financing activities	**1,380**	766	1,082	1,840	904
Dividends					
Common share dividends declared	**759**	648	555	489	453
Dividends paid per common share [1]	**0.98**	0.85	0.74	0.66	0.62
Shares outstanding *(millions)*					
Weighted average common shares outstanding [1]	**751**	741	728	720	711
Diluted weighted average common shares outstanding [1]	**761**	748	733	725	717

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

2 *Adjusted earnings represent earnings attributable to common shareholders adjusted for non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do no thave any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see pages 37 and 114.*

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2011	2010	2009	2008	2007
(per share amounts in Canadian dollars)					
Common share trading (TSX) [1]					
High	**38.17**	29.13	24.46	21.64	20.74
Low	**27.05**	23.02	17.60	16.55	16.81
Close	**38.09**	28.14	24.32	19.78	20.01
Volume *(millions)*	**396**	461	457	585	408
Financial ratios					
Return on average shareholders' equity [2]	**12.0%**	12.9%	22.2%	22.2%	13.6%
Return on average capital employed [3]	**5.7%**	5.9%	8.9%	9.9%	7.0%
Debt to debt plus shareholders' equity [4]	**64.6%**	66.7%	66.2%	66.6%	66.5%
Earnings coverage of interest [5]	**3.1x**	2.6x	3.6x	3.8x	2.4x
Dividend payout ratio [6]	**66.2%**	63.9%	63.0%	70.2%	68.7%
Operating data					
Liquids Pipelines – Average deliveries *(thousands of barrels per day)*					
Canadian Mainline [7]	**1,554**	1,537	1,562	1,522	1,459
Regional Oil Sands System [8]	**329**	291	259	202	164
Spearhead Pipeline	**82**	144	121	110	103
Gas Pipelines, Processing and Energy Services – Average throughput volume *(millions of cublic feet per day)*					
Alliance Pipeline US	**1,564**	1,600	1,601	1,609	1,598
Vector Pipeline	**1,525**	1,456	1,334	1,321	1,034
Enbridge Offshore Pipelines	**1,595**	1,962	2,037	1,672	2,060
Gas Distribution – Enbridge Gas Distribution					
Volumes *(billions of cubic feet)*	**426**	409	408	433	440
Number of active customers *(thousands)* [9]	**1,997**	1,963	1,937	1,898	1,861
Heating degree days [10]					
Actual	**3,597**	3,466	3,767	3,802	3,659
Forecast based on normal weather	**3,602**	3,546	3,514	3,543	3,617

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

2 *Earnings applicable to common shareholders divided by average shareholders' equity (weighted monthly during the year).*

3 *Sum of after-tax earnings and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of shareholders' equity, Enbridge Gas Distribution preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).*

4 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*

5 *Earnings before income taxes and interest expense divided by interest expense (including capitalized interest).*

6 *Dividends per common share divided by adjusted earnings per common share.*

7 *Canadian Mainline includes deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.*

8 *Volumes are for the Athabasca mainline and the Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.*

9 *Number of active customers is the number of natural gas consuming EGD customers at the end of the period.*

10 *Heating degree days is a measure of coldness which is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto area.*

INVESTOR INFORMATION

COMMON AND PREFERENCE SHARES

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange (NYSE) under the trading symbol "ENB". The Preference Shares, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the following trading symbols:

Series A – ENB.PR.A
Series B – ENB.PR.B
Series D – ENB.PR.D
Series F – ENB.PR.F

REGISTRAR AND TRANSFER AGENT IN CANADA

For information relating to shareholdings, shareholder investment plan, dividends, direct dividend deposit, dividend re-investment accounts and lost certificates please contact:

CIBC Mellon Trust Company [1]
P.O. Box 700
Station B
Montreal, Québec, Canada H3B 3K3
Toll free: 800.387.0825
Internet: *canstockta.com/investorinquiry*
CIBC Mellon Trust Company also has offices in Halifax, Toronto, Calgary and Vancouver.

1 *Canadian Stock Transfer Company Inc. acts as the Administrative Agent for CIBC Mellon Trust Company*

CO-REGISTRAR AND CO-TRANSFER AGENT IN THE UNITED STATES

Computershare
480 Washington Blvd.
Jersey City, New Jersey
U.S.A. 07310

AUDITORS

PricewaterhouseCoopers LLP

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. Effective with dividends payable on March 1, 2008, participants in the Plan will receive a two per cent discount on the purchase of common shares with reinvested dividends. Details may be obtained from the Investor Information section of the Enbridge website at or by contacting CIBC Mellon Trust Company at any of the locations listed above.

NEW YORK STOCK EXCHANGE DISCLOSURE DIFFERENCES

As a foreign private issuer, Enbridge Inc. is required to disclose any significant ways in which its corporate governance practices differ from those followed by United States companies under NYSE listing standards. This disclosure can be obtained from the U.S. Compliance subsection of the Corporate Governance section of the Enbridge website at *enbridge.com*.

FORM 40-F

The Company files annually with the United States Securities and Exchange Commission a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company. In addition a link to it is available on the "Reports and Filings" subsection of the "Financial Reports" section of our website.

CORPORATE SOCIAL RESPONSIBILITY REPORT

Enbridge publishes an annual Corporate Social Responsibility report. The 2010 report is available on the Company's website at *csr.enbridge.com*.

REGISTERED OFFICE

Enbridge Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: 403.231.3900
Facsimile: 403.231.3920
Internet: *enbridge.com*

Annual Meeting

The Annual Meeting of Shareholders will be held in the Vanity Fair Ballroom, Le Meridien King Edward, Toronto, Ontario at 1:30 p.m. ET on Wednesday, May 9, 2012. A live audio webcast of the meeting will be available at enbridge.com and will be archived on the site for approximately one year. Webcast details will be available on the Company's website closer to the meeting date.

Le présent document est disponible en français.

Common and Preference Shares

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB". The Preference Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols:

Series A – ENB.PR.A

Series B – ENB.PR.B

Series D – ENB.PR.D

Series F – ENB.PR.F

2012 ENBRIDGE INC. COMMON SHARE DIVIDENDS

	1st Q	2nd Q	3rd Q	4th Q
Dividend	$0.2825	$–	$–	$–
Payment date	Mar. 1	Jun. 1	Sep. 1	Dec. 1
Record date [1]	Feb. 15	May 15	Aug. 15	Nov. 15
SPP deadline [2]	Feb. 23	May 25	Aug. 27	Nov. 26
DRIP enrollment [3]	Feb. 8	May 8	Aug. 8	Nov. 8

1 Dividend record dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year unless the 15th falls on a Saturday or Sunday.

2 The Share Purchase Plan cut-off date is five business days prior to the dividend payment date.

3 The Dividend Reinvestment Program enrollment cut-off date is five business days prior to the dividend record date.

Enbridge is committed to reducing its impact on the environment in every way, including the production of this publication. This report was printed entirely on FSC® Certified paper. The cover and feature pages were printed on Mohawk Via, which is manufactured entirely with wind energy and contains 100% post-consumer recycled fibre. The Management's Discussion and Analysis and Financial Statements were printed on Roland Envrio100 Print, which also contains 100% post-consumer recycled fibre and is manufactured using biogas energy.

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ENBRIDGE
Where energy meets people™

Enbridge Inc., a Canadian company, is a North American leader in delivering energy and one of the Global 100 Most Sustainable Corporations in the World. As a transporter of energy, Enbridge operates, in Canada and the U.S., the world's longest crude oil and liquids transportation system. The Company also has a significant and growing involvement in natural gas gathering, transmission and midstream businesses, and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company, and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in close to 1,000 megawatts of renewable and alternative energy generating capacity and is expanding its interests in wind and solar energy, geothermal and hybrid fuel cells. Enbridge employs approximately 6,900 people, primarily in Canada and the U.S. and is ranked as one of Canada's Greenest Employers and one of the Top 100 Companies to Work for in Canada. Enbridge's common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit enbridge.com.

enbridge.com

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Join the discussion.

Website: enbridge.com

Online Annual Report: ar.enbridge.com/ar2011

Online Corporate Social Responsibility Report: csr.enbridge.com

eBridge Newsletter: enbridge.com/mediacentre

Enbridge Facebook: facebook.com/enbridge

Enbridge Twitter: @enbridge_news

Northern Gateway Website and Blog: northerngateway.ca

Northern Gateway Facebook: facebook.com/enbridgenortherngateway

Northern Gateway Twitter: @northerngateway

Investor Relations:

Enbridge Inc. Investor Relations
3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: 800.481.2804
Outside North America: 403.231.5957
investor.relations@enbridge.com

Vice President, Investor Relations & Enterprise Risk
Jody Balko: 403.231.5720
jody.balko@enbridge.com

Director, Investor Relations
Jonathan Gould: 403.231.3916
jonathan.gould@enbridge.com

Media Inquiries:

Canadian Media: Enbridge Inc.
Jennifer Varey: 403.508.6563
jennifer.varey@enbridge.com
Toll-free Media Line: 888.992.0997

U.S. Media Hotline: 877.496.8142
USmedia@enbridge.com

ENBRIDGE
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Enbridge common shares trade on the Toronto Stock Exchange in Canada and on the New York Stock Exchange in the United States under the trading symbol ENB.

Enbridge Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: 403.231.3900
Facsimile: 403.231.3920
Toll free: 800.481.2804

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ENBRIDGE INC. *ANNUAL REPORT 2011*

Enbridge 2011 Corporate Social Responsibility Report

TAB A1d

ENBRIDGE 2012 CORPORATE SOCIAL RESPONSIBILITY REPORT



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Visit www.enbridge.com to learn more.

ABOUT ENBRIDGE

Over the past 60 plus years, Enbridge has become a leader in the safe and reliable delivery of energy in North America. We are proud that Corporate Knights has recognized us as one of the Global 100 Most Sustainable Corporations in the World.

We transport energy, operating the world's longest, most sophisticated crude oil and liquids transportation system. We have a significant, and growing, position in natural gas gathering, transmission and midstream businesses, and an emerging focus on power transmission.

We generate energy, expanding our interests in renewable energy and alternative energy technologies, including wind, solar and geothermal energy, fuel cells and waste heat recovery facilities.

We distribute energy, owning and operating Canada's largest natural gas distribution company, and provide distribution services in Ontario, Quebec, New Brunswick and New York State.

Enbridge manages and has a 69.2 per cent overall economic interest in Enbridge Income Fund and a 23.0 per cent overall ownership in Enbridge Energy Partners, L.P.

Enbridge's corporate headquarters are in Calgary, Alberta, and, as at September 30, 2012, we had over 10,000 employees in Canada and the United States. We are ranked as one of the Top 100 Employers to Work for in Canada, and one of Canada's Greenest Employers. Enbridge Inc. common shares trade on the Toronto and New York stock exchanges under the symbol ENB.

For more information about Enbridge, please visit http://www.enbridge.com/.

ABOUT THE ENBRIDGE 2012 CORPORATE SOCIAL RESPONSIBILITY REPORT

Enbridge's 2012 CSR Report was prepared using the Global Reporting Initiative (GRI) G3.1 sustainability reporting guidelines, which serve as a generally accepted framework for reporting on an organization's economic, environmental and social performance. Abbreviations such as EC1, EN3 and PR6 (in this report's Economic, Environment and Product Responsibility sections, respectively) refer to GRI Performance Indicators, which Enbridge addresses in this report. For more information on the GRI, please visit www.globalreporting.org.

Websites and Hyperlinks

Enbridge's 2012 CSR Report contains references to the websites of Enbridge Inc., certain of its affiliates and the Global Reporting Initiative (GRI) and to certain documents posted on these websites. In addition, the online version of Enbridge's 2012 CSR Report contains hyperlinks to these websites and documents. None of the information contained on, or connected to, these websites or documents is incorporated by reference in or otherwise part of Enbridge's 2012 CSR Report.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in Enbridge's 2012 Corporate Social Responsibility Report to provide the company's shareholders, potential investors and other stakeholders with information about the company and its subsidiaries and affiliates, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate," "expect," "project," "estimate," "forecast," "plan," "intend," "target," "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; expected costs related to leak remediation and potential insurance recoveries; the expected impact and cost of complying with current and proposed new environmental regulations, including GHG emissions regulations; business opportunities expected to arise due to the climate change issue; and future power consumption by the company and its subsidiaries.

Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; prices of crude oil, natural gas and natural gas liquids; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the company's projects; anticipated in-service dates; the implementation of proposed environmental regulations, including GHG emissions regulations; future demand for renewable energy and alternative energy technologies; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas and natural gas liquids, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the company operates, may impact levels of demand for the company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance; changes to regulatory parameters, including those related to GHG emissions; project approval and ongoing support; weather; economic and competitive conditions; exchange rates; interest rates; commodity prices; and supply and demand for commodities. These include, but are not limited to, those risks and uncertainties discussed in this 2012 Corporate Social Responsibility Report and in the company's filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this 2012 Corporate Social Responsibility Report or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the company's behalf are expressly qualified in their entirety by these cautionary statements.

AWARDS AND RECOGNITION

Corporate Social Responsibility Awards and Recognition

Over the years, Enbridge has received many CSR-related awards and much recognition. Criteria such as financial health; environmental performance; workplace health, safety and fairness; community relations; and public disclosure were considered in the following awards:

- **Alberta's Top Employers** 2010, 2011, 2012
- **Alberta's Most Respected Corporations (*Alberta Venture*)** – Top three for Financial Performance 2010
- **Best Crisis Management** (***IR Magazine Canada Awards***) 2011
- **Best Utility-Scale Project in North America**, Renewable Energy World (for Enbridge's Sarnia Solar Project) 2010
- **Canada's Greenest Employers** 2010, 2011, 2012
- **Canada's Top 100 Employers** 2010, 2011, 2012
- **Canada's Top Employers for Young People** 2011
- **Canada's 10 Most Admired Corporate Cultures** (Waterstone Human Capital) 2012
- **Canadian Institute of Chartered Accountants Corporate Reporting Award** 2011 – Enbridge was recognized for both its financial and sustainable development reporting
- ***Corporate Knights* Best 50 Corporate Citizens in Canada** 2010, 2011, 2012
- ***Corporate Knights* Global 100 Most Sustainable Large Corporations in the World** 2010, 2011, 2012
- **Dow Jones Sustainability Index (North America)** 2012/2013
- **Dow Jones Sustainability Index (World)** 2012/2013
- ***Financial Post's* Ten Best Companies to Work For** 2010
- **Forbes 100 Most Trustworthy Companies in America** (Enbridge Energy Partners) 2010, 2012
- **FTSE4Good Index** 2010, 2012, 2013
- **Gold Champion Level Reporter** (Canadian Standards Association's GHG Registry) 2009, 2010, 2011
- **Global 500 Carbon Disclosure Leadership List** (Carbon Disclosure Project) 2010, 2011, 2012
- **Intranet Design Annual 2010: The Year's 10 Best Intranets** 2010
- **Jantzi-Sustainalytics 50 Most Responsible Corporations in Canada** 2010
- **Outstanding Corporate and Employee Campaign Award** (United Way/Centraide Central New Brunswick for Enbridge Gas New Brunswick) 2010, 2011

STRATEGY AND PROFILE

ORGANIZATIONAL PROFILE

Enbridge Inc. is a leader in energy transportation and distribution in North America. As a transporter of energy, Enbridge operates the world's longest crude oil and liquids transportation system. In 2011, Enbridge delivered an average of approximately 2.3 million barrels per day of crude oil along its Mainline system to customers in Canada and the United States.

Enbridge also has a significant and growing involvement in natural gas gathering, transmission and midstream businesses, and an increasing involvement in power transmission.

As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State.

As a generator of energy, Enbridge has interests in close to 1,000 megawatts of renewable and alternative energy generating capacity and is expanding its interests in wind and solar energy, geothermal and hybrid fuel cells.

As at September 30, 2012, Enbridge had over 7,500 permanent employees and over 2,500 part-time, temporary and contract employees in Canada and the United States.

OPERATIONS AND ASSETS

Enbridge's activities are carried out through five business units: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments; and Corporate.

Liquids Pipelines – consists of common carrier and contract crude oil, natural gas liquids (NGLs) and refined products pipelines and terminals in Canada and the United States, including the Enbridge System, the Enbridge Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline interest and other feeder pipelines.

Gas Distribution – consists of natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD), which serves residential, commercial and industrial customers, primarily in central and eastern Ontario. This business unit also includes natural gas distribution activities in Quebec, New Brunswick and northern New York State.

Gas Pipelines, Processing and Energy Services – consists of investments in natural gas pipelines and processing facilities, renewable energy projects, Canadian midstream businesses, Enbridge's energy services businesses and international activities.

Investments in natural gas pipelines include Enbridge's interests in the United States portion of Alliance Pipeline (Alliance Pipeline U.S.), Vector Pipeline, and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include Enbridge's interest in Aux Sable, a natural gas fractionation and extraction business, and an interest in the development of Cabin Gas Plant in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico system. The energy services businesses manage Enbridge's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

Sponsored Investments – includes Enbridge's 23.0 per cent ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7 per cent investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP), and an overall 69.2 per cent economic interest in Enbridge

Income Fund (EIF), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. (EIFH). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of EIF include a crude oil and liquids pipeline and gathering system, a 50 per cent interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

Corporate – consists of the Enbridge's investment in Noverco Inc. (Noverco), new business development activities, corporate investments, and financing costs not allocated to the business units.

REPORT PARAMETERS

REPORT PROFILE

Enbridge's 2012 Corporate Social Responsibility (CSR) Report predominantly focuses on data collected and events that took place in 2011, although some significant events that took place in the first half of 2012 are also covered. Enbridge prepares a CSR Report each year. We published our previous CSR Report, which focused primarily on 2010 data, in October 2011.

Enbridge's 2012 CSR Report covers only information on the assets that Enbridge operates. The word "Enbridge" refers to the entire company, its subsidiaries and affiliates. Where possible, the data and statistics refer collectively to all of the facilities that Enbridge operates. However, when we report information pertaining to a specific company, business unit or project—for example, Liquids Pipelines or Enbridge Gas Distribution—we note it in the text.

Dollar figures refer to Canadian dollars unless otherwise indicated.

Enbridge's 2012 CSR Report was prepared using the Global Reporting Initiative (GRI) G3.1 sustainability reporting guidelines. These guidelines are intended to serve as a generally accepted framework for reporting on an organization's economic, environmental and social performance. They were designed for use by organizations of any size, sector or location and take into account the practical considerations faced by organizations ranging from small enterprises to those with extensive and geographically dispersed operations. The GRI guidelines contain general and sector-specific content that has been agreed on by a wide range of stakeholders around the world to be generally applicable for reporting an organization's sustainability performance.

To ensure that we have provided a balanced and reasonable presentation of our CSR performance, when determining the content for this report, we followed the GRI's "Reporting Guidance for Defining Content," which can be summed up in the following steps:

1. Identify the relevant topics
2. Determine the materiality of each topic by taking into account the external and internal factors suggested by the GRI
3. Prioritize the topics based on these factors and on an analysis of stakeholders

In addition to its "Reporting Guidance for Defining Content," the G3.1 Sustainability Reporting Guidelines include "Reporting Principles for Defining Content." These principles are: materiality, stakeholder inclusiveness, sustainability context and completeness.

To determine the materiality of the information that we included in our 2012 CSR Report, we took into account the following factors:

- The sustainability interests and topics raised by Enbridge's stakeholders
- The main concerns and future challenges facing the energy sector
- Relevant laws, regulations, international agreements and voluntary agreements of significance to Enbridge and our stakeholders
- Recognized impacts, risks and opportunities that affect sustainability
- Enbridge's values, policies, strategies, management systems, goals and targets
- Enbridge's stakeholders' interests and expectations
- Significant risks facing Enbridge

- The critical factors that enable Enbridge's success
- Enbridge's core competencies and the manner in which they could contribute to sustainable development

With these factors in mind, members of each of Enbridge's CSR Expert Reporting Groups:

- Aboriginal Relations
- Community Investment
- Community & Landowner Relations
- Economic Benefits
- Environment & Climate Change
- Governance
- Health & Safety
- Systems Integrity

met during the spring of 2012 to review which topic areas were most material to Enbridge's 2012 CSR Report, based on stakeholder interest and business impact. Enbridge's CSR Expert Reporting Groups comprise subject-matter experts in various areas of the company.

Enbridge amalgamated the topic areas into three materiality matrices: one for economic, one for environmental and one for social, as follows:

Economic Materiality Matrix				
		Low	Medium	High
Stakeholder Interest	High			• Economic benefit to: • Customers • Aboriginal communities • Communities • Shareholders/Investors
	Medium		• Economic benefit to: • Employees • Governments	• Economic benefit to suppliers • Financial implications of climate change
	Low			
	Business Impact			

Environmental Materiality Matrix				
		Low	Medium	High
Stakeholder Interest	High		• Air emissions • Fines/penalties	• GHG emissions • Energy use • Investing in renewables • Spills and releases/ Prevention and response • Pipeline integrity • Process safety • Emergency response • Public awareness and communication • Compliance with laws and regulations
	Medium	• Water use • Environmental expenditures • Land use	• Biodiversity/Habitat protection • Reclamation • Hazardous waste • Pipeline route selection	• Remediation • Facility maintenance
	Low	• Material use • Water discharges • Non-hazardous waste • Transport	• Facility design	
	Business Impact			

Social Materiality Matrix				
		Low	Medium	High
Stakeholder Interest	High		• Employee wellness	• Training and development • Employee compensation • Employee engagement • Succession management • Injury rates • Stakeholder engagement • Landowner relations • Process safety management • Contractor safety management • Emergency response • Aboriginal rights
	Medium	• Career transition services	• Diversity • Discrimination • Pay equity • Disease prevention/Industrial hygiene • Traditional knowledge	• Employee turnover • Performance management • Recruitment • Community development and investment • Facility maintenance
	Low	• Unions • Child labour/Forced labour	• Internal stakeholder engagement	• Absenteeism
	Business Impact			

The results of these exercises have influenced the structure and content of Enbridge's 2012 CSR Report microsite, as well as the level of detail and analysis the company provides for each topic area. For example, Enbridge has provided the greatest level of detail and analysis for topic areas that the CSR Expert Reporting Groups have determined to have high stakeholder interest and high business impact.

The CSR Expert Reporting Groups review the matrices each year to ensure that the company accounts for shifting levels of stakeholder interest and business impact.

To ensure that the information we included in our 2012 CSR Report met stakeholder inclusiveness guidelines, we applied the following tests suggested by the GRI:

- Enbridge can describe the stakeholders to whom it considers itself accountable
- The report content draws upon the outcomes of stakeholder engagement processes used by Enbridge in its ongoing activities and as required by the legal and institutional framework in which the company operates
- The report content draws upon the outcomes of any stakeholder engagement processes undertaken specifically for the report
- The stakeholder engagement processes that inform decisions about the report are consistent with the scope and boundary of the report

Enbridge's content passed these tests because it engaged the input of key employees through the CSR Expert Reporting Groups that it formed in early 2009.

The mandate of the CSR Expert Reporting Groups is to serve as the main providers of information for Enbridge's CSR Reports and to ensure the accuracy of the information provided. The Groups are also responsible for generating new ideas, discussing issues associated with the information gathering process and resolving these issues.

Enbridge's content also passed the stakeholder pertinence tests based on an exercise that we hired Canadian Business for Social Responsibility (CBSR) to complete several years ago. CBSR is a business-led, non-profit CSR consultancy and peer-to-peer learning organization that counsels its members on how to improve CSR performance. Through this stakeholder mapping exercise, we determined that Enbridge's stakeholders include:

- Associations and civil society groups
- Employees, contractors, unions, Board of Directors
- CSR rating organizations such as the Dow Jones Sustainability Index and Jantzi Research
- Customers
- Environmental and other non-governmental organizations
- Governments and government regulatory bodies in Canada and the U.S.
- Landowners
- Media
- Right-of-way communities, including Aboriginal and Native American communities
- Shareholders (retail and institutional investors)
- Debt holders

To determine the sustainability context of the information we included in our 2012 CSR Report, we applied the tests suggested by the GRI:

- Enbridge presents its understanding of sustainable development and draws on objective and available information as well as on measures of sustainable development for the topics covered in the report
- Enbridge presents its performance with reference to broader sustainable development conditions and goals, as reflected in recognized sectoral, local, regional and/or global publications
- Enbridge presents its performance in a manner that attempts to communicate the magnitude of its impact and contribution in appropriate geographical contexts
- Enbridge's report describes how sustainability topics relate to long-term organizational strategy, risks and opportunities, including supply-chain topics

To determine the completeness of the information we included in our 2012 CSR Report, we applied the tests suggested by the GRI:

- The report was developed taking into account the entire chain of entities upstream and downstream and covers and prioritizes all information that should reasonably be considered material on the basis of the principles of materiality, sustainability context and stakeholder inclusiveness
- The report includes all entities that meet the criteria of being subject to control or significant influence of Enbridge unless otherwise declared
- The information in the report includes all significant actions or events in the reporting period and reasonable estimates of significant future impacts of past events when those impacts are reasonably foreseeable and may become unavoidable or irreversible
- The report does not omit relevant information that would influence or inform stakeholder assessments or decisions, or that would reflect significant economic, environmental and social impacts

Enbridge's CSR Report covers the activities of each of its business units, but focuses on the assets that the company operates.

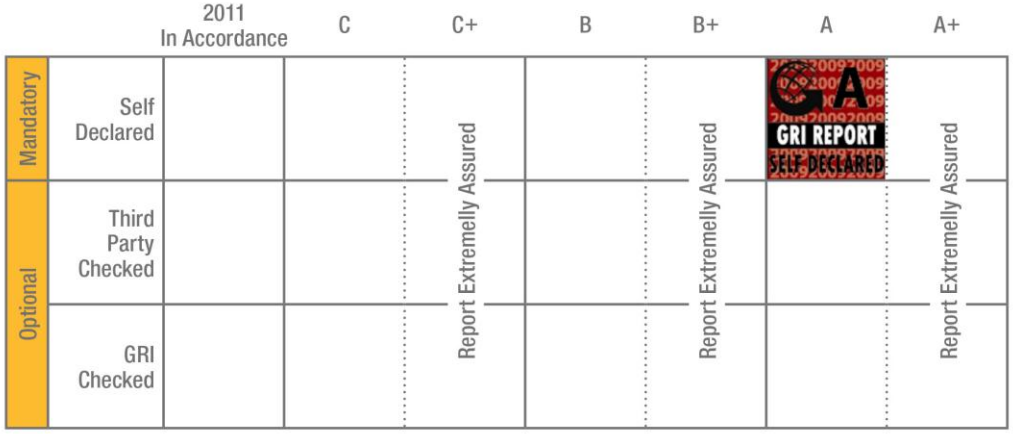
GRI CONTENT INDEX

The following table identifies the location of the GRI Standard Disclosures on Enbridge's website, www.enbridge.com/csr2012.

GRI Standard Disclosure	Web version (web page)
Strategy and Analysis (1.1 – 1.2)	**Strategy & Profile**
Organizational Profile (2.1 – 2.10)	**Organizational Profile**
Report Parameters (3.1 – 3.13)	**Report Parameters**
Governance, Commitments and Engagement (4.1 – 4.17)	**Governance, Commitments and Engagement**
Disclosure of Management Approach, per category	**Strategy & Profile, Economic Performance, Environmental Performance, Social Performance**
Core Performance Indicators	**Strategy & Profile, Economic Performance, Environmental Performance, Social Performance**

In preparing our 2012 CSR Report, we have addressed all of the GRI G3.1 Performance Indicators. We have also responded to each core G3.1 Indicator with due regard to the G3.1 "Materiality Principle." As a result of having met these requirements, and as per the Report Application Levels grid shown below, Enbridge has self-declared this report to be at the "A" application level. For more information on the GRI application levels, please visit https://www.globalreporting.org/reporting/reporting-framework-overview/application-level-information/Pages/default.aspx.

Report Application Levels



Data Quality Statement

The information contained in the Enbridge 2012 Corporate Social Responsibility Report was supplied by subject matter experts from each of Enbridge's business units. Where relevant, key information was sourced from Enbridge's 2011 Annual Report. Enbridge's internal auditors reviewed the statistics associated with Enbridge's energy consumption, greenhouse gas emissions, and spills and releases, health and safety performance and human resources statistics.

GOVERNANCE, COMMITMENTS AND ENGAGEMENT

GOVERNANCE (ENBRIDGE INC.)

Enbridge employs a variety of policies, programs and practices to manage corporate governance.

Enbridge Inc.'s common shares are listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE). Both exchanges have corporate governance guidelines or rules that apply to entities listed on their respective exchanges. Canadian securities regulators and the U.S. Securities and Exchange Commission have enacted or propose to enact additional corporate governance requirements.

Enbridge complies with all corporate governance rules now applicable to it and intends to comply with any new or additional corporate governance standards that will apply to it in the future.

BOARD OF DIRECTORS

Enbridge's Board of Directors functions independently of management and is accountable to its shareholders. With the retirement of Patrick D. Daniel as Director/President and CEO on September 30, 2012, Enbridge's Board of Directors comprises 12 Directors, 11 of whom are considered to be independent and one of whom, Al Monaco, serves as Enbridge's President and CEO.

The Enbridge Board of Directors is ultimately responsible for governance at Enbridge and for Enbridge's overall stewardship. The Board has full power to oversee Enbridge's business affairs and management, particularly in key areas such as governance, strategic planning, risk management, succession planning and corporate disclosure.

The Board:

- reviews and approves the strategic plan and provides guidance and monitors Enbridge's progress;
- monitors Enbridge's risk management programs and helps Enbridge identify principal risks;
- makes sure Enbridge has appropriate internal control and management systems in place to manage money, compliance and risk and that these systems are functioning appropriately;
- approves major projects, plans and initiatives that could materially affect Enbridge;
- approves all of Enbridge's major corporate communications policies, including Enbridge's corporate disclosure guidelines and all corporate disclosure documents; and
- appoints the CEO and other members of senior management, monitors senior management's performance and reviews the succession strategy for all senior management positions every year.

BOARD COMMITTEES

Enbridge's Board has four standing committees:

Audit, Finance & Risk Committee – The principal function of this committee is to review Enbridge's quarterly and annual financial statements and recommend their approval or otherwise to the Board. Committee members, who are required to possess financial knowledge and experience, are also responsible for recommending the appointment of Enbridge's external auditor and for compensating, retaining and overseeing the external auditor. The external auditors report directly to the committee. The committee also supervises internal audit functions and monitors disclosure in the financial statements, communicates directly with both internal and external auditors, has overview responsibility for management reporting on internal controls, and meets with external auditors and internal auditors independently of management to discuss, among other things, their qualifications, independence and objectivity. The committee also recommends the approval of news releases of financial results, reviews all financial information and financial statements, reviews the Management Discussion & Analysis section of Enbridge's quarterly and annual

financial reports and reviews the Annual Information Form. The committee also reviews the issue of equity or debt securities of Enbridge and oversees the filing of prospectuses or related documents with securities regulatory authorities.

The Audit, Finance & Risk Committee, together with the Board, also oversees an annual review of the principal risks to Enbridge, monitors Enbridge's risk management program and reviews risks in conjunction with internal and external auditors.

U.S. securities regulators also impose requirements on the functions of Enbridge's audit committee and Enbridge must comply with NYSE requirements for listed companies.

Corporate Social Responsibility Committee – The CSR Committee monitors and oversees recommendations with respect to human rights, stakeholder relations, community investment, and the environment, health and safety policies, practices and procedures of Enbridge and its subsidiaries. Included in its environment, health and safety mandate is the responsibility to: monitor and oversee recommendations regarding risk management guidelines; monitor practices and procedures followed in the conduct of operations to prevent injury to corporate and third-party persons and property, as well as to minimize any adverse impact; monitor and oversee policies, practices and procedures related to documentation of regulatory approvals, compliance and incidents; monitor and oversee emergency response planning and procedures; and review the communication methods used for applicable practices and procedures. The committee oversees an environmental risk management system, monitors its operation, and conducts regular site visits and orientation sessions to personally acquaint members of the committee and the Board with Enbridge's operating staff and facilities.

Governance Committee – The Governance Committee is mandated to be responsible for, and to make recommendations to, the Board concerning Enbridge's overall governance. Included in its mandate is the responsibility to define and review the mandates for the various Board committees, recommend the nomination of directors to Board committees, develop Enbridge's approach to governance issues, set corporate governance guidelines for the Board and assume responsibility for Enbridge's response to those guidelines.

The Governance Committee also has a process to monitor the quality of, and recommend changes to, the relationship between and among the Board, its committees and management, including the assessment of the performance of the Board as a whole and its committees, assessment of the Chair of the Board, as well as reviewing the contributions of individual directors.

One of the Governance Committee's objectives is to nominate a balanced mix of members to the Board who have the necessary experience and expertise to make a meaningful contribution in carrying out duties on behalf of the Board. The Governance Committee sets guidelines for recruiting new talent with criteria for relevant expertise, senior management experience or other qualifications, recognizing Enbridge's diversity goal of having more women and visible minorities on the Board.

The Governance Committee is also mandated to review and recommend to the Board the adequacy and form of remuneration of directors, and to ensure that the Board functions independently of management.

Human Resources & Compensation Committee – The Human Resources & Compensation Committee is responsible for reviewing and advising the Board on systems and effectiveness relating to employment, succession planning and remuneration of employees and officers.

The committee monitors the performance of senior management, oversees intellectual capital risk to ensure that management programs deal with succession planning and employee retention, and reports to the Board on organizational structure and succession planning matters. The committee reviews and monitors executive development programs, defines the Chief Executive Officer's responsibilities, and approves the Chief Executive Officer's objectives on an annual basis.

EXECUTIVE AND DIRECTOR COMPENSATION

Enbridge has a pay-for-performance philosophy and compensation programs for senior management, including the executive team, that are aligned with corporate and shareholder interests.

To attract and retain top talent, target total compensation is set around the median of the competitive market and a significant portion of total direct compensation is dependent on actual performance measured against short- and long-term performance goals, as approved by the Board.

Short-term incentive compensation for senior management is based on company, business unit and individual performance. Effective in 2011, company performance is measured by an annual earnings per share (EPS) target, as this metric best reflects Enbridge's overall corporate performance on an annual basis. EPS features prominently in the company's quarterly results discussions with external stakeholders and it is a metric that is broadly accepted by

investment analysts and shareholders.

Business unit performance measures encompass a variety of metrics, including safety and system integrity. In addition, workplace health and safety and environmental performance are among the key performance indicators that the Human Resources & Compensation Committee of the Board reviews each year.

Longer-term incentives include performance-based components that create a strong linkage to earnings growth and share price appreciation.

Enbridge compensates its directors (other than the President and CEO) in accordance with its directors' compensation plan. The main objectives of that plan are to attract and retain the most qualified individuals to serve as directors, to compensate directors to reflect the risks and responsibilities they assume when serving on the Board and Board Committees, and to offer directors compensation that is competitive with other comparable public companies. A further objective is to align the interests of directors with those of Enbridge's shareholders.

Enbridge's directors' compensation plan is based on annual retainers, rather than pay-for-performance. Annual retainers are paid in order to meet the directors' compensation objectives and help ensure the directors are unbiased when making decisions and carrying out their duties. While directors may elect to receive the annual retainer in the form of cash, Enbridge shares or Deferred Share Units (DSUs), a minimum portion of the retainer must be received in the form of DSUs. The DSUs serve to align the directors' interests with those of shareholders as the monetary benefit parallels the benefits received by the shareholders and cannot be accessed until directors resign from the Board.

For more information on corporate governance practices at Enbridge Inc., please visit http://www.enbridge.com/InvestorRelations/CorporateGovernance.aspx. For information on governances practices associated with Enbridge Income Fund Holdings Inc., please visit http://www.enbridgeincomefund.com/; with Enbridge Energy Partners, please visit http://www.enbridgepartners.com/EEP/; and with Enbridge Energy Management, please visit http://enbridgemanagement.com/EEQ/.

COMMITMENTS TO EXTERNAL INITIATIVES

United Nations Principle 15, the "Precautionary Approach."

With the goal of establishing a new and equitable global partnership through the creation of new levels of cooperation among states, societies and people, and recognizing the integral and interdependent nature of the Earth, the United Nations adopted 27 principles at its Conference on Environment and Development in Rio de Janeiro in June 1992. Among these was Principle 15, the "Precautionary Approach," which states that:

> In order to protect the environment, the precautionary approach shall be widely applied by States according to their capabilities. Where there are threats of serious or irreversible damage, lack of full scientific certainty shall not be used as a reason for postponing cost-effective measures to prevent environmental degradation.

While Enbridge has not formally adopted the precautionary approach, the company has informally done so by developing renewable and alternative energy solutions—in the form of wind, solar and geothermal power, waste heat recovery and integrated fuel cell technology.

Enbridge has also committed to stabilizing its environmental footprint at January 2009 levels in the areas on which the company has the greatest impact: on the trees it removes, the natural habitat it permanently alters, and the energy it uses to power its operations.

To that end, in May 2009, Enbridge announced that it would commit to three "Neutral Footprint" goals. Enbridge will:

1. Plant a tree for every tree it removes to build new pipelines and facilities
2. Conserve an acre of land for every acre of natural habitat it permanently impacts
3. Generate a kilowatt of renewable power for every kilowatt of power its operations consume

In June 2011, Enbridge created a Neutral Footprint dashboard, which shows where the company stands with regard to these three commitments. Enbridge updates the dashboard quarterly.

Externally developed economic, environmental and social charters, principles, or other initiatives to which Enbridge subscribes or endorses.

Enbridge recognizes the increasing public demand for corporations to be accountable and transparent in all of their business activities and to be seen as proactively dealing with the issues of the day. With that in mind, and in keeping with our commitment to transparency and CSR, in 2002, Enbridge adopted the Voluntary Principles on Security and Human Rights, which deals with responsible corporate action in conflict zones. We have incorporated these principles into our Statement on Business Conduct.

In addition, in 2003, Enbridge became a signatory to the United Nations Global Compact and committed to following its principles. The Compact is an initiative that brings companies together with UN agencies, labour and civil society to support principles in the areas of human rights, labour and the environment. Enbridge has committed to support and advance the Global Compact's principles and to make them part of its strategy, culture and daily operations.

Memberships in associations and advocacy organizations in which Enbridge has positions in governance bodies, participates in projects or committees, provides substantive funding, or views membership as strategic.

Enbridge maintains membership or associate status in a number of associations and advocacy organizations, including:

- Alberta Chamber of Commerce
- Alberta Emerald Foundation
- American Association of Oil Pipelines
- American Gas Association
- American Petroleum Institute
- Association for Financial Professionals
- Atlantic Centre for Energy
- Business for Social Responsibility
- Canadian Association of Petroleum Producers
- Canadian Business for Social Responsibility
- Canadian Chamber of Commerce
- Canadian Defense and Foreign Affairs Institute
- Canadian District Energy Association
- Canadian Energy Efficiency Alliance
- Canadian Energy Pipeline Association
- Canadian Gas Association
- Canadian Petroleum Tax Society
- Canadian Solar Industries Association
- Canadian Standards Association
- Canadian Wind Energy Association
- Circle for Aboriginal Relations
- Common Ground Alliance
- Conference Board of Canada
- Energy Council/Center for Environmental Energy Research
- Energy Council of Canada
- Globe Foundation EXCEL Partnership
- International Institute for Sustainable Development
- International Pipeline Conference Foundation

- Interstate Natural Gas Association of America
- London Benchmarking Group Canada
- National Association of Corrosion Engineers
- National Petroleum Council
- North Dakota Petroleum Council
- Northeast Gas Association
- Ontario Energy Association
- Petroleum Technology Alliance Canada
- Pipeline Research Council International
- Smart Commute Initiative (Toronto)
- Southern Gas Association
- Superior-Douglas Chamber of Commerce
- Texas Association of Business
- Texas Oil & Gas Association
- Texas Pipeline Association
- Texas Taxpayers and Research Association
- Three Rivers Manufacturers Association
- U.S. Oil & Gas Association
- University of Alberta Advisory Committee, Canadian Centre for Corporate Social Responsibility
- Will County Center for Economic Development (Joliet, IL)
- Wisconsin Manufacturers & Commerce
- Wisconsin Taxpayers Alliance

STAKEHOLDER ENGAGEMENT

To ensure that a variety of stakeholder views were incorporated into this report, Enbridge engaged the input of key employees (many of whom have direct access to various stakeholders) through the CSR Expert Reporting Groups that Enbridge formed in early 2009.

The mandate of the CSR Expert Reporting Groups is to serve as the main providers of information for Enbridge's CSR reports and to ensure the accuracy of the information provided. The Groups are also responsible for discussing issues associated with the information gathering process and for resolving these issues.

In 2008, we also contracted with Canadian Business for Social Responsibility (CBSR) to lead us through an exercise to help us identify our key stakeholders and to consult with them about Enbridge's CSR performance. CBSR is a business-led, non-profit CSR consultancy and peer-to-peer learning organization that counsels its members on how to improve CSR performance. Through this exercise, we determined that our stakeholders included:

- Associations and civil society groups
- Employees, contractors, unions, Board of Directors
- CSR rating organizations such as the Dow Jones Sustainability Index and Jantzi Research
- Customers (of Enbridge's pipeline and gas distribution businesses)
- Environmental and other non-governmental organizations
- Governments and government regulatory bodies in Canada and the U.S.
- Landowners

- Media
- Right-of-way communities, including Aboriginal and Native American communities
- Shareholders (retail and institutional investors)

As part of the exercise, CBSR interviewed representatives from the following stakeholder groups regarding their perceptions of Enbridge's 2007 CSR Report and of the company's CSR activities in general:

- Enbridge Board of Directors (CSR Committee)
- Saskatchewan Association of Pipeline Landowners Inc. (SAPL)
- Upstream customers (Nexen)
- National Energy Board
- London Benchmarking Group (LBG) Canada
- University of St. Michael's College
- Conference Board of Canada
- Pembina Institute

Enbridge's business units identify and select stakeholders with whom to engage by (a) defining the scope of a project and what impact it could have on other parties that have a direct correlation with the project's geographical vicinity/scope and (b) determining which regulatory bodies have jurisdiction over any proposed projects and what are the regulatory requirements for notification.

When identifying stakeholders with whom to engage in a given project, Enbridge aims to meet or exceed regulatory requirements regarding public consultation. We also aim to be open and transparent in our communication to stakeholders.

Enbridge engages stakeholders proactively and on an ongoing basis.

The company engages certain stakeholders (e.g. landowners, Aboriginal communities) early in the project planning process to ensure specific concerns are addressed so that the company can effectively address and resolve issues and adjust plans wherever necessary. These same stakeholders are often formally engaged later on during the regulatory review process.

Communication with stakeholders continues throughout the project cycle (regulatory review to construction to operation) in order to inform stakeholders and identify opportunities and issues.

Enbridge engages key stakeholders who live along our existing rights-of-way or close to an Enbridge renewable energy facility in both Canada and the U.S. through our Public Awareness Program. In all our stakeholder engagement efforts, including those aimed at Enbridge Gas Distribution customers, we utilize a full range of communication channels, including:

- Direct-mail brochures and letters
- Websites, with specific pages for projects, pipeline public awareness and safety, pipeline integrity, community investment and more
- A sustainability blog for employees
- Social media sites, including Facebook, Twitter and YouTube
- Toll-free telephone information lines
- Advertising
- News releases and media briefings
- Exhibits
- Videos
- Public meetings/open houses and face-to-face meetings with public officials
- Tours
- Community sponsorships and support from Enbridge employees for community events
- Emergency responder exercises
- Outreach programs to excavators

Through our stakeholder engagement activities, Enbridge addresses a broad range of topics and responds to a variety of questions and concerns, including:

- The relevance and importance of CSR in relation to Enbridge's core values (Integrity. Safety. Respect.)
- Construction timelines
- Impact of construction on communities
- Economic opportunities and benefits and compensation
- Environmental impacts of construction and environmental protection measures
- Potential impacts of a project on Aboriginal rights
- Emergency response and safety procedures
- Post-construction pipeline integrity maintenance and right-of-way restoration and maintenance

In the U.S., Enbridge is involved in the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) Pipelines and Informed Planning Alliance program, which is a multi-stakeholder consensus effort to develop best practices for development near pipelines and for assuring that those who host pipelines on their property understand how those pipelines are operated and what pipeline companies do to protect their near neighbours.

OVERALL MANAGEMENT APPROACH TO CORPORATE SOCIAL RESPONSIBILITY

Enbridge defines CSR as conducting business in a socially responsible and ethical way; protecting the environment and the health and safety of people; supporting human rights; and engaging, respecting and supporting the communities and cultures close to the company's operations.

CSR POLICIES AND VALUES STATEMENT

Enbridge has adopted a Corporate Social Responsibility Policy that covers business ethics and transparency; environment, health and safety; stakeholder relations; employee relations; human rights; and community investment. This policy applies to activities undertaken anywhere in the world by, or on behalf of, Enbridge and our subsidiaries and affiliates, whose operations we manage.

Enbridge also conducts business in accordance with our Statement on Business Conduct, which outlines our commitment to specific standards of conduct expected of our directors, officers, employees, consultants and contractors in all countries in which Enbridge conducts business. As well, a variety of other policies and related documents provide direction for specific activities that pertain to CSR. They are:

- Environment, Health and Safety Policy
- Aboriginal and Native American Policy
- Climate Change Policy
- Voluntary Principles on Security and Human Rights
- Community Investment Program Criteria and Guidelines

Enbridge Values

Enbridge is building on our foundation of operating excellence by adhering to a strong set of core values—integrity, safety and respect—that reflect what is truly important to us as a company as we interact with communities, the environment, and each other. These values represent a constant guide by which we make our decisions, as a company and as individual employees, every day.

We convey Enbridge's values succinctly and effectively to employees so that they understand what it means to work for Enbridge and how we expect all employees to act when faced with decisions or choices. For new employees, our values provide a strong, clear and simple set of principles to help them integrate into the organization.

Enbridge's value statement is: Enbridge employees demonstrate Integrity, Safety and Respect in support of our Communities, the Environment and Each Other.

HUMAN RIGHTS

Enbridge believes that we must consistently and rigorously uphold the highest standards of human rights in all of our work.

To that end, we thoroughly assess potential social, economic and environmental impacts of all of our projects through socio-economic and environmental studies during which we consider:

- The biophysical elements of the terrestrial and marine environment, including key receptors that could potentially be affected
- The project's economic impacts, including its effects on the national, provincial and regional economy
- Aboriginal rights and interests, including the current use of lands and resources for traditional purposes by Aboriginal persons
- The safety of project workers, and the safety of the communities in which the project would operate
- Potential human health impacts, including changes in the natural environment that could affect the physical health of people

In evaluating these various areas of human rights, we view them from the perspective of our Corporate Social Responsibility Policy, to which we are ethically and morally bound. Under this policy:

- Enbridge recognizes that governments have the primary responsibility to promote and protect human rights, and that we will work with governments and agencies to support and respect human rights within our sphere of influence
- Enbridge will not tolerate human rights abuses, and will not engage or be complicit in any activity that solicits or encourages human rights abuse
- Enbridge will always strive to build trust, deliver mutual advantage and demonstrate respect for human dignity and rights in all relationships it enters into, including respect for cultures, customs and values of individuals and groups
- In addition, in assessing the various areas of human rights, we look at them through the lens of our status as a signatory to the United Nations Global Compact, and of our adoption of the Voluntary Principles on Security and Human Rights

The UN Global Compact is an initiative that brings companies together with UN agencies, labour and civil society to support principles in the areas of human rights, labour and the environment. In 2003, Enbridge committed to supporting and advancing the Global Compact's principles and to making them part of our strategy, culture and daily operations.

The Voluntary Principles on Security and Human Rights pertain to responsible corporate action in conflict zones. Enbridge adopted these principles in 2002, and we have incorporated them into our Statement on Business Conduct.

COMPLIANCE AND ETHICS (PRINCIPLE 10 OF UN GLOBAL COMPACT)

Enbridge is committed to working against corruption in all forms, including extortion and bribery. Enbridge's commitment in this regard is derived from one of its core values, *Integrity*.

The value of integrity is embodied in Enbridge's Statement on Business Conduct, which requires employees to make decisions and conduct Enbridge's business in a responsible, honest and ethical manner. Enbridge's Statement on Business Conduct and Whistleblower Policy require employees to report (either directly or anonymously) any fraudulent activities or potential or actual events that are non-compliant with applicable legal requirements or Enbridge policies. Additionally, Enbridge has established a Compliance Policy that defines clear responsibilities for Enbridge's Vice President & Chief Compliance Officer and the respective business unit compliance officers. Enbridge's compliance officers are charged with overseeing Enbridge's Compliance Program, which is designed to minimize unethical behavior and support and demonstrate Enbridge's commitment to corporate responsibility and good governance.

As part of its Compliance Program, Enbridge undertakes a number of best practices to monitor and improve upon its compliance and ethics culture:

1. Policies – Enbridge has established a number of governance policies that are designed to ensure its employees conduct their work activities in accordance with applicable laws. These policies include the Statement on Business Conduct, the Whistleblower Policy and the Compliance Policy.

2. Enbridge Ethics & Conduct Hotline – Enbridge provides information that is readily available to all employees and contract workers describing the avenues available to raise any ethical or compliance issues directly to the responsible

Compliance Officers or other managers. Additionally, Enbridge maintains an Ethics & Conduct Hotline (the Hotline) where such issues can be raised anonymously through a third-party provider, 24 hours a day, 365 days of the year. Each report received through the Hotline is provided directly to Enbridge's Vice President & Chief Compliance Officer, as well as the responsible business-unit compliance officer, and is investigated to address and resolve any issues raised in the report. In 2011, Enbridge received 34 new hotline reports, of which nine related to human resources issues, 15 related to allegations of misappropriation or misuse of assets, three related to safety issues, two related to financial concerns and five related to customer concerns or complaints.

3. Tone At the Top – While Enbridge has had a Chief Compliance Officer and three compliance officers in its primary functional business units since 2009, in early 2012 Enbridge made a change to its management structure that demonstrates an even greater emphasis on compliance and ethics. On April 1, 2012, Enbridge appointed its first stand-alone Vice President & Chief Compliance Officer, whose role is solely dedicated to the oversight of Enbridge's overall state of compliance and enhancing Enbridge's culture of ethics and integrity.

4. Audit – In 2011, the role of Enbridge's Audit Services Department was expanded to cover all operational and financial audits. The Audit Services Department plays a key role in monitoring Enbridge's state of compliance and assisting with investigations into any unethical conduct, including allegations of bribery, fraud and corruption. The Audit Services Department is also charged with measuring the administration and effectiveness of the Compliance Program, including the effectiveness and accuracy of internal compliance reporting.

5. Training – In 2011, all Enbridge employees received online training in relation to the Statement on Business Conduct. Other training varies by business unit, but considerable training was provided to employees in 2011 and is continuing in 2012 in relation to Fraud Awareness, Ethics for People Leaders, Respectful Workplace and anti-corruption laws. In the Liquids Pipelines business unit, 45 employees with compliance functions were brought together for a full day Compliance Summit to discuss current compliance processes and issues.

6. Compliance Investigations and Reports – Enbridge's compliance officers coordinate investigations of material compliance matters, whether they arise directly from employees, through an incident or via the Hotline. All material non-compliance matters are reported by the Vice President & Chief Compliance Officer to the Audit, Finance & Risk Committee of Enbridge's Board of Directors. Additionally, Enbridge has employees with expertise in relation to audits and investigations who are available to assist the company's compliance officers with any investigations into material non-compliance issues.

7. Non-Retaliation – Enbridge is committed to the principle that no retaliatory action may be taken against anyone who raises non-compliance issues in good faith. Adhering to the non-retaliation principle is a key component of a strong culture of compliance and it also ensures that employees, contract workers and the public can feel confident that issues will be fairly and impartially reviewed and addressed.

8. Metrics – Although metrics vary from one business unit to another, Enbridge's Liquids Pipelines business unit maintains a compliance index metric that ties ethical and compliant conduct to each employee's business unit bonus incentives, which acts as a continuous reminder to employees of the importance placed on ethical behavior.

9. Anti-Corruption & Compliance/Ethics Affiliations – Enbridge's compliance officers and other employees participate in a number of organizations that provide training and promote the advancement of ethical conduct in organizations throughout North America. Some of the organizations to which Enbridge or its employees belong include: Society of Corporate Compliance & Ethics (SCCE), Open Compliance & Ethics Group (OCEG), Association of Certified Fraud Examiners (ACFE) and the Corporate Ethics Management Council (Conference Board of Canada).

INNOVATION

As part of our CSR commitment, Enbridge believes that it is our responsibility to be continuously innovative. As the operator of one of the world's largest and most complex energy delivery systems, our job is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible. And, as a company that delivers such an important commodity—energy—we must continually search for innovative ideas and new approaches, both for our existing pipeline business, through innovative approaches to leak detection and prevention, and for the business we are building for the future.

Innovative approaches to leak detection and prevention

We know that moving hydrocarbons will be our core business for a long time to come. Given this reality, we are

committed to continuous improvements to the safety and integrity of our system, and to achieving the goal of zero incidents. To achieve this goal, in addition to our ongoing safety and system integrity improvements, we actively seek out world-class leak detection and risk mitigation technologies in which to invest, and which we can apply to our operations. As part of this work, we:

- Collaborate with universities, private companies and multi-national corporations to support research
- Plan and conduct field trials with industry
- Identify emerging, pre-commercial leak prevention and detection technologies
- Invest in companies to help them commercialize promising new technologies

In the area of collaborating with universities, private companies and multi-national corporations to support research, we provide research funding and in-kind support. For example, we are reviewing 20 proposals from Alberta universities and major international research corporations aimed at developing radical new technologies to help attain continuous, real-time leak detection for even the smallest of leaks. These proposals range from a University of Alberta research project engaged in exploring the use of unmanned aerial vehicles (UAVs) to detect leaks over our pipeline rights-of-way to the development of tiny nanosensor networks that would be affixed to pipelines and that would detect even minute hydrocarbon releases instantaneously.

With respect to planning and conducting field trials with industry, we are working with NYSEARCH, a natural gas research, development and demonstration organization headquartered in New York City. Through Enbridge Gas Distribution, Enbridge is a member of NYSEARCH, and is participating in a field trial that involves Picarro, a Silicon Valley-based company that has developed an ultra-high sensitivity gas “sniffer” that can be mounted on a vehicle and driven around to monitor for gas leaks. The “sniffer” would augment foot patrols and could reduce the time it takes to survey a pipeline right-of-way for leaks.

Another of our field trials involves working with Synodon, an Edmonton-based company that uses a technology that was used on NASA's Terra Polar orbiting satellite. Synodon has adapted the technology for leak detection applications, and is currently testing the technology.

From June 18 to 21, 2012, the two companies mentioned above—Picarro and Synodon—joined Enbridge, Pipeline Research Council International (PRCI), and several other participating companies—Pergam Technical Services, LaSen and New Era Technology—in Mineral Wells, Texas, to test a number of advanced aerial leak detection methods for pipelines. Each company possesses different abilities, and each put their particular technology to the test to determine how they could offer the most sensitive and accurate form of leak detection.

Enbridge and the PRCI ranked each of the technologies based on their ability to detect leaks and determine a leak’s concentration and location. A final report is expected to be ready at the end of October 2012. Based on the report’s findings, Enbridge will determine how best to improve our leak detection abilities.

In the area of identifying emerging, pre-commercial leak prevention and early detection technologies, Enbridge has been investigating other possible leak detection technologies, including fibre optics, micro electromagnetic sensors and vapour sensing tools.

And we’ve been investing in various companies to help enable them to commercialize promising new technologies. In August 2012, we invested C$1.5 million in Syscor Controls & Automation Inc., a small Victoria, B.C.-based company, to help it develop a gas sensing technology for use on above-ground storage tanks (ASTs). Enbridge hopes to use Syscor’s technology as a tool to help us identify leaks in our ASTs. Once its technology has been refined, Syscor will make it available to all interested companies, helping to improve the entire oil and gas industry.

Innovative approaches to building our future business

For Enbridge to be a thriving organization in the future, we know that we have to become a leader in renewable and alternative energy generation. To that end, we have been investing heavily in renewable energy. In a matter of 12 years, the value of our renewable power assets have grown to about $3 billion.

The majority of our renewable and alternative energy investments are in wind and solar energy projects in various locations throughout North America. Together, Enbridge’s portion of the wind and solar energy assets in which we have interests have the capacity to produce about 960 megawatts of clean electricity.

But we also invest in other technologies, projects and companies that will contribute to a cleaner energy future. These technologies, projects and companies range from our investments in Morgan Solar (a Canadian start-up that is working on next-generation solar technology) and Hydorgenics (a small company working on developing large-scale renewable electricity storage), to our involvement in geothermal and run-of-river hydro projects.

NEUTRAL FOOTPRINT COMMITMENTS

As part of our ongoing efforts to find innovative ways to improve our business, we have pledged to stabilize our initial footprint through the following "Neutral Footprint" commitments:

- We will plant a tree for every tree we remove to build new facilities.
- We will conserve an acre of land for every acre of wilderness we permanently impact.
- We will generate a kilowatt of renewable energy for every kilowatt our operations consume.

These commitments were designed to reduce our environmental impact where it is felt most: on the trees we remove, the natural habitat we permanently impact and the energy we consume to power our operations. So far, we have met almost 70 per cent of our "tree for tree" commitment; over 300 per cent of our "acre for acre" commitment; and about 115 per cent of our "kilowatt for kilowatt" commitment (based on our forecasted growth in power consumption to 2015).

By meeting these commitments, Enbridge will stabilize our environmental footprint at January 2009 levels.

ENTERPRISE SECURITY

Security Management Standard

To meet the requirements of the United States Transportation Security Administration (TSA) *Pipeline Security Guidelines* adopted in December 2010, and the Canadian Standards Association *Z246.1-09 Security management for the petroleum and natural gas industry systems* (September 2009), Enbridge's Enterprise Security group has developed a Security Management Standard. This Standard applies to all onshore transmission and distribution pipeline assets for both natural gas and liquids. The Standard brings a risk-based approach to the application of security measures throughout the company and provides criteria that business units use to assess security risks to their personnel and facilities. In addition, it establishes baseline security risk reduction measures that should be implemented at each facility—commensurate to the identified risk.

Enterprise Security provides oversight to the company's business units in the development of their business-specific security programs and policies and in the conduct of physical security assessments of their operations and facilities. In addition, Enterprise Security acts as the enterprise-wide security liaison for enforcement and regulatory agencies in Canada and the U.S. and participates on behalf of the enterprise in various industry and federal government-sponsored security committees and security advisory groups in Canada and the U.S.

Foreign Travel Protection Policy

While traveling to, within or from countries other than Canada and the United States for business purposes, Enbridge employees and contractors may be exposed to greater risks to their personal security. The purpose of the Foreign Travel Protection Policy is to reduce the exposure to personal security risks potentially faced by employees and contractors while traveling to a foreign country on Enbridge business. The policy considers the security of personnel and provides a mechanism by which information can be delivered to the employee about issues affecting their security.

Enterprise Security's responsibilities under this policy include ensuring employees receive the appropriate and necessary pre-departure briefings, facilitation of the requisite security arrangements when necessary, as well as the debriefing of the traveler following travel, as required. The Expatriate Protection Policy mandates that employees and family members be made aware of the security issues that may affect their personal security while residing and working in a foreign country and further, was designed to reduce their exposure to personal security risks. As determined by Enterprise Security, the expatriate employee and family may be subject to additional country-specific security requirements dependent on the location of their assignment.

ENBRIDGE'S 2012 CSR REPORT

The following three sections of this report focus on Enbridge's Economic, Environmental and Social Performance. The Social section is further divided into Labour Practices and Decent Work, Human Rights, Society and Product

Responsibility. Each of the main three sections includes a scorecard highlighting Enbridge's goals, targets and performance in key areas deemed to be of high stakeholder interest and high business impact, as well as information pertaining to the Performance Indicators prescribed by the Global Reporting Initiative (GRI) G3.1 Sustainability Reporting Guidelines.

ECONOMIC PERFORMANCE

NOTE: Throughout this Economic Performance chapter, 2010 financial results have been adjusted to account for the 2-for-1 stock split in May 2011

CSR IS INTEGRAL TO HOW WE RUN OUR BUSINESS AND IS AT THE HEART OF OUR ECONOMIC SUCCESS.

Society needs a secure and reliable supply of energy. We need energy to heat and light our homes, businesses, schools and hospitals. We need energy to move people, goods and information. Energy literally drives economies around the world.

This is where Enbridge fits in.

Enbridge's number one social responsibility is to deliver the energy North Americans need—crude oil and refined products, natural gas, environmentally responsible power—in the safest, most reliable and most efficient way possible.

We transport and deliver this energy through our infrastructure, connecting vital sources of supply with refiners and consumers across the North American continent. In doing so, we're playing a key role in the delivery of secure and reliable energy that supports economic stability and growth.

Enbridge's existing infrastructure extends throughout Canada and the United States. We operate the world's longest, most complex crude oil and liquids pipeline system, shipping more than two million barrels of crude oil and petroleum products every day; and in 2011, we successfully entered the power transmission business.

The company's natural gas gathering and transmission system spans the continent, from northern British Columbia to the ultra-deep water of the Gulf of Mexico, moving over six billion cubic feet of gas daily.

We also deliver clean-burning natural gas to consumers through Canada's largest natural gas distribution company, Enbridge Gas Distribution (EGD), which serves nearly two million customers and is adding approximately 35,000 new customers every year. EGD has been delivering energy to consumers for over 160 years.

We're also investing in renewable energy and alternative technologies to support society's desire for a lower impact energy future. We now have interests in close to 1,000 MW of renewable and alternative energy projects—eight wind farms, four solar farms, a geothermal facility, four waste heat recovery facilities, and a fuel cell power plant—that provide a broad platform from which to grow.

For Enbridge, CSR is also about ensuring the company's financial strength. Enbridge's future growth is predictable. The steady growth of our liquids pipelines, natural gas transportation and distribution, and renewable and alternative energy businesses have and will continue to drive strong earnings growth and even more significant cash flow growth in coming years. The company brought over $10 billion in projects into service in 2009 and 2010, as at year end 2011 had over $13 billion of capital to deploy on commercially secured projects in the 2011-2015 period, and had over $30 billion of additional projects under development. The secured projects provide the company with confidence in being able to achieve a 10 per cent average annual growth rate of adjusted earnings per share from 2010 through the middle of this decade.

Over the past 10 years, Enbridge's total shareholder return (TSR) has increased on average 17 per cent and the company is focused on maintaining this strong track record. In 2011 alone, our TSR reached 40 per cent, paying dividends of $0.98 a share, or a total of $759 million to Enbridge Inc. shareholders.

Enbridge also delivers significant and quantifiable direct economic benefits to employees

in the form of compensation, to communities in the form of donations and other investments, to governments in the form of taxes, and to customers in the form of access to markets and enhanced services.

Enbridge invests significantly in hundreds of charitable, non-profit and community organizations every year with the aim of building sustainable communities across our operating regions in Canada and the United States. We believe these investments—in 2011, they reached $13 million—are an essential part of being a good neighbour and are a contributing factor in maintaining the company's social license to operate.

Economic Scorecard Results			
Objectives	**2011 Results**	**2010 Results**	**Challenges**
1. Deliver superior long-term value to Enbridge shareholders as measured by Total Shareholder Return (TSR)	40% TSR in 2011 (for more details, please see Part 1 of the Economic Scorecard Commentary below)	20% TSR (for more details, please see the 2011 CSR report)	Enbridge's value proposition is based on maintaining a reliable business model. However, Enbridge's business activities are subject to various risks. For details about Enbridge's risk profile, please see the section titled "Risks" below, as well as GRI Performance Indicator section "EC2." For additional details on Enbridge's risk management practices and principal risks, please see the Risk Management section of Enbridge Inc.'s 2011 Annual Report.
2. Demonstrate high-quality and sustainable earnings per share growth	11% growth to $1.48 in adjusted earnings per common share (for more details, please see Part 2 of the Economic Scorecard Commentary below)	13% growth to $1.33 in adjusted earnings per common share (for more details, please see the 2011 CSR Report)	
3. Payout a high proportion of earnings in the form of a growing dividend stream to Enbridge shareholders	$0.98 per common share, an increase of 15% from 2010 (for more details, please see Part 3 of the Economic Scorecard Commentary below)	$0.85 per common share, up 15% from 2009 (for more details, please see the 2011 CSR Report)	
4. Establish a long-term track record of growth in supporting the communities in which Enbridge operates	Invested $13.0 million in more than 550 charitable, non-profit and community organizations (for more details, please see Part 4 of the Economic Scorecard Commentary below)	Invested $11.5 million in more than 350 charitable, non-profit and community organizations (for more details, please see the 2011 CSR Report)	

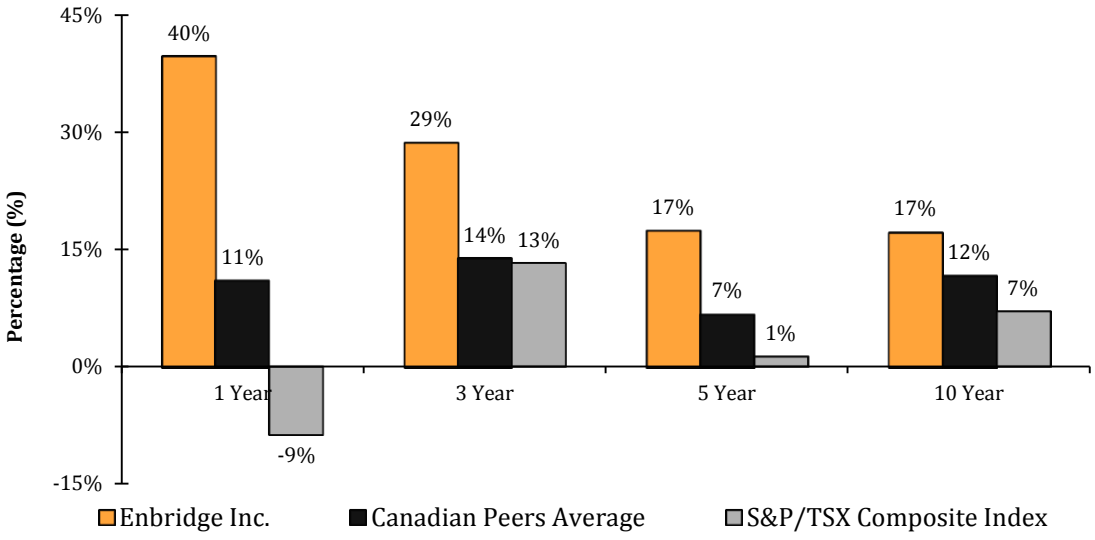
ECONOMIC SCORECARD COMMENTARY – 2011

1. DELIVER SUPERIOR LONG-TERM VALUE TO ENBRIDGE SHAREHOLDERS AS MEASURED BY TOTAL SHAREHOLDER RETURN (TSR)[1].

During 2011, Enbridge achieved a solid 40 per cent TSR as a result of the company's continued growth prospects, increasing dividend, and its lower risk profile when compared to its Peer Group[2] and the broader market index. Enbridge's Peer Group averaged a TSR performance of 11 per cent during 2011, while the TSX index actually lost ground during 2011. Further, over a longer term horizon (three, five and 10 years), Enbridge has consistently outperformed both the TSX index and the Peer Group as indicated in the chart below.

TOTAL SHAREHOLDER RETURN – TSX

As at December 31, 2011



1 Total Shareholder Return: the total return of a stock to an investor that includes both capital gains and re-invested dividends.

2 Peer Group: Canadian Utilities, Fortis, TransCanada, TransAlta and Emera.

2. *DEMONSTRATE HIGH-QUALITY AND SUSTAINABLE EARNINGS PER SHARE GROWTH.*

The diversity of Enbridge's businesses and strategic positioning of its assets contribute to the reliability of the company's growth. Adjusted earnings[3] per share (EPS) grew 11 per cent in 2011, and are expected to grow by 10+ per cent per year on average through the middle of the decade. In addition, Enbridge's track record for EPS growth over the last decade has averaged close to 10 per cent per year as indicated in the chart below.

10-YEAR ADJUSTED EARNINGS PER SHARE GROWTH



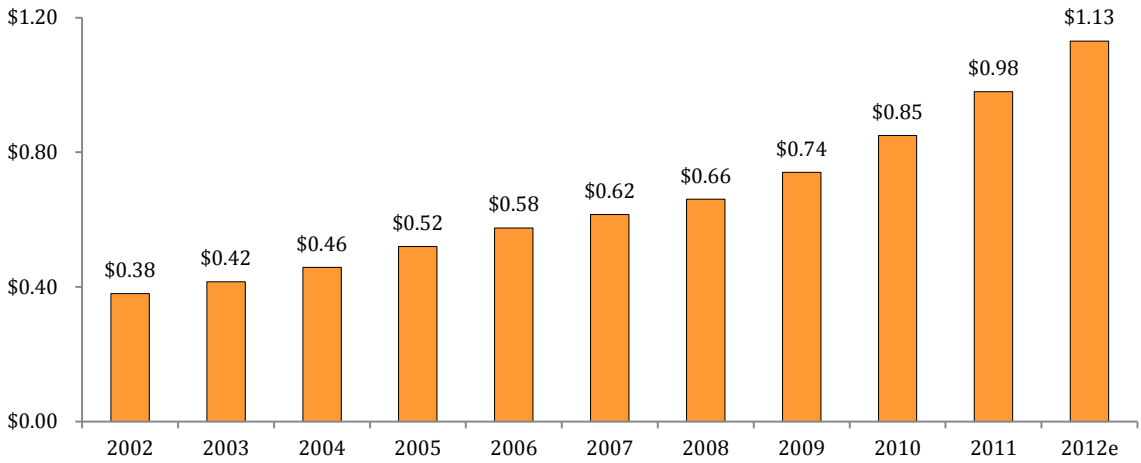
*2012 earnings per share guidance range: $1.58 to $1.74 (prepared under US GAAP).

3. Adjusted Earnings: This document contains references to adjusted earnings/(loss), which represent earnings or loss applicable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the company and set the company's dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by Canadian GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See the Non-GAAP Reconciliations section on page 76 of the 2011 year end Management Discussion & Analysis for a reconciliation of the GAAP and non-GAAP measures.

3. *PAYOUT A HIGH PROPORTION OF EARNINGS IN THE FORM OF A GROWING DIVIDEND STREAM TO ENBRIDGE SHAREHOLDERS.*

Enbridge's record in this category is unmatched in its sector. The 15 per cent dividend increase the company announced in December 2011 was its 17th consecutive annual increase. Over the last decade, Enbridge's dividend growth has significantly outperformed that of its peers and the company is focused on continuing this performance. It is expected that dividend growth will track or exceed earnings growth through the middle of the decade.

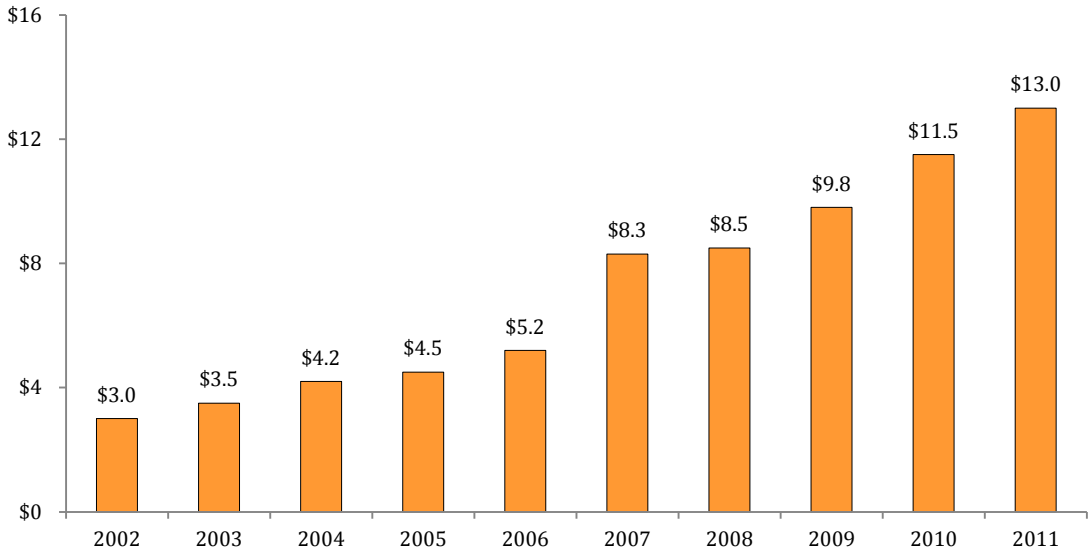
10-YEAR HISTORICAL DIVIDEND PER SHARE GROWTH



4. *ESTABLISH A LONG-TERM TRACK RECORD OF GROWTH IN SUPPORTING THE COMMUNITIES IN WHICH ENBRIDGE OPERATES.*

In 2011, Enbridge invested $13 million in charities, non-profit and community organizations. This investment amount is growing with corporate earnings, and represents approximately 1 per cent of Enbridge's profits.

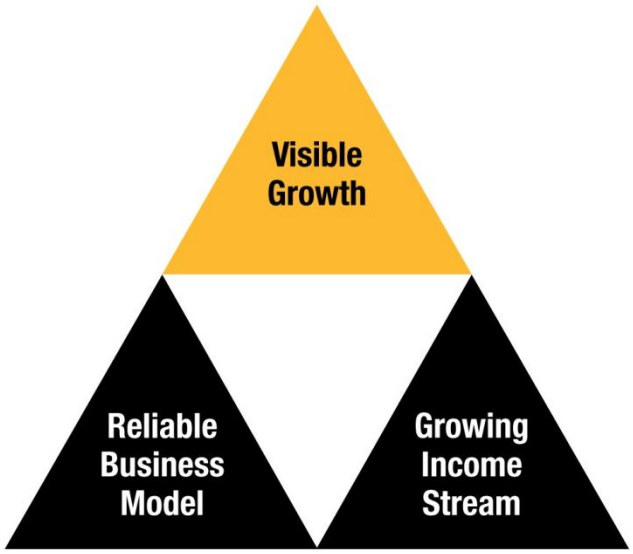
10-YEAR HISTORICAL COMMUNITY INVESTMENT ($ MILLIONS)



CORPORATE STRATEGY

Enbridge's Investment Proposition

Enbridge's unique investment proposition is based on an overarching strategy that brings together three desirable characteristics: Growth, Income and Reliability.



This combination has served the company and its shareholders well. Enbridge's long history of successfully implementing this strategy is evidenced by its sector leading total shareholder return, whether measured on a one-year, 10-year or even a 55-year basis.

Enbridge expects to continue to build on its strong track record of growth through the middle of this decade, with a full slate of potential investment opportunities that fit within the reliable business model that the company's investors have come to count on.

1. VISIBLE GROWTH

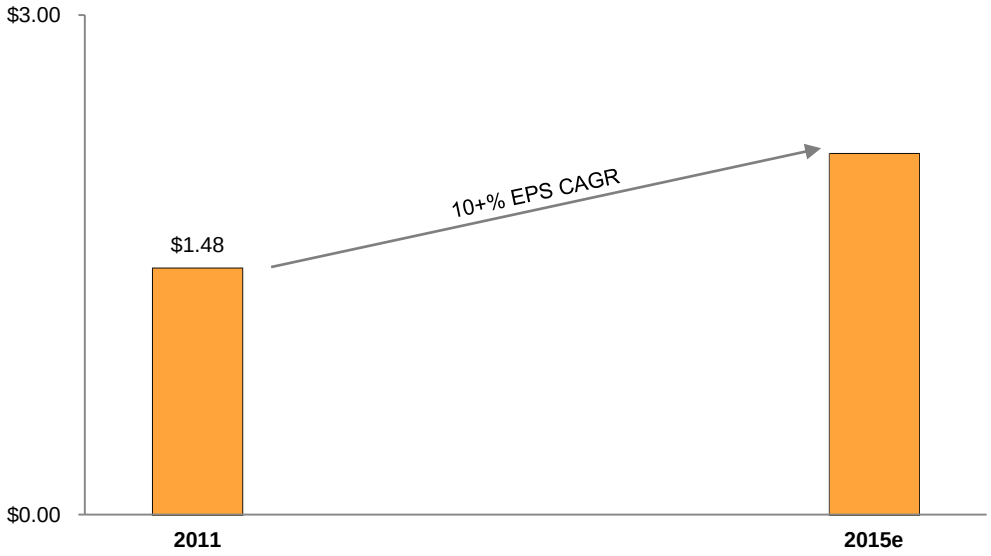
Enbridge's growth is driven by the ongoing need for new energy infrastructure development. In 2011 alone, Enbridge secured $8 billion in new growth projects across its business units. At year-end, Enbridge had $13 billion in secured growth projects, all of which are expected to be in service by 2015.

As a result of these new projects, earnings per share have grown steadily over time at an attractive rate. Further, given Enbridge's secured project inventory, we are very confident in achieving a 10+ per cent annual average adjusted EPS growth rate through 2015.

Earnings Growth

- 25 per cent EPS growth in 2009
- 13 per cent EPS growth in 2010
- 11 per cent EPS growth in 2011

LONG-TERM EARNINGS PER SHARE GROWTH



CAGR: Compound Annual Growth Rate

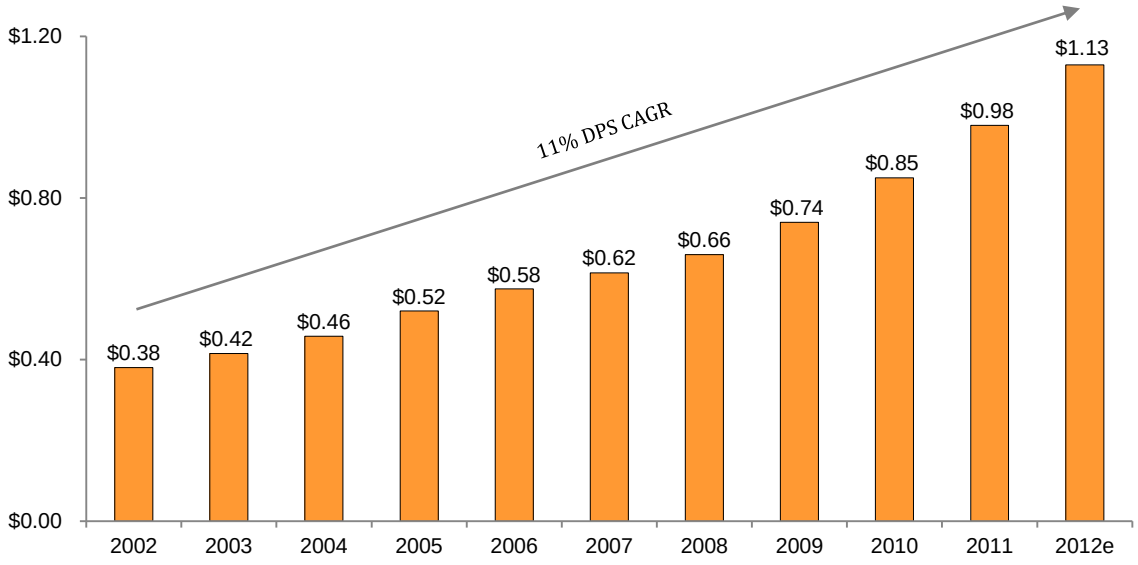
Along with higher EPS, the company's healthy slate of growth projects is expected to drive an even greater growth in its cash flows. Enbridge's ability to generate free cash flow adds further value to its shareholders by providing funding flexibility as well as opportunity for additional distribution increases.

2. GROWING INCOME STREAM

At no point in Enbridge's long history has it ever decreased its dividend payment. In fact, the dividend has been increased each of the last 17 years, and over the past decade the dividend has grown on average by 11 per cent. The dividend provides an attractive yield to the investor, and given the expected growth in earnings and free cash flow, Enbridge expects to continue to grow the dividend through the middle of the decade.

- 15 per cent dividend increase in 2010, 2011 and 2012
- Expected continued dividend growth in line with, or exceeding, earnings (10+ per cent per year)

DIVIDEND PER SHARE GROWTH 2002 – 2012e



DPS CAGR: Dividend per Share Compound Annual Growth Rate

3. RELIABLE BUSINESS MODEL

Enbridge looks to consistently structure its business to reliably deliver steady, visible and predictable results. This is evidenced in its contractual arrangements, its risk management frameworks, and its overall philosophy and approach to business. As a result, Enbridge's business model produces adjusted earnings you can count on.

- 90+ per cent of the company's revenues are generated from investment grade counterparties
- Less than 5 per cent of Enbridge's earnings are exposed to commodity price, interest rate and foreign exchange risks

For more information on Enbridge's corporate strategy, industry fundamentals, growth projects, risk management practices and company performance, please see the company's 2011 year-end Management Discussion and Analysis.

ECONOMIC PERFORMANCE INDICATORS

ECONOMIC PERFORMANCE

EC1

Direct economic value generated and distributed, including revenues, operating costs, employee compensation, donations and other community investments, retained earnings, and payments to capital providers and governments.

SUMMARY TABLE OF DIRECT ECONOMIC VALUE GENERATED AND DISTRIBUTED

Enbridge Inc.	2011 ($million)	2010 ($million)	2009 ($million)
Revenues	19,402	15,127	12,466
Commodity costs	14,854	11,291	9,011
Operating and administrative expenses	1,720	1,466	1,430
Adjusted earnings[1]	1,110	984	855
Payments to shareholders[2]	759	648	555
Payments to lenders[3]	749	711	656
Total compensation[4]	935	813	786
Donations and other community investments[5]	13	11.5	10
Payments to governments[6]	100	233	325

1. Adjusted earnings is a non-GAAP measure representing earnings attributable to common shareholders adjusted for non-recurring factors.
2. Includes cash dividends and dividends reinvested through the Common Share Dividend Reinvestment and Share Purchase Plan.
3. Includes total interest payments on debt during the year net of capitalized interest.
4. Includes amounts for annual payroll, annual incentive rewards, employee benefits, employee training and development, and employee relocations. At December 31, 2011, Enbridge had 6,922 permanent employees.
5. Includes investments in charitable and not-for-profit organizations.
6. Includes property taxes, business taxes, provincial capital taxes and income taxes paid.

For information pertaining to Enbridge Income Fund Holdings Inc., please visit http://www.enbridgeincomefund.com/; to Enbridge Energy Partners, please visit http://enbridgepartners.com/EEP/; and to Enbridge Energy Management, please visit http://enbridgemanagement.com/EEQ/.

DISCUSSION ON DIRECT STAKEHOLDER ECONOMIC VALUE ADDED

In helping to satisfy society's need for secure supplies of energy through Enbridge's core business of transporting natural gas and petroleum products, the company's activities provide a significant and quantifiable direct economic benefit to a broad group of stakeholders.

Shareholders / Lenders

Enbridge Inc. shareholders realize returns through a combination of capital appreciation and dividends. 2011 was another strong year for Enbridge Inc. share price performance on the Toronto Stock Exchange. Investors holding Enbridge Inc. stock for the entire year realized share price appreciation of 35 per cent. As a result, Enbridge's overall market value increased by $8 billion to $30 billion. Furthermore, in 2011, Enbridge paid dividends of $0.98/common share or a total of $759 million to Enbridge Inc. shareholders. The combination of compounding dividends and capital gains equated to a total shareholder return of 40 per cent in 2011.

Ongoing support for Enbridge's share price comes in part from indices that provide business rankings based on information about the social, ethical and environmental policies and practices of organizations. These indices are based on the concept that a company's commitment to CSR will sustain and grow long-term shareholder value. As a result, a certain segment of investors choose to direct their investments towards these companies. During the past several years, Enbridge has been included in the following indices:

- Dow Jones Sustainability Index (North America)
- FTSE4Good Index
- Jantzi Social Index (JSI)

Enbridge Inc. lenders realize returns through interest payments on short- and long-term debt and repayment of principal at maturity. Enbridge Inc. once again met all contractual debt obligations for the year. Interest payments made to lenders during 2011 totaled $749 million.

For information on shareholder/unitholder returns for Enbridge Income Fund Holdings Inc., please visit http://www.enbridgeincomefund.com/; for Enbridge Energy Partners, please visit http://enbridgepartners.com/EEP/; and for Enbridge Energy Management, please visit http://enbridgemanagement.com/EEQ/.

Employees

Enbridge's business operations provide jobs and contracting opportunities in many communities in Canada and the U.S. Headquartered in Calgary, Enbridge has major offices in Edmonton, Toronto and Houston and numerous field offices in our areas of operations. Combined, Enbridge had over 7,500 permanent employees in Canada and the United States. In 2011, Enbridge's payments to employees for salary as well as annual incentive programs totaled approximately $762 million. The company also provides direct economic benefits to employees through savings plans, retirement/pension plans, training programs, as well as health benefit plans. The value of these totaled $173 million in 2011.

For more information on Enbridge's employment practices, please refer to the section "Social Performance: Labour Practices and Decent Work" of this report.

Community

Directed by its social vision statement, Enbridge concentrates its investments in focus areas that contribute to enriching its communities. The six areas are: Lifelong Learning; Community Leadership; Natural Legacy; Arts and Culture; School Plus; and Safe Community. For descriptions of these six areas, please see ''Society – SO1 – Community Partnerships and Investments – Strategy' in the Social Performance chapter of this report.

By investing in each of these key areas with our dollars, partnerships and human capital, Enbridge is able to support organizations that contribute to the economic and social development of communities near the company's operations. We believe these investments are essential to being a good neighbour and are a contributing factor in maintaining the company's social license to operate.

Enbridge partners with charitable and non-profit organizations in our various geographic regions in Canada and the U.S. that have the skills and expertise to effect change.

In the year ended December 31, 2011, Enbridge's actual enterprise-wide community investment expenditure totaled $13 million, which the company invested in more than 550 charitable, non-profit, and community organizations. This total represents approximately one per cent of Enbridge's 2011 Canadian pre-tax profit.

Other direct economic community benefits, although more difficult to quantify, arise as a result of new projects in

and around Enbridge's right-of-way communities. These include job creation, skills training, as well as the purchase of goods and services in and around those communities. Please see "EC9" below for recent examples of projects highlighting these direct and indirect economic benefits.

For more information on Enbridge's community investment, please see ''Society – SO1 – Community Partnerships and Investments" in the Social Performance chapter of this report.

Government

As a result of our operations within communities across North America, Enbridge pays income, property, business and other required taxes to local, state, provincial and federal governments in Canada and the U.S. These funds are ultimately used in part to fund and operate public services and infrastructure, both locally and nationally. In 2011, Enbridge paid $100 million in income, property, business and other required taxes in the two countries.

Customers

Enbridge's gas distribution business provides close to 2 million customers in Canada and upper New York State with access to one of the lowest cost, and cleanest burning, fuel sources—natural gas. Accessing this essential service at a lower cost helps families to manage their cost of living.

Ontario-based Enbridge Gas Distribution (EGD) has distributed over $56 million to customers through the incentive regulation sharing model, which concluded its fourth year in 2011. This agreement has benefited Enbridge's customers and improved returns to shareholders. EGD is one of the fastest growing utilities in North America, adding approximately 35,000 new customers per year. (For more information on incentive regulation, please see page 65 of Enbridge Inc.'s 2011 year-end Management Discussion and Analysis.)

EGD also works with its gas distribution customers through its demand-side management (DSM) programs to increase the efficient use of valuable energy resources, thereby further reducing each household's costs, while at the same time reducing environmental impact. Since 1995, EGD has helped customers reduce their natural gas cumulative consumption by about 7.0 billion cubic metres through participation in its DSM programs (the equivalent of enough gas to supply approximately 2.3 million homes[1] for one year) and net energy savings to customers of approximately $2.1 billion. Through these DSM activities, EGD has helped its customers avoid cumulatively approximately 13.3 million tonnes of carbon dioxide emissions[2]. Measures like these move Enbridge closer to realizing its emission reduction targets, despite the pressures of significant growth in its customer base.

1 Assumes a typical residential customer uses 3,064 m^3 per year to heat their home and water

2 Assumes 1.89 kgs of CO_2 are emitted for each m^3 gas that is consumed

Enbridge's activities also provide a direct, yet not so easily quantifiable, economic benefit to its hydrocarbon transportation customers. Every day through our energy transportation systems in Canada and the U.S., we provide our energy producer customers with direct access to markets. Pipelines are the lowest cost and safest transportation solution for large volumes of hydrocarbons. Without this infrastructure, these customers would not be able to achieve the netback pricing that they do for their products. Furthermore, their resulting increased profitability in turn can lead to their growth, which can in turn lead to increased employment and community investment.

EC2

Financial implications and other risks and opportunities for the organization's activities due to climate change.

Climate change and the other changes that climate change will trigger challenge Enbridge with the following financial and business risks:

1. INCREASED REGULATORY BURDEN RESULTING FROM GOVERNMENTS' RESPONSE TO CLIMATE CHANGE AND THE IMPERATIVE TO REDUCE GHG EMISSIONS

The GHG-related regulations under which the company will have to operate in the future will most likely conform in a broad sense to the final U.S. regulations.

Regulatory risks to the company include the issue of local gas distribution companies being required to take responsibility for their customers' emissions from the use of natural gas. Under the proposed cap-and-trade system, the company likely will also be managing both the free allocation and purchase of credits on behalf of customers, a function that companies such as Enbridge Gas Distribution have not traditionally been required to do.

Enbridge could also be exposed to increased power costs associated with its operations, if regulatory constraints associated with climate change are imposed on power utilities. The company anticipates that there

will be no competitive disadvantage to Enbridge if regulatory costs are uniform internationally (i.e., if they impact Enbridge's competitors to the same degree).

Costs are difficult to quantify at this time because related policies in North America and elsewhere are in a state of flux.

2. THE LONG-TERM DRIVE TOWARD A MORE CARBON CONSTRAINED FUTURE AND LESS RELIANCE ON FOSSIL FUELS

Over the longer term, as society transforms to a less carbon intensive energy system, both oil and natural gas, as fossil fuels, will become less desirable as energy sources and more expensive due to increased regulation.

Although availability of renewable and alternative energy is growing, oil and natural gas will continue to be a preeminent energy source in the near- and mid-term. This will provide a continuing need for the current Enbridge services.

Increased investment in renewable and alternative energy is expected to provide opportunities for Enbridge in the longer term and contribute to offsetting the risks associated with a carbon-constrained future.

3. THE IMPACTS OF INCREASED SEVERE WEATHER EVENTS ON ENBRIDGE'S INFRASTRUCTURE SYSTEM

The most severe weather events that Enbridge operations experience are hurricanes along the Texas Gulf coast. However, Enbridge systems are part of a broadly based logistics network that connects producers to consumers, where all parties are aligned in their contingency planning to shut-down in advance of severe storms and resume operations and energy supply as a first priority, following the storm event, thus limiting impacts.

4. INVESTOR RISK

There is a growing pool of investment capital worldwide that is dedicated to investments in environmentally responsible and sustainable companies. Further, Enbridge is experiencing growing interest in its business from CSR rating services whose reports can influence these investors' perceptions. Enbridge believes that its ability to respond in a timely and transparent manner to requests for information regarding its environmental commitment enhances its corporate reputation. Enbridge's policy is clear on establishing targets to offset impacts and publicly reporting on progress.

5. TECHNOLOGY DEVELOPMENTS

To mitigate risk and capitalize on emerging technologies, Enbridge, through an internal dedicated department, tracks developments and identifies and screens appropriate new technologies. Technologies of interest are generally associated with new and improved energy delivery and efficiency, as well as renewable and alternative low-impact energy generation.

Enbridge has made significant investments with respect to wind power, solar power, geothermal power and fuel cells. Evaluations concerning carbon capture and storage are ongoing.

Opportunities arising from climate change

Enbridge believes that the company is in a good position to take full advantage of many of the opportunities related to the climate change issue, including the following:

- With an increased focus on demand-side management activities and conservation, the company's recognized expertise in this area is expected to provide a good platform for growth and for offering fee-for-service services to current customers and others.
- There will be increased opportunities for select renewable and alternative energy delivery services in the realm of district energy, which will change the way customers will receive energy in the future. Services along these lines may be offered to third parties.
- As Enbridge's customers become more aware and educated about their carbon exposure issues, the company is expected to be in a strong position to be able to help them manage their emissions, thus creating a stronger link with them for further collaborative activities.
- Enbridge has interests in eight wind power projects, four solar farms, four waste heat recovery facilities, one geothermal facility and one fuel cell. Together, Enbridge's interests have a combined capacity of approximately 960 megawatts, which is enough electricity to meet the power requirements of 290,500

homes, while also avoiding over 1.4 million tonnes of greenhouse gas emissions each year. Enbridge expects future wind and solar opportunities to come through expanding its existing operations, as well as developing new greenfield projects near Enbridge operations throughout North America, particularly where operating synergies can be applied.

- In 2008, Enbridge officially launched the world's first hybrid fuel cell power plant that is designed for gas utility pressure reduction stations. The plant harvests pipeline energy that would otherwise be wasted and the fuel cell operates without burning any fuel to produce about 2.2 megawatts of environmentally preferred, near zero-emissions electricity—enough to serve about 1,700 homes. Enbridge has exclusive North American distribution rights for the hybrid fuel cell technology. Enbridge plans to replicate the plant throughout its distribution network in Ontario and market the hybrid fuel cell to other natural gas pipeline companies in North America.
- Enbridge is one of five participants in the Saskatchewan Aquistore carbon capture and sequestration project, which is managed by the Petroleum Technology Research Centre. This initiative is expected to play a major role in advancing industry and government's knowledge of CO_2 capture and sequestration.

EC3

Coverage of the organization's defined benefit plan obligations.

Enbridge maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other post-employment benefits other than pensions to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected unit credit method. This method involves actuarial calculations using several assumptions, including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality, and termination rates. These assumptions are determined by Enbridge management and are reviewed annually by the company's actuary. Actual results that differ from assumptions are amortized over future periods and, therefore, could materially affect the expense recognized and the recorded obligation in future periods.

The company remains able to pay the current benefit obligations using cash from operations. Please see Note 27 to Enbridge's Consolidated Financial Statements for the year ended December 31, 2011, which appears on pages 169-171 of the 2011 Annual Report, for disclosure of the difference between the actual and the expected results for the past two years.

Funding in 2012 will be approximately $106 million.

EC4

Significant financial assistance received from government.

Enbridge sells the power that it produces from its Ontario renewable energy projects (listed in the table below) to the Ontario Power Authority (OPA) under long-term—generally, 20-year—Power Purchase Agreements. The contracted power prices per MWh for these projects are currently higher than the market rates for the Ontario wholesale electricity market, and are generally comparable to the prices paid by the OPA under their new Feed-in Tariff (FIT) program. For more information on the FIT program, please visit their website at fit.powerauthority.on.ca.

Enbridge also receives incentives for energy production over a 10-year period for three projects under the Government of Canada's ecoENERGY for Renewable Power program. Under the program, the Sarnia Solar project receives $5 per MWh for energy production, while the Enbridge Ontario Wind and Talbot Wind projects receive $10 per MWh.

In the U.S., the Cedar Point wind project qualified for the U.S. Department of the Treasury 1603 grant program, under which the project received a cash grant of up to 30 per cent of the project capital costs upon completion of the project. This will also be the case for the Silver State North Solar facility in Nevada that was brought into service in May 2012.

ENBRIDGE'S RENEWABLE ENERGY PROJECTS

Canada	Output	Capital Cost	Status
Amherstburg Solar	15 MW	$0.07 billion	Operating
Enbridge Ontario Wind	190 MW	$0.5 billion	Operating
Greenwich Wind	100 MW	$0.3 billion	Operating
Lac Alfred Wind	150 MW (net)	$0.3 billion (net)	Under-construction
Sarnia Solar – Phase 1	20 MW	$0.1 billion	Operating
Sarnia Solar – Phase II	60 MW	$0.3 billion	Operating
Talbot Wind	100 MW	$0.3 billion	Operating
Tilbury Solar	5 MW	$0.02 billion	Operating
Total	640 MW	$1.9 billion	

United States	Output	Capital Cost (USD)	Status
Cedar Point Wind	250 MW	$0.5 billion	Operating
Neal Hot Springs Geothermal Project	22 MW (net)	$0.1 billion (net)	Under-construction
Silver State North Solar	50 MW	$0.2 billion	Operating
Total	322 MW	$0.8 billion	

Enbridge is a consortium member of Project Aquistore, a carbon capture and storage research project led by the Petroleum Technology Research Centre in Saskatchewan. Project Aquistore has received $5 million from the Government of Canada through the Sustainable Technology Development Corporation as well a $5 million commitment from the Government of Saskatchewan through the Go Green Fund. Project Aquistore has also applied for $9 million from NRCan through the ecoEnergy Technology Initiative (ecoETI).

Enbridge receives no other financial assistance from governments other than as described above.

MARKET PRESENCE

EC5

Range of ratios of standard entry-level wages by gender compared to local minimum wage at significant locations of operation.

Enbridge's remuneration policies are company-wide policies, and there is no significant variation by location. Salary levels are determined using an objective and equitable process that considers the internal value of the role, market rates of pay, as well as employee skill and competency. Enbridge utilizes an objective performance management system that permits top performers to achieve higher-than-average increases in any given year.

Average salary ratio male to female by job ladder level (%)	
Level 1	102.8
Level 2	102.6
Level 3	101.6
Level 4	102.8
Level 5	102.0
Level 6	104.7
Level 7	100.8

Minimum wage versus Enbridge start rates

Region	Minimum Wage	Enbridge Entry-level Minimum Wage	Enbridge Entry-level Maximum Wage	Ratio of Standard Minimum Wage to Enbridge Entry-level Wage
Ontario	$10.25			
Toronto		$17.83	$26.74	173.95% - 260.88%
Alberta	$9.40			
Calgary		$20.52	$28.97	218.30% - 308.19%
Edmonton		$14.72	$20.79	156.60% - 221.17%
Texas	$7.25			
Houston		$ 14.12	$19.93	194.76% - 274.90%

EC6

Policy, practices and proportion of spending on locally based suppliers at significant locations of operation.

Enbridge's CSR Policy states that "Enbridge will strive to provide employment and economic opportunities in the communities where we operate."

While Enbridge does not have a formal policy regarding buying from locally-based suppliers and it does not formally track its locally-based expenditures, the company can say that, in practice, it meets the majority of its needs through local suppliers.

The company has a clearly defined management and governance structure for all major projects and in that regard strategic relationships have been developed with suppliers and contractors.

For example, over the last four to five years, Enbridge Major Projects has sourced finished pipe worth approximately $1.5 billion from Canadian-located manufacturing facilities. This has had positive impacts on local businesses and the people they employ. At any given time during Enbridge's pipe production, these manufacturers could employ approximately 700 employees in their facilities working directly on Enbridge's pipeline manufacturing needs. Additionally, there would be a number of businesses and workers that would be positively impacted indirectly by this local pipe production.

Furthermore, as part of its Aboriginal and Native American Policy, Enbridge commits to offering sole-sourced contracting opportunities to qualified Aboriginal and Native American suppliers and contractors where appropriate, and encourages joint venture opportunities between Aboriginal/Native American businesses and non-Aboriginal/Native American businesses when it builds capacity and supports mutual business interests.

EC7

Procedures for local hiring and proportion of senior management hired from the local community at locations of significant operation.

Overall, Enbridge does not have a formal policy regarding hiring locally, but in practice most of the people that the company hires are, in fact, hired locally.

Through our Aboriginal and Native American Policy, we commit to implementing measures to enable Aboriginals and Native Americans to become part of our permanent workforce at a level that is representative of regional demographics and encompasses a wide spectrum of career levels. For information on our approach to Aboriginal economic development, please refer to the section "Social Performance: Society – SO1 – Aboriginal & Native American Relations" of this report.

In Canada, Aboriginal people are a designated group under the Employment Equity Act. Enbridge Liquids Pipelines falls under this act and as such, this group comes under the diversity mandate with specific hiring targets over three years, as well as programs and activities to support Aboriginal inclusion in our workforce. Liquids Pipelines has hired a Manager, Diversity and formed a Diversity Steering Committee, and initiatives are under way to examine current Aboriginal workplace recruitment and retention activities, with the view to increasing Aboriginal workplace participation to represent regional population demographics.

INDIRECT ECONOMIC IMPACTS

EC8

Development and impact of infrastructure investments and services provided primarily for public benefit through commercial, in-kind, or pro bono engagement.

Energy is the great enabler and is fundamental to almost everything people do. Yet, in developing countries, access to and affordability of energy can be prohibitive and has a very real impact on the quality and length of life of people in those countries.

Enbridge, through the energy4everyone Foundation (e4e), is highlighting and tackling energy poverty by improving access to energy for targeted communities in Africa and Latin America; and demonstrating to people in developed nations the significant positive impact and value of energy in addressing poverty.

With a vision of empowering people and communities to improve their own lives by providing energy to everyone, e4e seeks to implement practical and sustainable solutions to improve access to energy for communities in need.

e4e designs each of its projects for triple bottom line results—Economic (savings from a more efficient technology, improvement of income level and productive time savings); Environmental (reduction of greenhouse gases, savings of wood fuel and reduced deforestation); and Social (improved access to health, education and means of communication).

Enbridge has established an Employee Volunteer Assignment to give our employees the opportunity not only to implement an e4e project, but also to promote a better understanding of e4e, the energy challenges faced by communities in need, and how e4e sponsored projects are designed to offer sustainable, long-term solutions to communities in need. Each Enbridge employee who has participated as an e4e volunteer was responsible for their own transportation to and from the project site (for example, Peru) and used a week of their personal vacation time

For more information on energy4everyone and the projects in which it is currently engaged, please visit e4e's Facebook page at http://www.facebook.com/energy4everyone#!/energy4everyone.

EC9

Understanding and describing significant indirect economic impacts, including the extent of impacts.

Pipeline construction is one way that Enbridge generates positive direct economic benefits.

However, the company's pipeline projects also provide significant related indirect economic benefits to stakeholders, such as surrounding communities. For example, it is estimated that in the U.S. in 2009, the construction of the Alberta Clipper and Southern Lights projects created more than 3,000 temporary construction-related jobs. The workers hired for these jobs earned family-supporting wages and benefits and made purchases estimated to total more than $60 million at lodging facilities, restaurants, gasoline service stations, laundry facilities, convenience stores and other retail establishments, all of which provided an economic boost to communities along the pipeline right-of-way.

Furthermore, Enbridge works extensively with many local vendors, consultants and contractors on all areas of project planning—from environmental inspectors to car dealers for fleet vehicles.

Enbridge's Northern Gateway Pipelines project is another excellent example of a project that will contribute significant direct and indirect economic benefits to the communities along our right-of-way and other stakeholders across the country.

For example, in 2011, Northern Gateway developed an Education, Training and Employment Strategy as a mechanism to help local community members develop the essential and transferable skills necessary to work in the growing pipeline and construction sectors. As part of the overall strategy, Northern Gateway launched a $1.5-million Education and Training Fund to support flexible community-based training specific to the pipeline and construction sector. Northern Gateway is working with local Aboriginal and non-Aboriginal communities, as well as training providers, to design custom education and training-to-employment programs, and utilizes the fund to cover shortfall costs not funded through existing federal and provincial programs. As part of this initiative, Northern Gateway contributed $80,000 to the Trade Winds to Success program to use towards trades training for members of six Aboriginal groups in proximity to the proposed Project corridor. Northern Gateway will continue to actively engage in workforce planning initiatives in both Alberta and British Columbia as a mechanism to deal with present and anticipated skilled labour shortages in the pipeline and construction sector.

For further details, please refer to the Northern Gateway website, including its stand-alone CSR report (http://csr.enbridge.com/northerngateway2010/).

For more information on the direct economic benefits that Enbridge generates, please see EC1 above.

ENVIRONMENTAL PERFORMANCE

WE'RE COMMITTED TO CONDUCTING OUR BUSINESS IN AN ENVIRONMENTALLY SUSTAINABLE WAY.

Enbridge operates the largest and most complex liquids pipeline system in the world. We recognize that this comes with great responsibilities, and we make the safety and integrity of our pipeline system our highest priority.

Over the past 10 years, Enbridge has delivered almost 12 billion barrels of crude oil, and more than 99.999 per cent of that product safely arrived at its destination. Safety has always been at the heart of our operations, which is why the recent spill incidents we've experienced have only served to heighten our resolve to prevent all spills. In 2011 alone, we invested approximately $400 million in a wide range of pipeline and facility integrity programs and initiatives to ensure continued improvement. That investment will increase to $800 million in 2012. Our objective is to be the industry leader in the protection of our workers, the public and the environment.

Enbridge is also resolved to lead the way in developing renewable and alternative energy technologies that have less impact on the environment. Enbridge is involved in eight wind power projects, four solar farms, four waste heat recovery facilities, one geothermal facility and an integrated fuel cell. Enbridge's share in these assets equals a capacity of close to 1,000 megawatts, or enough electricity to supply the equivalent of almost 300,000 homes. Enbridge's renewable and alternative energy investments also result in the avoidance of over 1.4 million tonnes of greenhouse gas emissions each year.

For its part, Enbridge Gas Distribution is working with customers through its demand-side management (DSM) programs to increase the efficient use of valuable energy resources, thereby lowering each household's energy costs, while at the same time reducing environmental impact. Since 1995, EGD has helped customers reduce their natural gas cumulative consumption by about 7.0 billion cubic metres through participation in its DSM programs (the equivalent of enough gas to supply approximately 2.3 million homes for one year) and net energy savings to customers of approximately $2.1 billion. Through these DSM activities, EGD has helped its customers avoid over 13.3 million tonnes of carbon dioxide emissions.

Enbridge has also formally committed to stabilizing its own environmental footprint through our Neutral Footprint initiative. As of 2009, we're counteracting our environmental impacts within five years of their occurrence—planting a tree for every tree we remove; conserving an acre of natural habitat for every acre we permanently impact; and generating a kilowatt of renewable energy for every kilowatt of power our operations consume. This strategic approach to CSR benefits all of Enbridge's stakeholders and society at large.

Environmental Scorecard Results				
Objectives	**2011 Results**	**2010 Results**	**Details available in GRI Performance Indicator Section**	**Challenges**
Reduce Canadian absolute direct GHG emissions to 20% below 1990 levels by 2010	Enbridge was able to confirm that the target was met and will set future targets for reducing direct emissions from its assets once it has fully completed an emissions inventory and once there is greater clarity regarding the regulatory framework(s) emerging across the North American jurisdictions where the company has operations.	21% reduction from 1990 levels	EN18	Increased demand for energy Operational growth Diversity of operations
Develop enterprise-wide carbon data and GHG management strategies	Continued implementation of Emissions Data Management System, which we now aim to have operational before the end of 2012 in Canada and before the end of 2013 in the U.S.	Implementation under way. Emissions Data Management System will be operational by Q1 2012.	EN18	Operational differences between jurisdictions company-wide growth Design and installation difficulties of the Emissions Data Management System, resulting in implementation delays
Help customers use energy wisely through demand-side management programs	Saved about 77 million cubic metres of natural gas (enough to supply about 25,000 homes with natural gas for a year). Since its inception in 1995, these programs have helped our customers avoid the emission of over 13 million tonnes of carbon dioxide.	Saved about 65 million cubic metres of natural gas (enough to supply about 21,000 homes with natural gas for a year)	EN26/EN27	Enbridge can encourage customer efficiency but cannot enforce it
Invest in renewable and alternative energy technologies	Completed 250-MW Cedar Point Wind Energy Project in Colorado Completed 99-MW Greenwich Wind Project in Ontario Acquired 50% interest in 300-MW Lac Alfred Wind Project in Quebec Completed 15-MW Amherstburg II Solar Project Acquired 5-MW Tilbury Solar Project	Achieved commercial operation of 80-megawatt (MW) Sarnia Solar Project Completed 99-MW Talbot Wind Project Acquired majority interest in 99-MW Greenwich Wind Energy Project in Ontario Invested in 250-MW Cedar Point Wind Energy Project in Colorado Invested in 35-MW (22-MW net) Neal Hot Springs Geothermal Project in Oregon (to be completed in 2012)	EN6	Identifying opportunities and applying technologies Competitive rates of return for renewable and alternative energy projects

Objectives	2011 Results	2010 Results	Details available in GRI Performance Indicator Section	Challenges
Lead climate change solutions	Investments in renewable and alternative electricity generation (see above) and new emerging technologies—carbon capture and storage; bitumen extraction; solar power; run-of-river hydro; compressed natural gas storage; waste heat recovery; geothermal power; fuel cells; hydrogen production. (For a description of the above, please see EN6)	In June 2010, announced participation in the development of Project Pioneer, Canada's first fully-integrated carbon capture and storage project involving retro-fitting a coal-fired electricity plant. (Please see EN18 for a 2011 update)	EN18	Uncertainty surrounding proposed GHG regulations and legislation. High costs associated with implementing climate change technologies
Zero releases Minimize environmental impacts should releases occur	94 reportable spills, leaks and releases totaling approximately 2,366 barrels, of which 82 had a volume of 10 barrels or less and two were significant (greater than 100 barrels). Liquids Pipelines' spill volume in 2011 of 2,284 barrels represents that business unit's lowest annual spill volume of the past 10 years.	91 reportable spills, leaks and releases totaling approximately 34,258 barrels, of which 78 had a volume of less than 10 barrels and seven were significant (greater than 100 barrels). In July 2010, Enbridge experienced the most serious environmental incident in its long history—the leak of approximately 20,000 barrels of crude oil on its Line 6B pipeline near Marshall, Michigan.	EN23-25	While Enbridge's pipeline and system integrity initiatives contribute to reducing the risk of spills, leaks and releases, these measures cannot completely eliminate the risk. Therefore, Enbridge has comprehensive spill preparedness and response and environmental mitigation plans in place to respond rapidly and completely if a spill does occur.
Ensure no net increase to Enbridge's environmental footprint as a result of new projects in operation between 2009 and 2015.[1] Enbridge's Neutral Footprint commitments: tree for a tree; acre for an acre; kilowatt for a kilowatt	From the start of January 2009 through to the end of the second quarter of 2012: • 545,000 trees removed and 375,000 tree seedlings planted; and • approximately 1,700 acres of natural habitat disturbed and 5,260 acres conserved (surplus will be applied to future projects) • By the end of 2011, we were forecasting that our power consumption will grow by 2,668 GWh by 2015, while power generated from our renewable energy assets (both existing and under construction) will be 3,080 GWh.	From the start of January 2009 through to the end of the second quarter of 2011: just over half a million trees removed and 250,000 tree seedlings planted; 1,008 acres of natural habitat disturbed and 2,484 acres conserved (surplus of 1,476 acres will be applied to future project impacts) Enbridge's annual electricity consumption forecast to increase by 1,852 gigawatt hours (GWh). Enbridge's existing renewable power generating facilities and those under construction will produce approximately 2,327 GWh	EN6 re electricity consumption; and EN11-EN15 re land impacts	Identification of comparable areas for conservation Development of appropriate partnerships for tree planting The need to increase investments in demand-side management programs that help customers use energy wisely The need to increase investments in renewable and alternative energy technologies

1 Enbridge announced this objective, called Neutral Footprint, on May 6, 2009, at the company's Annual General Meeting of shareholders.

ENVIRONMENTAL PERFORMANCE INDICATORS

MATERIALS

EN1

Materials used by weight or volume.

EN2

Percentage of materials used that are recycled input materials.

Across the Enbridge organization, pipe and paper are the two most commonly used materials.

Pipe

The most significant purchase Enbridge makes is steel pipe, with which we construct our pipelines. 93.6 per cent of the pipe that Enbridge's primary supplier, Evraz Inc. NA, manufactures for the company is made from recycled steel. In 2011, Enbridge purchased 63,490 tonnes of pipe from Evraz. This equates to 59,427 tonnes of recycled steel being used.

Enbridge Gas Distribution (EGD) purchased approximately 1,530 tonnes of steel pipe and 918 tonnes of polyethylene pipe in 2011. The recycled content of its steel pipe ranges from 25 to 100 per cent. Regarding polyethylene pipe, 51 per cent of total pipe (above NPS 2 in size) purchased includes up to 30 per cent recycled material.

Paper

In 2011:

- Enbridge offices in Calgary used approximately 39 tonnes of printing/photocopying paper with 25 tonnes having 30 per cent recycled content. Enbridge's Calgary office recycled approximately 30 tonnes of paper in 2010.
- Liquids Pipelines' Edmonton offices used approximately 78 tonnes of paper, with 69 tonnes having 30 per cent recycled content.
- Gas Transportation used approximately 49 tonnes of paper.
- EGD used approximately 35 tonnes of paper, with 30 per cent recycled content. This is down from 39 tonnes in 2010 and 42 tonnes in 2009.

ENERGY

EN3

Direct energy consumption by primary energy source.

EN4

Indirect energy consumption by primary source.

ENBRIDGE'S IMPACTS

Enbridge's Liquids Pipelines systems in Canada and the U.S. primarily use electric pumps to move product through its pipelines, while the company's natural gas gathering, transmission and distribution systems use natural gas as fuel for the compressors that move the gas along their pipelines. Enbridge's gas distribution systems in Ontario, Quebec, New Brunswick and New York state are powered by electricity and natural gas. The company uses diesel fuel and natural gas to drive pumps in remote locations along the Enbridge Norman Wells Pipeline system in the Northwest Territories.

Direct energy consumption

The table below summarizes direct energy consumption associated with operations of Liquids Pipelines (Canada), Liquids Pipelines (U.S.), Vector Pipeline (U.S.), and Enbridge Gas Distribution (EGD). There are minor variances from previous CSR reports due to accounting/measurement refinements. All units in these tables are in gigajoules (GJ).

Liquids Pipelines (Canada) (GJ)	2011	2010	2009	2008
Stationary equipment – natural gas	**83,300**	**74,033**	**84,661**	**103,040**
Stationary equipment – propane, diesel	**44,535**	**43,179**	**35,745**	**29,140**
Mobile sources – all fuel types	**48,492**	**63,103**	**57,205**	**59,183**
Total	**176,327**	**180,315**	**177,611**	**191,363**

Table note: The above data includes natural gas energy used at Enbridge Inc.'s office in Edmonton.

Liquids Pipelines (U.S.) (GJ)	2011	2010	2009	2008
Stationary equipment – natural gas	**79,252**	**52,237**	**0**	**133,887**
Stationary equipment – liquid fuels	**82**	**64**	**32**	**100**
Mobile sources - all fuel types	**42,401**	**40,585**	**38,352**	**36,033**
Total	**121,735**	**92,886**	**38,384**	**170,020**

Vector Pipeline (U.S.) (GJ)	2011	2010	2009	2008
Stationary equipment – natural gas	**6,165,554**	**6,071,251**	**5,295,566**	**4,875,194**
Stationary equipment – liquid fuels	**0**	**0**	**0**	**0**
Mobile sources – all fuel types	**1,425**	**1,580**	**1,364**	**1,216**
Total	**6,166,979**	**6,072,831**	**5,296,930**	**4,876,410**

Table note: natural gas use for 2008 has been calculated based on the 2009 fuel-use rate per HP-hour.

Gas Transportation (GJ)	2011	2010	2009
Mobile sources – gasoline	**95,200**	**86,457**	**137,184**
Stationary equipment – diesel fuel	**524,867**	**414,190**	**153,048**
Total	**620,067**	**500,647**	**290,232**

Table note: Collection of this data was initiated in 2009.

Enbridge Gas Distribution (GJ)	2011	2010	2009	2008
Buildings and Operations				
Natural gas combustion	**657,359**	**540,795**	**480,362**	**482,328**
Fleet and Equipment				
Diesel vehicles	**49,073**	**50,195**	**46,154**	**40,302**
Gasoline vehicles	**53,520**	**53,499**	**55,844**	**64,500**
NGV (natural gas vehicles)	**45,860**	**50,847**	**44,534**	**49,015**
Total	**805,812**	**695,336**	**626,894**	**636,145**

Renewable electricity generation (GJ)	2011
Stationary equipment – natural gas	**24,786**
Stationary equipment – liquid fuels	**410**
Mobile sources – all fuel types	**907**
Total	**26,103**

Table note: This is the first time Enbridge has reported direct energy consumption associated with the operations of its renewable energy assets.

Corporate (GJ)	2011
Stationary equipment – natural gas	**16,797**
Stationary equipment – liquid fuels	**0**
Mobile sources – all fuel types	**24,466**
Total	**41,263**

Table note: In previous CSR reports, energy data for Enbridge's Corporate offices were included in the data of the Liquids Pipelines business unit.

Indirect energy consumption

The table below summarizes indirect energy consumption associated with operations of Liquids Pipelines (Canada), Liquids Pipelines (U.S.), and Enbridge Gas Distribution. Data on electricity consumption on the Vector Pipeline (U.S.) system has not been compiled but it is comparatively minor relative to the direct energy use on this natural gas transmission pipeline operation. All units in these tables are in gigajoules (GJ).

Liquids Pipelines (Canada) (GJ)	2011	2010	2009	2008
Electricity	**6,612,792**	**7,247,633**	**7,243,904**	**6,952,055**

Table note: The above data includes the electricity used in Enbridge's Edmonton and Calgary offices.

Liquids Pipelines (U.S.) (GJ)	2011	2010	2009	2008
Electricity	**7,351,434**	**7,591,274**	**7,576,462**	**8,065,406**

Gas Transportation (GJ)	2011	2010	2009	2008
Electricity	**1,968,522**	**601,758**	**665,399**	**-**

Enbridge Gas Distribution (GJ)	2011	2010	2009	2008
Buildings and Operations				
Electricity	**58,724**	**71,825**	**73,261**	**69,394**

Renewable electricity generation (GJ)	2011
Electricity	**10,345**

Corporate (GJ)	2011
Electricity	**9,145**

EN5

Energy saved due to conservation and efficiency improvements.

Enbridge strives to reduce energy use through efficiency improvements and conservation efforts.

Liquids Pipelines

As products in Enbridge's pipelines and power contracts change, we continually review natural flow rates for our liquids pipelines. The flow rates are designed to optimize pipeline operating pressures to match equipment and the types of products transported. By applying these rates to the pipeline, Enbridge works to optimize the operating performance of the system, thus lowering power costs and reducing maintenance. In addition, Enbridge has introduced additives in the pipeline to reduce friction of liquids products and optimize flow.

Indirect emissions from operations are due mainly to the electricity used at pump stations on the liquids pipelines system. There are both operating-cost and GHG-emission-reduction benefits when pumping operations are optimized and when more energy-efficient equipment is used. However, it is difficult to baseline and isolate these savings from other factors such as changing pipeline hydraulics, and therefore this report does not track reductions associated with these capacity increases.

Gas Transportation

Gas Transportation (GT) purchased three FLIR GasFind infrared cameras in 2011 for use in detecting leaks at

operating facilities. These cameras are capable of producing real-time images of fugitive emissions leaking from process equipment. The cameras are being used to conduct periodic surveys at facilities to identify leaks and other maintenance issues during routine operations, and to verify the integrity of initial construction and repairs at facilities. The ease of use and rapid-scan functionality of the cameras allow for a greater frequency of leak detection surveys at facilities, resulting in more rapid detection of leaking components for repair and reduced gas loss due to fugitive leaks from GT's facilities.

Enbridge Gas Distribution

Enbridge Gas Distribution (EGD) has been proactive in reducing its direct energy consumption by reducing its electricity and gas requirements to run its operations throughout its franchise areas. These actions have resulted in dramatically reducing EGD's gas and electricity usage, including the reduction of the EGD head office's 2011 electrical consumption by 82 per cent from the 1990 base. For example, EGD reduced its purchase of electricity for December 2011 to just 4,099 kWh from 1,064,578 kWh in 1990. This is attributable to reduction measures listed below and self-generation of electricity through its fuel cell/ turbo expander. (Enbridge launched the world's first integrated energy recovery and fuel cell power plant at EGD's head office in Toronto in 2008.) Considering the fact that EGD's head office building in Toronto maintains a data centre and process space, the ongoing savings are significant.

Actions taken to reduce direct energy consumption at EGD's head office building include:

- reusing the generator waste heat from the standby generator to provide necessary heat for the fuel cell power plant's turbo-expander system;
- improving controls to optimize the use of gas/electricity;
- adding a third chiller and fan coil units to reduce the power requirement for the data centre and allowing free cooling of the centre during the winter months;
- replacing the meter shop HVAC and process equipment to minimize energy use by installing hot water coils and improving the controls in this continuous operation; and
- installing new HVAC equipment, UPS and electrical redundancy, including efficient IT equipment and VM (virtual machine) servers requiring less power than previously.

Leading by example, EGD designed and commenced construction in July 2011 of a new 100,000-square-foot Technology Centre utilizing many of these technologies to target a 78 per cent gas reduction and a 68 per cent electricity reduction. The centre is designed to achieve a LEED[1] Gold rating when built and after evaluation.

In addition, EGD continues to implement energy efficiency measures in its operations. For example, line heater energy efficiency efforts implemented since 2000 are saving, on average, about 142,000 GJ per year.

EN6

Initiatives to provide energy-efficient or renewable energy based products and services, and reductions in energy requirements as a result of these initiatives.

The public's focus on conservation and climate change continues to motivate governments to increase their emphasis on energy efficiency and renewable and alternative energy initiatives, including wind, water, biomass, biogas, solar, waste heat, fuel cells and geothermal energy generation.

Consistent with our vision of being a leading energy delivery company, Enbridge is investing substantially in low-environmental-impact energy sources—both renewable and alternative—that help to reduce greenhouse gas emissions and address the issue of global climate change.

Since 2000, we have steadily increased our investments in clean energy projects. In just 12 years, our renewable energy assets have grown from virtually nothing to almost $3 billion.

The majority of Enbridge's renewable energy investments are in wind and solar energy projects. However, the company also invests in other technologies, projects and companies that will achieve returns similar to those realized by Enbridge's oil and gas transportation and delivery operations, and that will contribute to a cleaner energy future.

In May 2009, Enbridge announced an ambitious plan to stabilize Enbridge's environmental footprint. The company's Neutral Footprint Initiative is designed to reduce Enbridge's environmental impact where it is felt most: on the trees the company removes, the natural habitat Enbridge permanently alters, and the energy the company uses to power its operations. As part of this Neutral Footprint Initiative, Enbridge has committed to generating a kilowatt hour of renewable energy for every kilowatt hour of power the company's operations consume. Please see below in this EN6 section for more information on the Kilowatt for a Kilowatt aspect of the Neutral Footprint Initiative and the EN11-15 section for more information on the Tree for a Tree and Acre for an Acre aspects of the initiative.

[1] Leadership in Energy and Environmental Design (LEED) is an internationally recognized mark of excellence, providing building owners and operators with a framework for identifying and implementing practical and measurable green building design, construction, operations and maintenance solutions. LEED certification provides independent, third-party verification that a building was designed and built using strategies aimed at achieving high performance in key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection and indoor environmental quality.

Renewable and Alternative Energy

Enbridge's renewable and alternative energy portfolio is diversified and growing. The company's interests in wind, solar, geothermal, waste heat and integrated fuel cells generating capacity now total close to 1,000 MW. Enbridge's interests in alternative and renewable generation, in operation and under construction, have the capacity to supply the equivalent of more than 290,500 homes. Enbridge's renewable and alternative energy investments also result in the avoidance of over 1.4 million tonnes of greenhouse gas emissions each year.

The following table provides an overview of Enbridge's current renewable and alternative energy investments. More details about these are provided below the table:

RENEWABLE ENERGY

100 per cent owned and operated by Enbridge and its affiliates, except where less than full ownership/operatorship is indicated.

Project Name	Type	Generating capacity	Ownership	Location	In-service date
SunBridge	wind	11 MW	Enbridge Income Fund (50%)*	Gull Lake, Saskatchewan	2002
Magrath	wind	30 MW	Enbridge Income Fund (33%)*	Magrath, Alberta	2004
Chin Chute	wind	30 MW	Enbridge Income Fund (33%)*	Taber, Alberta	2006
Ontario Wind Project	wind	190 MW	Enbridge Income Fund	Bruce County, Ontario	2009
Talbot	wind	99 MW	Enbridge Income Fund	Chatham, Ontario	2010
Greenwich	wind	99 MW	Enbridge Inc. (90%)	Dorian, Ontario	2011
Cedar Point	wind	250 MW	Enbridge Inc.	Cedar Point, Colorado	2011
Lac Alfred	wind	308 MW	Enbridge Inc. (50%)	Amqui, Quebec	2012/2013
Sarnia Solar Project	solar	80 MW	Enbridge Income Fund	Sarnia, Ontario	2009 (20 MW) 2010 (60 MW)
Tilbury Solar Project	solar	5 MW	Enbridge Inc.	Tilbury, Ontario	2010
Amherstburg II Solar Project	solar	15 MW	Enbridge Inc.	Amherstburg, Ontario	2011
Silver State North Solar Project	solar	50 MW	Enbridge Inc.	Primm, Nevada	2012
Neal Hot Springs	geothermal	22 MW	Enbridge Inc. (20%)	Malheur County, Oregon	2012

ALTERNATIVE ENERGY

100 per cent owned and operated by Enbridge and its affiliates, except where less than full ownership/operatorship is indicated.

Project Name	Type	Generating capacity	Ownership	Location	In-service date
NRGreen Power	waste heat recovery	20 MW	Enbridge Income Fund (50%)*	Saskatchewan	2008
NRGreen Power	waste heat recovery	14 MW	Enbridge Income Fund (50%)*	Alberta	2013
Enbridge Hybrid Fuel Cell	fuel cells	2.2 MW	Enbridge Inc.	Toronto, Ontario	2008

*Enbridge Inc. owns 27.4 per cent of Enbridge Income Fund ordinary trust units, but holds a 69.2 per cent economic interest in the Fund assets due to its holdings in Enbridge Income Fund Holdings Inc. and ownership of ECT Preferred Units.

RENEWABLE ENERGY

Wind Power

Enbridge currently has interests in wind farms in Alberta (2), Saskatchewan (1) , Ontario (3), Quebec (1) and Colorado (1), which, once all completed, will have a combined total capacity of about 1,017 MW (709 MW of that capacity was operational in 2011). Enbridge's share in these assets equals approximately 800 MW.
In 2011, Enbridge:

- completed the 99-MW Talbot Wind Project and the 99-MW Greenwich Wind Energy Project, both in Ontario, and the 250-MW Cedar Point Wind Energy Project in Colorado; and
- acquired 50 per cent interest in the 308-MW Lac Alfred Wind Project, which is expected to start delivering emissions-free energy to the Quebec grid by the end of 2012. This marks Enbridge's entry into the growing Quebec wind energy market, which is the second largest in Canada.

Wind-generated electricity is the fastest-growing sector of electricity generation in North America, as substantial technological advances and feed-in tariffs that offer a premium for wind power have enabled such projects to become economically attractive investments.

Enbridge expects future wind opportunities to come through expanding its existing operations and developing

new greenfield projects throughout North America.

Today, Enbridge's wind power investments have the capacity to supply 250,300 homes and avoid the emission of approximately 1.2 million tonnes of CO_2 per year.

Solar Power

Enbridge believes that solar energy represents meaningful opportunities for long-term growth. The company currently has interests in solar farms in Ontario (3) and Nevada (1) with a combined total capacity of about 150 MW.

The company first entered into solar energy in a significant way in 2009 with its investment in the 80-MW Sarnia Solar facility, one of the largest photovoltaic solar energy facilities in North America.

In early 2011, Enbridge acquired two new solar energy projects in Ontario from First Solar, a leading manufacturer of photovoltaic solar panels. The Tilbury Solar Project and the Amherstburg II Solar Project have a combined generating capacity of 20 MW.

In March 2012, Enbridge acquired a 100 per cent interest in the 50-MW Silver State North Solar Project near Las Vegas, Nevada, and starting in May 2012 the output from this utility-scale facility is being sold to NV Energy under a 25-year power purchase agreement.

Today, Enbridge's solar power investments have the capacity to supply 25,000 homes and avoid the emission of approximately 92,000 tonnes of CO_2 per year.

Geothermal Power

In mid-2010, Enbridge invested in the 35-MW (22-MW net) Neal Hot Springs Geothermal Project. The project, which is located in Oregon's Malheur County, is being developed by U.S. Geothermal Inc., which will also construct and operate the facility. Scheduled to be operational in autumn 2012, it will deliver electricity to the Idaho Power grid under a 25-year power purchase agreement. Geothermal energy is energy recovered from the heat of the earth's interior. The annual yield for the project will be about 293,000 MWh, which is enough to power about 3,500 homes.

Run-of-river hydro

With Coastal Hydropower Corporation, Enbridge has invested in the Wasdell Falls Run-of-River Hydroelectricity Project on Ontario's Severn River north of Toronto. The project generates hydroelectricity using highly efficient low-head turbines (VLH). This project has a low impact on its surroundings. Without substantial alterations to rivers and canals, it directs water through a slow-moving turbine that then returns the water to the river.

Morgan Solar

In 2011, Enbridge invested in next-generation solar technology through a $9.8-million investment in Morgan Solar, a Canadian start-up. The investment is intended to help Morgan Solar commercialize a new line of concentrating photovoltaic (PV) panels, which use plastic lenses to boost solar cells' power output. The technology provides an innovative means of generating solar power more efficiently and less expensively and with a lower environmental footprint.

Hydrogenics

In 2012, Enbridge entered into a partnership with Hydrogenics Corp. to develop large-scale electricity storage. The two companies will jointly develop a 1-megawatt, power-to-gas energy storage project in Ontario to prove the technology at a utility scale.

Hydrogenics' water electrolysis technology will convert surplus renewable energy into hydrogen gas, and Enbridge's expertise in the ownership and operation of natural gas pipelines will enable the partnership to offer seasonal electricity storage capability to the electricity sector.

The technology could be particularly advantageous in markets with large amounts of renewable energy from intermittent sources such as wind. By converting the electricity to gas and storing it in the vast natural gas pipeline networks, more renewable energy can be stored for long periods, increasing the amount of clean energy that is available for consumers.

Renewable Natural Gas/Biogas

Enbridge and other gas pipeline companies are evaluating business opportunities linked to developing renewable natural gas supplies for pipelines.

These opportunities include the potential for new pricing structures that could encourage investments that add pipeline-quality biogas from landfills and other renewable sources to the province's natural gas distribution system.

ALTERNATIVE ENERGY TECHNOLOGIES

Waste Heat Recovery

Enbridge Income Fund has a 50 per cent investment in NRGreen Power, which operates four non-regulated waste heat recovery facilities located in Saskatchewan along the Alliance Pipeline. (Enbridge Inc. has a 69.2 per cent economic interest in Enbridge Income Fund.) These four facilities combined produce approximately 20 MW of power. In 2011, NRGreen announced plans to build a fifth facility at Alliance's Windfall Compressor Station near Whitecourt, Alberta, that will deliver up to 14 MW of electricity and is expected to be in service in late 2013.

NRGreen generates electricity by harnessing the waste heat produced by Alliance Canada's gas turbines at its compressor stations and using it to produce electricity. The four facilities that are currently operational plus the new facility will together generate enough energy to meet the power needs of approximately 34,000 homes and avoid the emission of approximately 253,300 tonnes of CO_2 per year.

Fuel Cells

Enbridge launched the world's first integrated energy recovery and fuel cell power plant at Enbridge Gas Distribution's head office in Toronto in 2008.

The power plant is designed for gas utility pressure reduction stations, converting unused pipeline energy, a byproduct of distributing natural gas to customers, into electricity. Our Toronto plant generates 2.2 MW of clean electricity, or enough to serve up to 1,700 homes.

Genalta Power Inc.

In 2012, Enbridge invested in Genalta Power, a privately held Canadian corporation that owns and operates independent power plants that produce and sell environmentally friendly electricity from waste energy sources. Genalta works with site owners to provide: base-load green energy; increased plant efficiencies; operating cost reductions; greenhouse credits and emission reductions; and long-term sustainable energy. Genalta capitalizes on opportunities in the independent power market by developing dependable, cost-effective and environmentally responsible power generation facilities.

ENBRIDGE'S NEUTRAL FOOTPRINT INITIATIVE – KILOWATT FOR A KILOWATT

As part of our Neutral Footprint Initiative, Enbridge has committed to generating a kilowatt hour of renewable energy for every kilowatt hour of additional power its operations consume above 2008 levels (January 1, 2009, being the start date for applying the company's neutral footprint commitment). The company will fulfill this commitment within five years of the additional power consumption.

Each year, Enbridge will compile the forecasted power consumption for Enbridge's company-wide operations. Any net increase in power consumption will be counterbalanced by the company's investments in economically viable renewable energy production. Enbridge will address growth in its electricity consumption on a five-year rolling basis consistent with the long-range planning horizon.

Enbridge's investments in new renewable power generation will, at a minimum, be proportional to the growth in electricity consumption by its operations, beginning January 1, 2009. Because Enbridge's electricity consumption fluctuates from year to year, we base this commitment on our long-term consumption forecast. By mid-2012, we were forecasting that our power consumption will grow by 2,668 GWh by 2015, while power generated from our renewable energy assets (both existing and under construction) will be 3,080 GWh. For the current status of our Kilowatt for Kilowatt commitment, please see our Neutral Footprint dashboard.

EN7

Initiatives to reduce indirect energy consumption and reductions achieved.

Organization-wide

At the end of 2011, Enbridge had 24 active TelePresence video conference rooms. These installations increase efficiency in the organization by making it easier for employees to meet virtually face-to-face. This reduces travel and increases productivity. In 2011, Enbridge estimates that this resulted in over 1,820 fewer trips between the company's offices in Canada and the United States. This avoided 2.8 million kilometres (about 1.7 million miles) of air travel, which resulted in about 116 tonnes of CO_2 emissions being avoided. These estimates are based on just one third of the actual usage of the video conference facilities.

Liquids Pipelines
Liquids Pipelines has various energy savings initiatives in place, including the following:

Edmonton office
- installed energy-efficient lighting
- battery recycling program
- motion sensors installed in new meeting rooms to turn out lights when inactive
- in 2009, in order to reduce waste, we have created “water bottle free zones” in our Calgary and Edmonton offices. Instead of using plastic water bottles, water chillers have been installed
- locker room renovations to promote health and wellness and walking and cycling to work
- toner cartridges are recycled

Calgary office
- battery recycling program
- printers/copiers use 30 per cent recycled paper and are set to default to 2-sided printing
- light/motion sensors installed to control lighting
- washroom renovations included low-flush toilets and sinks and hands-free flush and sinks for less water use
- Styrofoam-free kitchens
- new carpet tiles are made of recyclable materials
- locker rooms to promote health and wellness and walking and cycling to work
- low-flow showerheads

Superior office
- light/motion sensors installed to control lighting
- restrooms have low-flush toilets and sinks
- Styrofoam-free kitchens

Gas Transportation
GT has various energy savings initiatives in place, including the following:

Houston Office
- battery recycling program
- paper recycling program
- printers and copiers set to default to 2-sided printing
- light/motion sensors to control lighting
- Styrofoam-free kitchen initiative
- toner cartridges are recycled
- aluminum cans recycled

Springtown Office
- aluminum cans recycled
- paper recycling program
- toner cartridges are recycled

Enbridge Gas Distribution
Actions taken to reduce indirect energy consumption at EGD’s head office building in Toronto include:
- operating Energy Recovery the Direct FuelCell®-Generation (DFC®-ERG) Power Plant and turbo expander to generate up to 2.2. megawatts of green power for use in the building;
- completion of the “2N Project” to provide a second distribution grid connection for redundancy of the data centre and tying the fuel cell into the building as a direct source of the building power;

- producing building power requirements from the standby generator for use in the building; and
- setting back all lighting/HVAC/workstation power.

WATER

EN8

Total water withdrawal by source.

EN9

Water sources significantly affected by withdrawal of water.

EN10

Percentage and total volume of water recycled and reused.

Enbridge does not use water to transport liquid hydrocarbons or natural gas. Therefore, the company's operations use only a small amount of water.

During new pipeline construction, Enbridge tries to avoid crossing waterways and wetlands. However, when we must cross them, any disturbances we cause during construction are temporary because we fully restore these areas to their previous states and use a variety of measures to minimize our impacts.

For example, in some instances when our pipelines have to cross water, we employ horizontal directional drilling to bore under water bodies and install thicker walled pipe. Other measures we take include trenching and encasing the pipe in concrete. We also time construction to cause the least impact—for example, during winter when water flow is slow or frozen and biodiversity is seasonally low.

When construction is completed, we conduct hydrostatic testing before the line becomes operational. This involves filling a section of the new line with water, generally withdrawn locally from the environment, and pressuring that section to check and confirm its functionality. In doing so, we follow company policy and regulatory standards and criteria, which include testing the water before releasing it back into the same watershed it came from.

When a pipeline is operational, Enbridge's pipeline integrity programs regularly assess the line both internally, with in-line sensing devices (smart pigs) and externally, with sensing devices and test excavations.

Surface water

Enbridge has established standards and procedures for managing water runoff from its facilities and during pipeline construction. The company has many controls in place and implements others as required by the project or relevant regulatory body. The controls used include berms and containment areas to prevent offsite contamination at facilities, as well as inspection and controlled discharge procedures.

Groundwater

In 2011, Liquids Pipelines continued its system-wide groundwater monitoring program. This program provides regular monitoring of Enbridge facilities to proactively identify potential impacts to groundwater, allowing the company to identify potential issues and maintain compliance with regulatory requirements. In 2011, the company expanded its network by adding groundwater monitoring networks at several U.S. facilities including Bartlett, North Dakota; Ladysmith, Wisconsin; Forest, Missouri; Manhattan, Illinois; and Cushing, Oklahoma.

Liquids Pipelines also continued its remediation efforts to manage groundwater contamination associated with Enbridge's Hardisty Caverns. Prior to Enbridge's acquisition of the facility, the clay liner used to contain the brine in cavern operations leaked. Enbridge operates 10 deep recovery wells to extract the contaminated groundwater either for reuse in the brine pond as makeup water, or for disposal in an onsite disposal well. The recovery wells will serve two purposes: (1) to slowly clean the groundwater by removing the contaminated water; and (2) to hydraulically contain the site, stopping further migration of the brine contamination. It is anticipated that all deep recovery wells will be installed by the end of 2012.

In 2011, Enbridge continued operation of a groundwater remediation system at its Metiskow (Saskatchewan) station. This system is required to treat groundwater contamination identified at the site. It involves groundwater recovery, treatment and reinjection systems that are designed to contain and treat groundwater contamination.

Enbridge also continued to operate a groundwater recovery and treatment system at the site of a February 2007 leak near Exeland, Wisconsin. This system is successfully recovering groundwater from the site and preventing migration to a local creek. By mid-2011, the extent of groundwater impact had been reduced by 50 per cent.

BIODIVERSITY

EN11

Location and size of land owned, leased, managed in, or adjacent to, protected areas and areas of high biodiversity value outside protected areas.

EN12

Description of significant impacts of activities, products and services on biodiversity in protected areas and areas of high biodiversity value outside protected areas.

EN13

Habitats protected or restored.

EN14

Strategies, current actions and future plans for managing impacts on biodiversity.

EN15

Number of IUCN Red List species and national conservation list species with habitats in areas affected by operations, by level of extinction risk.

Enbridge views biodiversity conservation as an important part of responsible environmental management and routinely incorporates ways to avoid and conserve wildlife habitat into its project planning and maintenance activities.

Moreover, in May 2009, Enbridge announced an ambitious plan to stabilize the company's environmental footprint. Our Neutral Footprint Initiative is designed to reduce Enbridge's environmental impact where it is felt most: on the trees the company removes, the natural habitat Enbridge permanently alters, and the energy the company uses to power its operations. As part of this Neutral Footprint Initiative, Enbridge has committed to planting a tree for every merchantable tree the company removes and helping to conserve an acre (or hectare) of natural habitat for every acre (or hectare) the company permanently impacts. Please see below for more information on the Tree for a Tree and Acre for an Acre aspects of the Neutral Footprint Initiative.

Enbridge's Approach

Enbridge always conducts detailed environmental impact assessments for our new pipeline projects, not only to comply with regulations, but also to meet our own requirements, which often exceed regulatory requirements. These assessments include reviewing potential routing alternatives to avoid, minimize, or mitigate our impact on sensitive areas.

After consulting with natural resource management agencies, Enbridge may, for example, determine that alignment changes to a pipeline could eliminate or greatly reduce short- and long-term construction impacts. Historically, such measures have enabled Enbridge to protect old-growth forests and avoid disturbing sensitive wetlands and endangered species habitats.

Enbridge also evaluates water-crossings on a case-by-case basis to minimize impacts to rivers and streams. The company incorporates environmental construction procedures into all projects and provides related training or guidelines to employees and contractors.

Mapping pipelines for species at risk

In Canada, Enbridge's Liquids Pipelines business is regulated under the Species at Risk Act (SARA), which aims to protect wildlife species and conserve biological diversity. We first mapped our Canadian mainline system in 2004, using digital mapping technology, to identify areas along parts of our right-of-way where there may be species at risk. In 2011, we continued to update this system to ensure the company is working with the most accurate and effective data. This enables environment staff to identify sensitive wildlife habitat at specific locations before we undertake projects or pipeline maintenance activities.

In the U.S., Enbridge's mainline segments have digital data regarding threatened or endangered species that are protected under the Endangered Species Act. As well, when Enbridge undertakes major construction or maintenance activities, it incorporates appropriate avoidance measures or restrictions. In preparation for an expansion, Enbridge also surveys the area and takes appropriate measures to limit impact.

Managing vegetation

Vegetation management activities at our facilities and on our pipeline rights-of-way focus on using the most environmentally-appropriate and economical ways of keeping our rights-of-way clear for inspection. Our vegetation management plans and procedures stipulate that the visible results and perceived impacts of vegetation management activities on adjacent landowners and the general public must be considered when those activities are being planned and implemented.

Protecting soils and waterways

We are committed to protecting the environmental integrity of soils and waterways in and around our operations, and we have led the development of best practices in preserving agricultural land. As part of this work, we are implementing practices that limit the long-term impact on cultivated lands when developing projects.

Protecting sensitive habitats

For projects, Enbridge conducts exhaustive analysis of various routing alternatives to determine whether these alternatives would avoid or minimize impacts to natural resources, reduce or eliminate engineering and constructability concerns, and avoid or minimize conflicts with existing or proposed residential and agricultural lands. The alternative analysis focuses on minimizing the length of the pipeline to the extent practicable, while also minimizing the environmental impacts to specific resources. At times, a pipeline route will traverse distinct natural communities. Therefore, Enbridge conducts surveys of the entire project route to identify sensitive natural and cultural resources such as wetlands, water bodies and plant/animal populations. Enbridge utilizes the survey results to identify areas requiring alternative construction techniques, timing restrictions to minimize impacts during breeding or spawning seasons for certain sensitive species, or route variations to minimize or avoid impacts to sensitive plant species. Certain features cannot be avoided and as such stringent conditions from regulators are applied and specific mitigation is set out and approved by various regulatory agencies.

Where sensitive habitats have been identified, Enbridge implements situation-specific operational plans and protocols to minimize impacts to sensitive species. Examples of this include measures to protect Boreal Caribou populations in the Northwest Territories and Alberta, moose habitat along the Athabasca Pipeline system, and the Karner Blue butterfly in Wisconsin. We restrict maintenance activities and implement special precautions to ensure our operations have minimal impact on these species.

Enbridge Gas Distribution implements either environmental screening or environmental assessment (depending on project scope) to identify any features that may be impacted by construction or maintenance activities and puts into place mitigation measures to protect them. The company uses horizontal directional drilling when crossing beneath watercourses, and before doing so always obtains permits from respective conservation authorities and provincial ministries as required. It further ensures protection of watercourses through regular pipe inspections. In 2011, Enbridge Gas Distribution did not conduct any activities in protected areas or areas of high biodiversity; and, apart from an easement on the western edge of Springwater Provincial Park, which is located near Midhurst, Ontario, Enbridge Gas Distribution does not have any pipe installed in environmentally sensitive areas.

In the U.S., some of Gas Transportation's pipelines are located in lakes/navigable waterways and within high bio-diverse land areas. Gas Transportation undertakes all activities in such a way as to ensure that it minimizes impacts and complies with regulations.

Enbridge's Neutral Footprint Initiative

As part of our Neutral Footprint Initiative, Enbridge has committed to:

- planting a tree for every merchantable tree the company removes; and
- helping to conserve an acre (or hectare) of land for every acre (or hectare) of natural habitat the company permanently impacts.

These measures will be implemented within five years of the impact occurring.

Tree for a Tree

Enbridge will plant a tree for every merchantable tree we remove to construct or expand our facilities or rights-of-way. The trees Enbridge counts and therefore replaces will be of adequate size to be considered "merchantable timber" as defined by the relevant local regulator.

Enbridge will replace trees from either forested or non-forested land (such as brush/scrub, prairie, grassland, alpine, rangeland, meadows, pasture or cultivated land). The company will plant them in such a way that it takes into account the following priority considerations:

1. Enbridge will plant trees to meet regulatory commitments and approval conditions.

2. Enbridge will plant trees to maintain slope stability, control erosion and meet reclamation guidelines and aesthetic requirements.

3. Enbridge will plant trees to meet the needs of local communities.

Enbridge will not always replace trees in the immediate area of impact, but will take into account land availability, local desire and consent. From the start of January 2009 through to the end of the second quarter of 2012, Enbridge had removed approximately 545,000 trees and had planted 375,000 tree seedlings. (Planting numbers lag removal numbers because in northern regions trees are removed during the winter season when the ground is frozen and seedlings are planted during the spring and summer.)

Acre for an Acre

Enbridge will help conserve an acre of natural habitat for every acre that it permanently impacts. The natural habitat Enbridge conserves could be forested land, wetlands or native prairie.

Enbridge will conserve the land while working with the Nature Conservancy of Canada (see below) and other organizations. As such, their guidelines and recommendations will determine how and where the land is conserved, and will ensure that it is of high ecological value.

The land Enbridge conserves may not be in the same area or region as the land that is impacted, and may not be "like for like." Rather, Enbridge and our partners will make conservation decisions based on biological value and availability.

This commitment does not replace or negate Enbridge's regulatory obligations to reclaim land when it is decommissioning an asset.

Since the beginning of 2009 through to the end of the second quarter of 2012, approximately 1,700 acres (approximately 690 hectares) of natural habitat have been disturbed and Enbridge has contributed to conserving over 5,260 acres (approximately 2,100 hectares). The surplus will be applied to future projects.

Nature Conservancy of Canada / The Conservation Fund – In early 2010, Enbridge invested $2.5 million in support of the Nature Conservancy of Canada's work to preserve and protect important and sensitive natural habitats across Canada. Through this investment, some of the best remaining wildlife habitat in Canada is being conserved. The investment is particularly significant at this time because, thanks to matching funds from sources including the Government of Canada's Natural Areas Conservation Program, our contribution of $2.5 million will trigger a conservation impact of more than $10 million.

Similarly, in the United States in late 2011, Enbridge invested US$3 million in The Conservation Fund, which partners with community, government and corporate organizations to help them fulfill their conservation priorities. This partnership will allow us to meet our acre-for-an-acre commitment in the U.S.

EMISSIONS, EFFLUENTS AND WASTE

GHG EMISSIONS

EN16

Total direct and indirect GHG emissions by weight.

EN17

Other relevant indirect GHG emissions by weight.

Note regarding the tables below:

The term "direct" emissions refers to emissions (fugitive, combustion, vented) that result from activities associated with company-owned facilities and from company-owned vehicles and are also sometimes referred to as Scope 1 emissions.

The term "indirect" emissions refer to emissions from purchased electricity where the emissions occur at facilities owned by a third party and are sometimes referred to as Scope 2 emissions.

Liquids Pipelines

The tables below summarize total direct (Scope 1) and indirect (Scope 2) GHG emissions associated with Enbridge's Liquids Pipelines operations in Canada and the U.S. The emissions are measured by tonnes of carbon dioxide equivalent (t CO_2e). In addition, estimated Scope 1 GHG emissions for Vector Pipeline Ltd., which is operated by the U.S. Liquids business unit, are provided in a separate table below.

Scope 1 (t CO_2e)	2011	2010	2009	2008
Liquids Pipelines – Canada	**12,388**	**12,367**	**11,971**	**12,693**
Liquids Pipelines – U.S.[1]	**7,282**	**5,758**	**2,980**	**9,639**
Total	**19,670**	**18,125**	**14,951**	**22,332**

1 The Scope 1 estimates for the U.S. subsidiaries include vehicle emissions and fugitives (CH4 and CO2) from terminal operations. Line heater, fire pump, and emergency generator combustion-related GHG emissions are also included for Enbridge Energy, Limited Partnership. Currently, the Scope 1 inventory does not include emissions from space heating, water heating, and other small combustion sources; however, these sources are minor in terms of U.S. Liquids' total Scope 1 and 2 emissions profile.

Scope 2 (t CO_2e)	2011	2010	2009	2008
Liquids Pipelines – Canada	**1,114,698**	**1,138,296**	**1,103,801**	**1,041,923**
Liquids Pipelines – U.S.	**1,573,849**	**1,630,793**	**1,624,746**	**1,726,446**
Total	**2,688,547**	**2,769,089**	**2,728,547**	**2,768,369**

Scope 1 (t CO_2e)	2011	2010	2009	2008
Vector Pipeline L.P.	**383,391**	**377,010**	**337,586**	**316,213**

Table notes: The Scope 1 estimate for Vector Pipelines includes stationary combustion (primarily the gas-fired compressor turbines), vehicles and system vented and fugitive emissions. Some vented and fugitive source estimates are based on default industry (INGAA) emission factors.
Scope 2 emissions for Vector Pipeline have not been estimated at this time, but would be comparatively minor relative to the company's Scope 1 emissions profile.

Gas Transportation

Gas Transportation implemented a greenhouse gas database in 2010 to calculate CO_2e emissions. GT's estimated emissions for 2011 were:

Scope 1 – Direct – 2,175,400 tonnes of carbon dioxide equivalent (t CO_2e), compared with 1,020,388 tonnes in 2010. GT's Scope 1 estimate for 2011 combines combustion data calculations and estimates based on 2008 emissions data extrapolated to GT facilities extant in 2011. The GHG numbers in this CSR Report will not be the same as those reported by GT to the U.S. Environmental Protection Agency (U.S. EPA) in September 2012 for two main reasons: (1) the numbers in this report reflect emissions from all GT facilities, whereas the U.S. EPA only requires submissions from facilities that exceed reporting thresholds; and (2) the calculation method used for this report likely is different than that required by the U.S. EPA, which had not finalized its methodology at the time GT made these calculations

Scope 2 – Indirect – 311,846 t CO_2e, compared with 95, 327 t CO_2e in 2010. The increase in GT's Scope 2 emissions in 2011 over previous years reflects GT's improved electricity consumption database, implementation of which began in the first half of 2011.

Scope 1 ($t CO_2e$)	2011	2010	2009	2008
Gas Transportation	**2,175,400**	**1,020,388**	**1,077,900**	**2,445,000**

Scope 2 ($t CO_2e$)	2011	2010	2009	2008
Gas Transportation	**311,846**	**95,327**	**135,000**	**168,000**

Enbridge Gas Distribution

Enbridge Gas Distribution also operates three smaller gas distribution companies in New Brunswick (Enbridge Gas New Brunswick), Quebec (Gazifère) and upper New York state (St. Lawrence Gas). Each of these companies' emissions is about 1 per cent of those of Enbridge Gas Distribution. However, Enbridge continues to track these emissions by tonnes of carbon dioxide equivalent ($t CO_2e$).

Scope 1 – Direct Emissions ($t CO_2e$)	2011	2010	2009	2008
Enbridge Gas Distribution	**269,524**	**319,486**	**315,806**	**313,845**

Table note: The net reduction in GHG emissions for the Enbridge Gas Distribution business units in 2011 over prior years reflects a variety of factors including the introduction of a new quantification method for buried pipe fugitive emissions, which resulted in a substantial reduction in the GHG emissions estimated for this source. Prior years' data (i.e. for the period from 1990 to 2010) have not been restated on a similar basis to reflect this new method and are therefore not fully comparable to the 2011 data.

Scope 2 – Indirect Emissions ($t CO_2e$)	2011	2010	2009	2008
Enbridge Gas Distribution	**2,164**	**2,616**	**2,653**	**3,773**

Renewable electricity generation

The following summarizes total direct (Scope 1) and indirect (Scope 2) GHG emissions associated with Enbridge's renewable electricity generation business unit.

Scope 1 ($t CO_2e$)	2011
Renewable electricity generation	**1,340**

Scope 2 ($t CO_2e$)	2011
Renewable electricity generation	**892**

Table note: This is the first time Enbridge has reported GHG emissions associated with the operations of its renewable electricity generation assets.

Transportation sources

The following summarizes total direct (Scope 1) and indirect (Scope 2) GHG emissions associated with Enbridge's airplanes and ground transportation.

Scope 1 ($t CO_2e$)	2011
Transportation sources	**2,509**

Table note: In previous CSR reports, emissions data for the company's corporate jet and mobile sources were included in the data of Enbridge's Liquids Pipelines business unit.

EN18

Initiatives to reduce GHG emissions and reductions achieved.

Enbridge's position on climate change and carbon pricing

Enbridge's Climate Change Policy recognizes that climate change is a critical global issue. We also acknowledge that dealing with climate change is a shared responsibility with implications for citizens, governments and business. Enbridge is committed to being part of a collaborative solution. We recognize that meaningful GHG reductions will require governments to collaborate with both industry and the consuming public to establish clear, realistic GHG emissions objectives, public policies and effective regulations.

Through public policies, a defined price for CO_2 emissions should be established and compliance options should focus on promoting both near-term reductions and the advancement of technology for larger future reductions.

With respect to a cap-and-trade system versus a carbon tax, both approaches could establish a carbon price. The former results in emissions certainty, whereas a tax creates price certainty. Enbridge recognizes that the two market instruments are not mutually exclusive. However, given that the operational infrastructure required for a cap-and-trade system does not currently exist and that taxation schemes are well established, it is very likely that a carbon tax would be significantly less expensive, as well as being more transparent to administer.

Our Targets

As part of our commitment to conduct business in an environmentally sustainable way, we set targets to lower our Canadian direct greenhouse gas emissions.

In 2005, Enbridge achieved its corporate target to reduce its Canadian direct GHG emissions by 15 per cent below 1990 levels. The company actually achieved an 18 per cent reduction.

Enbridge subsequently set a new reduction target for the 2010 inventory year of 20 per cent below 1990 levels and in 2011 we determined that we had achieved a 21 per cent reduction below 1990 levels, primarily through upgrading facilities and equipment. We achieved these reductions at the same time as increasing pipeline throughput by 47 per cent.

Enbridge continues to evolve its Carbon Management Strategy that will include further actions to reduce its own direct emissions. As the majority of the company's direct emissions emanate from its Canadian Gas Distribution and Services and U.S. Gas Transportation business units, the company is focused on finding ways to reduce those emissions.

Enbridge will set future targets for reducing direct emissions from its assets once it has fully completed an emissions inventory and once there is greater clarity regarding the regulatory framework(s) emerging across the North American jurisdictions where the company has operations.

With regards to completing an emissions inventory, Enbridge is designing and installing an emissions data management system. We anticipate that Phase 1, covering GHG emissions, will be operational in the fourth quarter of 2012. We expect Phase 2, which will manage criteria air contaminant emissions data, to be operational by the third quarter of 2013. The system will facilitate compliance with emissions reporting requirements in both Canada and the United States.

Enbridge Gas Distribution's GHG Reduction Initiatives

Since the early 1990s, Enbridge Gas Distribution (EGD) in Ontario has undertaken many initiatives to reduce GHG emissions from its natural gas distribution operations. The largest of these initiatives is the multi-year, multi-million dollar cast iron replacement program, which is scheduled for completion in 2012. In 2011, EGD replaced 70 kilometres (43 miles) of cast iron mains, reducing annual GHG emissions by an estimated 4,800 tonnes of carbon dioxide equivalent (t CO_2e). This cast iron pipe program has delivered an estimated cumulative reduction in annual emissions of 115,000 t CO_2e. EGD has also replaced the high-bleed pneumatic devices that vent natural gas to the atmosphere as part of their normal operating procedure with devices that are low or no bleed, and reduced the venting associated with odorant pumps. These efforts have reduced annual GHG emissions levels from pneumatic equipment by 16,800 t CO_2e, a 96 per cent decrease over 1990 levels.

Ongoing efforts to save energy and reduce GHG emissions from line heater fuel use—for example, the installation of new heater technologies and application of improved temperature control strategies—also continue to yield reductions. The most recent three-year average of line heater GHG emissions is 7,400 t CO_2e below 2000 levels, which represents a 69 per cent reduction in emissions. This significant reduction is attributed in part to these efficiency efforts and in part to external variables such as lower natural gas transmission system delivery pressures.

EGD's management of GHG emissions from its operations extends to many other activities that are more difficult to quantify. For example, emissions from third-party damages are reduced through public awareness campaigns, the "Ontario One Call" service and installation of excess flow valves on all new service line installations. Also, newer station designs now incorporate more welded connections, reducing the number of threaded or flanged connections where fugitive emissions can occur.

Approximately 95 per cent of EGD's light-duty fleet vehicles, as well as six of its heavy-duty dump trucks, run on natural gas, reducing EGD's GHG emissions compared to operating them on gasoline and diesel. Also, through aggressive energy-efficiency upgrades, energy use and GHG emissions at EGD's Toronto-area, five-story headquarters are now lower than in 1977 when the building was only two stories high.

Carbon Dioxide Sequestration

Carbon capture and sequestration (CCS) involves capturing carbon dioxide (CO_2) from large industrial sources before it is emitted into the atmosphere. Once captured, CO_2 can be safely and permanently stored in deep geological formations or injected into mature oil reservoirs to enhance oil recovery.

Enbridge has been involved in several initiatives in Canada that have been investigating the feasibility of the long-term commercial sequestration of CO_2 in deep saline aquifers.

CO_2 capture, pipelining and sequestration developments are widely considered to be one of the most immediate, feasible and meaningful ways to reduce greenhouse gas emissions on a large scale and address the challenges posed by climate change.

These initiatives could play a major role in advancing industry and government's knowledge of CO_2 capture and sequestration.

Project Aquistore (Saskatchewan)

Enbridge is participating in Project Aquistore, a collaborative effort among government, industry and research institutions to demonstrate that storage of CO_2 in deep geologic formations is a safe, effective solution for greenhouse gas emissions reduction.

This integrated carbon capture, transportation, injection and storage project will see CO_2 captured from a source in southeast Saskatchewan. This is targeted to begin in 2014. Approximately 500 to 1,000 tonnes per day will be transported via pipeline for injection into a nearby deep saline formation at 2,000 to 3,000 metres in depth. Results of the project will be available for the benefit of future CCS projects, government policy and regulation development, and for large stationary industries to consider geological storage as an option for mitigating greenhouse gas emissions.

The project proponent is Petroleum Technology Research Centre and contributing partners include Sustainable Development Technology Canada, CCRL, SaskEnergy, Enbridge, the Government of Saskatchewan, SaskPower and Schlumberger.

Project Pioneer (Alberta)

In April 2012, Project Pioneer's industry partners announced they will not proceed with this CCS project, which was to have been Canada's first fully-integrated carbon capture and storage project involving retro-fitting a coal-fired electricity generating plant.

Project Pioneer was a joint effort by TransAlta Corporation, Capital Power L.P., Enbridge Inc., and the federal and provincial governments to demonstrate the commercial-scale viability of CCS technology.

The first step and an essential part of the project was to prove the technical and economic feasibility of CCS through a front end engineering and design (FEED) study before making any major capital commitments.

Following the conclusion of the FEED study, the industry partners determined that, although the technology works and capital costs were in-line with expectations, the market for carbon sales and the price of emissions reductions were insufficient to allow the project to proceed.

Enbridge brought to Project Pioneer expertise in the design and construction of pipeline infrastructure, as well as extensive knowledge in CO_2 sequestration.

CO_2 Slurry Project (Alberta)

The CO_2 Slurry Pipeline Project is an industry consortium initiative being led by Enbridge to build a CO_2 slurry pipeline in Alberta.

In March 2010, the Government of Alberta announced that it had awarded Enbridge funding of $1 million for the "$CO_2$ Slurry Pipeline Research Initiative" under the government's Clean Air and Climate Change: Technology and Innovation Program.

The "CO_2 Slurry Pipeline Research Initiative" represents Phase 1 of the three-phase CO_2 Slurry Pipeline Project. Phase 1 has involved demonstrating proof of the concept, as well as demonstrating the technical viability of a long-distance CO_2 slurry pipeline for transporting petroleum coke, sulphur and other solids, such as limestone. A report on the results and recommendations regarding Phase 1 is expected before the end of 2012.

By providing a useful purpose for CO_2, companies such as oil sands producers can offset some of the costs associated with capturing and storing it. They can also create new markets for products (such as sulphur, petroleum coke and limestone) that are in demand throughout the world, but that have been stranded from their markets due to a lack of suitable transportation infrastructure. In addition, a slurry pipeline will help industry benefit the environment. CO_2 that would otherwise be emitted into the atmosphere would be used to transport goods. Once that objective has been met, the CO_2 would then be pipelined to sites where it could be used for enhanced oil recovery, or to areas where it could be permanently sequestered in deep saline aquifers.

OZONE DEPLETING SUBSTANCES

EN19

Emissions of ozone-depleting substances by weight.

While Enbridge continues to use halocarbon-containing equipment (in some vehicles, drinking water fountains, refrigeration and air conditioning systems), the company no longer has any infrastructure containing a significant quantity of ozone depleting substances. Enbridge had no reportable releases in 2011.

Liquids Pipelines has an ozone-depleting Substances Environmental Management Plan in place for its Canadian operations. The plan includes phase-out of halon-containing fire extinguishing equipment and a commitment to find alternatives to minimize Enbridge's use of other ozone-depleting substances. Enbridge reviews the plan every three years and updates it as necessary to reflect changes in the company's inventory and changes in applicable legislation. The plan was updated in 2011.

Enbridge Gas Distribution does not have ozone-depleting substances in its fire suppressant equipment and reported zero emissions of ozone-depleting substances in 2011.

EMISSIONS

EN20

NO, SO and other significant air emissions by type and weight.

Enbridge's Impacts

The major air emissions released by Enbridge facilities include methane, carbon monoxide, nitrogen oxides (NO_x) and volatile organic compounds (VOCs). Other contaminants released, but in much smaller quantities, include sulphur dioxide (SO_2), hydrogen sulphide and particulate matter and hazardous air pollutants such as hexane.

We work to keep air emissions from our operations below regulated limits. In some cases, we have exceeded regulatory requirements and have installed environmentally friendly technologies in our facilities that reduce air contaminant emissions. The largest source of VOC emissions from Enbridge's Liquids Pipelines operations is from tank storage.

Reporting Criteria Air Contaminants

Criteria air contaminants (CAC) are a group of common air pollutants released from sources, including incineration, industrial production, fuel combustion and transportation vehicles. Enbridge has established programs that define its roles, responsibilities and timelines for reporting its CAC emissions to various government agencies in Canada and the U.S.

In Canada, Liquids Pipelines and Enbridge Gas Distribution track and report annual CAC emissions under the National Pollutant Release Inventory. The air contaminants covered under the regulation include NO_x, SO_2, VOCs, carbon monoxide and particulate matter. In the U.S., Enbridge Liquids Pipelines monitors and reports on CAC emissions in compliance with state and federal regulations.

Liquids Pipelines

With the completion of the first phase of Enbridge Liquids Pipelines' contract tankage project in Hardisty, Alberta, in 2009, Enbridge and other industry partners established an ambient air monitoring network to monitor the air quality in the area. The stations collect and monitor the air quality both continuously and on the National Air Pollution Surveillance schedule. In addition to the air monitoring stations, Enbridge conducts semi-annual head space air sampling on each storage tank to ensure emission-control devices are functioning.

Enbridge is also a member of the Strathcona Industrial Association (SIA), which owns and operates an air monitoring network in the City of Edmonton and Strathcona County. The stations continuously monitor the air quality around Enbridge's Edmonton Terminal.

In the U.S., Enbridge tracks and reports to the Environmental Protection Agency's Toxic Release Inventory and to state regulators on VOC emissions for Liquids Pipelines terminals.

Liquids Pipelines has a rigorous maintenance program in place that includes regular inspections of emission control devices and repair or replacement of them to ensure they meet regulatory criteria.

Gas Transportation

Enbridge's Gas Transportation business unit is continually looking for opportunities to upgrade its gas facilities and pipelines in ways that contribute to operating, environmental and safety goals. One example is acid gas injection, which uses advanced technology to compress acid gas, primarily hydrogen sulphide and carbon dioxide, and inject the gases into suitable underground reservoirs, thereby avoiding emissions to the atmosphere.

Enbridge opened its second acid gas injection well near the Aker Treating Plant in 2006. In 2011, the facility injected 45,434 tonnes of carbon dioxide and avoided 304 tonnes of sulphur dioxide that would have resulted from a traditional gas treating facility.

The following criteria pollutant emissions were reported by the Gas Transportation facilities that are required to provide emission inventories:

Gas Transportation (tonnes)	2011	2010	2009	2008
CO	1,816	2,085	2,299	2,965
NO_X	3,094	3,266	3,745	4,131
VOCs	1,405	1,811	1,044	1,208
SO_2	311	764	648	1,329

Enbridge Gas Distribution

In Canada, Enbridge Gas Distribution (EGD) reports annual criteria air contaminant emissions under the National Pollutant Release Inventory (NPRI). The air contaminants covered under the regulation include NO_X, SO_2, VOCs, carbon monoxide and particulate matter. EGD reports on three locations—Chatham and Corunna, both of which are natural gas compressor stations; and Seckerton, which is an oil battery. Emissions are calculated using emission factors or site/equipment specific data.

Enbridge Gas Distribution (tonnes)	2011	2010	2009	2008
CO	152	86	123	139
NO_2	323	246	199	214
VOCs	22	15	9	12

EFFLUENTS

EN21

Total water discharge by quality and destination.

Enbridge's operations use only a small amount of water, as the company does not use it to transport liquid hydrocarbons or natural gas.

Enbridge occasionally acquires and discharges water to hydrostatically test the integrity of new or existing pipelines and tanks. Since existing pipeline sections have transported liquid petroleum or natural gas, the company analyzes and treats this test water, as needed, before returning it to the environment. Water returned to source meets discharge criteria established by local regulatory.

Please see the "Water" section (EN8) in this report for more information.

WASTE

EN22

Total weight of waste by type and disposal method.

Enbridge's operations produce mostly non-hazardous wastes consisting of paper, scrap metals, package materials and construction-related materials. Typically, Enbridge's operations generate only limited amounts of hazardous wastes.

Enbridge promotes consistent waste management practices across the company's businesses.

Overall, Enbridge makes every effort to reduce and minimize its waste volumes, regardless of hazard classification, through measurement and management programs at its various facilities. The company also tries to find beneficial ways to reuse waste by-products.

The development of waste management tracking and training programs helps employees not only meet regulations, but more effectively recover waste.

Following are some examples of Enbridge's waste management and minimization practices:

- Liquids Pipelines' operations in the U.S. provide employees across all of its operating areas site-specific guidance to help ensure sound waste management handling and disposal.
- Liquids Pipelines' Edmonton Facilities Operations team has:
    - Implemented a garbage-bag reduction program in all downtown Edmonton buildings, and to lessen the number of garbage bags thrown away each day by the cleaners, we have asked them to dump the garbage instead and only replace the bags if there is wet garbage.
    - Implemented a blue-bag recycling program in the Enbridge Place and Enbridge Tower buildings.
    - Switched out standard products offered for kitchen and cleaning (e.g., dish soap, cloths, wipes) with only green alternatives and we are expanding this into other areas such as pens, folders, etc. where possible.)
    - Implemented a TeraCycle program—recycling pens to be up cycled into products for resale.
    - Begun providing dishware and flatware for all newly renovated floors to discourage use of disposable products such as paper cups and plates, plastic cutlery, etc.
- Enbridge Gas Distribution reports liquid and solid hazardous waste and liquid industrial non-hazardous waste to the Ontario Ministry of the Environment's Hazardous Waste Information Network. These registerable wastes are generated through operation of EGD's facilities, as well as through its field operations.

SPILLS AND RELEASES

EN23

Total number and volume of significant spills.

EN24

Weight of transported, imported, exported, or treated waste deemed hazardous under the terms of the Basel Convention Annex I, II, III and VIII, and percentage of transported waste shipped internationally.

EN25

Identity, size, protected status and biodiversity value of water bodies and related habitats significantly affected by the reporting organization's discharges of water and runoff.

As the operator of one of the world's largest and most complex energy delivery systems, our job is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible. For us, doing our job well is the basis of corporate social responsibility. It is also our ongoing commitment to each and every one of our stakeholders.

Enbridge's goal is—and will always be—to prevent all spills, leaks and releases from our energy transportation and distribution systems. No spill will ever be acceptable to us and we are more determined than ever to meet our

goal of zero incidents. The safety and integrity of our operations remains our highest priority.
The vast majority of the spills that Enbridge does experience:

- are small (less than 10 barrels each);
- occur at Enbridge facilities such as pump stations and terminals and are completely contained within those facilities and never leave the site; and
- are discovered very soon after they occur, which allows for rapid response and clean-up and results in low or no environmental impact.

Also, spills are infrequent relative to the volume of liquids products that Enbridge transports. Typically, Enbridge safely delivers over 99.999 per cent of the volume it ships in any given year. For example:

- Over the past 10 years, Enbridge's Liquids Pipelines business unit has delivered almost 12 billion barrels of crude oil and liquids with a safe delivery record of 99.999 per cent.
- In 2011, Liquids Pipelines transported over 1.6 billion barrels of crude oil and liquids and recorded 58 reportable spills representing a total of 2,284 barrels. In other words, Liquids Pipelines safely delivered 99.9999 per cent of the substantial volume it shipped in 2011, which is consistent with Liquids Pipelines' safe-delivery performance in prior years. Of those 58 spills, 49 of them, or approximately 85 per cent, had a volume of 10 barrels or less; 50 of them, or approximately 86 per cent, occurred at Enbridge facilities; and eight of them, or approximately 14 per cent, occurred on Enbridge rights-of-way. Liquids Pipelines' spill volume in 2011 of 2,284 barrels represents this business unit's lowest annual spill volume of the past 10 years.

With that said, no incident is acceptable to us. We have always, and we will continue to, go to great lengths to investigate and understand every release incident and apply what we learn to ensure continued improvement.

Spill Prevention

We implement rigorous measures during design, construction and operation of our pipelines to prevent spills from occurring. These measures include avoidance of environmentally sensitive areas, meeting all special design requirements for areas such as road, river and creek crossings, and investing heavily in pipeline safety and integrity programs. While these measures contribute to reducing the risk of a release, they cannot eliminate it.

In order to address these residual risks, we have comprehensive spill response and environmental mitigation plans in place to respond rapidly and completely if spills do occur. No matter what the size or location of the spill, we take every incident very seriously and treat it as a top priority.

Responding to Spills

When Enbridge experiences a spill, the company's highest priority is the safety and protection of people and the environment and the rapid response and thorough containment and clean-up in such a way as to minimize the impacts. Following are the typical steps that Enbridge takes in responding to an oil spill:

- Containment is the first order of business as Enbridge works to address the environmental impact. Simply put, the smaller the area that is touched by the oil, the less damage is done and the easier it is to clean up.
- As it contains the oil, Enbridge works to capture it and safely remove it from the environment. As it removes the oil, Enbridge is very careful to keep it from spreading to uncontaminated vegetation, water or soil.
- For the vast majority of spills, whether they are large or small, Enbridge recovers a high percentage of the oil and injects it back into the pipeline.
- Water, soil and vegetation that have come into contact with oil is typically removed and disposed of at an appropriate waste disposal facility. As affected water, soil and vegetation are removed, Enbridge is very careful not to spread the oil to uncontaminated areas. The company establishes what needs to be removed based on a comprehensive clean-up plan, environmental testing and monitoring, physical inspection and guidance from government regulators.
- Enbridge works closely with wildlife experts to minimize impacts on wildlife and assist and rehabilitate animals that have come in contact with oil.

We develop plans for remediation and reclamation with the input of affected stakeholders and environmental regulators. Our goal is to address the requirements of all regulators and stakeholders and to restore the area as closely as possible to its pre-spill condition or to a state that is acceptable to the local community.

Each release occurrence is investigated to determine a root cause and findings are incorporated into the company's Integrity Management programs.
For a detailed report on Enbridge's ongoing initiatives to mitigate the environmental impacts of our services, including

pipeline and system integrity initiatives, spill mitigation, and spill preparedness and response measures, please see "Products and Services – EN26/EN27 – Pipeline and System Integrity" below.

ENBRIDGE'S PERFORMANCE – 2011 REPORTABLE SPILLS

In this section, we report 2011 spills firstly on a company-wide basis and secondly by three of our business units—Liquids Pipelines; Gas Transportation; and Enbridge Gas Distribution.

Definitions

Technically, a reportable spill, leak or release is one that is large or significant enough that the company is required to formally notify a regulatory agency. (Enbridge uses the terms "spills," "leaks" and "releases" interchangeably.) Despite this technical definition, as part of our efforts to continually improve our operations, we record and address even small releases that we are not required to report to regulators.

Notes regarding the tables in this section:

- "Onsite" refers to spills that occurred at Enbridge facilities. Most onsite spills are completely contained within the company's facilities and are quickly cleaned up with minimal or no environmental impact.
- "Offsite" refers to spills that occurred on Enbridge rights-of-way.
- A reportable spill, leak or release is one that meets the requirements for formal notification to a regulator.

2011 REPORTABLE SPILLS – COMPANY-WIDE

Enbridge company-wide had a total of 94 reportable spills, leaks and releases in 2011 totaling approximately 2,366 barrels (Liquids Pipelines: 2,283.5 barrels; Gas Transportation: 47.07 barrels; Enbridge Gas Distribution: 35 barrels). Of the 94 spills:

- 82 of them or approximately 87 per cent had a volume of 10 barrels or less;
- 53 of them or approximately 56 per cent occurred at Enbridge facilities ("onsite"); and
- 41 of them or approximately 44 per cent occurred on Enbridge rights-of-way ("offsite").

2011 REPORTABLE SPILLS, LEAKS AND RELEASES – COMPANY-WIDE

		0-1 bbls	2-10 bbls	11-100 bbls	>100 bbls
Onsite		**26**	**17**	**9**	**1**
Offsite		**30**	**9**	**1**	**1**
Sub-total		**56**	**26**	**10**	**2**
Total	**94**				

REPORTABLE SPILLS, LEAKS AND RELEASES (COMPANY-WIDE) – FIVE-YEAR CONSOLIDATED DATA

Year	Total Number of Spills	Total Spills Volume (bbls)
2011	**94**	**2,366**
2010	**91**	**34,258**
2009	**103**	**8,441**
2008	**92**[1]	**2,842**
2007	**65**	**13,772**

1 Adjusted down from the 93 spills reported in Enbridge's 2009 CSR Report because one Enbridge Gas Distribution planned and permitted release of water in 2008 was incorrectly counted as a spill.

2011 REPORTABLE SPILLS – LIQUIDS PIPELINES

In 2011, Liquids Pipelines transported over 1.6 billion barrels of crude oil and liquids on its systems in Canada and the U.S. and recorded 58 reportable liquid spills, leaks or releases totaling approximately 2,284 barrels—the business unit's lowest annual spill volume of the past 10 years. In the U.S. in 2011, Enbridge had zero PHMSA*-reportable spills (spills above 5 barrels) from its onshore liquids pipelines, including valve sites. (*PHMSA: Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation)

Of Liquids Pipelines' 58 spills:

- 49 of them or approximately 85 per cent had a volume of 10 barrels or less;
- 50 of them or approximately 86 per cent occurred at Enbridge facilities ("onsite"); and
- 8 of them or approximately 14 per cent occurred on Enbridge rights-of-way ("offsite").

Please see below for reports on Liquids Pipelines' significant spills in 2011 and the first half of 2012, as well as an update on Enbridge's response to the leak in July 2010 of approximately 20,000 barrels of crude oil on Enbridge's Line 6B pipeline near Marshall, Michigan.

LIQUIDS PIPELINES – 2011 REPORTABLE SPILLS BY VOLUME AND LOCATION

		0-1 bbls	2-10 bbls	11-100 bbls	> 100 bbls
Onsite		**26**	**16**	**7**	**1**
Offsite		**3**	**4**	**0**	**1**
Sub-total		**29**	**20**	**7**	**2**
Total	**58**				

LIQUIDS PIPELINES – VOLUME OF TOTAL REPORTABLE SPILLS

Year	Total Number of Spills	Total Spills Volume (bbls)
2011	**58**	**2,283.5**
2010	**80**	**34,122**
2009	**89**	**8,353**
2008	**80**	**2,681**
2007	**59**	**13,756**[1]

1 Total Spills Volume in 2007 has been adjusted upward from the 11,956 barrels reported in the 2009 CSR Report because a volume correction for one spill that occurred in 2007, which was included in the 2008 CSR Report, was inadvertently omitted in the 2009 CSR Report.

REPORTABLE SPILLS HISTORY – LIQUIDS PIPELINES

Over the past 10 years, Enbridge's Liquids Pipelines business unit has delivered almost 12 billion barrels of crude oil and liquids with a safety record of 99.9992 per cent. Most of Liquids Pipelines' spills are less than a barrel and occur inside pump stations ("onsite") where any spilled oil is readily contained and recovered without entering the natural environment.

LIQUIDS PIPELINES – VOLUME OF TOTAL REPORTABLE SPILLS COMPARED WITH TOTAL DELIVERY VOLUME – 2002 TO 2011

Year	Total Number of Spills (Onsite / Offsite)[1]	Total Spills Volume (barrels) (Onsite / Offsite)[1]	Total Annual Delivery Volume (barrels)	Percentage of Annual Delivery Volume Safely Delivered (%)	Percentage of Annual Delivery Volume Safely Delivered (%) excluding Onsite[1] Spill Volumes
2011	58 (50 / 8)	2,284 (637 / 1,646)	1,641,262,240	99.9999	99.9999
2010	80 (61 / 19)	34,122 (2,710 / 31,412)	1,487,709,454	99.9977	99.9998
2009	89 (83 / 6)	8,353 (6,524 / 1,829)	1,333,947,614	99.9994	99.9995
2008	80 (72 / 8)	2,681 (2,587 / 94)	1,256,268,675	99.9998	99.9998
2007	59 (52 / 7)	13,756 (902 / 12,854)	1,199,657,322	99.9989	99.9999
2006	62 (54 / 8)	5,434 (3,177 / 2,258)	1,198,602,588	99.9995	99.9997
2005	70 (63 / 7)	9,825 (9,448 / 377)	1,060,531,358	99.9991	99.9991
2004	64 (45 / 19)	3,114 (318 / 2,796)	1,123,230,798	99.9997	99.9999
2003	58 (41 / 17)	6,377 (6,142 / 235)	867,686,223	99.9993	99.9993
2002	46 (38 / 8)	14,680 (7,944 / 6,734)	733,440,396	99.9980	99.9989
TOTAL	666 (559 / 107)	100,626 (40,389 / 60,237)	11,902,336,668	99.9992 (average over 10 years)	99.9997 (average over 10 years)

1 "Onsite" refers to spills that occurred at Enbridge facilities. Most onsite spills are completely contained within the company's facilities and are quickly cleaned up with minimal or no environmental impact. "Offsite" refers to spills that occurred on Enbridge rights-of-way.

ENBRIDGE'S LIQUIDS PIPELINES SPILLS PERFORMANCE COMPARED WITH CANADA AND U.S. PIPELINE INDUSTRY

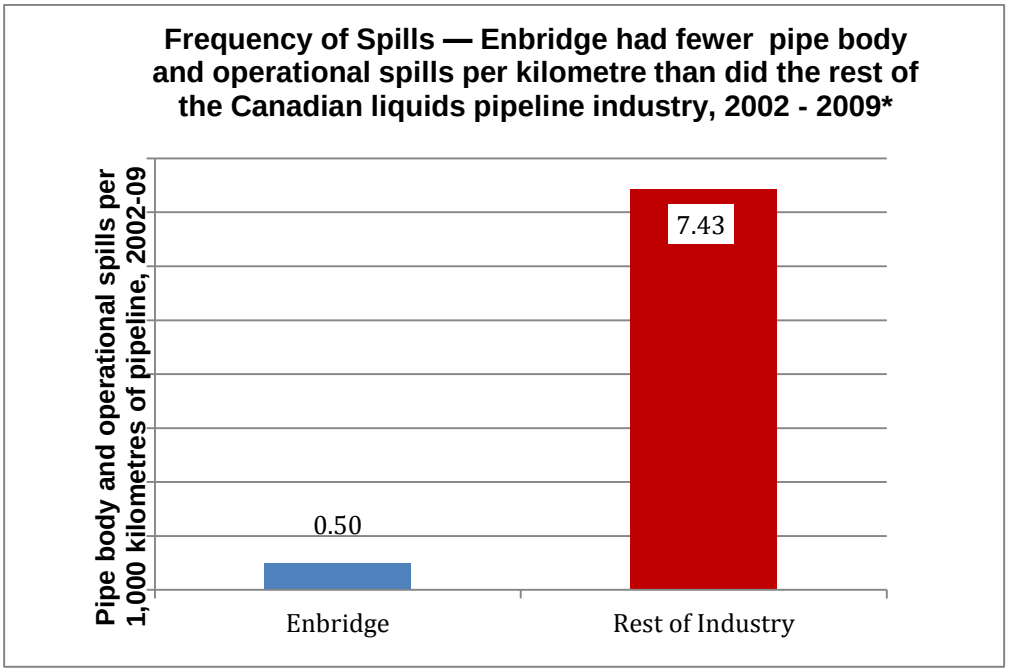
Canada (2002-2009)

Comparing Enbridge's Liquids Pipelines performance to that of the rest of the Canadian pipeline industry, in the period 2002 to 2009:

Frequency of Spills Comparisons

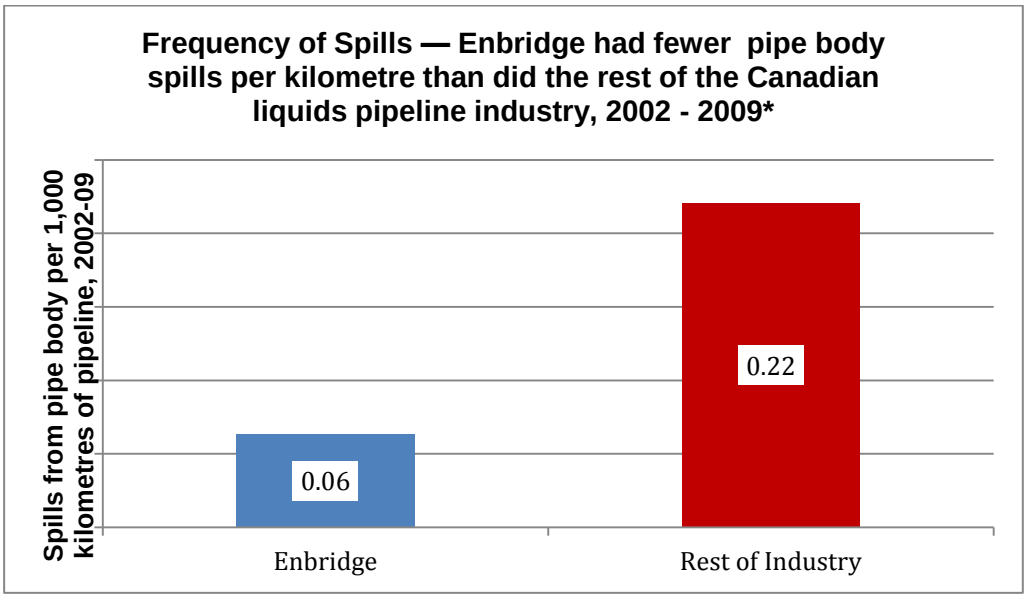
- Enbridge experienced 0.5 spills (including pipe body and operational spills) per 1,000 kilometres of pipeline, compared with an average of 7.43 spills (including pipe body and operational spills) per 1,000 kilometres of pipeline for the rest of the liquids pipeline industry in Canada. In other words, Enbridge's pipe body and operational spill frequency was approximately 93 per cent better than that of the rest of the industry.

[Note: A "pipe body" spill is a spill that originates from the body of the pipe. An "operational spill" is a spill that originates from a pipeline component such as a flange, valve, pump or storage tank.]



* These data pertain to pipe body AND operational spills (spills that originate from pipeline components such as flanges, valves, pumps or storage tanks). The data include spills of 1.5 m^3 (9.43 barrels) or more. "Frequency of Spills" refers to the number of events. This comparison is based on data that Enbridge and other liquids pipeline operators submitted to Canada's Transportation Safety Board (TSB). The data for the industry as a whole are available through Canada's National Energy Board (NEB). At the time of publishing this report, data were available only up to and including 2009. The data pertain only to the liquids pipelines in Canada that are federally regulated (i.e. the liquids pipelines that cross provincial or national boundaries). In Enbridge's case, the data pertain to our Enbridge Pipelines Inc., Westspur, Southern Lights and Norman Wells pipelines. This bar graph shows the relationship between Enbridge's pipe body and operational spill frequency ratio and that of the rest of the federally-regulated Canadian liquids pipeline industry.

- Enbridge experienced 0.06 spills (including only pipe body spills) per 1,000 kilometres of pipeline, compared with an average of 0.22 spills (including only pipe body spills) per 1,000 kilometres of pipeline for the rest of the liquids pipeline industry in Canada. In other words, Enbridge's pipe body spill frequency was about 70 per cent better than that of the rest of the industry.



* These data pertain to pipe body spills only. Operational spills (spills that originate from pipeline components such as flanges, valves, pumps or storage tanks) are excluded from the data. The data include spills of 1.5 m^3 (9.43 barrels) or more. "Frequency of Spills" refers to the number of events. This comparison is based on data that Enbridge and other liquids pipeline operators submitted to Canada's Transportation Safety Board (TSB). The data for the industry as a whole are available through Canada's National Energy Board (NEB). At the time of publishing this report, data from the NEB were available only up to and including 2009. The data pertain only to the liquids pipelines in Canada that are federally regulated (i.e. the liquids pipelines that cross provincial or national boundaries). In Enbridge's case, the data pertain to our Enbridge Pipelines Inc., Westspur, Southern Lights and Norman Wells pipelines. This bar graph shows the relationship between Enbridge's pipe body spill frequency ratio and that of the rest of the federally-regulated Canadian liquids pipeline industry.

Volume Spilled Comparisons

- Enbridge spilled 306 barrels of liquids (including both pipe body and operational spills) per 1,000 kilometres of pipeline, compared with an average of 355 barrels of liquids (including both pipe body and operational spills) per 1,000 kilometres of pipeline for the rest of the Canadian liquids pipeline industry. In other words, Enbridge's pipe body and operational spill volume was about 14 per cent better than that of the rest of the industry.
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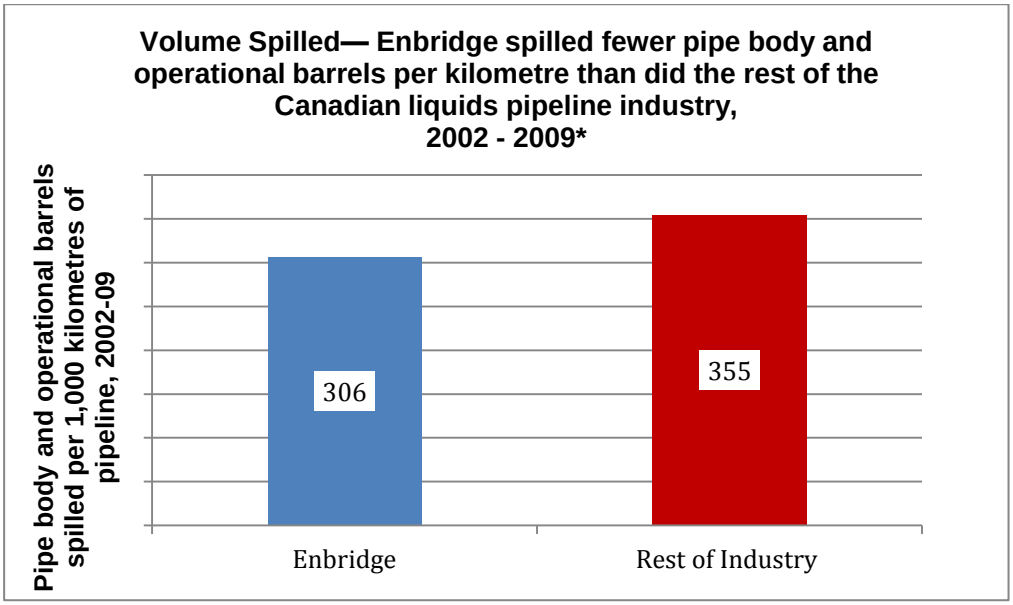
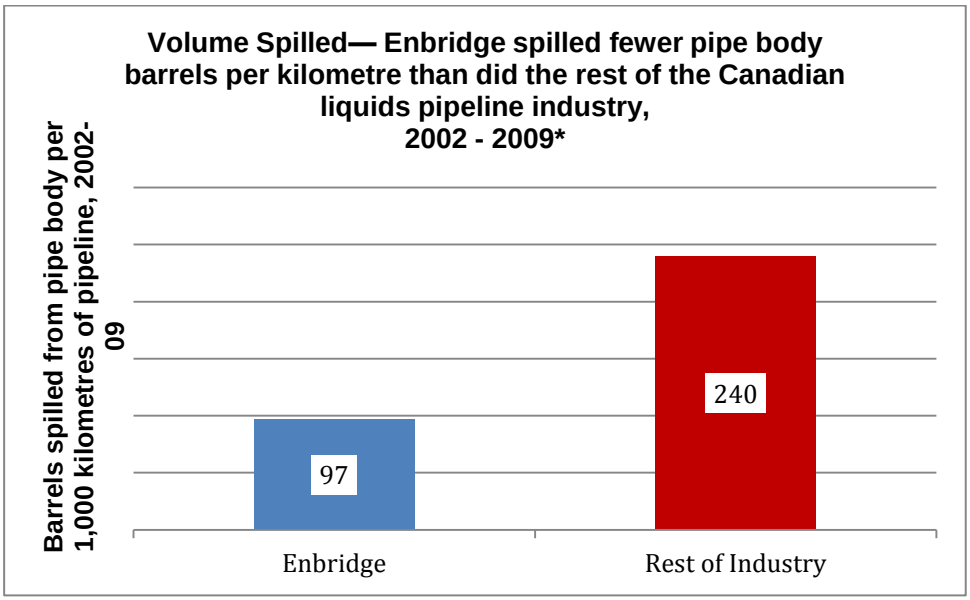


* These data pertain to pipe body AND operational spills (spills that originate from pipeline components such as flanges, valves, pumps or storage tanks). The data include spills of 1.5 m^3 (9.43 barrels) or more. "Frequency of Spills" refers to the number of events. This comparison is based on data that Enbridge and other liquids pipeline operators submitted to Canada's Transportation Safety Board (TSB). The data for the industry as a whole are available through Canada's National Energy Board (NEB). At the time of publishing this report, data were available only up to 2009. The data pertain only to the liquids pipelines in Canada that are federally regulated (i.e. the liquids pipelines that cross provincial or national boundaries). In Enbridge's case, the data pertain to our Enbridge Pipelines Inc., Westspur, Southern Lights and Norman Wells pipelines. This bar graph shows the relationship between Enbridge's pipe body and operational spill frequency ratio and that of the rest of the federally regulated Canadian liquids pipeline industry.

- Enbridge spilled 97 barrels of liquids (including only pipe body spills) per 1,000 kilometres of pipeline, compared with an average of 240 barrels of liquids (including only pipe body spills) per 1,000 kilometres of pipeline for the rest of the Canadian liquids pipeline industry. In other words, Enbridge's pipe body spill volume was about 60 per cent better than that of the rest of the industry.



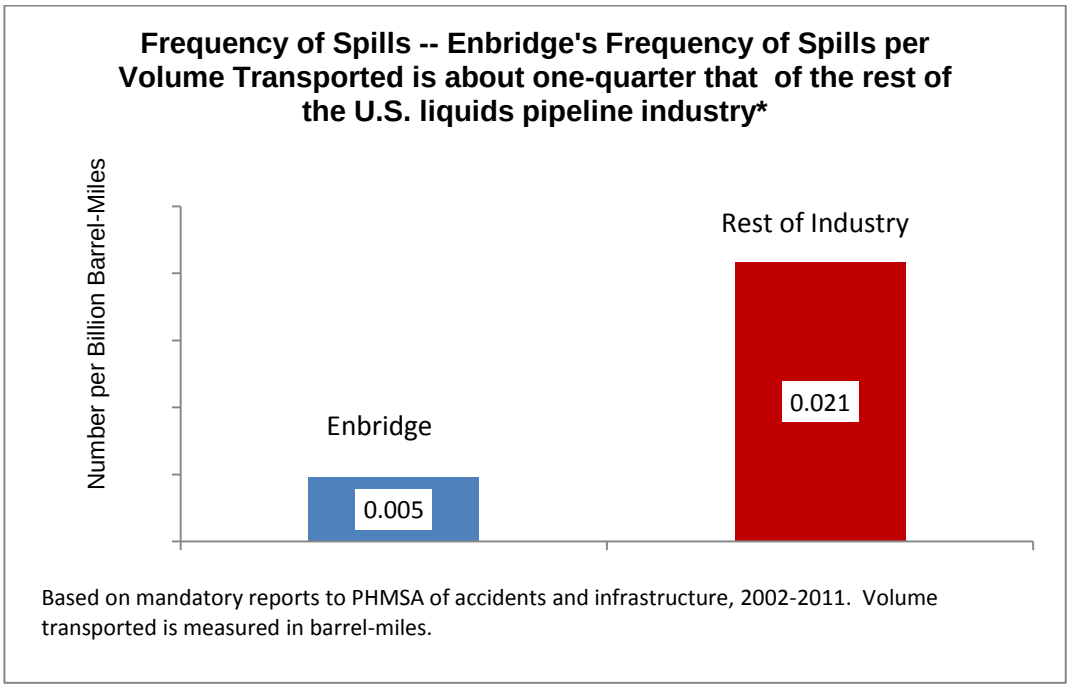
* These data pertain to pipe body spills only. Operational spills (spills that originate from pipeline components such as flanges, valves, pumps or storage tanks) are excluded from the data. The data include spills of 1.5 m^3 (9.43 barrels) or more. "Frequency of Spills" refers to the number of events. This comparison is based on data that Enbridge and other liquids pipeline operators submitted to Canada's Transportation Safety Board (TSB). The data for the industry as a whole are available through Canada's National Energy Board (NEB). At the time of publishing this report, data from the NEB were available only up to and including 2009. The data pertain only to the liquids pipelines in Canada that are federally regulated (i.e. the liquids pipelines that cross provincial or national boundaries). In Enbridge's case, the data pertain to our Enbridge Pipelines Inc., Westspur, Southern Lights and Norman Wells pipelines. This bar graph shows the relationship between Enbridge's pipe body spill frequency ratio and that of the rest of the federally-regulated Canadian liquids pipeline industry.

U.S. (2002-2011)

Comparing Enbridge's Liquids Pipelines performance in the U.S. to that of the rest of the U.S. pipeline industry, in the period 2002 to 2011:

Frequency of Spills Comparison

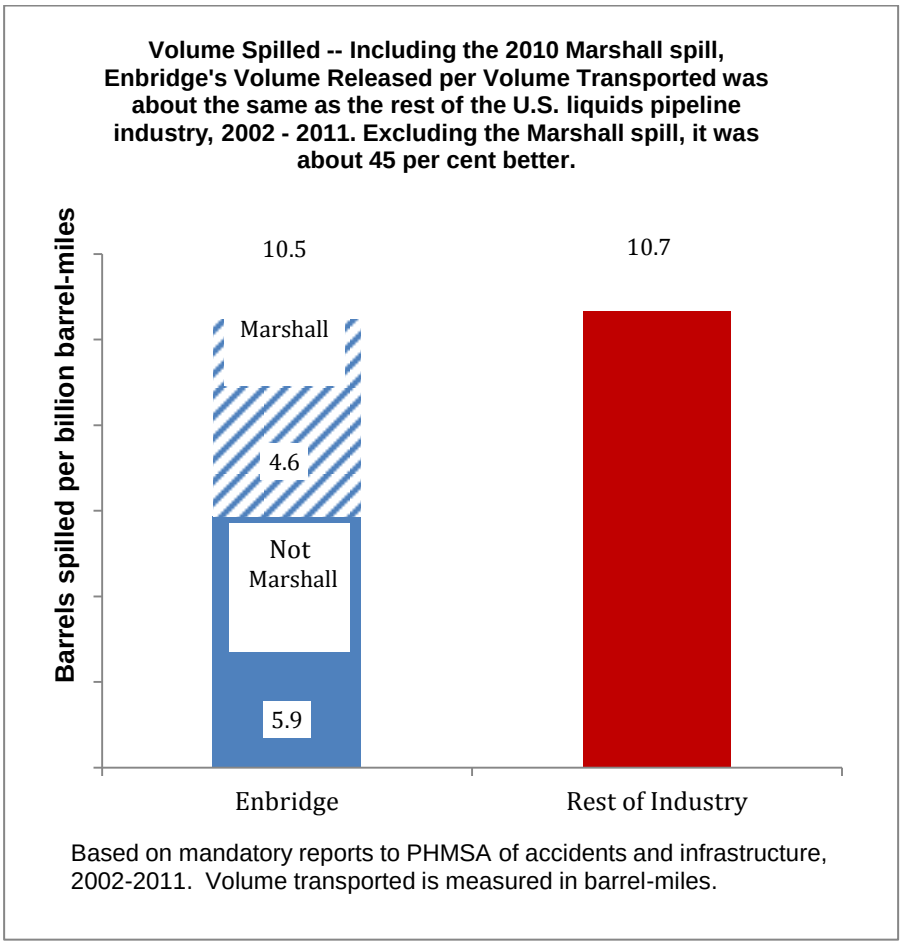
- Enbridge experienced 0.005 spills per billion barrel-miles, compared with an average 0.021 spills per billion barrel-miles for the rest of industry. In other words, Enbridge's spill frequency was about 75 per cent better than that of the rest of the industry.
- While Enbridge compares favourably in terms of spill frequency to the rest of the U.S. liquids pipeline industry, it is important to note that the entire industry is improving. The number of annual spills that the U.S. liquids pipeline industry (onshore) experienced along their rights-of-way over the three-year period of 2008 to 2010 was 60 per cent less than the number that the industry experienced over the three-year period of 1999 to 2001. (Source: U.S. pipeline industry's voluntary Pipeline Performance Tracking System)



* Spills from onshore pipelines, including valve sites. Spills that took place within stations or terminals on company property are excluded from the data. The data include spills of five barrels or more, or those involving a release to water, death, injury, fire explosion or damages exceeding US $50,000; for smaller spills, operators were not required to specify the part of the system, such as onshore pipelines, including valve sites until 2010. "Frequency of Spills" is the number of events. "Volume Transported" refers to the total amount of petroleum liquids shipped in the U.S. between 2002 and 2011 in billion barrel-mile units. This bar graph shows the relationship between Enbridge's spill frequency per volume transported and that of the rest of the U.S. liquids pipeline industry. This comparison is based on data available through PHMSA's databases for its mandatory accident and mileage reports from operators (Forms 7000-1 and 7000-1.1).

Volume Spilled Comparison

- When the spill volumes associated with Enbridge's 2010 Marshall spill are included, Enbridge's spill volume between 2002 and 2011 was comparable to that of the rest of the U.S. liquids pipeline industry. When the Marshall spill volumes are excluded, Enbridge's spill volume during the same period was about 45 per cent better than the average spill volume of the rest of the U.S. industry.
- It is important to also note that the entire industry is improving. The number of barrels of liquids spilled by the U.S. liquids pipeline industry along their rights-of-way over the three-year period of 2008 to 2010 was 35 per cent less than the number of barrels spilled over the three-year period of 1999 to 2001. (Source: U.S. pipeline industry's voluntary Pipeline Performance Tracking System)



* Spills from onshore pipelines, including valve sites. Spills that took place within stations or terminals on company property are excluded from the data. The data include spills of five barrels or more, or those involving a spill to water, death, injury, fire explosion or damages exceeding US $50,000; for smaller spills, operators were not required to specify the part of the system, such as onshore pipelines, including valve sites until 2010. “Volume Spilled” is the number of barrels spilled. “Volume Transported” refers to the total amount of petroleum liquids shipped in the U.S. between 2002 and 2011 in billion barrel-mile units. The resulting bar graph shows the relationship between Enbridge’s spill ratio and that of the industry. This comparison is based on the data available through U.S Department of Transportation databases for its mandatory accident and mileage reports from operators (Forms 7000-1 and 7000-1.1).

SPILL COSTS – LIQUIDS PIPELINES – JULY 2010 TO JUNE 2012

Note: Enbridge defines "significant spill" as any release greater than 100 barrels or that entails clean-up costs of $1,000,000 or more.

Significant Spill in 2011

Life-to-date costs incurred by Enbridge as a result of the one significant product leak that occurred across its entire Canada and U.S. liquids pipelines system in 2011 (the Norman Wells Pipeline leak; please see below for a report), total approximately $40 million. This total includes internal and external costs relating to spill response, repair, clean-up and remediation activities.

Line 6B Spill (near Marshall, Michigan) – July 2010

On July 26, 2010, a leak of approximately 20,000 barrels of crude oil occurred on Line 6B on Enbridge Energy Partners, L.P.'s (EEP) subsidiary's Lakehead System near Marshall, Michigan. (Please see "Significant Spills Summary – Liquids Pipelines" below for more details).

During the second quarter of 2012, cleanup of the areas affected by the Line 6B release had been substantially completed, which allowed the Kalamazoo River and Morrow Lake to be re-opened for recreational use. EEP will continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations, including remediation and restoration of the area, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All the initiatives that EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) related to the Line 6B crude oil release, which indicated a US$3.7 million civil penalty. EEP agreed to pay the penalty proposed by PHMSA. EEP has included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012, the U.S. National Transportation Safety Board (NTSB) presented the results of its investigation into the Line 6B crude oil release and subsequently posted its final report on July 26, 2012.

As a result of additional work needed as noted above and the civil penalty assessed by PHMSA, EEP has revised the total estimate for costs to US$785 million ($131 million after-tax attributable to Enbridge) for this incident, before insurance recoveries, and excluding fines and penalties which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above, as of June 30, 2012, an increase of US$20 million from March 31, 2012. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at June 30, 2012. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Incident (in Romeoville, Illinois) – September 2010

On September 9, 2010, a leak of approximately 9,000 barrels of crude oil occurred on Line 6A on EEP's Lakehead System in Romeoville, Illinois (please see "Significant Spills Summary – Liquids Pipelines" below for more details).

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million, excluding lost revenue of approximately US$3 million.

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million, before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Future Costs and Liabilities

Future costs associated with monitoring and rehabilitating affected areas are determined only after clean-up and assessment, which is often a multi-seasonal process. Liabilities such as fines and penalties are only determined subsequent to investigations and legal and regulatory processes. Therefore, total costs and liabilities cannot yet be determined for spills that occurred in 2010, 2011 and 2012.

SIGNIFICANT SPILLS SUMMARY – LIQUIDS PIPELINES – JULY 2010 TO JULY 2012

Near Marshall, Michigan

On July 26, 2010, a release of crude oil on Line 6B of Enbridge Energy Partners, L.P.'s (EEP) subsidiary's Lakehead system was reported near Marshall, Michigan. The company estimates that 3,180 m^3 (20,000 barrels) of crude oil leaked at the site, and of that an estimated 1,271 m^3 (8,000 barrels) reached Talmadge Creek, a tributary that feeds the Kalamazoo River. The released crude oil affected approximately 38 miles (61 kilometres) of area along the Talmadge Creek and Kalamazoo River waterways between Marshall and downstream of Battle Creek, Michigan. A multi-agency effort led by the U.S. Environmental Protection Agency (EPA), the Michigan Department of Environmental Quality (MDEQ), and other federal, state and local agencies are guiding the clean-up and remediation efforts.

The removal and replacement of the pipeline segment that failed was completed in 2010 under the supervision of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), which required Enbridge to perform specific tasks to ensure the safety of the pipeline before returning it to service. These steps were completed, and the pipeline was safely returned to service on September 27, 2010.

Enbridge and EEP conducted a detailed internal investigation of this incident in the weeks following the crude oil release and have made many enhancements to their processes, procedures and training as a result of the findings of their investigation, including in the company's Edmonton control centre. Incident prevention, detection and response have also been enhanced. On July 26, 2012, the U.S. National Transportation Safety Board (NTSB) released its report on its investigation into the Line 6B crude oil release. Enbridge and EEP committed to carefully examining the findings in the NTSB report and make further adjustments as necessary to the enhancements they have already made since the incident.

The Line 6B release was unprecedented for Enbridge and the company has taken full responsibility for the incident since the beginning, pledging that we would address the impacts of the release on the natural environment and would address the financial and other needs of individuals and businesses in the community.

During the winter and early spring of 2012, EEP continued to work closely with Michigan state and U.S. Environmental Protection Agency (U.S. EPA) officials on the final work in the Kalamazoo River. During this period, EEP completed the remediation of a number of smaller Kalamazoo River overbank sites, as well as the affected areas along Talmadge Creek.

On April 18, 2012, EEP announced that cleanup, under the direction of the U.S. EPA, had progressed to the point that a section of the Kalamazoo River had been opened for recreational use. The first section opened from the access site near Perrin Dam (Marshall Public Works building) to Saylor's Landing. Saylor's Landing is one of five new public river access sites that Enbridge has built for the community.

Then, on June 21, 2012, EEP announced that the Kalamazoo River and Morrow Lake were open for recreational use.

Even with the river open, EEP will continue to perform activities related to cleanup under the direction of the U.S. EPA and the MDEQ.

As part of the Corrective Action Order on Line 6B, PHMSA also directed Enbridge to replace a section of the pipeline located beneath the St. Clair River, which forms the border between Michigan and Ontario. A dent in that section had been confirmed during a 2009 in-line inspection. While the dent was most likely there since installation in the late 1960s, following the Marshall leak the public tolerance for any risk on Enbridge's system was understandably low and scrutiny by elected and regulatory officials was very high. Enbridge completed the repair in June 2011, well before the September 2011 PHMSA deadline.

For more detailed and up-to-date information about Enbridge's response to the Line 6B leak, please visit http://response.enbridgeus.com/response/.

In Romeoville, Illinois

On September 9, 2010, a crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois. The pipeline was shut down within minutes of the company being notified of the leak and the section of the pipeline where the leak occurred was isolated. Oil was released onto a roadway and then into a

storm water retention pond. Approximately 300 personnel and contractors were deployed to clean up and remediate the affected areas. Approximately 1,431 m^3 (9,000 barrels) of crude oil were released, of which approximately 222 m^3 (1,400 barrels) were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The company has fulfilled its obligations under the clean-up and remediation order from the U.S. Environmental Protection Agency and is continuing to pursue final remediation obligations with the Illinois Environmental Protection Agency. The cause of the crude oil release is being investigated by the U.S. National Transportation Safety Board.

Near Wrigley, Northwest Territories

On May 9, 2011, a leak occurred on Enbridge's Norman Wells Pipeline approximately 50 kilometres south of Wrigley and 150 kilometres south of Willowlake River in the Northwest Territories. The leak was reported to the Northwest Territories 24-hour Spill Report Line and Enbridge's emergency response plans were activated. It is estimated that 258.8 m^3 (1,628 barrels) of crude oil was released.

The site is located in a remote area with significant access restrictions, and the leak received substantial attention from regulators and local First Nations.

Enbridge implemented an aggressive response and remediation plan for the site, with the goal of removing all contamination and returning the site as close as possible to its pre-spill condition in a timely manner.

Excavation of all contaminated soils from the site was completed in late November 2011. These soils were staged at the leak site or an off-site staging area until highway and ice-road conditions would allow for transport to approved waste handling facilities for final disposal in January-April 2012.

The majority of site restoration work had been completed by spring 2012, with final restoration scheduled for completion during summer 2012.

In accordance with plans submitted to the National Energy Board, Enbridge will be monitoring groundwater in and around the former excavation area to confirm the successful removal of the groundwater impacts.

Monitoring of surface water, groundwater and reclamation success will continue until established goals have been achieved.

Near New Lenox, Illinois

On March 3, 2012, two third-party vehicles left the end of a public road (T-intersection) within an industrial area and struck an above ground pig sending trap within an Enbridge fenced facility on Line14/64 near New Lenox, Illinois.

A drain line on the bottom of the pig sending trap severed, and a release of crude oil and fire occurred.

Enbridge detected a pressure anomaly on Line 14/64, and the line was immediately shutdown and isolated by closing valves.

Local emergency responders notified Enbridge of the fire at its facility and the fire was subsequently extinguished.

The collision resulted in two fatalities at the scene; both were occupants of the third-party vehicles. To date, the status of any other occupants of the vehicles has not been confirmed.

An estimated 238.5 m^3 (1,500 barrels) of crude oil were released from the pig sending trap; of that amount, more than 190.8 m^3 (1,200 barrels) were estimated to have been consumed during the fire. The remainder of oil was contained within Enbridge property and clean-up activities were conducted with the oversight of the United States and Illinois Environmental Protection Agencies.

Sampling conducted after excavation activities were complete verified that the cleanup was a success. Community air monitoring identified no concerns. Enbridge anticipates having regulatory closure later in 2012.

An investigation of the incident was conducted by the local police department, and Enbridge is conducting an internal investigation.

Near Elk Point, Alberta

On June 18, 2012, approximately 230 m^3 (1,446 barrels) of crude oil leaked at Enbridge's Elk Point Pump Station on Line 19 (Athabasca Pipeline) near the town of Elk Point, Alberta.

At approximately 5:41 a.m. MST on June 18, Enbridge's monitoring system detected a drop in pressure indicating a possible oil release on Line 19. At 5:51 a.m. MST, the Enbridge pipeline control centre initiated a shutdown of the line and isolation of Elk Point Pump Station. Enbridge immediately contacted local emergency response organizations and notified civic authorities and regulatory agencies. The area was secured and clean-up operations began immediately. There was no risk to public health or safety. No water or wildlife was impacted

The release was largely contained within the pumping station site. Approximately 200 m^3 (1,258 barrels) were contained on the Enbridge site and approximately 30 m^3 (188 barrels) was released on an adjacent landowner's field.

Line 19 was safely restarted on the afternoon on June 18. However, the line was again shut down the afternoon of June 19 on the order of Alberta's Energy Resources Conservation Board (ERCB) as the ERCB and Enbridge continued their investigation. With the approval of the ERCB, Line 19 was safely restarted at approximately 23:30

MST on June 19, while the Elk Point Pump Station remained isolated and shut down pending investigation and completion of clean up and repairs. The cause of the release appeared to be a failure of a flange gasket in the pumping station. The flange gasket was replaced, all other gaskets were tested and station piping was fully inspected.

After receiving approval from the ERCB, Enbridge safely restarted the Elk Point Pump Station on June 24, and normal operations resumed.

Site cleanup was conducted in compliance with all applicable government regulations and Enbridge's own stringent standards for safety and the environment. All contaminated soil has been removed from onsite and offsite areas and disposed of at an approved waste management facility. A groundwater and surface water monitoring program has been implemented to confirm the absence of impacts to groundwater and surface water in the area of the release.

Near Grand Marsh, Wisconsin

On July 27, 2012, EEP reported a release of crude oil from Line 14 on its Lakehead System near Grand Marsh, Wisconsin.

Within minutes of detecting a pressure drop on the line, operators at the Enbridge Pipelines Control Centre shut down and isolated the line. Enbridge emergency crews were promptly deployed to the site.

The oil was contained in a field. The initial estimate of the volume released was approximately 190.8 m^3 (1,200 barrels). No one was injured. Enbridge's immediate focus was to keep its workers and the public safe as it worked to remove the oil and clean up the site. Enbridge notified and worked with emergency officials and the appropriate regulators.

On July 30, 2012, the Pipelines and Hazardous Materials Safety Administration (PHMSA) issued a Corrective Action Order with conditions to return Line 14 to service, and on August 1, 2012, PHMSA issued an amendment to the Corrective Action Order with additional restart conditions. Enbridge submitted the Restart Plan to PHMSA on August 1 and the Lakehead Plan to PHMSA on August 2. The Lakehead Plan describes improvements that will be made in operational areas on the Lakehead System along with other initiatives, many of which were already under way. PHMSA approved the amended return to service plan on August 6, 2012, and Enbridge safely restarted Line 14 on August 7, 2012.

At the time of preparing this report, the cause of the release had not been determined and was being investigated. The Wisconsin Department of Natural Resources had approved the Cleanup Plan and Enbridge was conducting cleanup and site restoration in compliance with all government regulations and our own stringent safety and environmental standards. Although there had been no groundwater impact, we were monitoring nearby drinking wells as a precaution.

2011 REPORTABLE RELEASES – GAS TRANSPORTATION

In 2011, Gas Transportation had 11 reportable releases totaling 47.07 barrels in its pipelines division and had no reportable releases in its trucking division. Nine of the 11 spills were categorized as offsite (totaling 5.07 barrels) and the remaining two spills (totaling 42 barrels) were contained onsite. Eight of the 11 spills involved one barrel or less.

Gas Transportation trucking (DPI) delivered approximately 59.95 million barrels in 2011; pipelines in Gas Transportation delivered 33.08 million barrels in 2011.

Note to the following two tables:

- Unless otherwise noted, data covers natural gas transmission, gathering, processing and trucking operations of Enbridge Energy Partners, L.P. and Enbridge Offshore operated by Enbridge Inc.
- Number of spills includes liquid spills from gas transmission and the limited number of liquids pipelines that are included in Enbridge's Gas Transportation Business.
- 1 barrel = 0.159 cubic metres or 42 United States gallons (all liquid products).

GAS TRANSPORTATION – 2011 REPORTABLE SPILLS BY VOLUME AND LOCATION

		0-1 bbls	2-10 bbls	11-100 bbls	> 100 bbls
Onsite		**0**	**0**	**2**	**0**
Offsite		**8**	**1**	**0**	**0**
Sub-total		**8**	**1**	**2**	**0**
Total	**11**				

GAS TRANSPORTATION – VOLUME OF TOTAL REPORTABLE SPILLS

Year	Total Number of Spills	Total Spills Volume (bbls)
2011	**11**	**47**
2010	**7**	**35**
2009	**13**	**88**
2008	**9**	**159**
2007	**4**	**10**

2011 REPORTABLE SPILLS – ENBRIDGE GAS DISTRIBUTION

Enbridge Gas Distribution experienced 25 reportable spills in 2011, totaling 35 barrels, including gas, oil and other substances.

EGD reported all the spills to the Spills Action Centre of the Ontario Ministry of Environment and all impacted areas were restored in a timely manner, with no further actions required.

One reportable spill occurred when a contractor was digging to expose a valve and hit it, resulting in a release of 150 gallons of brine into the excavation. The spill was contained in the excavation and a vacuum truck was used to recover the brine.

Another reportable spill occurred when a faulty compressor leaked oil into a pipeline during a pipeline cleaning operation. The cleaning pigs exiting the pipeline pushed approximately one gallon of oil into an excavation. All impacted soil was removed from the excavation for proper disposal.

The remaining 23 spills are attributed to bentonite frac-outs as a result of horizontal directional drilling (HDD) activity.

ENBRIDGE GAS DISTRIBUTION – 2011 REPORTABLE SPILLS BY VOLUME AND LOCATION OF SPILL

	0-1 bbls	2-10 bbls	11-100 bbls	> 100 bbls
Onsite	**0**	**1**	**0**	**0**
Offsite	**19**	**4**	**1**	**0**
Sub-total	**19**	**5**	**1**	**0**

Total **25**

ENBRIDGE GAS DISTRIBUTION – VOLUME OF TOTAL REPORTABLE SPILLS

Year	Total Number of Spills	Total Spills Volume (bbls)
2011	**25**	**35**
2010	**4**	**101**
2009	**1**	**0.02**
2008[1]	**3**	**2**
2007	**2**	**6**

1 2008 totals were adjusted down from those reported in Enbridge's 2009 CSR Report because a planned and permitted release of water by EGD in 2008 was incorrectly counted as a spill.

Monitoring and remediating past actions

Throughout Enbridge's Canadian and U.S. systems, Enbridge conducts programs to assess historic leak sites. Some of these sites have been in existence for more than 50 years and, in many instances, the contamination has resulted from practices that were the standard of the day but are no longer acceptable. Enbridge assesses historic release locations systematically and takes further actions where warranted.

Some examples include:

- Liquids Pipelines continued to work on delineating, monitoring and/or remediating historic leak sites with work occurring at various locations along the pipeline system. A number of leak sites were successfully "closed" in 2011 and early 2012, meaning that Enbridge had remediated the sites to the satisfaction of the landowners and appropriate regulatory agencies. Examples include: May 2011 leak at Terrebonne Station, Quebec; Glenavon, Saskatchewan Regional Bioremediation Facility; September 2009 leak near Odessa, Saskatchewan; and April 2007 leak near Glenavon, Saskatchewan.

- Gas Transportation's plant in Springtown, Texas, treats and processes gas and its plant in Harmony, Mississippi, which is no longer in operation, previously treated and processed gas. Past operations at these plants, before Enbridge ownership, released hydrocarbons, which have been detected in local groundwater. Regarding the contamination at the Springtown plant, Enbridge concluded remediation activities and received a "No Further Action" determination from the Texas Railroad Commission. In Mississippi, Enbridge is currently working with state agencies to aggressively remediate soil and groundwater contamination. An in-situ air sparging/soil vapour extraction system was installed in 2010 to aid in remediation of groundwater contamination. While ongoing monitoring indicates that the company's efforts are having a positive effect, it will continue to monitor this progress under the supervision of the state and will take any necessary actions should the situation change.

EN26

Initiatives to mitigate environmental impacts of products and services, and extent of impact mitigation.

EN27

Percentage of products sold and their packaging materials that are reclaimed by category. [Note: Not relevant to Enbridge]

PIPELINE AND FACILITY INTEGRITY

According to the Association of Oil Pipelines (AOPL), pipelines are the safest and most efficient method of transporting fuels. Replacing even a modest-size pipeline, which might transport 150,000 barrels per day, would require 750 tanker-truck loads a day, which equates to a load delivered every two minutes around the clock. Replacing the same pipeline with a railway train of tank cars carrying 2,000 barrels each would require a 75-car train to arrive and be unloaded every day.

Pipelines also have the least amount of releases of any transportation mode. Liquids pipeline spills along rights-of-way have decreased over the past decade, in terms of both the number of spills and the amount of product spilled, so that today ruptures on pipelines are rare. According to the Canadian Energy Pipeline Association (CEPA), in Canada between 2002 and 2009: ruptures on federally regulated pipelines averaged slightly more than one per year, a decline of 55 per cent from the previous eight years; and the average annual volume released from liquids pipelines was two litres for every million litres transported, meaning 99.9998 per cent of the product was transported safely.

In addition to the fewest releases, pipeline transportation has the lowest energy input requirements and carbon footprint as compared to other transportation modes (barge, truck, rail and marine). With the volumes that must be transported, pipelines are the only feasible method for moving the enormous quantities of petroleum North America consumes each day.

PIPELINE AND FACILITY INTEGRITY – ENBRIDGE'S APPROACH

Enbridge aims to be a North American leader in pipeline and system facility integrity, and our goal is to prevent all spills, leaks and releases from our energy transportation and distribution systems.

We underpin these objectives in our Environment, Health and Safety Policy, which states that "our goal is to have no accidents and to cause no harm to the environment."

To achieve these objectives, we invest heavily every year in pipeline safety through a branch of technology known as pipeline integrity management and maintenance. For example, in 2011, Enbridge's Liquids Pipelines business unit alone invested approximately $400 million in programs and initiatives related to pipeline and facility integrity and, in 2012, we plan to spend more than $800 million to ensure the safety and integrity of our system.

For Enbridge, pipeline integrity management and maintenance encompasses the tools, technologies and strategies needed to ensure that pipeline networks have the strength and operating fitness to perform safely, reliably and in an environmentally responsible manner.

As part of this discipline, Enbridge:

- follows environmentally sound practices;
- takes a proactive approach to pipeline inspection and repair;
- invests in advanced leak and damage prevention and pipeline integrity management technologies;
- implements rigorous monitoring programs that include Enbridge's leadership in the use of sophisticated inline inspection tools that identify features in the pipeline;

- implements preventive maintenance programs, including inspection and repair digs;
- participates in industry forums to share and exchange knowledge;
- pursues and supports technology research;
- contributes to the development of national pipeline safety standards and industry recommended practices;
- supports state and provincial excavation one-call efforts to reduce the risk of third-party damage to pipelines and enforcement of “Call Before You Dig” and three-digit (811) one-call systems for excavators;
- implements public awareness programs to keep property owners, neighbours and contractors along Enbridge’s rights-of-way informed about the company’s pipeline system and remind them of their obligation to call before digging;
- conducts mock emergency exercises to train employees and external stakeholders should an emergency occur;
- sets integrity performance targets for its Liquids Pipelines, Gas Transportation and Enbridge Gas Distribution business units that are tied to employee compensation;
- reports leaks or spills from its pipelines in accordance with the requirements of regulatory authorities in Canada and the U.S.; and
- investigates all spills, leaks and releases to determine the root cause and incorporate findings into Enbridge’s prevention programs to minimize future risk.

Generally speaking, Enbridge’s full range of ongoing pipeline and facility integrity initiatives fall within the following seven focus areas:

1. Design, materials and construction
2. Public awareness
3. Monitoring and preventive maintenance
4. Long-term infrastructure planning
5. Leak detection
6. Preparedness and response
7. Environmental mitigation

Please see below for reports on these seven focus areas.

1. FOCUS ON DESIGN, MATERIALS AND CONSTRUCTION

Enbridge’s focus on pipeline safety begins at the planning stage.

For major projects, we implement rigorous processes and practices during design and construction to ensure the operational integrity of our pipelines.

Design and construction measures include, among others:

- having a rigorous, multi-disciplinary route selection process that identifies pipeline corridors and line locations that achieve an acceptable balance of engineering, environmental and economic considerations;
- maintaining world-class standards for engineering and design, including meeting all special design requirements for areas such as road, river and creek crossings;
- maintaining world-class standards for materials procurement, including selection of pipeline materials, corrosion inhibiting coatings, and cathodic protection; and
- using world-class construction practices, including a commitment to identify, mitigate and proactively manage potential construction project effects on the environment and also paying close attention to environmentally sensitive areas and at-risk species.

2. FOCUS ON PUBLIC AWARENESS

Public awareness of pipeline activity is a vital element of pipeline safety.

We ensure that emergency officials and residents along our pipeline routes are well informed of all pipeline activities and safety procedures.

We pursue this in a number of different ways, beginning with an ongoing commitment to open and transparent consultation with the individuals who live along our pipelines and those who may become neighbours as the pipeline network grows. For example, Enbridge Gas Distribution's (EGD) commitment to its customers does not stop at natural gas delivery. EGD is also committed to safety, and a key factor is educating its customers on natural gas safety through ongoing communication to increase public awareness. EGD provides information and tips to help ensure safe natural gas use through both bill inserts and media campaigns. The media campaigns cover EGD's franchise area and include radio ads for "Call Before You Dig" and carbon monoxide (CO) safety. The CO campaign is also supported by billboard advertisements. EGD is also working to improve public awareness among landowners along "vital main" corridors.

In the U.S., Enbridge is involved in the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) Pipelines and Informed Planning Alliance (PIPA) sponsored program, which is a multi-stakeholder consensus effort to develop best practices for development near pipelines and for assuring that those who host pipelines on their property understand how those pipelines are operated and what pipeline companies do to protect their near neighbours. In 2010, the program issued two reports: *Partnering to Further Enhance Pipeline Safety In Communities Through Risk-Informed Land Use Planning: Final Report of Recommended Practices;* and *Building Safe Communities: Pipeline Risk and its Application to Local Development Decisions*. Copies of these reports, as well as current information about the program are available at PHMSA's website at http://primis.phmsa.dot.gov/comm/pipa/LandUsePlanning.htm.

3. FOCUS ON MONITORING AND PREVENTIVE MAINTENANCE

Enbridge believes that pipeline safety and reliability begin with prevention.

This means recognizing conditions that have been known to cause pipeline failures in the past and then working to minimize the risk.

It also means adopting advanced leak and release prevention technologies, following environmentally sound practices and taking a proactive approach to pipeline testing and repair.

Following are some of the monitoring and maintenance measures that Enbridge takes:

Combating Corrosion

Because of their location and the products they carry, pipelines may come in contact with water and bacteria, all of which can corrode steel.

Both the interior and exterior of the line are potentially subject to corrosion.

Enbridge mitigates the threat of corrosion by:

- using high-quality materials and anti-corrosion coatings that are specified during the design phase of the pipeline;
- using cathodic protection (a low-level electric current applied to the pipe, or sacrificial anodes connected directly to the pipe) to inhibit external corrosion of underground pipelines;
- using modeling to predict corrosion growth rates along pipelines;
- using specialized corrosion inhibitors injected directly into the crude fluid being shipped to address internal corrosion;
- scheduling regular monitoring and inline inspections to check for corrosion;
- using inline devices known as "pigs" to clean and inspect pipelines from the inside; and
- scheduling excavation and repair programs identified by inline inspections.

Enbridge continues to pursue new methods to prevent or manage corrosion. Currently, the company is helping to lead research and development that will further cathodic protection, coating science, inline inspection technologies and improved methods to monitor and mitigate internal corrosion.

Managing Cracking

Cracking is a phenomenon that can occur in metals, including pipeline steel. Cracking occurs at unique locations along a pipeline where the necessary conditions exist. These conditions include a pre-existing initiation point in

the pipe surface, a fluctuation in stress in the pipe, and in some cases an environment that promotes a cracking mechanism. While it is common for these conditions to exist individually, it seldom occurs that these conditions all combine on the pipeline system to result in a crack that might affect the pipeline operation. We monitor our pipeline system and carry out extensive mitigative activities to reduce the potential for cracking to occur.

Enbridge is committed to being at the forefront of technological developments and research relating to the cracking phenomenon and its diagnosis. These efforts have resulted in rigorous programs for monitoring and managing cracking, with the key activity being the use of ultrasonic inline inspection technologies for our liquids pipelines. For its part, EGD is scheduled to use the next generation of EMAT (electromagnetic acoustic transducer) technology in 2013 to check for the occurrence of cracking in its high-stress pipelines (lines operating at higher pressure).

Over the past 15 years, Enbridge has carried out a number of actions to enhance industry's development of advanced inspection technologies and field evaluation methods. The company also continues to actively participate in a variety of industry forums that are focused on cracking.

Managing Mechanical Damage

Mechanical damage describes conditions on a pipeline such as dents, gouges, scrapes, etc. that can be created by a variety of outside forces such as rocks, impact from equipment during construction, or impact from third-party excavating equipment while the pipeline is in service.

These types of conditions may result in either a penetration of the pipeline at the time of occurrence or the initiation and growth of a crack over time.

Managing mechanical damage requires the integration of data from several inspection technologies, including caliper tools (deformation sizing), metal-loss tools, and crack tools, as each of them provides detail that can be used to characterize these conditions.

Through sponsorship and technical leadership of joint industry research projects, Enbridge has actively pursued improvements to both inline inspection technologies and engineering models that characterize the pipe condition. This work has provided the industry with improved methods of managing mechanical damage to pipelines.

Damage Prevention

The greatest risk facing EGD's pipelines is damage caused by third-party excavators, so for many years EGD has been focusing on educating both excavators and locators. EGD's efforts have shown results. Over the past 10 years, while locate requests have increased 112 per cent, the number of recorded damages per 1,000 locates has decreased by 70 per cent, total damages have decreased by 36 per cent, and locate error rates have decreased by 15 per cent. In 2011, EGD continued to see a decline in the number of damages per 1,000 locates. The following table illustrates the improvements EGD and its affiliates have made in reducing incidents that cause damage.

	2007	2008	2009	2010	2011
# of damages by third parties	2,194	2,076	2,116	1,969	1,605
# of locates	340,571	379,817	401,105	402,584	495,646
# of damages per 1,000 locates	6.4	5.5	5.3	4.9	3.2

EGD continuously looks for new ways to protect pipeline assets through innovative strategies and incorporating industry best practices. Recent initiatives include completing a marketing research study on the effectiveness of consumer communication programs, and training for locators. Also, efforts to move forward on a single national "Call Before You Dig" phone number continue. In the spring of 2012 the Government of Ontario passed legislation to establish a mandatory One Call system in Ontario. In the field, improved tracer wire technology, as well as the introduction of traceable rods in service lines will assist in providing additional protection to assets.

In 2011, EGD also expanded the Sewer Lateral Cross Bore Program, which was piloted in 2010 to address the potential that natural gas lines installed using trenchless technology may have inadvertently intersected sewer service lines. Also, when a blocked sewer is being cleared outside the walls of buildings by municipal sewer operators, plumbers, drain cleaners or the general public, there is the potential to damage a natural gas line, creating a serious safety risk. In 2011, the audience of the sewer inspection program was expanded and additional marketing communication activities were carried out during seasonal excavation peaks. The Canadian

Gas Association (CGA) also recognized EGD with the Public Safety Award for contributions to improving public safety due to this program. While the Ontario Technical Standards and Safety Authority has issued a legal requirement for all pipeline license holders to have effective sewer intersect risk mitigation programs in place, the EGD program is considered industry-leading and as a result is being used as a template for provincial adoption.

Carrying Out Inline Inspections

Sophisticated inline inspection (ILI) technology is a vital element in Enbridge's pipeline integrity program.

We use sensitive ILI tools to measure the size, frequency and location of even minute changes in the walls of our major pipelines.

These sophisticated tools enable us to inspect the inside and outside of our pipes on a millimetre-by-millimetre scale. In 2011, we conducted 150 ILI runs.

Although most anomalies discovered are minor and do not threaten the integrity of our system, we analyze and monitor all of them through periodic inspections to see how anomalies change over time.

Implementing a Comprehensive Program of Pipeline Integrity Digs

Enbridge's constant monitoring and inspection of its pipelines alerts the company to locations to check for corrosion, cracks or other anomalies.

The company follows up in line inspections by carrying out investigative digs in the field. Each dig involves digging up a section of buried line to examine and, if needed, repair and recoat the pipe and rebury the line.

Enbridge conducts all digs to a high environmental standard. In natural environments, before beginning work, the company completes screening tests to identify environmental issues and measures needed to minimize impacts to land, vegetation and wildlife.

Enbridge conducts similar environmental reviews for other small engineering and operation and maintenance projects.

In 2011, we completed over 1,900 integrity verification digs along our mainline liquids pipelines system in Canada and the United States, compared with approximately 1,500 in 2010.

For its part, EGD started a 10-year baseline program in 2003 for high-stress pipelines (lines operating at higher pressure). In 2011, EGD completed 29 integrity verification digs on the 393 kilometres (244 miles) of pipeline that are in the program, while U.S.-affiliate St, Lawrence Gas completed 10 integrity digs with 145 kilometres (90 miles) of transmission pipe.

Patrolling the Line

Prevention depends on a constant round of inspections to spot potential trouble spots along major pipeline rights-of-way.

Using aircraft, land vehicles or foot patrols, we regularly monitor our major pipeline routes, on the lookout for potentially damaging activities such as unauthorized digging and construction.

Monitoring Pipeline Depth

To help ensure the protection and integrity of our pipelines, Enbridge has implemented a pipeline depth monitoring program.

The program was developed with the aim of making sure major pipelines are covered by the appropriate amount of soil.

To monitor pipeline depth, the company uses specialized electronic equipment that locates and records the pipeline depth for these pipelines every 50 metres. At EGD, the equivalent program records pipeline depth every 30 meters, with an inspection frequency of every three years.

In addition to monitoring the pipeline depth, a global positioning system (GPS) is also used to record pipeline coordinates and observe right-of-way conditions such as terrain, land use, damages or deficiencies.

Integrity within Facilities

In 2004, Liquids Pipelines added facility integrity measures such as a Leak Reduction Team and small piping integrity initiatives to its existing programs.

A team of subject-matter experts in Engineering, Operations and Integrity guides a leak reduction program for the network of facilities throughout the system, including pump stations and terminals.

Enbridge is committed to ensuring that all of our facilities, including pump stations and terminals, are operated and maintained in a safe, responsible manner. This is accomplished through the use of design standards; equipment and construction specifications; commissioning, operating and maintenance procedures; and targeted tankage, equipment and piping inspections.

Through 2010 and 2011, all pump station and terminal locations were visually inspected to identify opportunities for improvement (according to the Facility Inspection Protocol that was developed in 2009). The resulting recommendations are being addressed in 2012. In addition to those inspections, targeted inspections of the components within the facilities occur on an ongoing basis to assure the integrity of our assets.

When a release occurs, it is investigated and analyzed. Based on this investigation, corrective actions are developed to reduce the likelihood of reoccurrence and/or reduce the consequence through improved detection. The Leak Reduction Team focuses on leak reduction, then reviews both the investigation and corrective actions to determine if there are any additional actions that would improve the integrity across all facilities.

4. FOCUS ON LONG-TERM INFRASTRUCTURE PLANNING

Enbridge evaluates the condition of its pipeline system to determine the optimal method of ensuring long-term operability and reliability.

The methods considered include pipe replacement, pipeline rehabilitation (coating replacements), continued inline inspections and repairs.

The analysis considers factors such as ease and safety of implementation, economic evaluations, and operational expectations—all with the requirement that pipeline safety will not be compromised.

Long-term planning is focused on the pipeline system, with its condition assessed using inline inspection and other key parameters from Enbridge's operations. For example, 14 sections of new pipe and a river crossing had been completed on Enbridge's Line 6B by the end of 2011, with a further 120 kilometres (75 miles) of pipe replacement scheduled on this line by year-end 2012.

For its part, Enbridge's Gas Transportation (GT) business unit has initiated a pipe replacement project that will remove from service old legacy pipelines in the North Texas area that have a history of leaks. By the end of 2013, approximately 238 gathering pipelines will be revamped, replaced or abandoned in an effort to reduce leaks.

5. LEAK DETECTION

Spills, leaks and releases happen for a variety of reasons. Pipelines that come into contact with water, bacteria and chemicals can corrode, both internally and externally. People can inadvertently damage pipelines through unauthorized digging and construction or poor excavation practices.

Enbridge has adopted advanced leak-detection technologies. Our leak detection capabilities are designed to meet and exceed the requirements of: the National Energy Board's Onshore Pipeline Regulations, 1999; the Canadian Standards Association's CSA Z662/Annex E; the U.S. Department of Transportation's CFR 49 Part 195; and the American Petroleum Institute's API 1130.

We monitor our pipelines for possible leaks using four primary methods, each with a different focus and featuring differing technology, resources and timing. Used together, these methods provide overlapping and comprehensive leak-detection capabilities.

Monitoring – Enbridge's Pipeline Controller monitors pipeline conditions (such as pipeline pressure) through the Supervisory Control and Data Acquisition (SCADA) system, which is designed to identify unexpected operational changes such as pressure drops that may indicate a leak. Additional sensors monitored through SCADA such as concentrations of explosive vapour (LEL), pump seal failures, equipment vibration levels and sump levels can also be used by the controller to identify a potential leak.

Visual surveillance and odour reports – These are reports of oil or mercaptan odours from third parties and from Enbridge's aerial and ground line patrols. Third-party reports are handled through an emergency telephone line, which affected publics and local emergency officials are made aware of through Enbridge's Public Awareness Programs. Liquids Pipelines typically conducts aerial line patrols every two weeks on its systems, while Enbridge Gas Distribution conducts weekly patrols on most of its lines. Gas Transportation conducts a series of leak surveys, including mobile, building and walking surveys.

Scheduled line-balance calculations – Sometimes called "over/short reports" in the industry, these are calculations of oil inventory that are carried out at fixed intervals, typically every two and 24 hours. A rolling, 24-hour calculation is also maintained at a set time each day. The purpose of these calculations is to identify unexpected losses of pipeline inventory that may indicate a possible leak.

Computational Pipeline Monitoring (CPM) – CPM is a computer-based system that utilizes measurements and pipeline data to detect anomalies that could indicate possible leaks. The CPM system provides a sophisticated computer model of Enbridge's pipelines that continuously monitors changes in the calculated volume of oil between two fixed points on the system. If the calculated volume of oil is less than expected, then an alarm is

triggered in Enbridge's Control Centre. The cause of the alarm is investigated immediately.

Starting in 2011, Liquids Pipelines undertook a program to define its leak detection performance on a line-by-line basis across the system, and performance targets for each have been set. Flow meters and additional instrumentation are being added to improve leak detection performance system wide. Research and assessment is under way on a variety of leak detection technologies, including those used during aerial right-of-way surveillance and internal pipeline inspection. EGD has a similar program of research and field trial investigations to improve leak detection capabilities.

GT is currently coordinating and heading up an industry-wide field test/trial to evaluate the effectiveness of new technologies in detecting leaks of natural gas from energy transportation pipelines, using sensors deployed in standard pipeline patrol aircraft. The field test took place in June 2012, using GT pipelines in the North Texas area. The test involved a series of controlled gas releases from specified locations. Multiple vendors were invited to fly a series of routes under varying conditions before, during, and after a controlled leak utilizing a standard Flame Ionization Unit to locate possible leak sources and confirm emission rates. Through this process, vendors will provide similar test data, which then can be evaluated to determine the sensitivity and accuracy of natural gas leak detection technologies.

6. FOCUS ON EMERGENCY PREPAREDNESS AND RESPONSE

While Enbridge's pipeline and system integrity initiatives described above contribute to reducing the risk of spills, leaks and releases and mitigating their impacts, these measures cannot completely eliminate the risk.

Therefore, Enbridge has comprehensive emergency preparedness and response and environmental mitigation plans in place to respond rapidly and completely if an emergency does occur.

Preparedness

Enbridge's emergency and crisis preparedness plans are designed to minimize the impact of an incident and comply with regulatory requirements.

Employees throughout Enbridge's business units in Canada and the United States participate in regular emergency response drills and simulations to test and improve procedures. These range from tabletop exercises, where employees discuss responses to various scenarios, to full-scale deployment exercises with local emergency agencies, using equipment to practice recovery and clean-up in various terrains and on water, as applicable.

As an additional measure in 2011, Enbridge created and began specialized training for a cross-business-unit response team to respond to large-scale events anywhere in North America that would require more resources than a single region or business unit could provide. The response team will be conducting major training exercises involving all of Enbridge's business units, emergency response contractors and consultants, and federal, state/provincial and local emergency response agencies.

All of the company's operating facilities maintain regular contact with communities and first responder organizations to keep them up to date and coordinated with Enbridge's operations and contingency plans.

Enbridge Safe Community Program

Strong relationships with emergency responders in Enbridge's areas of operation throughout North America are a top priority for the company.

One of Enbridge's flagship community investment programs is its Safe Community Program, which provides monetary grant support for first responders, police agencies, fire-fighters, emergency medical services and other related health providers who would respond to emergency situations along any of Enbridge's pipeline rights-of-way.

The grant support helps eligible organizations acquire new safety-related equipment, obtain professional training and deliver safety education programs in their communities.

As a result of feedback received from a 2011 survey of emergency response agencies that have received grants through our Safe Community Program, we have begun development of an interactive training program for emergency responders to cover all elements of our operations. The training, which will be deployed online via email and also in person, will launch in the U.S. in late 2012; we are concurrently working on a plan to deploy the program in Canada. The training program will include elements of "Pipeline Emergencies," a program developed through a partnership between the National Association of State Fire Marshals (NASFM) and the Pipeline and Hazardous Materials Safety Administration (PHMSA) and widely accepted as world class in training for pipeline emergencies.

Response

When an emergency occurs, Enbridge carries out emergency response procedures to shut down and isolate the impacted pipe, notify the appropriate government and regulatory agencies, contain the substance as appropriate, and manage potential environmental and safety impacts.

In addition, Enbridge works closely with emergency first responders, landowners, regulatory agencies and other concerned parties to develop any necessary remediation and monitoring plans.

Enbridge also conducts root-cause incident investigations and reviews the effectiveness of the incident response. Lessons learned are shared within the company and with industry and local responders.

In the event a large gas leak occurs over a short period of time, the risk of an explosion or blast can be significant. To mitigate potential consequences, GT is currently working with Stanford Research Institute (SRI) and Pipeline Research Council International (PRCI) to perform full-scale pipeline tests to evaluate the performance of blast mat mitigation strategies that have been developed to mitigate the consequences produced by the rupture of a natural gas pipeline. GT originated this research project, which can be used industry wide to identify viable concepts for mitigating this sort of damage.

7. FOCUS ON ENVIRONMENTAL MITIGATION

Enbridge has a strong record of environmental stewardship and regulatory compliance, and we work closely with federal, provincial and state regulators and authorities to ensure that we build, operate and maintain our pipelines and facilities safely and with the utmost regard for the protection of the environment.

When Enbridge experiences a leak, our highest priority is the safety and protection of people and the environment and the rapid response and, where applicable, thorough containment and clean-up in such a way as to minimize the impacts. Following are the typical steps that we take for an oil spill:

- Containment is the first order of business as Enbridge works to address the environmental impact. Simply put, the smaller the area that is touched by the oil, the less damage is done and the easier it is to clean up.
- As it contains the oil, Enbridge works to capture it and safely remove it from the environment. As it removes the oil, Enbridge is very careful to keep it from spreading to uncontaminated vegetation, water or soil.
- For the vast majority of spills, whether they are large or small, Enbridge recovers a high percentage of the oil and injects it back into the pipeline.
- Water, soil and vegetation that have come into contact with oil is typically removed and disposed of at an appropriate waste disposal facility. As affected water, soil and vegetation are removed, Enbridge is very careful not to spread the oil to uncontaminated areas. The company establishes what needs to be removed based on a comprehensive clean-up plan, environmental testing and monitoring, physical inspection and guidance from government regulators.
- Enbridge works closely with wildlife experts to minimize impacts on wildlife and assist and rehabilitate animals that have come in contact with oil.

Enbridge develops plans for remediation and reclamation with the input of affected stakeholders and environmental regulators. Our goal is to address the requirements of all regulators and stakeholders and to restore the area as closely as possible to its pre-spill condition or to a state that is acceptable to the local community.

DEMAND-SIDE MANAGEMENT

Enbridge is committed to helping customers use energy wisely. Enbridge Gas Distribution (EGD) has more than 30 demand-side management (DSM) programs covering all market sectors that encourage customers to adopt energy-saving equipment and reduce consumption of natural gas.

EGD does this by:

- Conducting energy audits of commercial and industrial customers' operations to identify opportunities to improve energy efficiency
- Providing financial rebates and incentives to all types of customers—from homeowners to large industrial customers—to encourage them to adopt energy-saving equipment and practices

- Working with industry and trade associations in various sectors—such as chemicals, construction, automotive, food and beverage, and pulp and paper—to promote DSM programs and contribute to industry standards and best practices
- Partnering with governments, suppliers and equipment manufacturers to invest in new energy-efficient technologies that benefit ratepayers and enhance the competitiveness of EGD's business
- Participating in consumer and community events to promote and ensure that program opportunities are well publicized and accessible to all consumers, including low-income earners
- Ensuring that all of its incentives and rebate offers are available on its website for fast and easy review and downloading

In 2011, EGD's DSM programs saved approximately 77 million cubic metres[1] of natural gas, which is enough to supply approximately 25,000 homes[2] with natural gas for a year.

Since 1995, EGD's DSM programs have cumulatively delivered about 7.0 billion cubic metres of natural gas savings (the equivalent of enough gas to supply approximately 2.3 million homes for one year[2]) and net energy savings to customers of about $2.1 billion. Through these DSM activities, EGD has helped its customers avoid cumulatively approximately 13.3 million tonnes of carbon dioxide emissions[3].

1 2011 natural gas m^3 savings have been audited; however, they are still subject to final regulatory approval and the clearance of accounts with the Ontario Energy Board.

2 Assumes that a typical residential customer uses 3,064 m^3 of natural gas per year to heat their home and water.

3 Assumes that 1.89 kgs of CO_2 are emitted for each m^3 of gas that is consumed.

Contributing to policy on DSM

As a recognized DSM leader in the natural gas industry, EGD is frequently invited to provide advice on DSM initiatives.

In early 2011, the Ontario Energy Board (OEB) released new draft DSM Guidelines to set the framework for DSM until 2014.In response to the Board's invitation, Enbridge submitted extensive comments.

Later in 2011, the Board released a letter inviting comment on the future of natural gas DSM in Ontario and again, Enbridge responded.

The new DSM Guidelines for natural gas utilities that the Board published in June 2011 reflect some of Enbridge's recommendations.

In response to one of the requirements of the new guidelines, Enbridge and Union Gas proposed the development of a new utility/stakeholder body—the Technical Evaluation Committee (TEC)—with a mandate to establish common technical standards for natural gas DSM in Ontario. This approach was accepted by the intervenors, and the utilities worked together with intervenors to develop the detailed Terms of Reference. These were then submitted by the utilities with full support of the intervenors and accepted by the OEB. The TEC will reduce duplication of effort between the two utilities and also serve to further reduce regulatory time in proceedings before the OEB. The changes to the DSM Guidelines and framework still include a DSM incentive that provides utility shareholders with a share of the benefits from DSM initiatives. The DSM results have positive impacts, not only for the customers participating in the DSM programs, but also for broader conservation efforts in the province of Ontario.

COMPLIANCE

EN28

Monetary value of significant fines and total number of non-monetary sanctions for noncompliance with environmental laws and regulations.

Enbridge manages compliance with laws and regulations through system controls and regular reviews that include training and awareness, adopting best practices, inspections and third-party audits. We consider any regulatory notification or penalty to be important and expect our employees and contractors to fully comply with all regulatory, legislative and permit requirements. Regulatory notifications are formal written notices by regulators that Enbridge may not be adhering to legal, regulatory or permit requirements. Examples include enforcement actions, summonses, charges, stop and control orders, Notices of Violation (NOVs), and formal warnings. In the event that Enbridge's performance falls short of this expectation, we carry out rigorous reviews and institute corrective actions, as we did for each non-compliance issue noted below.

Liquids Pipelines

In 2011, Liquids Pipelines received no notifications from government agencies for environmental issues.

On July 2, 2012, Enbridge received a Notice of Probable Violation (NOPV) from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) related to the 2010 Line 6B crude oil release near Marshall, Michigan, which indicated a US$3.7 million civil penalty. Enbridge agreed to pay the penalty proposed by PHMSA.

Gas Transportation

As of May 10, 2012, Gas Transportation in the U.S. had received 20 NOVs covering 2011 with a total fine amount of US$29,376, and there were three open NOVs, fines for which, if any, had not yet been determined.

Enbridge Gas Distribution

Enbridge Gas Distribution (EGD) received no notifications, fines or orders for non-compliance with environmental regulations in 2011.

COMPANY-WIDE REGULATORY NOTIFICATIONS AND FINES

	2011	2010	2009	2008	2007
Regulatory Notifications[1]	**20**	**25**	**25**	**14**[4]	**15**
Regulatory Fines Incurred (thousands of Canadian dollars)	**$29.7**	**$1,176**[2]	**$1,159.3**[3]	**$59.9**	**$4.9**

1 Enbridge responded promptly to address the concerns associated with all notifications.

2 Includes US$1-million settlement agreement with the Wisconsin Department of Justice for air compliance violations received at Enbridge's crude oil pipeline breakout storage terminal at Superior, Wisconsin. Many of the violations were self-reported by Enbridge to the Wisconsin Department of Natural Resources after Enbridge discovered them during the course of a facility audit. Since then, Enbridge has corrected the issues or is in the process of correcting them.

3 A settlement regarding three NOVs issued by the Wisconsin Department of Natural Resources was reached in January 2009 and included a US$730,000 fine and a US$370,000 statutory assessment. The NOVs pertained to environmental infractions that Enbridge allegedly committed while constructing its Southern Access pipeline in 2007.

4 Reduced from the total of 12 reported in the 2009 CSR Report because one U.S. Department of transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) notification was incorrectly counted as an environmental regulatory notification.

TRANSPORT

EN29

Significant environmental impacts of transporting products and other goods and materials used for the organization's operations and transporting members of the workforce.

Enbridge Gas Distribution (EGD) has the largest natural gas vehicle fleet in Canada, with over 597 of its 785 vehicles running on low-emission fuel. By converting these vehicles to natural gas, EGD has reduced carbon dioxide fleet emissions by an estimated 700 tonnes annually.

In addition to using low-emission fuel, EGD is taking further actions to reduce vehicle emissions. This includes replacing older trucks with newer ones that meet stricter emissions standards. EGD has also reduced the fleet size by standardizing vehicle designs and building versatility into its fleet. For jobs where three trucks would have been previously required, each with its own capabilities, EGD has built three different job functions into one truck.

EGD also operates seven natural gas vanpools for its employees living in the Greater Toronto Area who commute to work at its Victoria Park offices in Toronto. Each vanpool can hold eight passengers and a driver. In total the program saves about 300 tonnes of CO_2 annually. Employees benefit by reducing their vehicle fuel and maintenance costs, lowering stress, having preferred parking at the EGD office and having pride in knowing that they are doing their part for the environment and to relieve traffic congestion. Additional vanpools are being planned for EGD's new Technical Operations Training Centre in Markham, Ontario, once employees are relocated to that site.

In addition, beginning in February 2012, EGD has partnered with Smart Commute and other businesses along the Consumers Road transportation hub to participate in a three-month pilot program for a shuttle bus for employees between the EGD office and the Don Mills subway station. This is designed to encourage employees to use the public transportation system more. This bus operates during the commuting hours, as well as at lunch time.

TOTAL ENVIRONMENTAL PROTECTION EXPENDITURES

EN30

Total environmental protection expenditures and investments by type.

Enbridge spends hundreds of millions of dollars annually on environmental assessment, protection and other initiatives. While some of these actions are mandatory, such as impact assessments and reporting of operational emissions, many others are voluntary, such as tree-planting, conserving natural habitats, and public disclosures about the company's environmental, social, and economic performance.
Enbridge's environmental activities include:

- Pipeline integrity (approximately $400 million invested by our Liquids Pipelines business unit in 2011)
- Emissions Data Management System (approximately $5 million invested in 2011)
- Tree planting (approximately $0.25 million invested in 2011)
- Conservation of natural habitat (approximately $0.83 million invested in 2011)
- GHG management and reporting
- GHG auditing
- Groundwater monitoring
- Site containment / drainage
- Environmental seminars for staff
- Environmental Management System audit
- Earth Week Campaign
- Soil assessments
- Sponsorships of environmental groups (e.g. Ducks Unlimited; Trout Unlimited; Pheasants Forever; etc.)
- Corporate Social Responsibility reporting
- Waste management (e.g. minimization, reuse, and recycling)
- Participation in industry association activities
- Compliance with all applicable regulatory requirements
- Regulatory reporting
- Government approvals
- Aquatic assessments
- Geo-technical assessments
- Contaminated soil management
- Environmental assessments

SOCIAL PERFORMANCE

WE'RE COMMITTED TO SUSTAINING SAFETY FOR OUR EMPLOYEES AND THE PUBLIC, AND TO BUILDING STRONG AND VIBRANT COMMUNITIES.

The people of Enbridge work hard every day to demonstrate to all of our stakeholders that we'll always live up to our core values of Integrity, Safety, and Respect.

We believe that Enbridge's success is rooted in treating people fairly. That's why we're always looking for new ways to enhance our employees' and stakeholders' quality of life, and it's why we invest in initiatives that provide real, tangible benefits to the communities where we operate across North America.

These investments range from programs designed to attract, engage, inspire and retain employees to initiatives that ensure that Enbridge's operations are as safe as possible. Our initiatives also extend to Enbridge's policies on human rights and on how we conduct business in a way that aligns with our commitments to building trust, demonstrating respect for human dignity and human rights in all relationships, and enabling mutual advantages.

We work with Aboriginal communities to ensure they achieve sustainable benefits from our projects and operations, including opportunities in equity partnership, training and education, employment, procurement, business development and community investment. For example, the Enbridge School Plus Program aims to inspire young Aboriginal students in Canada to remain in school in order to achieve their full potential. Since 2009, the program has enriched the education of over 8,500 youth in over 50 schools by providing over $2.2 million in grants in support of educational programming.

Our values and commitments are also reflected in our support to help fight cancer through the Enbridge Ride to Conquer Cancer in Quebec, Ontario, Alberta and British Columbia.

They're demonstrated by our Safe Community Program through which we provide monetary support to emergency responders in the communities in and around which Enbridge operates. In 2011, Enbridge contributed over $1.2 million to the program, supporting approximately 425 first-responder organizations in right-of-way communities in Canada and the U.S.

Our values and commitments are the basis for the Enbridge Natural Legacy Program, which provides us with an opportunity to demonstrate our ongoing commitment to environmental stewardship, habitat remediation and protection.

And they're why we encourage employee volunteerism through our Volunteers in Partnership program and recognize employees' efforts to give back to their communities, allowing us to gain a better understanding of the communities in which it operates, the challenges they face and the ways Enbridge can best contribute.

In 2011, Enbridge invested $13 million in more than 550 charitable, non-profit, and community organizations to help make communities better places to live. We believe that these investments are essential to being a good neighbour and are a contributing factor in maintaining the company's social license to operate.

Social Scorecard Results				
Objectives	**2011 Results**	**2010 Results**	**Details available in GRI Performance Indicator Section**	**Challenges**
SAFETY				
Strive for zero accidents, injuries or incidents	**In 2011, one incident claimed the life of a contractor.[1] In February 2012, one incident claimed the life of an employee of a contractor.[2]** **The enterprise-wide Lost Time Severity Rate was 3.02, which was a significant improvement from 2010 and significantly better than the five-year average of 6.93.** **The enterprise-wide Total Recordable Injury Frequency was 0.97, which was an improvement from 2010 and significantly better than the five-year average of 1.54.** **In January 2012, Enbridge implemented Lifesaving Rules across the whole enterprise, an initiative designed to reduce and eliminate fatalities within Enbridge's operations.**	**In 2010, one incident claimed the life of one employee and injured another seriously.[3]** **The enterprise-wide Lost Time Severity Rate for 2010 was 10.78.** **The enterprise-wide Total Recordable Injury Frequency for 2010 was 1.81.**	**LA7/LA8**	**Maintaining the best possible health and safety practices in a time of significant growth for the company**

1. On October 11, 2011, there was a fatality at Enbridge Gas Distribution Inc. involving a contractor carrying out landscaping work in Mooretown, Ontario.
2. On February 28, 2012, a contractor's worker on the Woodland Pipeline Project suffered a fatal injury when the side boom he was operating flipped over into a ditch while helping prepare for a tie-in weld.
3. Nalvester Maxie died in January 2010 after a hydrogen sulfide release at the Bryans Mill natural gas treating plant near Douglassville, Texas.

Objectives	2011 Results	2010 Results	Details available in GRI Performance Indicator Section	Challenges
HUMAN RESOURCES				
Attract the best talent and develop, engage, and retain workforce; Target: maintain "Best Employer Status" (65% or higher) Maintain employee turnover rate; Target: maintain voluntary turnover in the range of 2% to 4.5% Develop and retain critical talent; Target: maintain critical turnover in the range of 1% to 2% Maintain employee training investment at a market-competitive level; Target: between 1.25% and 1.5% of salary costs	Enterprise-wide employee engagement score from the 2012 Employee Perspectives Survey: 79% Voluntary turnover as a percentage of total workforce population: 3.7% Voluntary employee turnover as a percentage of total critical workforce: 2.3% Average expenditure per employee on Learning & Development: approximately $1,360. Expenditure as a percentage of salary costs: 1.24%	Enterprise-wide employee engagement score: 75% Voluntary turnover as a percentage of total workforce population: 2.6% Voluntary employee turnover as a percentage of total critical workforce: 1% Percentage of employees enterprise-wide who positively rate the statement "Employee Learning & Development is strongly supported at this organization.": 76% Average expenditure per employee on Learning & Development – approximately $1,300. Expenditure as a percentage of salary costs: 1.22%	Engagement: Labour Practices and Decent Work – Goals and Performance – Employee Communications Turnover: LA2 Average Learning & Development expenditure: LA10	Accelerated growth, especially in western Canada (the projected significant workforce increases associated with this growth; increasingly constrictive and tighter competitive market) Recruitment (ability to source, recruit, integrate, manage and grow people requires accelerated timelines and different approaches) Leadership capacity and capability (ensuring appropriate leadership capacity for both operational oversight and developing/mentoring individuals; broadening and deepening our leadership pool more quickly and consistently) Employee development (changing/emerging skill requirements) Workforce planning (ability to accurately forecast workforce numbers and skills required to successfully deliver business objectives; maintaining an appropriate work/life balance)

Objectives	2011 Results	2010 Results	Details available in GRI Performance Indicator Section	Challenges
COMMUNITY AND LANDOWNER RELATIONS / ABORIGINAL AND NATIVE AMERICAN RELATIONS				
Transparent, proactive and frequent communication Opportunities for communities to benefit from relationships with Enbridge	Through our Safe Community Program, began developing an interactive training program for emergency responders to cover all elements of our operations The 2011 Enbridge School Plus Program funded 33 eligible First Nations schools, and benefited over 3,900 First Nations youth As of the May 31, 2012, 60 per cent of eligible Aboriginal communities along the proposed Northern Gateway pipelines right of way, representing 60 per cent of the First Nations' population (and 80 per cent of the combined First Nations' and Metis' population) had agreed to be part owners of the proposed Northern Gateway pipelines. Northern Gateway launched a $1.5-million Education and Training Fund to support flexible community-based training specific to the pipeline and construction sector.	For Alberta Clipper and Southern Lights pipelines, Enbridge and landowner association representatives formed a joint committee to address systemic issues along the right-of-way. Enbridge upstream projects (projects north of Edmonton) provided a total of $7.7 million of economic opportunities to Aboriginal communities in Canada. The 2010 Enbridge School Plus Program funded 36 eligible schools and benefited over 3,850 youth. Northern Gateway announced an Aboriginal Economic Benefits Package, which included an offer to eligible Aboriginal groups of a long-term equity partnership with Northern Gateway and potential opportunities arising from the project, such as employment, training and procurement.	SO1, SO9, SO10 – Community and Landowner Relations; Aboriginal & Native American Relations	Meeting stakeholders' diverse needs and expectations

Objectives	2011 Results	2010 Results	Details available in GRI Performance Indicator Section	Challenges
COMMUNITY PARTNERSHIPS AND INVESTMENTS				
Invest in building sustainable communities, focusing on six areas: Lifelong Learning; Community Leadership; Natural Legacy; Arts & Culture; School Plus; and Safe Community	**Invested $13 million in more than 550 charitable, non-profit, and community organizations** **Almost two years since its inception, our enterprise-wide Enbridge VIP Program, which supports the volunteer efforts of our employees, has engaged over 1,100 employees and contributed $280,000 and over 4,500 hours to the community.**	**Invested $11.5 million in more than 350 charitable, non-profit and community organizations**	**SO1, SO9, SO10 – Community Partnerships and Investments**	**Ensuring the greatest returns on investment** **Ensuring that investments truly help communities be sustainable** **Highly diverse communities and needs**

SOCIAL PERFORMANCE: LABOUR PRACTICES AND DECENT WORK

GOALS AND PERFORMANCE

Enbridge believes that people are the basis of the company's success and the foundation of its vision of being North America's leader in delivering energy. Enbridge recognizes that engaging a highly skilled workforce will be critical to the company as it moves toward achieving its business goals.

In 2011, the Human Resources (HR) Leadership Team updated Enbridge's HR strategy to ensure it continues to be aligned with the company's current and anticipated business needs.

Enbridge is growing and expanding quickly. During 2011, we had a net increase to our workforce of 578 permanent employees (full time and part time). At the end of the year we had 6,922 permanent employees (full time and part time) in Canada and the U.S., as well as 230 temporary and 1,610 contract employees who support seasonal and project work associated with specific projects. Moreover, in 2012 alone, Enbridge's workforce (employees plus contractors) is expected to grow by over 2,000 across the enterprise, and our new three-year HR strategy is designed to address this rapid growth. As at September 30, 2012, we had over 7,500 permanent employees and over 2,500 part-time, temporary and contract employees in Canada and the United States.

Key initiatives in 2011 related to the HR strategy included: refreshing Enbridge's values statement; developing a comprehensive resourcing strategy; building capacity for change management; and enhancing talent management. Included below are details on these and other ongoing HR initiatives:

Enbridge Values

Enbridge is building on our foundation of operating excellence by adhering to a strong set of core values—integrity, safety and respect—that reflect what is truly important to us as a company as we interact with communities, the environment, and each other. These values represent a constant guide by which we make our decisions, as a company and as individual employees, every day.

We convey Enbridge's values succinctly and effectively to employees so that they understand what it means to work for Enbridge and how we expect all employees to act when faced with decisions or choices. For new employees, our values provide a strong, clear and simple set of principles to help them integrate into the organization.

Enbridge's value statement is:

Enbridge employees demonstrate Integrity, Safety and Respect in support of our Communities, the Environment and Each other.

Associated with these values and commitments are a series of statements that clearly indicate the behaviours we expect from our employees:

Integrity

- Maintain truth in all interactions
- Do the right thing; do not take the easy way out
- Take accountability for our actions, without passing blame to others
- Follow through on commitments

Safety

- Relentlessly ensure the safety of our communities, customers, contractors, partners and employees
- Take a proactive approach to identifying and preventing safety issues
- Take immediate action when a safety issue is identified
- Continually seek ways to improve safety performance

Respect

- Value the contributions of others
- Take the time to understand the perspective of others
- Treat everyone with unfailing dignity

Supporting our Communities

- Support the company's effort in strengthening the communities in which we live and work
- Support the volunteerism efforts of our fellow employees

Supporting the Environment

- Consider the potential short and long term environmental impacts before proceeding with any activity
- Consistently strive towards a neutral footprint on the environment

Supporting Each Other

- Share knowledge and experience to help others
- Encourage individual development of each other
- Work collaboratively to achieve common goals

Over the next few years, we will apply these behavioural statements to all of our HR programs and services, including recruitment, succession planning, and performance management.

Resourcing Strategy

In 2011, Enbridge's HR department developed a comprehensive Resourcing Strategy to address the significant workforce growth the company is experiencing. Key accomplishments related to this strategy include:

- Designed and staffed a dedicated recruitment team, which now provides leaders with beginning-to-end support in all their recruiting endeavours
- Modified Enbridge's Employee Referral Program by increasing award amounts and opening the program to contractors

- Developed targeted resourcing tools for Enbridge's frequently recruited/challenging positions
- Conducting a New Hire Survey to determine why recent hires chose Enbridge and how they found out about the company and its positions
- Engaged an external company to provide comprehensive resourcing support, including enhancement of social media as a recruitment tool and enhancing Enbridge's career website to reach new sources of talent

Building Change Management Capacity

In a company growing as quickly as Enbridge, change is a part of our day-to-day life, so it is necessary to continue building Enbridge's in-house change-management capacity.

Historically, our business has relied on external consultants to manage our change initiatives. To address the challenges with this approach and to enhance our ability to lead and manage changes, HR introduced in 2011 a standard, in-house change management methodology. Sessions with senior leaders and teams across the enterprise have yielded positive feedback and have reinforced the importance of this work and the value it adds to the business.

To address their needs, Enbridge Gas Distribution has built an in-house team of change specialists that assists the business with managing large- and medium-scale change initiatives.

Talent Management

Talent management is a fundamental focus at Enbridge and a critical component of the value proposition we offer to employees. Strong talent management processes also support Enbridge's success during periods of growth and change such as the one we are now experiencing, and ensure a seamless transition when we lose experienced employees due to retirement. Enbridge's commitment to effective people management practices, including employee recognition, identification of high-potential and succession candidates, enhanced employee development and career planning, have contributed to securing Enbridge's position as an employer of choice within the various markets in which the company operates.

Enbridge's leaders actively manage the attraction, retention, development and transition of the company's workforce, with support from the Human Resources department. Their work focuses on employee engagement, leadership and employee development, succession and career management, mentorship, and knowledge transfer.

Enbridge is committed to advancing its culture of leadership and employee development at all levels in the organization. Succession management is a significant focus as the company seeks to attract, develop, engage, retain and promote leaders of today and tomorrow. Senior-level succession management was another area of focus in 2011, and resulted in a broader range of job rotations across multiple business units and functions.

Enbridge also continued to enhance its leadership and employee development programs in 2011 with a particular focus on expanding our mentorship, project management and leadership programs.

Enbridge restructured its HR function in 2010 into enterprise-wide Centres of Expertise (COEs) to improve efficiencies and enhance our ability to leverage existing programs and services across the company. This initiative continues to bear fruit. For example, Enbridge University, which previously only supported employees in western Canada, was adopted in 2011 by all Enbridge business units across all company locations, increasing employee access to a wide range of courses. (For more information on Enbridge University, please see GRI Performance Indicator LA11 in this section, below.)

In addition to offering a broad array of in-house and external leadership and employee development programs, Enbridge offers a Tuition Reimbursement Program, which provides financial support to employees who advance their education through external learning programs in support of their current and future careers at Enbridge. Enbridge also offers a company-wide scholarship program to help employees' children access post-secondary education in the field of their choice.

Performance Management

Performance management at Enbridge is central to the company's ability to meet its business objectives and manage and sustain a high-performance workforce. Leaders help employees contribute to Enbridge's business success by developing performance objectives that are aligned with the company's strategic business goals. Leaders provide regular performance feedback to employees to guide their performance, work planning and ongoing development in each performance year. Leaders are also accountable for working collaboratively with employees to address future development requirements through the creation of individual development plans.

Effective performance management ensures strong performance, provides an opportunity for leaders to recognize and reward performance, and gives leaders the information they need to support employees' ongoing development with a view to skills and career advancement.

For more information, please see GRI Performance Indicator LA12 in this section, below.

Diversity and Equal Opportunity

Enbridge has a diverse workforce that is represented by multiple generations and minority group members.

With increasing frequency, women are taking leadership roles. As at December 31, 2011, women occupied 29 per cent of supervisory roles in the company, and 17 per cent of female employees were in senior management roles (director level and above).

In 2005, Enbridge initiated a program called Women@Enbridge to support women's career advancement and professional development. The program focuses on leadership development, mentorship and peer coaching, and has the ultimate goal of contributing to business value and the company's success. It was rolled out throughout the company in 2007, is well subscribed to by employees, and is an ongoing success.

In 2011, Enbridge's Liquids Pipelines business unit enhanced their focus on diversity by creating a Manager, Diversity position and implementing a three-year Employment Equity and Diversity Plan for all Liquids Pipelines operations in Canada. Initiatives and accomplishments in 2011 include:

- the establishment of an Employment Equity/Diversity Committee to provide advice and guidance in the development, implementation and evaluation of the Employment Equity and Diversity Plan;
- the development of the three-year Employment Equity and Diversity Plan to strategically manage diversity within Liquids Pipelines;
- launching a comprehensive communications strategy;
- developing new positions in partnership with the Rotary Club and the Alberta Association of Community Living;
- sponsoring the National Educational Association of Students with Disabilities conference for the first time in Edmonton;
- sponsoring scholarships for Women Building Futures and Students with Disabilities;
- developing a new Accommodation Policy; and
- developing online versions of Liquids Pipelines' self-identification questionnaire and accompanying training video for a February 2012 launch.

Total Compensation

Enbridge has a full array of compensation and benefit programs designed to attract and retain talent. In addition to base salary, almost all regular (union and non-union) employees participate in an annual incentive plan, which rewards performance relative to a combination of predefined targets established at company, business unit and individual levels. Mid-term incentive plans are also extended to management-level roles.

On the benefits side, Enbridge offers a comprehensive selection of life, health and dental coverage, along with defined-benefit and defined-contribution pension plan options. The company reviews these programs regularly to maintain its competitive position and to ensure they are meeting employees' needs.

Enbridge's total compensation programs continue to evolve to meet business needs. Beyond delivering a competitive level of total compensation, the programs' design and flexibility will be critical in helping the company respond to changing workforce demographics and the evolving needs of employees.

For more information, please see GRI Performance Indicator LA3 in this section, below.

Positive Work Environment

Enbridge is committed to developing and maintaining a diverse and inclusive work environment, and promotes a healthy and positive work environment.

Enbridge's policies affirm the company's strong commitment to treating all employees with dignity and respect. Enbridge also subscribes to the principles of a fair and equitable work environment.

Enbridge's work environment promotes a diversity of roles and enriched job experience through project work, secondment opportunities, cross-business unit mobility and participation on cross-functional teams.

Enbridge also supports employees who are interested in actively contributing to the communities in which they live and work, through a variety of volunteer opportunities and through the company's annual employee-led United Way campaign. Employees who significantly contribute to their communities on their own time are recognized annually and, under our Volunteers in Partnership program, a donation is made by Enbridge to their respective charities.

The value of mentoring and being mentored contributes to a positive work environment. Enbridge's mentorship programs, both internal and external, offer an additional opportunity for the company to support employees in their roles and enhance their workplace experience. Enbridge's internal mentoring program now operates across the

enterprise.

We regularly recognize our employees' achievements through a range of formal activities and programs, including service awards, monetary gifts, recognition through internal communications channels and creating opportunities for challenging assignments.

Employee Communications

Enbridge continues to enhance its employee communications practices to ensure that employees are informed of business information, company developments and career opportunities by using the most appropriate communications tools and through the active support of supervisors who communicate with their teams.

Effective communications ensure that employees are informed about Enbridge and are engaged in their work, particularly during times of growth and change.

Enbridge's leaders seek to foster an environment committed to open and frank communication. The company offers a dedicated channel for employees to communicate their feedback to their leaders through the Employee Perspectives survey.

The Employee Perspectives Survey is an important component of Enbridge's commitment to its people and is an important gauge of employee engagement levels. Enbridge employees are invited to provide their feedback on a wide variety of topics, such as benefits, work-life balance, work processes, social responsibility and more. The results are then used to generate insights that are incorporated in the development of business and people-focused strategies. To allow full involvement of employees at all levels in determining solutions and provide sufficient time to implement action plans, Enbridge conducts this survey on a bi-annual basis. The survey is administered by the third-party consulting firm Aon Hewitt.

Enbridge's 2012 employee engagement score of 79 per cent was up 4 per cent compared with the previous survey in 2010 and placed the company within the "Best Employer" zone, significantly exceeding the North American average and several other benchmarks, including the averages for all Alberta employers, the Canadian oil and gas industry, and the North American energy industry. Engagement scores are based on responses to key engagement questions that reflect the percentage of team members who are emotionally and intellectually committed to the company. Team member engagement is a vital measure for any company because high engagement scores connect with high organizational performance, productivity, team-member satisfaction and retention.

Key findings from the survey were that Enbridge employees think that:

- Enbridge's organizational reputation and people-focused policies are among its key strengths;
- challenging and enjoyable work keeps them engaged; and
- Enbridge should continue to focus on increasing performance-related drivers such as career opportunities and recognition, which were critical engagement drivers across all demographic groups.

Enbridge is proud of these survey results and is committed to building sustainable, people-focused strategies that respond to employee needs.

Enbridge continues to be recognized as a best employer. Listed below is some of the recognition we received in 2011:

- ***Canada's Top 100 Employers***: Canada's Top 100 Employers project is a national competition to determine which employers lead their industries in offering exceptional workplaces for their employees. Enbridge was recognized for being an industry leader in attracting and retaining employees. This is the seventh consecutive year Enbridge has been on the list, and tenth since the list's inception 12 years ago.
- ***Canada's Greenest Employers***: Launched in 2007, this special designation recognizes the employers that lead the nation in creating a culture of environmental awareness in their organizations.
- ***Canada's Top Employers for Young People***: This special designation recognizes the employers that offer the nation's best benefits for younger workers.
- ***Canada's Top Employers for Canadians Over 40***: This special designation recognizes employers that lead the nation in creating special programs and benefits of interest to employees aged 40 years and older. The broad range of pension and other initiatives a company offers are also considered in selecting the winners.
- ***Alberta's Top Employers***: Alberta's Top Employers is an annual competition organized by the editors of Canada's Top 100 Employers in partnership with the Human Resources Institute of Alberta. The award recognizes companies for best practices in recruitment and retention

Enbridge continues to use a number of one-way and two-way communications vehicles to regularly exchange information with employees. Among these are:

- *elink*, the Enbridge Intranet, which was significantly improved in 2007 and 2008 in response to employee feedback and was recognized in 2009 by the Neilson Norman Group as being one of the 10 Best Company Intranets in the World;
- *Link*, Enbridge's employee magazine; and
- regular electronic bulletins for various business units.

One Enbridge business unit has implemented an executive "blog" feature that provides an opportunity for employees to post responses to blogs written by various Executive Team members. Enbridge's Corporate Social Responsibility team also initiated a blog focused on sustainability and CSR issues—addressing what the CSR team, the company and others are doing in the area of CSR; and inviting Enbridge employees to share their comments, ask questions, and make suggestions about how to improve the company's CSR performance.

In addition, Enbridge holds annual employee meetings across the organization to ensure that employees receive the latest information about the company's plans for strategic growth, CSR strategies and plans, and its investments in talent and people. These meetings provide an opportunity for employees to meet with Enbridge's Executive Management team, local senior leadership and guests to discuss challenges and opportunities, and to raise questions about the company's workplace, business and employee programs.

Labour Relations and Collective Bargaining

Enbridge believes that healthy and cooperative labour relations—built on trust, respect and integrity—contribute to its business goals and objectives. The company continues to maintain and foster a cooperative approach to the union/management relationship through joint committees with various unions and industrial councils. These committees meet regularly to resolve outstanding matters, as well as to advise on and discuss issues of mutual concern. For more information about Enbridge employees covered by negotiated agreements, please see GRI Performance Indicator LA4 in this section, below.

Health and Safety Management

Enbridge is committed to excellence in health and safety performance throughout the organization.

In January 2012, Enbridge implemented "Lifesaving Rules" and training for all Enbridge employees and contractors.

To draw up the rules, a team of safety professionals reviewed historical incidents throughout the company that have resulted in significant harm, such as fatalities.

The six Lifesaving Rules are:

1. **Hazard Management**: Always ensure an analysis of potential hazards has been completed and proper authorization received prior to starting the work.
2. **Driving Safety**: Only drive a vehicle or operate equipment when not under the effect of alcohol or any substances that cause impairment.
3. **Confined Space Entry**: Always follow procedures for Confined Space Entry.
4. **Ground Disturbance**: Always follow procedures for locating, positively identifying and excavating buried facilities.
5. **Isolation of Energized Systems**: Always follow procedures for Lockout / Tag-out.
6. **Reporting of Safety-Related Incidents**: Always report significant safety related incidents.

The Lifesaving Rules are applicable to all employees and contractors, and are communicated, clarified and reinforced across all business units at Enbridge.

For their part, the company's business units have health and safety management systems in place and implement annual health and safety initiatives aimed at reducing risks and incidents and ensuring continuous improvement.

Following is a summary of current health and safety actions by business unit:

Liquids Pipelines

Liquids Pipelines' goal is to achieve a safety culture in which people look out for one another and work collaboratively in identifying, preventing and correcting health and safety issues.

Liquids Pipelines has embraced safety as a core value, has established a target of zero injuries and is committed to continually improve its safety performance. The following is a summary of 2011 health and safety initiatives that were undertaken in order to focus on and improve upon various key elements within the existing Liquids Pipelines Health & Safety Management System.

- ***Safety Culture***: With the assistance of DuPont Sustainable Solutions and under the direction of an Executive Steering Team that was established, Liquids Pipelines dedicated significant effort to strengthening its safety

culture in 2011. Activities included completion of a safety perception survey across Liquids Pipelines, provision of safety training sessions for Operations Managers, implementation of safety culture improvement teams in the pipeline control centre and two operating regions, and implementation of process improvement teams focused on contractor safety management and incident investigation. In addition, a process safety management scoping study was completed to define the scope of process safety that exists within Liquids Pipelines and to assess the need and scope for any further work required in this area. Finally, in conjunction with other Enbridge business units, Liquids Pipelines developed and communicated six new Life Saving Rules for employees and contractors.

- ***Hazard Assessment***: An effective hazard identification, assessment and control program is critical to the success of a Health & Safety Management System. A new hazard assessment standard was implemented in 2011 across all operating regions within Liquids Pipelines. The new standard provides guidance and requirements for identification, assessment, and control of hazards associated with the design, construction, operation and maintenance of the pipeline system.
- ***Safety Training***: Liquids Pipelines completed a review of safety training requirements for field operation employees and implemented an electronic learning management system for managing and tracking completion of safety training. The system is further being used as a platform for delivery of various electronic safety training courses (e-courses) required by field operations employees.
- ***Integrated Incident Management System***: In conjunction with other Enbridge business units, Liquids Pipelines participated in the evaluation, selection and purchase of an Enbridge enterprise-wide, third-party environmental, health and safety software suite. Upon its purchase, a Liquids Pipelines project was initiated and is under way to develop an integrated incident management system tool for use in completing incident notifications, recording incident investigation findings, identifying causal factors, identifying and tracking completion of recommendations, analyzing incident trends, and reporting incident statistical data. The integrated incident management tool will be used for incidents that result in or have the potential to result in impacts to people, environment, property, and process. The tool is expected to be fully implemented in 2012.
- ***Driving Safety/Awareness Initiative***: Given the geographical extent of the Enbridge Liquids Pipelines system, driving safety is a key element and focus area of the Health & Safety Program. In addition to ongoing participation in driver training programs, a comprehensive participative “Driving to Excellence” campaign was implemented across Liquids Pipelines in 2011. The intent was to raise awareness regarding three key areas as identified within a Driving Perception Survey that was conducted in 2010 and through analysis of motor vehicle incidents that occurred from 2008-2010. The three key areas of focus included vehicle circle checks, distracted driving and parking.
- ***Safety Management Performance Standards***: Safety Management Performance Standards were established and implemented for Operations People Leaders in 2010 and were continued in 2011. The standards require operations management personnel to complete and document targeted numbers of safety observations, work practice inspections, field hazard assessment reviews and contractor work practice inspections at specified frequencies. These standards were developed to increase operations management participation and oversight of safety practices in order to further develop and sustain a strong safety culture.

Major Projects

Enbridge Major Projects (MP) is committed to the protection of the health and safety of our employees, contractors, and the general public. We view safety as a core value, and believe that all incidents are preventable, and that effective health and safety management is a key project deliverable. On an annual basis, MP uses leading and lagging safety performance indicators to identify key opportunities to strengthen our construction contractor’s safety performance and project safety performance overall.

- **Key Construction Safety Risks**: MP has identified key safety risks that cause a high frequency of injuries or present a high potential for injury such as hand hazards, ground disturbance and the use of side booms/pipe layers. MP is introducing targeted safety programs and practices to address these risks.
- ***Construction Safety Standards***: MP recognizes that clear expectations are the foundation of strong performance. To better define our safety expectations and ensure they represent industry best practice, MP is revising the current contractor safety expectations to ensure they cover the relevant construction activities and represent industry best practice.
- ***Supervisory Safety Leadership***: Strong consistent safety leadership from supervision is a key expectation of our construction contractors and a driver of positive safety performance. MP is undertaking a program to

develop construction specific safety leadership training that will be conducted at the initiation of a project to ensure that expectations are clear and a commitment to the safe execution of the project is achieved.

- ***Industry Safety Leadership***: The safe execution of our projects is significantly impacted by the overall safety culture of the construction industry. To drive an improvement in the safety culture of the pipeline construction industry, MP will be leading a Pipeline Construction Safety Workshop that will involve key construction contractors and pipeline industry partners.

Enbridge Gas Distribution (EGD)

EGD is strongly committed to the safety of the general public, its customers, employees and contractors. EGD's continued commitment to improve safety performance in 2011 emphasized the concept that injuries are an exception to the norm; and the theme "Path to Zero" accentuates the efforts toward zero accidents and incidents. EGD is strengthening its health and safety culture through a number of ongoing initiatives:

- ***Safety Culture***: EGD recognizes the role of a strong and positive health and safety culture in keeping employees safe. Part of this involves management engagement and the establishment of clear expectations. Central Safety Committee, a new permanent governance structure responsible for managing all aspects of safety at EGD, is in operation and providing valuable safety leadership and decision making. Local safety committees are being established regionally to drive safety innovations both top-down and from the field upwards, and enhance focus and direction for safety within line management. A number of safety process improvement teams have been established to sustain and enhance the effectiveness of various safety programs such as: incident investigations; safety observations; safety communications and engagement; and process hazard assessment. The introduction of six key Life Saving Rules has been effectively rolled-out to employees and contractors to promote and safeguard the principles of individual responsibility.
- ***Safety Performance Measurement***: EGD continues to emphasize the importance of measuring its safety performance metrics (Employee Safety Index, Public Safety and Reliability Index) by continuing to set aggressive targets.

An increased focus on safety and reliability of the natural gas systems is also supported by the EGD scorecard, where a number of safety- and pipeline integrity-related key performance indicators are heavily weighted and account for 40 per cent of the total EGD scorecard. Each EGD employee has specific safety objectives as part of the annual performance goals to help support the EGD scorecard and to drive excellence in health and safety performance throughout the organization.

Gas Transportation (GT)

GT's health and safety philosophy reflects Enbridge's strong, company-wide commitment to excellence in health and safety performance.

In 2010, GT developed and implemented a comprehensive Health and Safety Management System (HSMS) to provide a structured approach and a framework for measurement and accountability of activities.

In 2012, GT is carrying out a comprehensive Operational Risk Management program that includes several initiatives specific to worker safety. As part of this program, GT has also contracted DuPont Sustainable Solutions to provide consulting services related to assessment, implementation and sustainability of an improved safety culture within the organization. Specific initiatives associated with this program and the safety culture initiative include:

- ***Operating Procedures***: Enbridge recognizes the importance that clear and comprehensive operating procedures play in safe operations. Accordingly, GT is undertaking an initiative to revise all operating procedures within its Process Safety Management (PSM) facilities so that they cover key processes within these facilities.
- ***Process Safety information (PSI)***: GT has undertaken an initiative to update PSI information at its PSM facilities throughout the business unit. In recognition of the importance of this information in the safe operation of its facilities, GT will institute a Continuous Improvement Program in conjunction with the Management of Change (MOC) program to ensure that PSI is being properly generated and modified when necessary.
- ***Safety Organizational Structure***: A strong safety culture is one in which employees are included in the overall management of safety as a discipline. In 2012, GT will undertake an initiative to develop and implement an integrated safety organizational structure that includes line staff.

- ***Safety Leadership***: A key element of a strong safety culture includes strong leadership from all levels of management. GT will provide comprehensive training and coaching to all People Leaders to further drive this strong culture.
- ***Safety Training***: GT will conduct a review of training requirements for all field employees and the Learning Management System will be implemented to track and manage these training metrics for each employee.

POLICY

The Enbridge People Strategy

Based on Enbridge's belief that people are and will forever be the basis of the company's success, Enbridge has adopted a People Strategy to proactively and deliberately manage the employment relationship through a set of enterprise-wide principles.

The People Strategy represents the articulation of the guiding principles that are the foundation of policies, programs, practices and due diligence within Enbridge and is consistent with the Enbridge governance structure.

These principles are applied across the enterprise, while empowering business unit discretion in implementation.

The Enbridge People Strategy was adopted by the Corporate Leadership Team in July 2005 and was integrated into the 2005 Enbridge Strategic Plan. It remains a foundational cornerstone today.

The strategy incorporates the following elements:

Employee accountability – Enbridge employees have the responsibility and authority to guide and operate the business*.*

Workforce planning and talent management – Enbridge actively invests in its people through workforce planning, talent management leadership development, succession planning and performance management.

Total compensation – Enbridge is committed to providing competitive total compensation that will directly contribute to its ability to attract and retain employees.

Employee communication – Enbridge is committed to a culture of continuous open and frank communication.

Work environment – Enbridge is committed to a positive and challenging work environment that facilitates employee performance, employee engagement and a culture of innovation.

Enbridge's Health & Safety Commitment

Enbridge's strong commitment to the protection of the health and safety of our employees and the general public is spelled out in our Environment, Health & Safety Policy.

We believe that prevention of accidents and injuries benefits everyone, and delivers increased value to our shareholders, customers and employees.

Enbridge's goal is to have no accidents. To this end, we conduct business in a manner that recognizes health and safety management as an integral part of our activities, and our employees are responsible for conducting their activities in a manner that makes health and safety a primary part of their daily activities.

TRAINING AND AWARENESS

In keeping with the People Strategy, Enbridge's Human Resources department and the company's leadership offer a number of programs and services to advance and reinforce Enbridge's focus on people and relationships. Among these are:

- enhanced orientation and "onboarding" programs and practices for new employees;
- workforce transition programs for employees leaving Enbridge;
- leadership and employee development programs;
- internal and external mentorship programs;
- the Women@Enbridge community and the delivery of programs in each business unit;
- the Enbridge Intranet to support employee communications;

- recruitment and career development programs;
- employee benefit programs; and
- individual development and career planning.

Health and Safety Training
Enbridge's individual business units are responsible for health and safety training, which includes such elements as company-wide Safety Stand Downs and in-house training to ensure that all Enbridge employees and contractors have the skills needed to safely perform their duties.

LABOUR PRACTICES AND DECENT WORK PERFORMANCE INDICATORS

EMPLOYMENT

LA1

Total workforce by employment type, employment contract and region, broken down by gender.

Permanent employees
As at December 31, 2011, Enbridge employed 6,922 permanent employees. This total was divided as follows:

	Male	Female	Total
Liquids Pipelines (Canada & US)	1,763	705	2,468
Major Projects (Canada & US)	189	108	297
Gas Pipelines (Gas Transportation)	1,213	398	1,611
International	23	14	37
Gas Distribution and Services	1,337	860	2,197
Corporate	152	160	312
ENTERPRISE	**4,677**	**2,245**	**6,922**

A large majority (99 per cent) of Enbridge's permanent workforce is full time. The breakdown is 6,843 full time and 79 part-time permanent employees.

Temporary and contract employees
As at December 31, 2011, Enbridge employed 230 temporary employees – 118 male and 112 female. There were 1,610 contractors working at Enbridge in various capacities at that point in time. The contractor workforce was divided as follows:

	Male	Female	Total
Liquids Pipelines (Canada & US)	447	209	656
Major Projects (Canada & US)	262	113	375
Gas Pipelines (Gas Transportation)	76	53	129
International	5	1	6
Gas Distribution and Services	227	66	293
Corporate	95	56	151
ENTERPRISE	**1,112**	**498**	**1,610**

LA2

Total number and rate of new employee hires and employee turnover by age group, gender and region.

New employee hires

Enbridge hired 933 regular employees in 2011—614 males and 319 females. For the year ended December 31, 2011, the breakdown of new hires by gender and business unit was as follows:

	Liquids Pipelines (Canada & US)	Major Projects (Canada & US)	Gas Pipelines	Gas Distribution	Corporate & International	Enterprise-wide
Male	221	42	240	78	33	614
Female	128	36	61	58	36	319
Total	**349**	**78**	**301**	**136**	**69**	**933**

For the year ended December 31, 2011, the breakdown of new hires by age group and business unit was as follows:

	Liquids Pipelines (Canada & US)	Major Projects (Canada & US)	Gas Pipelines	Gas Distribution	Corporate & International	Enterprise-wide
Up to 24	63	9	22	25	1	120
25-29	67	22	68	32	16	205
30-34	69	8	45	19	15	156
35-39	53	10	39	14	10	126
40-44	44	12	29	19	8	112
45-49	25	7	38	16	6	92
50-54	20	4	40	10	9	83
55-59	7	5	16	1	4	33
60+	1	1	4	0	0	6
Total	**349**	**78**	**301**	**136**	**69**	**933**

Turnover

Total turnover for 2011 was 445 permanent employees. For the year ended December 31, 2011, the turnover rate breakdown by gender and region business unit and gender was as follows:

		Liquids Pipelines (Canada & US)	Major Projects (Canada & US)	Gas Pipelines	Gas Distribution	Corporate & International	Enterprise
Voluntary	Male	3.2%	1.6%	8.0%	0.7%	5.7%	3.8%
	Female	4.3%	5.6%	4.5%	1.4%	7.5%	3.5%
	Total	**3.5%**	**3.0%**	**7.1%**	**1.0%**	**6.6%**	**3.7%**
Retirement	Male	1.2%	0.5%	0.7%	3.0%	1.7%	1.6%
	Female	1.4%	0.0%	0.5%	2.8%	1.1%	1.7%
	Total	**1.3%**	**0.3%**	**0.6%**	**2.9%**	**1.4%**	**1.6%**
Involuntary	Male	0.8%	0.5%	1.8%	1.1%	1.1%	1.2%
	Female	1.1%	0.9%	2.5%	0.3%	1.7%	1.1%
	Total	**0.9%**	**0.7%**	**2.0%**	**0.8%**	**1.4%**	**1.1%**
Total Turnover	Male	5.2%	2.6%	10.5%	4.9%	8.6%	6.5%
	Female	6.8%	6.5%	7.5%	4.5%	10.3%	6.3%
	Total	**5.6%**	**4.0%**	**9.7%**	**4.7%**	**9.5%**	**6.4%**

For the year ended December 31, 2011, the turnover by age group was as follows:

		Up to 24	25-29	30-34	35-39	40-44	45-49	50-54	55-59	60+	Total
Voluntary	Male	2.0%	4.5%	5.5%	4.8%	3.8%	3.5%	3.2%	1.7%	4.1%	3.8%
	Female	7.8%	7.4%	6.4%	4.4%	2.1%	2.2%	1.8%	0.5%	1.1%	3.5%
	Total	**3.8%**	**5.6%**	**5.8%**	**4.6%**	**3.2%**	**3.1%**	**2.8%**	**1.4%**	**3.4%**	**3.7%**
Retirement	Male	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.2%	14.7%	1.6%
	Female	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.8%	27.7%	1.7%
	Total	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**5.3%**	**17.9%**	**1.6%**
Involuntary	Male	1.4%	2.0%	1.4%	0.5%	1.6%	0.8%	1.3%	0.3%	1.4%	1.2%
	Female	0.0%	1.6%	1.3%	0.4%	1.8%	0.6%	1.8%	1.0%	0.0%	1.1%
	Total	**0.9%**	**1.9%**	**1.4%**	**0.5%**	**1.7%**	**0.8%**	**1.5%**	**0.5%**	**1.0%**	**1.1%**
Total Turnover	Male	3.4%	6.5%	6.9%	5.3%	5.4%	4.4%	4.6%	7.3%	20.2%	6.5%
	Female	7.8%	8.9%	7.7%	4.7%	3.8%	2.8%	3.5%	7.2%	28.7%	6.3%
	Total	**4.7%**	**7.4%**	**7.2%**	**5.1%**	**4.9%**	**3.8%**	**4.2%**	**7.3%**	**22.3%**	**6.4%**

LA3

Benefits provided to full-time employees that are not provided to temporary or part-time employees, by significant location of operations.

Enbridge believes in sharing the success of the company with the people who make it happen—our employees.

Enbridge's competitive and flexible Total Compensation package—which includes compensation, benefits, education reimbursement and time off—allows each employee to choose the plan that best suits the needs of his or her situation.

We provide competitive base salaries for our employees, as well as an incentive compensation program that rewards employees' personal performance, as well as the performance of the company overall and the business unit to which they belong.

Enbridge's benefit programs include a comprehensive selection of health and welfare, income protection, savings, and defined-benefit and defined-contribution pension plan options that are market based and competitively positioned to ensure they are meeting employees' needs.

Some of the highlights of Enbridge's Total Compensation package include:

- a flexible benefits program that allows each employee to select the level of coverage needed for his or her family in the areas of health, dental, insurance and disability;
- a pension plan to help employees in their retirement;
- business travel accident insurance;
- an annual performance-based incentive compensation program;
- external education and training cost reimbursement for courses that are approved by the employee's supervisor;
- an employee scholarship program offered to employees' children who attend post-secondary educational institutions;
- paid time off/vacation, plus paid personal days off (depending on location);
- an Employee and Family Assistance Program;
- a fitness subsidy program;
- an emergency childcare program;
- flexible work hours and alternative work arrangements; and
- a group savings plan.

We also encourage our employees to actively participate in community organizations. Through the company's Volunteers in Partnership (VIP) program, we recognize employee contributions of time and dollars to charitable organizations by providing additional support in terms of paid volunteer time and top-up financial contributions.

Part-time and temporary employees

In Canada, permanent part-time employees working 24 or more hours per week receive the same benefits and employer-provided flex credits as full-time employees. Employees working more than 14 and less than 24 hours per week also receive the same benefits but have a reduced level of employer-provided flex credits.

Temporary employees have reduced coverage and are only eligible for business travel accident insurance, life insurance equal to their annual salary, coverage for health and dental subject to 50 per cent co-insurance, and 50 per cent provincial health care coverage (where applicable).

In the U.S., full-time employees—i.e., employees who work 30 hours or more per week—receive a full complement of benefit options. Part-time employees are eligible to participate in the cash balance pension plan, the 401(k) plan and receive business travel accident insurance.

LA15

Return to work and retention rates after parental leave, by gender.

Enbridge does not currently track this information but we will endeavour to provide it in the 2013 CSR Report.

LABOUR/MANAGEMENT RELATIONS

LA4

Percentage of employees covered by collective bargaining agreements.

As of December 31, 2011, there were 1,057 employees covered by a negotiated agreement, representing 15.3 per cent of the permanent employee base.

Area within Enbridge	Bargaining Unit	Geographical Area	Number of Employees as of December 31, 2011
Enbridge Gas Distribution	Local 975, Communications, Energy and Paperworkers Union of Canada (CEP)	Ontario (Franchise Area)	750
Enbridge Gas Storage	Joint Industrial Council	Sarnia, Ontario	14
Liquids Pipelines – Canada	Joint Industrial Councils (3)	Northwest Territories, Alberta, Saskatchewan	126
Liquids Pipelines – U.S.: Chicago and Superior Regions	Local 2003, United Steel Workers of America (USW)	Minnesota, Wisconsin, Michigan, Illinois, Indiana	118
Liquids Pipelines – U.S.: Cushing Region	United Steel Workers of America (USW)	Kansas, Oklahoma, Missouri	24
St. Lawrence Gas	International Brotherhood of Electrical Workers (IBEW)	Massena, New York	25
Total Number of Employees Covered by a Negotiated Agreement			1,057

LA5

Minimum notice period(s) regarding operational changes, including whether it is specified in collective agreements.

The Enbridge Gas Distribution/Local 975 CEP collective agreement contains a 60-day minimum notice period.

Enbridge's other collective bargaining agreements do not contain any minimum notice periods.

OCCUPATIONAL HEALTH AND SAFETY

LA6

Percentage of total workforce represented in formal joint management-worker health and safety committees that help monitor and advise on occupational health and safety programs.

Enbridge's entire workforce is represented in formal joint management-worker health and safety committees. While the structure of these committees varies between business units, a common element is the participation of both employees and management representatives.

In 2011, each of the operating business units within Enbridge began a Safety Culture enhancement initiative. One component of this initiative was to establish a clear Health & Safety Committee structure that serves to promote participation and engagement at all levels and to establish clear lines of communication for decision making within the organization. These committees and the new structure are being implemented in 2012.

There was a significant increase in EH&S personnel within the company, with the number rising from 94 in 2010

to 123 in 2011. This represents Enbridge's increased focus on EH&S excellence and the company's commitment to reaching a world-class EH&S culture.

LA7

Rates of injury, occupational diseases, lost days and absenteeism, and number of work-related fatalities by region and by gender.

Note: The statistics quoted below are consolidated data for the following operating business segments and units: Liquids Pipelines; Gas Pipelines (the Enbridge operated portion of the Vector natural gas pipeline); Enbridge Gas Distribution; Gas Transportation; and Major Projects. They are based on the 6,573 employees working for those entities as of December 31, 2011, and exclude corporate (head office) employees.

Enbridge's injury rate in 2011 was 0.97 recordable injuries per 200,000 hours worked, compared with 1.81 in 2010. (Although we do report and track first-aid incidents, they are not included in the frequency rate.) The rate of 0.97 is significantly stronger than the five-year average of 1.54, and represents one of the organization's strongest years compared with historical performance.

Enbridge's lost-day rate in 2011 was 0.18 lost days injuries per 200,000 hours worked, compared with a rate of 0.28 in 2010. This compares favourably to a six-year historical average of 0.30. The 2011 rate of 0.18 is also one of the strongest recorded by Enbridge compared with historical performance. (Lost days begin the day after the incident and include calendar days after the date of the injury.)

All incidents, whether regulatory recordable or not, are reported to local supervisors, as well as the company's Health & Safety Department for tracking, trending and communications regarding potential lessons learned.

Enbridge's absentee rate in 2011 was 3.77 days absent per employee.

Work-related fatality

Enbridge had no employee fatalities in 2011.

However, we are deeply saddened to report that, on October 11, 2011, there was a fatality at Enbridge Gas Distribution Inc. (EGD) involving a contractor carrying out landscaping work in Mooretown, Ontario. In August 2012, the Ontario Ministry of Labour charged EGD with five counts under the *Occupational Health & Safety Act* (Ontario) in connection with the event. We do not report or comment on details relating to matters that are before the courts.

In addition, on February 28, 2012, an Enbridge contractor died while working on our Woodland Pipeline Construction Project in northern Alberta. This individual sustained a fatal injury when the side boom he was operating flipped over into a ditch while he was helping prepare for a tie-in weld.

Enbridge immediately stopped work both at the site and on the pipeline spread. Alberta Occupational Health & Safety (OH&S) attended the scene of the incident and issued a Stop Use Order for the use of all side booms on the spread and a Stop Work Order for the tie-in activities at the location of the incident. Prior to construction resuming, an OH&S Order required a full mechanical inspection of all side booms and a revision to the Contractor's Job Safety Analysis for tie-in welding.

Enbridge went beyond OH&S requirements and requested that the contractor's mechanical inspections be vetted by an independent consultant before allowing side boom work to resume. Additionally, the contractor was only allowed to return to work after the OH&S orders were lifted and all operators (a) reviewed the safe-work procedures, practices and the Job Safety Analysis for side booms and pipe layers, and (b) physically demonstrated knowledge in operating the emergency shutdown devices on the side booms and excavators.

Enbridge has conducted an internal investigation into the incident and cooperated fully with the emergency officials and regulators in their incident investigation.

LA8

Education, training, counseling, prevention and risk-control programs in place to assist workforce members, their families or community members regarding serious diseases.

Enbridge takes safety seriously. Before employees are authorized to perform any job that may have health or safety risks associated with it, they must complete mandatory training. As well, within each of the company's business units and at each of its sites, Enbridge has established health and safety committees that meet regularly to discuss and proactively implement changes in response to legislation, new policies and practices and new understandings gained from analyzing incidents.

If an employee should be injured on the job, Enbridge arranges for counselors to be brought in for the team.

Enbridge also offers the Employee and Family Assistance Program (EFAP) to employees and their families in need of help in a variety of areas. In addition to providing assistance in dealing with an illness or injury, employees and their families can access help related to:

- alcohol and drug dependencies;
- marital and family concerns;
- outplacement and retirement issues;
- bereavement;
- depression; stress and anxiety; and
- long-term or major illness.

All services under the EFAP are provided by, or coordinated through, an independent consulting firm with certified professional counselors. All EFAP counselors are qualified psychologists or social workers, who are required to maintain employees' confidentiality.

Under the EFAP, Enbridge covers the initial assessment and the first four hours of counseling. Extended health care plans provide ongoing coverage to certain maximums.

Enbridge's short- and long-term disability plans also include a variety of healthcare, support and counselor assistance.

Additionally, Enbridge has in effect several programs and initiatives that focus on the health of our employees and families such as pandemic planning and other health initiatives within the business units.

In January 2012, Enbridge implemented a significant safety initiative called Lifesaving Rules across the whole enterprise. A team of safety professionals reviewed historical incidents throughout the company that have resulted in significant harm, including fatalities. These incidents were reviewed for common elements in an effort to determine common high-risk activities that could be focused on in an elevated manner to reduce and eliminate fatalities within Enbridge's operations. The outcome of this review was Enbridge's Six Lifesaving Rules, as follows:

1. **Hazard Management**: Always ensure an analysis of potential hazards has been completed and proper authorization received prior to starting the work.
2. **Driving Safety**: Only drive a vehicle or operate equipment when not under the effect of alcohol or any substances that cause impairment.
3. **Confined Space Entry**: Always follow procedures for Confined Space Entry.
4. **Ground Disturbance**: Always follow procedures for locating, positively identifying and excavating buried facilities.
5. **Isolation of Energized Systems**: Always follow procedures for Lockout / Tag-out.
6. **Reporting of Safety-Related Incidents**: Always report significant safety related incidents.

The Lifesaving Rules are applicable to all employees and contractors, and are communicated, clarified and reinforced across all business units at Enbridge to all employees and contractors and when violated result in an increased level of scrutiny and termination as the first consideration.

LA9

Health and safety topics covered in formal agreements with trade unions.

The business units (and partial segments) within the Enbridge group of companies that employ individuals who are represented by trade unions are Liquids Pipelines and Enbridge Gas Distribution (EGD). However, only the collective agreement that EGD has with the Communications, Energy and Paperworkers Union (CEP), local 975, includes topics related to health and safety. Article 2 of the Union Management Cooperation document states the following:

2.04 – The company and the Union recognize the importance of a strong commitment to the Health and Safety of our work force and therefore agree and commit to the following:

a. Compliance with a standard that, as a minimum, meets all applicable laws and regulations as of April, 1998, and reflects applicable industry standards.

b. That Enbridge will provide and maintain a safe and healthy work environment, safe equipment and will follow operating practices that will safeguard all employees and the public.

c. The elimination of the source of dangers to the health, safety and physical well being of our employees is of paramount importance.

d. That procedures are in place to ensure the efficient delivery of, and accessibility to, Health and

Safety Training.

e. That Enbridge and the Union will work together to ensure all employees are aware of their rights and obligations with respect to these commitments.

f. That unacceptable performance of health and safety responsibilities will not be tolerated.

g. Development and communication of a Safety Management System.

2.05 – The company and the Union also recognize the importance of Joint Health and Safety Committees, comprising knowledgeable employees, to achieve these commitments and agree to ensure that the committees have the necessary support to fulfill their role.

TRAINING AND EDUCATION

LA10

Average hours of training per year per employee by employee category.

In 2011, Enbridge's investment in training and development was approximately 1.2 per cent of total salary costs. This equated to $1,363 per employee.

We use a learning management system to track training information pertaining to our employees. However, because Enbridge's business units have specific training needs and training programs that are not centrally managed, no data is available to report enterprise-wide statistics on the yearly average number of training hours.

Enbridge's investment in training and education provides internal technical training, functionally specific training, and leadership and core competency training, enabling our employees to acquire and enhance the skill sets needed to perform their best in their current roles and prepare for future roles.

Health and Safety Training

Environment, Health & Safety training in 2011 totaled 36,567 hours, or an average of 5.6 hours per employee.*

* This includes the 6,573 employees working for Liquids Pipelines, Gas Pipelines (the Enbridge operated portion of the Vector natural gas pipeline), Enbridge Gas Distribution, Gas Transportation, and Major Projects as at December 31, 2011, and excludes Corporate (head office) employees.

LA11

Programs for skills management and lifelong learning that support the continued employability of employees and assist them in managing career endings.

Enbridge values its employees and believes in continuously providing opportunities for the development their skills and capabilities. The company has learning and development programs available to all employees and leaders. Programs are regularly evaluated in order to make enhancements and standardize the offerings across the organization where appropriate.

Enbridge has a learning framework that supports employees and leaders across the company in achieving their development goals. Employees create individual development plans regularly and, in partnership with their leaders, execute their development plans annually.

Enbridge offers a comprehensive "Getting Onboard at Enbridge" program that supports new employees throughout their first three months of employment at Enbridge to ensure early success in their new roles.

Our Education Tuition Reimbursement Program provides financial support to employees who advance their education through external learning programs in support of their current and future careers at Enbridge.

Enbridge continues to offer relevant, high-calibre internal programs to meet the diverse non-technical, functional, and technical learning and development needs of our employees across North America.

We offer internal programs that enhance core and leadership competencies across the organization through our Enbridge University (ENBU) via three unique campuses—two in Canada and one in the U.S. Each campus offers a variety of programming in the areas of energy studies, business acumen, leadership development, project and risk management, and personal excellence. Programs are led by either external facilitators or subject-matter experts from within Enbridge. Courses are delivered through instructor-led sessions or via self-directed online courses, depending on the nature of the course material. Courses are focused on concepts and skills that Enbridge employees and leaders can apply directly in their current roles and will help them qualify for future opportunities.

Enbridge also supports development opportunities through:

- externally-offered courses, certificates, designations, and degrees;
- on-the-job training through special projects or volunteer experiences;
- coaching and mentoring; and
- self-directed learning such as reading and e-learning modules.

Other approaches that Enbridge uses to broaden and develop staff include:

- in-house career planning workshops;
- providing information to employees regarding flexible job progression through career ladders;
- providing opportunities for targeted internal job rotations or job assignments; and
- specific training on the individual development planning process across Enbridge.

As employees approach retirement, Enbridge offers pre-retirement workshops to assist them in making a successful transition to retirement from the workplace. This includes segments on financial planning, goal setting and lifestyle changes.

LA12

Percentage of employees receiving regular performance and career development reviews, by gender.

In 2011, Enbridge leaders completed performance reviews—via Enbridge's online performance management system—covering 80 per cent of the company's permanent employees. Performance feedback for the remaining ~20 per cent was captured through a paper-based mechanism. The 20 per cent includes unionized employees, as well as some small groups in operating areas in Canada and the U.S.

DIVERSITY AND EQUAL OPPORTUNITY

LA13

Composition of governance bodies and breakdown of employees per employee category according to gender, age group, minority group membership and other indicators of diversity.

Board of Directors

With the retirement of Patrick D. Daniel as Director/President & CEO on September 30, 2012, Enbridge's Board of Directors comprises 12 Directors, 11 of whom are considered to be independent and one of whom, Al Monaco, serves as Enbridge's President & CEO.

As at October 1, 2012, Enbridge Inc.'s Board of Directors consisted of the following directors:

- David A. Arledge
- James J. Blanchard
- J. Lorne Braithwaite
- J. Herb England
- Charles W. Fischer
- V. Maureen Kempston Darkes
- David A. Leslie
- Al Monaco
- George K. Petty
- Charles E. Shultz
- Dan C. Tutcher
- Catherine L. Williams

Biographies of the directors are available at
http://www.enbridge.com/InvestorRelations/CorporateGovernance/BoardofDirectors.aspx.

Permanent employees

As at December 31, 2011, Enbridge employed 6,922 permanent employees. The approximate breakdown by gender was 68 per cent male and 32 per cent female. The breakdown by age group was as follows:

Age Group	Employee Count
up to 24	211
25 to 29	702
30 to 34	880
35 to 39	841
40 to 44	964
45 to 49	1,066
50 to 54	1,086
55 to 59	786
60 and above	386
Enterprise Total – Permanent	6,922

The average age was 43.7 years. The average age of females was 42.8 and the average age of males was 44.1.

As of December 31, 2011, Enbridge's senior management, which is defined as director level and above, included 36 females and 179 males. This equates to 83 per cent male and 17 per cent female.

Temporary employees

Enbridge employed 230 temporary employees at December 31, 2011. The approximate breakdown by gender was 51 per cent male and 49 per cent female. The breakdown by age group was as follows:

Age Group	Employee Count
up to 24	48
25 to 29	53
30 to 34	27
35 to 39	17
40 to 44	11
45 to 49	15
50 to 54	10
55 to 59	15
60 and above	34
Enterprise Total – Temporary	230

Diversity & Inclusion

Enbridge does not keep employment statistics based on membership in identified diversity groups on an enterprise-wide basis.

In Canada, individual business units comply with jurisdictional requirements for reporting.

Liquids Pipelines (Canada) complies with the regulations of the Employment Equity Act, and as such, is required to report annually on workforce composition in relation to the four equity groups covered by the Act: women; people with disabilities; visible minorities; and Aboriginal people. Each new employee receives a workforce survey questionnaire, asking him or her to voluntarily self-identify if they are a member of one or more of the four groups. This information is provided to the federal government and is also utilized internally to provide information on areas of under-representation both in terms of aggregate representation and representation at various levels of the organization. The information guides Enbridge's strategic diversity and equity initiatives with the goal of developing a workforce that aligns with the availability of the equity groups in the labour force, as well as becoming more representative of the communities in which the company operates.

Enbridge's U.S. operations routinely track the minority composition of their workforce to comply with government reporting. Effective October 1, 2010, the company implemented an Affirmative Action Plan in the U.S. In compliance with the plan, Enbridge tracks the ethnicity of all job applicants and employees based on a self-identification process. Through tracking efforts, the company identifies specific jobs in which it has an under-representation of minority groups. Through analysis of this information, Enbridge has established placement goals and has enhanced recruitment efforts to diversify its applicant pool, with the goal of establishing a workforce that is more representative of the geographic areas in which the company operates.

Enbridge fully supports employment equity legislation requiring that fair and equitable employment opportunities be available to all people. We are committed to creating a workforce that, at all levels, is representative of the diverse population we serves and to providing a working environment that encourages all people to participate on an equitable basis in employment, training and career advancement opportunities consistent with their abilities, qualifications and aspirations.

Enbridge is committed to an inclusive and respectful workplace. Our employment equity and affirmative action programs have the following principal objectives:

- The achievement and maintenance of a workforce in compliance with relevant legislation, taking into account such factors as workforce availability and the evolving social and economic situation of these groups, as well as Enbridge's operational objectives.
- The identification and removal of systemic barriers in employment systems, policies, procedures and practices that may have an adverse effect on the employment or career progression of any employee.
- The implementation of special measures and programs to correct the effects of employment disadvantages and to promote the workforce participation of designated groups.

As such, management will:

- Hire based on merit and job requirements, ensuring that the recruitment lens captures the available labour force in its entirety.
- Treat employees equitably with respect to access to developmental and career advancement opportunities, training and other conditions of employment consistent with their performance and qualifications.
- Support and be committed to programs and initiatives that foster equal employment opportunity and non-discrimination.

Enbridge Liquids Pipelines has created a dedicated position—Manager, Diversity—that is implementing a three-year Employment Equity and Diversity Plan for all Liquids Pipelines operations in Canada. A Diversity Steering Committee has been formed, and has undertaken a number of activities and initiatives that promote diversity and inclusion across the Liquids Pipelines business unit.

LA14

Ratio of basic salary and remuneration of women to men by employee category, by significant locations of operation.

Enbridge's remuneration policies are company-wide policies, and there is no significant variation by location. Salary levels are determined using an objective and equitable process that considers the internal value of the role, market rates of pay, as well as employee skill and competency. Enbridge utilizes an objective performance management system that permits top performers to achieve higher-than-average increases in any given year.

Average salary ratio male to female by job ladder level (%)

Level 1	**102.8**
Level 2	**102.6**
Level 3	**101.6**
Level 4	**102.8**
Level 5	**102.0**
Level 6	**104.7**
Level 7	**100.8**

Minimum wage versus Enbridge start rates

Region	Minimum Wage	Enbridge Entry-level Minimum Wage	Enbridge Entry-level Maximum Wage	Ratio of Standard Minimum Wage to Enbridge Entry-level Wage
Ontario	$10.25			
Toronto		$17.83	$26.74	173.95% - 260.88%
Alberta	$9.40			
Calgary		$20.52	$28.97	218.30% - 308.19%
Edmonton		$14.72	$20.79	156.60% - 221.17%
Texas	$7.25			
Houston		$ 14.12	$19.93	194.76% - 274.90%

Ratio of CEO's base salary to that of average employee

In 2011, the ratio of then Enbridge President and Chief Executive Officer Patrick Daniel's base salary to that of the average employee salary was 14.1. Mr. Daniel's base salary in 2011 was $1,279,000. To calculate "average employee salary," we included only salaries of regular, non-union, full-time employees.

Enbridge's executive compensation programs are designed to motivate management to deliver strong corporate performance and invest the company's capital in ways that minimize risk and maximize return, while supporting Enbridge's core business goals.

We benchmark our executive compensation programs against a group of similar companies in Canada and the U.S. to ensure we are rewarding our executives at a competitive level.

Our base salaries offer fixed compensation for performing day-to-day responsibilities, while balancing the individual's role and competency, market conditions and attraction and retention issues.

SOCIAL PERFORMANCE: HUMAN RIGHTS

POLICY

The Human Rights section of Enbridge's CSR Policy states that:

- Enbridge recognizes that governments have the primary responsibility to promote and protect human rights. Enbridge will work with governments and agencies to support and respect human rights within our sphere of influence.
- Enbridge will not tolerate human rights abuses and will not engage or be complicit in any activity that solicits or encourages human rights abuse.
- Enbridge will always strive to build trust, deliver mutual advantage and demonstrate respect for human dignity and rights in all relationships it enters into, including respect for cultures, customs and values of individuals and groups.

In addition, Enbridge's Statement on Business Conduct states that:

- Enbridge is committed to ensuring its employees are treated fairly, compensated appropriately, and hired and promoted without discrimination by reason of race, nationality, ethnic origin, colour, religion, age, gender, marital status, family status, sexual orientation, political belief or disability.
- Enbridge shall establish and maintain safe working conditions and conduct its operations in an environmentally responsible manner in accordance with applicable environmental laws, regulations and standards. All employees and contractors shall be aware of and comply with Enbridge's applicable health, safety and environmental policies.
- Enbridge shall support the protection and observance of human rights and freedoms within its sphere of influence and has adopted the Voluntary Principles on Security and Human Rights as set forth by the U.S. Bureau of Democracy, Human Rights and Labor.
- The Statement on Business Conduct is applicable to the Enbridge Group of Companies, their directors, officers, employees, consultants and contractors in all countries in which Enbridge conducts business

TRAINING AND AWARENESS

As a condition of employment, all new employees are required to read and provide written acknowledgement of their agreement to follow Enbridge's Statement on Business Conduct, the human rights elements of which are outlined in the Policy section above. Thereafter, all employees must certify their compliance with the Statement on Business Conduct each year. The annual certification process for each employee includes the completion of mandatory Statement on Business Conduct refresher training, which is coordinated and rolled-out each January on an enterprise-wide basis.

Please see Enbridge's response to GRI Performance Indicator HR3 below for details about the company's ongoing mandatory employee training on human rights-related subjects.

MONITORING AND FOLLOW-UP

Enbridge complies with, and conducts business in accordance with, the principles set out in the human rights legislation of the countries in which the company operates. If, after investigating an alleged incident, Enbridge found that a transgression had occurred, it would follow up with an appropriate level of discipline, including termination and possibly referring the matter to law enforcement authorities for potential prosecution.

Enbridge recognizes the increasing public demand for corporations to be accountable and transparent in all of their business activities and to be seen as proactively dealing with the issues of the day. With that in mind, and in keeping with our commitment to transparency and CSR, in 2002, Enbridge adopted the Voluntary Principles on Security and Human Rights, which deal with responsible corporate action in conflict zones. These principles have been incorporated into the company's Statement on Business Conduct.

In addition, in 2003, Enbridge became a signatory to the United Nations Global Compact and committed to following its principles. The compact is an initiative that brings companies together with UN agencies, governments, labour and civil society to support principles in the areas of human rights, labour and the environment. Enbridge has committed to support and advance the Global Compact's principles and to make them part of the company's strategy, culture and daily operations.

HUMAN RIGHTS PERFORMANCE INDICATORS

INVESTMENT AND PROCUREMENT PRACTICES

HR1

Percentage and total number of significant investment agreements and contracts that include clauses incorporating human rights concerns, or have undergone human rights screening.

HR2

Percentage of significant suppliers, contractors and other business partners that have undergone human rights screening, and actions taken.

Enbridge strictly adheres to Canadian and U.S. human rights laws with regard to its North American operations. Further, Enbridge's activities are governed by its Statement on Business Conduct and by the Voluntary Principles on Security and Human Rights, which the company has adopted and which were established by the U.S. Bureau of Democracy, Human Rights and Labor. As such, Enbridge does not include human rights clauses or human rights screening in any of its North American investment agreements.

HR3

Total hours of employee training on policies and procedures concerning aspects of human rights that are relevant to operations, including the percentage of employees trained.

Enbridge recognizes and ensures compliance with all human rights laws and regulations.

As a condition of employment, all new employees are required to read and provide written acknowledgement of their agreement to follow Enbridge's Statement on Business Conduct, the human rights elements of which are outlined in the Policy section above. Thereafter, all employees must certify their compliance with the Statement on Business Conduct each year. The annual certification process for each employee includes the completion of mandatory Statement on Business Conduct refresher training, which is coordinated and rolled-out each January on an enterprise-wide basis.

Policy and practice are reinforced throughout the company via ongoing mandatory training.

Each business unit has different training packages that address such subjects as maintaining a respectful workplace, anti-harassment and violence in the workplace. All new hires take such training either immediately upon

being hired or within three months of being hired. Employees are required to undertake refresher courses every two to three years. If requested, training can also be provided to groups or departments between refresher training cycles. Enbridge continually revisits the content and delivery methodology of these courses to ensure that the information is up-to-date and accessible.

NON-DISCRIMINATION

HR4

Total number of incidents of discrimination and corrective actions taken.

Enbridge management is not aware of any incidents of discrimination taking place in the company in 2011.

FREEDOM OF ASSOCIATION AND COLLECTIVE BARGAINING

HR5

Operations and significant suppliers identified in which the right to exercise freedom of association and collective bargaining may be violated or at significant risk, and actions taken to support these rights.

Enbridge is not involved in any operations in which the right to exercise freedom of association and collective bargaining may be at significant risk.

CHILD LABOUR

HR6

Operations and significant suppliers identified as having significant risk for incidents of child labour and measures taken to contribute to the effective abolition of child labour.

Enbridge follows the labour laws of the countries in which it operates and does not hire children.

Further, Enbridge's activities are governed by its Statement on Business Conduct and by the Voluntary Principles on Security and Human Rights, which the company has adopted and which were set forth by the U.S. Bureau of Democracy, Human Rights and Labor.

FORCED AND COMPULSORY LABOUR

HR7

Operations and significant suppliers identified as having significant risk for incidents of forced or compulsory labour and measures to contribute to the elimination of forced or compulsory labour.

Enbridge follows the labour laws of the countries in which it operates and does not practice forced or compulsory labour.

Further, all of Enbridge's activities are governed by its Statement on Business Conduct and by the Voluntary Principles on Security and Human Rights, which the company has adopted and which were set forth by the U.S. Bureau of Democracy, Human Rights and Labor.

SECURITY PRACTICES

HR8

Percentage of security personnel trained in the organization's policies or procedures concerning aspects of human rights that are relevant to operations.

Enbridge employs two full-time and two part-time security personnel. All have a full understanding of the company's Statement on Business Conduct.

Further, all of Enbridge's activities are governed by its Statement on Business Conduct and by the Voluntary Principles on Security and Human Rights, which the company has adopted and which were set forth by the U.S. Bureau of Democracy, Human Rights and Labor.

INDIGENOUS RIGHTS

HR9

Total number of incidents of violations involving rights of indigenous people and actions taken.

Enbridge is sensitive to the rights and culture of indigenous peoples and has adopted an Aboriginal and Native American Policy that outlines key principles for Aboriginal relations and promotes the understanding of both Aboriginal and Native American peoples and issues that are important to them.

Enbridge is not aware of any incidents of violations involving the rights of indigenous people in 2011.

SOCIAL PERFORMANCE: SOCIETY

POLICY

Enbridge's CSR Policy and its Aboriginal and Native American Policy govern the company's stakeholder relations.

Enbridge also has a set of Community Partnerships & Investment program criteria and guidelines that guide its community investment activities. They are as follows:

Community Partnerships & Investments – Program Criteria and Guidelines

The company considers investment and sponsorship opportunities in communities where Enbridge operates that are:

- within a 20-kilometre (10-mile) radius of its pipeline right-of-way; or, in the case of Enbridge Gas Distribution (EGD), within EGD's franchise areas in Ontario and New Brunswick;
- important to the community as determined by best practice comparison, community-based research, and information gathered through on-going stakeholder relationships;
- beneficial to the greatest possible number of people;
- significant to the long-term interests of the community; and
- supportive of one of the focus areas (see below) that Enbridge views as integral for a sustainable community.

Focus Areas

Directed by the company's social vision statement, Enbridge concentrates its investments in focus areas that contribute to enriching our communities.

Through 2011, Enbridge grouped its community investment activities by six focus areas, as follows:

Arts & Culture: Enbridge contributes to making communities culturally vibrant places where its employees want to live and work. Enbridge does that by investing in visual and performing arts, as well as programs and organizations that bring cultural events to communities.

Community Leadership: Enbridge's community investment focus on community leadership reflects the company's commitment to innovative initiatives that improve the quality of life for members of Enbridge communities. Enbridge strives to promote leadership in its communities by supporting the United Way, health care institutions and health programs; and social services organizations. Enbridge encourages employee volunteerism by offering Volunteers in Partnership, a program to support organizations for which Enbridge's employees volunteer.

Lifelong Learning: Enbridge recognizes that education is one of the most valuable gifts one can give. Enbridge is committed to educational opportunities for students and adults, and Enbridge focuses its investments on scholarships for higher education and programs that improve literacy and skills in math and science.

Natural Legacy: Because Enbridge recognizes that the way we treat the planet is our natural legacy, Enbridge invests in programs that promote environmental stewardship, conservation, habitat remediation and habitat protection. Additionally, Enbridge invests in environmental education to help equip the next generation to take on environmental challenges.

Safe Community: The safety of the communities in which Enbridge operates and the people who live and work along Enbridge's system remains the company's highest priority. Therefore, Enbridge appreciates the important contributions of police, EMS, firefighters and others who help keep our communities safe. Through its Safe Community program, Enbridge provides grants to local first responders in areas of Enbridge operations to help with

obtaining equipment, training, public awareness and volunteer recognition. Additionally, Enbridge supports safety initiatives that are important in the communities where the company operates.

School Plus: Enbridge provides Canadian Aboriginal youth in grades K to 12 with enrichment programs to engage them in the education process, encouraging them to remain in school. This will enable them to pursue advanced education or training, and to secure better jobs in the future, which will contribute to positive and sustainable change in their communities.

TRAINING AND AWARENESS

Several employees within Enbridge's Public, Government and Aboriginal Affairs department have taken the Certificate in CSR, offered by the University of St. Michael's College, Continuing Education in the University of Toronto, in partnership with the Conference Board of Canada.

Enbridge includes a CSR section in each of its regular new employee onboarding sessions and annual employee meetings.

MONITORING AND FOLLOW-UP

In 2005, Enbridge signed on as one of 10 founding members of the London Benchmarking Group Canada (LBG Canada). LBG Canada is a member-driven association working toward a higher standard in the management, valuation and performance measurement of corporate community involvement. Using the LBG model, Enbridge is able to evaluate community contributions consistently and maximize the impact of its corporate community involvement programs. LBG is a structured process that includes goal setting, clarity on the investment required to achieve a desired outcome and performance measurement of the result.

For more information on the benchmarking Enbridge is doing through its association with LBG Canada and recent assessment results, please see the report below in "Society Performance Indicators – SO1 – Community Partnerships and Investments – Benchmarking and Assessment."

SOCIETY PERFORMANCE INDICATORS

LOCAL COMMUNITIES

SO1

Percentage of operations with implemented local community engagement, impact assessments, and development programs.

SO9

Operations with significant potential or actual negative impacts on local communities.

SO10

Prevention and mitigation measures implemented in operations with significant potential or actual negative impacts on local communities.

Enbridge manages the impacts of its operations on communities through three areas of enterprise-wide activity that have complementary programs and practices: community and landowner relations; Aboriginal and Native American relations; and community partnerships and investments. Following are detailed reports on all three of these areas.

COMMUNITY AND LANDOWNER RELATIONS

Assessing Impacts

Many of Enbridge's projects require the company, as the proponent, to develop and submit a comprehensive Environmental and Socio-Economic Assessment (ESA) or similar study or document. An ESA is prepared to provide the current environmental and socio-economic baseline conditions along a proposed pipeline route and in the vicinity

of proposed facilities. An ESA also typically evaluates project alternatives, and determines and compares potential effects a proposed project will have on the natural and human environment.

The socio-economic component of an ESA evaluates potential adverse and positive impacts to communities by assessing aspects such as human occupancy and resource use, heritage resources, traditional land and resource use, social and cultural well-being, human health and aesthetics, infrastructure and services, employment, and the economy.

An integral component in determining socio-economic effects of a project includes collecting and evaluating information obtained during consultations with numerous stakeholders, including: environmental interest groups; landowners and occupants; municipal, provincial and federal agencies; and Aboriginal groups. Once potential effects have been identified and analyzed, residual effects are predicted and their significance is assessed. Measures are then proposed to avoid or mitigate the identified effects.

Major Projects – Public Involvement Programs

We are currently undertaking dozens of large Enbridge-led construction projects across North America. Whether a particular Enbridge project pertains to building new pipelines, crude oil tanks, power transmission lines, or alternative energy projects, the company uses proactive public communication and consultation programs to support two-way communication. Enbridge's philosophy is to be as transparent as possible with our stakeholders. The company accomplishes this by undertaking timely, honest and open communication with stakeholders and communities located near planned projects that may have an impact on them.

When Enbridge proposes a new project, as a first step we implement a Public Involvement Program (PIP) that is specifically designed to take the unique aspects of that project into account. Factors such as environmental sensitivities, private or public lands, and nearby neighbours are carefully considered. The purpose of the PIP is to build public awareness and understanding, gather stakeholder input, answer questions, learn about community interests and perspectives and whenever possible implement changes to project design or scope to minimize adverse impacts.

As part of this program, landowners, Aboriginal communities, community residents, stakeholder organizations, public officials, chambers of commerce and the media in communities close to Enbridge's activities receive regular project updates via newsletters, posters, regulatory compliance mailings, telephone calls, a website, community open house meetings and in-person visits.

While many stakeholders are satisfied to receive the company's project information at the start of the process and then simply be informed on a timely basis about progress and new developments, other individuals or groups have interests or concerns that require personal consultations. These consultations can vary widely—from negotiations with First Nations, private landowners and recreational users of public land; to engagement with multi-stakeholder advisory groups; to discussions about economic opportunities with local contractors.

Operations – Public Awareness Programs

Enbridge knows that our neighbours during construction will also be our neighbours for the many years that the project will be in operation, and we look for and welcome the opportunity to invest in long-term collaborative consultation relationships towards building sustainable communities.

Through our Public Awareness Programs, we have a scheduled communication process through which (a) landowners, communities and all other relevant stakeholders are kept informed about a pipeline and related initiatives and issues and (b) we seek comments from the affected public and address questions and concerns. Our Public Awareness Programs are focused on raising awareness of pipelines in communities, the importance of calling a local one-call centre or 811 before any digging project, and how to recognize the warning signs of a potential pipeline emergency and what to do—or what not to do—in response.

Our programs take many forms. For example:

- Enbridge representatives meet regularly with local emergency responders, excavators, schools, public officials and other community stakeholders along the company's rights-of-way to share information about the pipelines, damage prevention, leak detection, and Enbridge's emergency contact information.
- In addition, Enbridge's Safe Community program provides contributions to local emergency responders to purchase equipment or to fund training activities that help keep communities safe. We also make targeted donations in communities near our rights-of-way to support environmental, educational, health and safety, cultural and other community initiatives. Enbridge representatives often hand-deliver the cheques and use those face-to-face meetings as an opportunity to talk about the company's Public Awareness Program and encourage stakeholders to contact their Enbridge representative at any time with any questions or concerns.

- Further, Enbridge personnel conduct regular emergency response drills and training exercises and invite local emergency responders to participate as they would in the event of an actual emergency.
- The meetings, the community investment program and the emergency response drills all provide opportunities to foster relationships, while also increasing the community's understanding of Enbridge's pipelines.

Community Relations Advisors

In early 2010, Enbridge added a specific Community Relations Advisor function to Liquids Pipelines' operations to focus on building healthy, open and long-lasting relationships with communities and residents near the company's operating assets, as well as the projects it is planning or constructing.

Enbridge's Community Relations Advisors are helping to develop and implement community engagement plans that meet the needs of local stakeholders. They are also identifying and proactively addressing and resolving emerging concerns in key communities and regions and ensuring that the company's corporate social responsibility initiatives are supported within local communities.

Leak on July 26, 2010, on Enbridge's Line 6B near Marshall, Michigan – Responding to Community Needs

Taking care of the communities is a vital part of Enbridge's ongoing response to the leak on its Line 6B in Michigan.

Enbridge opened community centres in Marshall and Battle Creek within days following the incident to provide a way for the public to ask questions about the spill or to submit claims for damages. In general, the claims issues ranged from property impacts to expenses incurred as a direct result of the leak to medical issues.

Enbridge also initiated a home purchase program for people living within 200 feet (61 metres) of Talmadge Creek and the Kalamazoo River. The program was designed to help maintain property values to help minimize any immediate adverse reactions to the housing market because of the spill. By the time the program ended in July 2011, the company had purchased over 150 homes.

A toll-free information hotline was established immediately following the incident. Issues addressed in the calls ranged from questions about air and water quality to reporting locations of oiled wildlife. In conjunction with U.S. Fish and Wildlife, a Wildlife Response Center was established in Marshall and began taking in animals within a few days following the spill. Several types of oiled wildlife, including ducks, geese, beavers and turtles were treated at the centre, and most were released back into their natural habitat.

By spring 2012, cleanup, under the direction of the U.S. Environmental Protection Agency, had progressed to the point that the Kalamazoo River and Morrow Lake had been reopened for recreational use.

Based on input from local residents, community leaders and recreation groups, much of our community efforts have focused on increasing access to the Kalamazoo River.

Enbridge has created or improved five river access sites to encourage recreational opportunities along the Kalamazoo River. Three new locations were dedicated in the fall of 2011. They are called Saylor's Landing, Angler's Bend and Paddler's Grove. In June 2012, Calhoun County reopened Historic Bridge Park to the community where Enbridge added parking, enhanced the playground and picnic area, and added a handicap-accessible boat lift. Enbridge is also establishing a portage route around Ceresco Dam to provide a safe and legal way for people to navigate around the dam.

Measuring Effectiveness

There are many long-term benefits to fostering good relations with stakeholders and building trust and goodwill with the landowners and communities along Enbridge's rights-of-way.

For one, if landowners and communities already know Enbridge and believe they have been treated fairly by the company in the past and that the company cares about its communities and the safety of everything it does, then they are more likely to support Enbridge and any of its future expansion initiatives and will be more open to discuss and negotiate their needs with Enbridge.

Moreover, Enbridge employees and their families live in these same communities, and they share the same goals as their neighbours, which is to build strong, thriving, safe and sustainable communities.

Pipeline safety also enters into the equation. When stakeholders are well informed about Enbridge and its operations and trust the company and know that the company wants to hear from them, then they are more likely to be quicker to call the company if they smell, hear or see something out of the ordinary with regards to the company's operations.

The actions or reactions of Enbridge's stakeholders are the primary indicators of the company's community relations performance and that of the Public Awareness Program. Key performance indicators for Enbridge include:

- positive or negative feedback gathered in meetings with stakeholders;

- concern/support from elected officials regarding matters important to the projects;
- letters of support;
- positive, negative or balanced media coverage;
- level of opposition to projects;
- timely regulatory approvals of the projects; and
- conflict mitigation through effective communication and a meaningful consultation process with stakeholders.

By fostering positive relations and addressing stakeholders' concerns proactively, Enbridge has been able to move forward on its growth projects with the support of landowners, communities, and Aboriginal and Native American neighbours.

Enbridge conducts formal and informal surveys to measure the effectiveness of its programs. For example:

- In the U.S., Enbridge is required by federal regulation to conduct an annual implementation review of the Public Awareness Program, and to evaluate program effectiveness once every four years. The effectiveness evaluation is conducted through a collaborative survey program, incorporating feedback from emergency responders, public officials, excavators and people who live and work near our pipelines. The survey measures their understanding of pipeline safety and retention of information they would have received as part of a company's pipeline public awareness baseline direct mail program. This information is paired with statistics and metrics from the annual implementation review to help determine if the program is effective and if any changes to the program are indicated.
- Enbridge also uses informal measures of media interest (news and blog clips) to gauge stakeholder interest in certain topics such as proposed pipeline construction in their area, as well as to develop educational and open-house materials that are responsive to stakeholder questions that are raised in media stories.
- Strong relationships with emergency responders in Enbridge's areas of operation throughout North America are a top priority. As a result of feedback received from a 2011 survey of emergency response agencies that have received grants through our Safe Community Program, we have begun development of an interactive training program for emergency responders to cover all elements of our operations. The training, which will be deployed online, will launch in the U.S. in late 2012; we are concurrently working on a plan to deploy the program in Canada in 2013. The training program will include elements of "Pipeline Emergencies," a program developed through a partnership between the National Association of State Fire Marshals (NASFM) and the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) and widely accepted as world class in training for pipeline emergencies.

Continual Improvement

Enbridge aims for continual improvement of its community relations initiatives to reinforce the company's long-standing commitment to being a good neighbour and maintain positive relationships with landowners, tenants and communities along the company's rights-of-way.

For example, the relationships that Enbridge Gas Distribution (EGD) builds with communities through its community events, sponsorships of community activities or meetings with key stakeholders have helped establish EGD as a good corporate citizen. Some recent examples:

- Through EGD's sponsorship of Project Zero, which is a public education program aimed at reducing residential fire and carbon monoxide (CO) deaths to zero, the Ontario Fire Marshal's office was able to distribute over 2,700 combination smoke and CO alarms to 11 municipalities across the province in 2011.
- Through its commitment to the Winter Warmth program, EGD assisted over 1,300 low-income families and individuals with payment of their natural gas bill during the winter of 2010/2011.
- Through EGD's title sponsorship for the Enbridge CN Tower Stair Climb for United Way, United Way Toronto raised over $2.2 million in 2011.

ABORIGINAL & NATIVE AMERICAN RELATIONS

Aboriginal and Native American communities comprise some of Enbridge's most important neighbours.

The terms "Aboriginal" and "Native American" are commonly used to refer to the original inhabitants of Canada and the U.S.—those who lived on the continent before other groups arrived from other parts of the world. In Canada,

the term “Aboriginal” includes First Nations, Métis and Inuit peoples.

Enbridge recognizes the history, uniqueness and diversity of Aboriginal and Native American peoples. Positive relationships with Aboriginal and Native American peoples, based on mutual respect and trust will help them and the company to realize our respective aspirations and will help Enbridge to reach its strategic business objectives.

Enbridge’s relations with Aboriginal and Native American people are extensive. In Canada, for example, Enbridge rights-of-ways are located in proximity to approximately 60 First Nation communities. As Enbridge’s network expands, the breadth and depth of these relationships will grow.

Enbridge is committed to respectful relations, early engagement, meaningful dialogue and forthright and sincere consultation with its Aboriginal neighbours in Canada and its Native American neighbours in the U.S.

Enbridge shares with them a high regard for the environment and for tradition and, as such, the company respects their land, heritage sites, and traditional knowledge and land use.

Aboriginal and Native American Policy

Enbridge first formalized the principles that guide its relations with Aboriginal and Native American people in its Indigenous Peoples Policy, which the company adopted in 2001.

Since then, a great number of legal decisions in Canada have interpreted the nature of Aboriginal and treaty rights under the Constitution Act. These decisions have interpreted government’s duty to consult and, where necessary, accommodate Aboriginal people when their Aboriginal and/or treaty rights are impacted by government decision making, including regulatory approvals.

Also, starting in 2007, Enbridge embarked on an unprecedented number of pipeline expansion projects in both Canada and the U.S. All of these projects required regulatory approval from government agencies.

Consequently, in 2008, Enbridge reviewed its existing Indigenous Peoples Policy and, in early 2009, approved and adopted a revised Aboriginal & Native American Policy

The goal of the policy is to help achieve mutually beneficial relations with Aboriginal and Native American communities in proximity to or, in some significant way, affected by Enbridge’s operations. The policy and supporting guidelines are designed to ensure a consistent, thorough approach to consultation and engagement with Aboriginal and Native American people.

In the policy, Enbridge affirms that the company:

- recognizes the legal and constitutional rights possessed by Aboriginal people in Canada and by Native Americans in the U.S.;
- respects the traditional ways, Aboriginal and Native American heritage sites, and the relationship that Aboriginal and Native American peoples have with the land and the environment;
- engages in forthright and sincere consultation with Aboriginal and Native American peoples about Enbridge’s projects and operations that have an impact upon their legally and constitutionally protected rights;
- commits to working with Aboriginal and Native American peoples to achieve sustainable benefits for them resulting from Enbridge’s projects and operations, including opportunities in training and education, employment, procurement, business development and community investment; and
- fosters understanding and respect for local Aboriginal and Native American peoples among Enbridge’s employees and contractors.

Read the full Aboriginal & Native American Policy.

Enbridge’s Approach

Enbridge’s Aboriginal & Native American Policy provides direction to Enbridge employees in their interaction and engagement with Aboriginal and Native American peoples located near the company’s projects and operations.

Enbridge’s interaction and engagement is regular and consistent and spans the life of the project—from the planning and regulatory approval phases, through construction and then ongoing after a project becomes operational.

Enbridge designs its engagement activities to meet all legal and government (federal, provincial and state) regulatory requirements.

Open and ongoing two-way communication is the vital link that allows the company to:

- identify the interests and concerns of the people who may be affected by Enbridge operations; and
- explain Enbridge’s plans, expectations and constraints.

Enbridge's wide range of engagement activities include:

- regular communication through correspondence and project update newsletters;
- presentations at tribal government meetings;
- community open houses;
- job fairs;
- emergency preparedness exercises; and
- community investments and sponsorships.

Topics of communication and discussion typically include proposed pipeline routes, facility location, water course crossings, summaries of environmental studies, outcomes from the identification of traditional-use sites and opportunities to achieve sustainable benefits, including employment and procurement.

ABORIGINAL & NATIVE AMERICAN RELATIONS – RECENT INITIATIVES AND SIGNIFICANT EVENTS

The following is an overview of recent Aboriginal and Native American Relations developments in Canada and the U.S.

CANADA – CORPORATE

Enbridge engages in broad-based national initiatives that can impact and benefit Aboriginal people, communities and organizations throughout Canada.

Major Aboriginal Community Investment

School Plus

The Enbridge School Plus Program, which the company developed in partnership with the Assembly of First Nations (AFN), supports enriched programming and extracurricular activities in First Nations schools near major Enbridge pipeline routes in Canada. The overall goal of the program is to encourage First Nations youth to stay in school by assisting schools in offering sports activities, music or arts programs, field trips and school clubs.

The initial three-year pilot program, launched in 2009, provided funding to 42 eligible First Nations schools located in proximity to Enbridge's mainline right-of-way between central Alberta and southwest Manitoba, and in proximity to the company's first wind farm near Kincardine, Ontario. In the first three years of the program, grants totaling more than $2 million have been made under the Enbridge School Plus banner.

In 2011, Enbridge made grants to 33 eligible First Nations schools, and over 3,900 First Nations youth benefited from the program. One of the 33 programs was the Montana First Nation's Meskanahk Ka-Nipa-Wit School's Youth Education and Career Pathways SAIT Summer Camp program, which offers junior high school students the opportunity to explore and become more aware of post-secondary education and career options at the SAIT Polytechnic campus in Calgary. Participating students earned certificates in two of four programs offered at SAIT: heavy duty mechanics, professional cooking, video production, and web design. In order to be eligible to attend the summer camp, students at Meskanahk Ka-Nipa-Wit School had to have an attendance rate of over 85 per cent during the school year.

Due to the success of the pilot School Plus Program, Enbridge is expanding the School Plus Program in 2012 to include communities along the Enbridge mainline right-of-way in Ontario and Quebec. The expansion will bring to 87 the number of on-reserve schools eligible to apply for grants under the program.

Throughout 2011, Enbridge also continued to support School Plus initiatives that strengthen Métis and urban Aboriginal communities. These partnerships were initiated in early 2010 as an adjunct to the original on-reserve program. In 2011, the expanded program supported a partnership with the MacKenzie Art Gallery in Regina, Saskatchewan, to support its Urban Outreach program, which provides enriched arts instruction to students at inner-city Regina schools with high Aboriginal enrollment. Enbridge has also partnered with the University of Winnipeg to fund a program that provides inner-city students with the chance to engage in enriched science-oriented educational activities through the Enbridge Eco-Kids on Campus program. The expanded School Plus Program also includes

partnerships with Métis Child and Family Services of Edmonton and the Stardale Women's Group of Calgary.

The Banff Centre

In 2011, Enbridge continued its commitment to provide $1 million over seven years to The Banff Centre in Banff, Alberta, to support Aboriginal leadership and management programming, including a program dedicated to developing the leadership skills of Indigenous women leaders. In addition to supporting the Centre's Aboriginal leadership programming as a whole, Enbridge's partnership with The Banff Centre guarantees 12 annual scholarships for First Nations members whose communities are located in proximity to Enbridge's proposed Northern Gateway Pipeline right-of-way.

Canadian Aboriginal Writing and Arts Challenge

Enbridge is the presenting sponsor for the Historica-Dominion Institute's annual Canadian Aboriginal Writing and Arts Challenge, a national competition inviting young Aboriginal Canadians to showcase their creative writing talent, or their skill in the visual arts. In June 2011, the Canadian Aboriginal Writing and Arts Challenge awarded scholarship prizes to the best submissions in each of two age categories in both the writing and arts components.

CANADA – PROJECTS AND OPERATIONS

Enbridge continues to be an industry leader in building strong relationships with First Nations and Métis communities. Building on the successes of 2010, and through construction of a number of pipeline expansion/extension projects (Christina Lake, Woodland, Wood Buffalo, Athabasca, Waupisoo, and Bakken), Aboriginal communities and member-owned businesses realized an economic benefit of approximately $24.1 million in 2011.

In the first quarter of 2012, project construction had yielded approximately $14.9 million in additional direct and indirect spend to Aboriginal communities.

Bakken Hearing

In 2011, Enbridge participated in NEB hearings to consider and approve the proposed Bakken pipeline, a 124-kilometre extension of an existing pipeline running from Berthold, North Dakota, to Steelman, Saskatchewan. The proposed extension would transport crude oil between a new pump station near the Steelman terminal and an existing terminal at Cromer, Manitoba. Enbridge developed and executed a comprehensive Aboriginal consultation plan to engage with six First Nations and one Métis organization that are located within 30 kilometres of the proposed pipeline right-of-way.

As part of its new process, the NEB had notified some 27 Aboriginal communities and groups of the hearing, many of which were located far from the proposed right-of-way, and provided capacity funding to five Aboriginal intervenors. Enbridge responded to each intervenor, asking for an opportunity to meet to provide information concerning the proposed project and to ascertain their concerns. Enbridge met with four of the intervenors, as the fifth did not indicate a desire to meet. At the meetings, Enbridge responded to community concerns, which included questions as to how the proposed project would affect the exercise of their aboriginal and treaty rights. Enbridge advised the four communities that through our due diligence, we had confirmed that project lands were not subject to any rights of access for the purpose of exercising aboriginal or treaty rights. In addition, in accordance with our normal practice, we engaged the communities concerning their ability to participate in the project through the provision of services or labour. Ultimately, as a result of our engagement, two of the Aboriginal intervenors removed their objections to the proposed project.

At the conclusion of the hearings, the NEB approved the project, and found that Enbridge's Aboriginal consultation was fulsome and appropriate, and had provided the relevant Aboriginal communities with all project information necessary for them to identify their concerns.

Norman Wells Pipeline Release

Regrettably, on May 9, 2011, Enbridge experienced a release of oil on its Norman Wells Pipeline approximately 50 metres south of Wrigley and 150 metres south of Willowlake River in the Northwest Territories. Within four hours of confirming the release, Enbridge operations personnel notified neighbouring Aboriginal communities and organizations. The Aboriginal communities and organizations of Pehdzeh Ki First Nation, which had first reported the release to Enbridge, as well as Liidlii Kue First Nation, Dehcho First Nations, Fort Simpson Métis Nation Local #52 and the residents of the Willowlake River Settlement played an integral role in the consultation process, which greatly supported the remediation of the release site. The remediation of the release site was completed on April 2, 2012.

Enbridge's long-standing relationships with Aboriginal communities and organizations in the Northwest Territories provided the basis for an open and transparent consultation process related to the release site, where all parties involved had the opportunity to raise concerns and provide input.

The release-site remediation provided a significant economic opportunity to Aboriginal businesses in the region. Aboriginal business arms of the communities of the Pehdzeh Ki and Liidlii Kue First Nations provided $6,300,000 in services and labour to the remediation of the release site.

Operations

Housing is one of the most significant issues facing Aboriginal communities. Enbridge is pleased to continue our long-standing partnership with Habitat for Humanity. In 2010, Enbridge partnered with Habitat for Humanity and the Technical Services Advisory Group (TSAG) of Treaty 6 in Alberta in support of urban Aboriginal housing. In 2011, we topped up our original $100,000 donation made in 2010 with another $10,000 to help TSAG raise enough funds to support another home for a First Nation family.

Enbridge also partnered with Habitat for Humanity and Métis Capital Housing Corporation by providing $45,000 towards the renovation and refurbishment of three housing units in the Mill Woods and Sherbrooke areas of Edmonton. As a result of this partnership, three local Métis families will become new homeowners.

Enbridge also made a contribution to the Heart Lake First Nation near Lac La Biche, Alberta, that helped them install a fully functioning kitchen in their new community building. This beautiful facility will serve members of the Heart Lake community for many years to come.

Enbridge has a three-year partnership with Mother Earth's Children Charter School (MECCS) to support the school's hot-lunch program and the purchase of a permanent home for the school. We have made a total commitment of $330,000 to the school ($110,000 in each of the years 2011, 2012 and 2013). The only First Nation charter school in Alberta, MECCS offers a unique educational experience for its students, engaging them with their cultural roots and connecting them to Mother Nature through lessons based on Aboriginal teachings. Through our efforts and support, we are pleased to report that MECCS has been able to secure a permanent home for the school through the purchase of the St. John's School at Genesee, Alberta.

In 2011, Enbridge also made commitments in support of Aboriginal language and literacy initiatives. Enbridge has made a three-year commitment to the Canadian Indigenous Languages and Literacy Development Institute (CILLDI) at the University of Alberta. Since 2007, Enbridge has been a supporter of CILLDI through a variety of programs such as Elder in Residence, Young Women's Circle of Leadership in Partnership with Women Building Futures, and many scholarship opportunities. In 2011, Enbridge supported CILLDI's objectives in the revitalization of Canada's Aboriginal languages through the Enbridge Indigenous Language Leadership Awards. Through our support, Enbridge hopes to help make it easier for Aboriginal educators to attend the institute. Enbridge is offering up to eight awards of $2,500 each to support teachers from the Treaty 6, 7, and 8 areas in Alberta to take summer training at CILLDI to support the preservation of Aboriginal languages.

Enbridge also supports the Partners Active in Resource Sharing (PAIRS) program at Alexander Mackenzie Secondary School, which is attended by many students from the Aamjiwnaang First Nation, in Sarnia, Ontario. PAIRS is an initiative of the Lambton Kent District School Board, which connects high schools with local industry in order to enrich students' educational experiences. Enbridge has supported the program since 2010, which was the first year of a three-year commitment to the school. Our support has included office equipment, a process-control module to be assembled by the students, and a yearly financial contribution.

In 2011, Enbridge also supported the Alberta Business Awards of Distinction, the Regional Aboriginal Achievement Awards in Fort McMurray, the Aboriginal Role Models of Alberta and the Belcourt Brosseau Métis Awards.

Additional community investments made by Operations in 2011 included:

- S.I.R.E.N.S., the Charity – $500 for one Grade 9 scholarship and two Grade 12 scholarships
- Saskatchewan Indian Institute of Technologies – $3,000 scholarship
- Dakota Iapi Teunhindapi Consortium – $5,000 for language preservation

In our continuing desire to minimize our environmental footprint, Enbridge has supported a number of projects that will help further our objective of limiting or neutralizing potential environmental impacts.

The Walpole Island Land Trust, the first Aboriginal land trust to receive charitable status in Canada, was formed in 2008 to conserve and maintain the unique natural resources of the Walpole Island First Nation/Bkejwanong Territory. The area contains five different ecosystems and is home to one of the most pristine tallgrass prairies left in Canada, as well as many rare and endangered species. On May 20, 2011, Enbridge provided $20,000 to the Walpole Island Land Trust. The grant will help the Trust preserve and protect the natural habitat of a 171-acre wetland marsh on St. Anne Island in Ontario, just south of Sarnia. The funding from Enbridge will help protect rare and endangered species, to ensure they will be around for future generations to explore and discover.

Enbridge also supported a traditional and medicinal plant study with the Aamjiwnaang First Nation, near Sarnia, Ontario. This First Nation's Environment and Health Committee is completing a study of approximately 200 acres of forested land on the reserve to identify and catalogue the numerous species of local medicinal plants and outline their

intrinsic healing properties. The project will include community nature walks led by local members knowledgeable in traditional healing to teach community members about native species and how these plants and trees can be used as traditional medicines.

In 2011, Enbridge awarded more than $81,000 to First Nation and Métis communities in proximity to our rights-of-way under our signature Safe Community Program. The funds will assist the following communities to enhance the capacity of local first responder agencies and increase safety in their communities:

- Aamjiwnaang First Nation (Ontario)
- Walpole Island First Nation (Ontario)
- Kikino Métis Settlement (Alberta)
- Buffalo Lake Métis Settlement (Alberta)
- Heart Lake First Nation (Alberta)
- Whitefish Lake First Nation #128 (Alberta)
- Canupawapka Dakota First Nation (Manitoba)
- Sioux Valley Dakota Nation (Manitoba)

Approved programs included requests for emergency communication equipment; training courses in hazardous materials handling, first aid and CPR; emergency preparedness planning; and search and rescue equipment.

By early 2012, Enbridge had received applications from seven Aboriginal communities for funding under this program, indicating a growing interest in participation.

Projects

Enbridge was pleased to support a number of other educational institutes and life-long learning initiatives to Aboriginal communities in connection with our new pipeline projects, especially in northern Alberta. Enbridge provided a gift of $100,000 in support of the completion of Keyano College's Fort Chipewyan Campus in the Regional Municipality of Wood Buffalo, Alberta, demonstrating our commitment towards lifelong learning opportunities. With the completion of the new campus, students in this northern and remote community will have greater access to educational opportunities without having to leave their community.

During the first quarter of 2012, Enbridge provided $955,000 to support community initiative priorities and education in communities in proximity to pipeline projects under development. Enbridge understands that the communities themselves are in the best position to identify their needs, and as a result, we have agreed to allow the communities to allocate the funding for community purposes. The recipient communities will report back to Enbridge concerning the specific allocations.

Included in the above are the following initiatives:

- Mikisew Cree First Nation – 10-year commitment to education; $6,000 for 2011 contribution year
- Chipewyan Prairie Dene – 10-year commitment to education; $6,000 for 2011 contribution year
- Athabasca Chipewyan First Nation – 10-year commitment to education; $6,000 for 2011 contribution year
- Ocean Man First Nation – $3,000 scholarship

Enbridge supported the Dakota languages programs in Manitoba through a $5,000 contribution to the Dakota Iapi Teunhindapi Consortium and a $20,000 contribution to Brandon University's Dakota Language Program. Enbridge also supported the 2011 First Nations' Language Keepers Conference in December 2011. In Alberta, Enbridge has made a three-year commitment of $60,000 to the Saddle Lake Cree Nation's Family Life and Adult Literacy Initiative.

CANADA – ENBRIDGE NORTHERN GATEWAY PROJECT

In May 2010, Enbridge filed its application for the construction and operation of the Enbridge Northern Gateway Pipelines Project (the Project) with the National Energy Board (NEB). The Project involves a new twin pipeline system between Edmonton, Alberta, and a new marine terminal in Kitimat, British Columbia, to export petroleum and import condensate. Northern Gateway Pipelines Limited Partnership (Northern Gateway) continued to implement its Aboriginal Engagement and Consultation Program (Aboriginal Engagement Program) with Aboriginal groups in the provinces of British Columbia and Alberta.

Highlights of Northern Gateway's Aboriginal Engagement Program during 2011 and early 2012 were as follows:

Consultation and Engagement:

Northern Gateway's Aboriginal Engagement Program includes engagement not only with those Aboriginal groups located within the proposed right-of-way, but also with those Aboriginal groups located outside the right-of-way corridor who have expressed an interest in the Project.

In November 2011, Northern Gateway held a well-attended Aboriginal Business Summit (the Summit) at the Edmonton Marriott at River Cree Resort on the Enoch Cree Nation's Stony Plain Reserve. The twofold purpose of this invitation-only event was to:

- share information with delegates about the Project's progress to date and the many economic opportunities associated with the construction and operation of the pipelines; and
- provide an opportunity for Aboriginal and local leaders and businesses to meet leading competitors in pipeline construction and related services, and to explore ways to become involved in collaborative business arrangements, including partnerships, joint ventures, and employment and training opportunities, both near-term and in the future.

The Summit was a great success. It was attended by approximately 400 people and 40 businesses, including several local and Aboriginal businesses situated in proximity to the Project's proposed pipeline route. In total, 38 Aboriginal communities were represented by more than 150 Aboriginal delegates, including 18 First Nations Chiefs, which was a significant increase over the level of Aboriginal participation at the 2010 Summit in Vancouver. There were also over 170 delegates from the pipeline construction industry, including 24 delegates from organized labour, as well as eight government delegates and more than 16 delegates from local non-Aboriginal communities. The Summit consisted of a trade show, with 20 businesses taking part, several plenary sessions on topics related to the Project, and keynote addresses by distinguished presenters, including the President of the Canadian Energy Pipelines Association (CEPA) and the Mayor of the City of Edmonton.

In conjunction with the 2011 Summit, Northern Gateway also hosted a half-day session on employment and training opportunities and initiatives associated with the pipeline construction industry. Immediately preceding the Summit, Northern Gateway organized a tour of Suncor's Athabasca oil sands mining and extraction operations in Fort McMurray, Alberta, for six Aboriginal communities from British Columbia who were not familiar with the processes involved in recovering oil from the vast oil sands resources of northeastern Alberta. This tour resulted in participants gaining a greater understanding of the Athabasca oil sands and the progress being made by industry in reclamation and other areas of operations. In November 2011, Northern Gateway organized a similar tour of the Oil Sands Discovery Centre for three representatives of the Gitxsan Nation of British Columbia.

Northern Gateway continues to implement a process for Aboriginal Traditional Knowledge (ATK) studies to be completed by Aboriginal groups in relation to the Project, including:

- the sharing of the final ATK community report with the Aboriginal community;
- reviewing and tracking of ATK issues and concerns raised by the Aboriginal groups;
- flagging of issues that can be addressed immediately and subsequently discussed during ongoing technical meetings with the Aboriginal community; and
- recording issues that cannot be addressed immediately in an ATK tracking document by referencing the kilometre-post location of that site specific issue.

During 2011, Northern Gateway received six completed ATK studies from Aboriginal groups in Alberta. Currently, there are eight ATK studies under way with Aboriginal groups in Alberta, with at least five of these in the final stages of completion. Northern Gateway has scheduled Project technical sessions in the second and third quarters of 2012 with Aboriginal groups that have completed ATK studies. Northern Gateway will do the same for those groups that submit completed ATK studies during 2012.

In October and November 2011, Northern Gateway held several Project technical meetings with six Aboriginal groups, including five from Alberta and one from northeastern British Columbia to discuss various aspects of the proposed Project, and to address concerns and answer questions from community members related to the proposed Project. Northern Gateway also presented a session on water-course crossings to two of the groups. In addition, in cases where an Aboriginal group had completed an ATK study and identified issues and concerns in the study, Northern Gateway's technical team addressed the ATK issues and concerns during the technical session.

In 2011, Northern Gateway established the Burns Lake Aboriginal Communities Working Group (Working Group) for the regions of Fort St. James and Burns Lake, British Columbia. The purpose of the Working Group is to develop strategies to maximize the participation of Aboriginal communities and their members in business, economic, and

social opportunities relating to the development, construction and operation of the Project. The Working Group held its first meeting in June 2011, and schedules monthly meetings.

In the latter part of 2011, Northern Gateway representatives began working with community members from the Kitselas First Nation in British Columbia to establish a working group to discuss strategies for a more collaborative approach to project design optimization and environmental stewardship.

In April 2011, Northern Gateway conducted an open house with the Sawridge First Nation in Alberta to provide Project information to the First Nation, including Project technical information, information on proposed water-course crossings and an overview of the proceedings of the Joint Review Panel (JRP), which was established to review the proposed project. The JRP has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest.

In addition, Northern Gateway attended two community meetings in Alberta—with the Sturgeon Lake Cree Nation in October 2011; and with the Horse Lake First Nation in December 2011. At the Sturgeon Lake Cree Nation meeting, Northern Gateway provided a Project update to community members and presented information surrounding an Aboriginal Economic Benefits Package and on the JRP regulatory process. At the Horse Lake First Nation meeting, Northern Gateway provided information to community members regarding an Aboriginal Economic Benefits Package and answered general questions about the Project. (For more details about the Aboriginal Economic Benefits Package, please see below.)

Regulatory Application and Process:

Northern Gateway continued to notify Aboriginal groups included in the Aboriginal Engagement Program of updates and supplementary information filed with the JRP, including notification of the Update to the Application in April 2011, notification of the Update to the Project Application in June 2011, notification of Hearing Order OH-4-2011 by the NEB in May 2011 and Invitation by JRP in May 2011 to the public to attend public information sessions regarding the joint review process established for the Project.

The JRP secretariat conducted information sessions in Alberta and British Columbia in June 2011 to share information with the public on the JRP process and how to participate in the process. In the fall of 2011, Northern Gateway responded to thousands of information requests received in Round 1 and Round 2 of the Project application. A significant number of these information requests were submitted by Aboriginal groups from British Columbia and Alberta. The deadline for submitting written evidence by Aboriginal groups who intervened in the process was January 4, 2012. The JRP commenced its oral community hearings in Kitamaat Village on January 10, 2012. The initial oral hearings were for intervenors who had requested the right to supplement their written evidence orally. The majority of the presentations were from Aboriginal groups who provided oral evidence on their traditional activities in areas that might be impacted by the pipeline, terminal or tanker traffic.

Aboriginal Economic Benefits Package:

In 2011, Northern Gateway continued discussions regarding the Aboriginal Economic Benefits Package with eligible Aboriginal groups within three geographical regions: Alberta, interior British Columbia, and coastal British Columbia.

The Aboriginal Economic Benefits Package includes an Aboriginal Ownership Agreement (the Agreement), offering Aboriginal communities equity participation in the Project, as well as an opportunity to enter into a memorandum of understanding with Northern Gateway to further discuss potential opportunities arising from the Project, including employment, training, and procurement.

As of May 31, 2012, which was the deadline for entering into the Agreement, a majority of the groups eligible to participate as equity owners had signed up to do so. Almost 60 per cent of eligible Aboriginal communities along the proposed right of way, representing 60 per cent of the First Nations' population (and 80 per cent of the combined First Nations' and Metis' population) had agreed to be part owners of the proposed Northern Gateway pipelines. Half of the equity units taken up went to groups in British Columbia, and the other half to groups in Alberta.

Northern Gateway, under the current terms of the Agreement, cannot disclose the names of the Aboriginal groups who have entered into the Agreement until the commencement of the formal hearings in September 2012.

Education, Training and Skills Development:

In 2011, Northern Gateway developed an Education, Training and Employment Strategy as a mechanism to help local community members develop the essential and transferable skills necessary to work in the growing pipeline and construction sectors.

As part of the overall strategy, Northern Gateway launched a $1.5-million Education and Training Fund to support flexible community-based training specific to the pipeline and construction sector. Northern Gateway is working with local Aboriginal and non-Aboriginal communities, as well as training providers, to design custom education and training-to-employment programs, and utilizes the fund to cover shortfall costs not funded through existing federal and provincial programs. As part of this initiative, Northern Gateway contributed $80,000 to the Trade Winds to Success program to use towards trades training for members of six Aboriginal groups in proximity to the proposed Project corridor. Northern Gateway will continue to actively engage in workforce planning initiatives in both Alberta and British Columbia as a mechanism to deal with present and anticipated skilled labour shortages in the pipeline and construction sector.

In March 2011, Northern Gateway attended a career fair at the Paul First Nation in Alberta and provided Project information to participants, including information related to potential employment and training opportunities arising from the Project. Northern Gateway also distributed the Northern Gateway Skills Development Catalogue and National Energy Board information to interested persons.

In July 2011, Northern Gateway also attended the Industry Relations Community Lands Conference at the Horse Lake First Nation in Alberta and provided Project and Economic Benefits Package information.

Community Advisory Boards:

Northern Gateway is continuing to foster and support discussion of all components of the Project through Community Advisory Boards (CABs) that are comprised of a cross-section of interested groups, including First Nations, Métis organizations, business leaders, local government and environmental organizations. Aboriginal groups continue to participate in the CABs on an ongoing basis, with a total of eight Aboriginal groups in British Columbia attending meetings of the CABs during 2011. A total of 12 Aboriginal groups, representing Aboriginal groups from Alberta and British Columbia participated in the CAB meetings during 2011 and the first quarter of 2012.

In Alberta, during 2011, Northern Gateway facilitated two CAB meetings in Grande Prairie and two CAB meetings in Edmonton. During the first quarter of 2012, Northern Gateway facilitated one CAB meeting in Grande Prairie and one CAB meeting in Edmonton.

In June 2011, a significant CAB Conference held in Richmond, British Columbia, brought together both Alberta and B.C. Aboriginal groups and included participation of senior Project management, including then Enbridge CEO Pat Daniel. The CAB was attended by representatives of seven Alberta Aboriginal groups and eight British Columbia Aboriginal groups.

Community Sponsorships:

Throughout 2011, Northern Gateway continued to demonstrate its commitment to Aboriginal groups by providing financial support to cultural, social, sporting, and community well-being events to the following Aboriginal groups in British Columbia and Alberta, including, but not limited to, the following initiatives:

British Columbia

- BC Aboriginal Achievement Foundation – BC Aboriginal Business Awards
- Gitxsan Hereditary Chiefs – Gitxsan Chiefs Summit 2011
- Industry Council of Aboriginal Business – “On Common Ground” Celebration
- Lheidli Tenneh First Nation – Honour Your Health Challenge – 2011 Vancouver Sun Run
- Lheidli Tenneh First Nation – Christmas Party Donation
- McLeod Lake Indian Band – Annual General Assembly and Barbecue
- North East Native Advancing Society – Go Karts for Girls
- Northwest Community College – Heavy Equipment Operator Technician Program
- Prince George Métis Elders Society – Sharing Our Aboriginal Culture Celebration
- Prince George Aboriginal Youth Hockey – 15th Annual Youth Hockey Championships
- Seabird Island Band – 35th Elders Gathering
- Skin Tyee First Nation – Christmas Party donation

- Smithers Secondary School – Hot Lunch Program
- “Spirit of the Peace” Powwow Society – 6th Annual Spirit of the Peace Powwow
- Tl’azt’en Nation – Youth Sports
- Vancouver Venture for Diversity – Annual Golf Tournament
- West Moberly First Nations – Annual Moberly Days
- Yekooche First Nation – community investment
- 3M Sport – 2011 BC All Native Fastball Championships

Alberta

- Alexis Nakota Sioux Nation – Annual Community Pow Wow
- Alexis Nakota Sioux Nation – Christmas community event
- Buffalo Lake Métis Settlement – community investment
- Buffalo Lake Métis Settlement – Christmas community event
- Council for the Advancement of Native Development Officers – Maskwacis Youth Business Dream Catcher Program
- Duncan’s First Nation – community sponsorship
- Duncan's First Nation – community hockey event
- Enoch Cree Nation – Aboriginal Role Models of Alberta
- Enoch Cree Nation – Elders Christmas community event
- Kapawe’no First Nation – community sponsorship of elder and youth initiatives
- Kelly Lake First Nation – community sponsorship
- Kikino Métis Settlement – community rodeo
- Lesser Slave Lake Indian Regional – LSLIRC Annual Golf Tournament
- Native Network Inc. – Aboriginal Economic Summit
- Métis Nation of Alberta Association – Grande Prairie Métis Local #1990
- Métis Nation of Alberta Region II – Boxing Day Talent Show
- Métis Nation of Alberta - Region V – Youth Program
- Sawridge First Nation – community investment towards displaced members due to Slave Lake fires
- Sucker Creek First Nation – Elder and Youth Initiative
- Sturgeon Lake Cree Nation – Annual Charity Golf Tournament
- Treaty 8 First Nations of Alberta – Christmas Gala event
- Whitefish Lake First Nation – Annual Treaty Days
- Whitefish Lake First Nation – Keyano Pimee Golf Tournament

Enbridge Scholarships at The Banff Centre

Further to the report above about Enbridge’s national Aboriginal community investment in The Banff Centre, representatives from the following British Columbia Aboriginal communities received scholarships to participate in The Banff Centre’s week-long “Best Practices in Aboriginal Business and Economic Development” course in January 2011: Cheslatta Carrier Nation; Skin Tyee Nation; Tl’azt’en Nation; Yekooche First Nation; and West Moberly First Nations.

The course examined the fundamental issues of governance, such as the creation of culturally appropriate governmental institutions and the role of Aboriginal leaders in effectively planning, creating, and promoting economic policy for self-determined Aboriginal development.

The following topics were examined and explored:

- The Harvard Project on American Indian Economic Development

- Nation-building: Tools, policies, and leadership for Aboriginal governments
- Rethinking Aboriginal economic policy: insights and implications
- Case study presentations of “best practices” in Aboriginal economic policy and Aboriginal governance made by invited representatives
- Nation-building components: Asserting self-governance, building institutions, setting strategic direction, and taking action through strong leadership
- Separating politics and business: A community necessity
- Community economics model from an Aboriginal perspective
- All aspects of community economic development and business planning
- Financing Aboriginal economic ventures

In 2012, Enbridge has again committed to offering 12 scholarships to The Banff Centre’s Aboriginal Leadership and Management programming to representatives from British Columbia Aboriginal communities located along the proposed Northern Gateway right-of-way.

Challenges:

In 2011, British Columbia Aboriginal communities opposed to the Project participated in protest marches in the following communities:

- Prince George, British Columbia
- Terrace, British Columbia
- Prince Rupert, British Columbia
- Gitxsan Nation, British Columbia
- Calgary, Alberta

In May 2011, Chief Jackie Thomas of the Saik’uz First Nation of British Columbia and other members of the Yinka Dene Alliance met with Enbridge’s then President and CEO Pat Daniel and members of the company’s Board of Directors in Calgary, Alberta, prior to the Enbridge annual general meeting to discuss their group’s opposition to the Project. Chief Thomas and other members of the Yinka Dene Alliance also attended the annual general meeting and expressed their opposition there.

Aboriginal individuals protested against the Project at the Joint Review Panel (JRP) public hearings held in Edmonton in January 2012.

In early 2012, three trappers from the Kelly Lake Cree Nation expressed environmental concerns relating to the Northern Gateway pipeline. One of these trappers has a registered trap line within the Project’s corridor. Northern Gateway representatives will continue to meet with the trappers and Kelly Lake Cree Nation community members in an attempt to resolve their issues and concerns relating to the project.

On March 26, 2012, approximately 750 people took part in an anti-Project rally outside Enbridge’s Vancouver offices, and on March 31, 2012, a similar number protested outside the recreation centre in Comox, B.C., as the JRP heard presentations inside.

On April 2, 2012, a scheduled JRP hearing was cancelled because of security concerns after panel members were met by a large crowd of protesters at the Bella Bella, B.C., airport on April 1.

On May 9, 2012, several hundred protesters peacefully marched to the King Edward Hotel in Toronto, where Enbridge Inc.’s Annual General Meeting was being held. With media in attendance, the protesters chanted and drummed in the street outside the hotel.

Northern Gateway representatives continue, whenever possible, to meet with those Aboriginal communities who oppose the Project with a view to being afforded an opportunity to clarify misconceptions about the effects of the Project on Aboriginal reserve, treaty, and traditional territory lands, and to consider potential mitigation measures to address concerns raised by Aboriginal communities.

CANADA – ENBRIDGE GAS DISTRIBUTION

In June 2009, Enbridge signed a Cooperation and Land Use Agreement with the Mohawk Council of Akwesasne (MCA) that recognizes the importance of meaningful discussions between the parties and provides economic, social and community benefits for Akwesasne.

In 2011, this agreement provided the structure for dialogue regarding the installation by Niagara Gas

Transmission Ltd (NGTL), a wholly owned subsidiary of Enbridge Inc., of a new underground pipeline crossing the north channel of the St. Lawrence River using horizontal drilling technology.

On January 20, 2012, the Mohawk Council of Akwesasne held an official ceremony to recognize an infrastructure-related one-time contribution of $1 million from NGTL. Under the agreement, NGTL has committed to annual payments of approximately $100,000 for the next 20 years for the use of Akwesasne land for the new NGTL pipeline. The agreement also provides for on-going communication and cooperation protocols regarding NGTL activities in the Akwesasne community situated in eastern Ontario, near the Canada-U.S. border.

To build the crossing, Enbridge and NGTL worked closely with the MCA's Department of the Environment on a harmonized environmental assessment report, which incorporated traditional knowledge into project plans. One of the action items required by the report was the removal of the abandoned pipe and the protection of culturally important trees.

Enbridge and NGTL also ensured that it bought materials and rented workspace from local businesses, and structured contracts that promoted the hiring of Akwesasne workers and contractors.

CANADA – WIND AND SOLAR ENERGY

Enbridge Ontario Wind

Enbridge's 190-megawatt Ontario Wind Power Project located at Kincardine in Bruce County, Ontario, on the eastern shore of Lake Huron, went into full commercial operation in 2009. It is the fourth largest wind farm in Canada.

The wind farm is located within the traditional territory of the Saugeen Ojibway, which comprises two First Nations—the Chippewas of Nawash and Saugeen First Nation.

The agreements in place with the Saugeen Ojibway Nation include their participation in archeological work and in ongoing environmental monitoring, as well as potential employment, training and business opportunities for members of the Saugeen Ojibway Nation members.

Of the six permanent employees of the wind farm, two are members of the Saugeen Ojibway Nation.

In 2011, Enbridge worked to finalize the report on the environmental monitoring study conducted in 2010 with assistance from the Saugeen Ojibway Nation.

In 2011, Enbridge supported hockey teams from the Saugeen First Nation and the Chippewas of Nawash for their "Little NHL Hockey Tournament." Enbridge also contributed to Anishinabek Child & Youth Prevention Services for an after-school program. Enbridge also supported the Chippewas of Nawash 2011 golf tournament.

In 2011, the Enbridge School Plus Program provided over $19,500 in funding to the Chippewas of Nawash Cape Croker Elementary School for a music and band enrichment program, as well as a sports and leadership camp.

Sarnia Solar Project

In connection with this project, Enbridge has maintained a relationship with the Aamjiwnaang First Nation, whose reserve is located in proximity to Sarnia, Ontario. In 2011 and 2012, Enbridge provided financial support for this First Nation's Youth After School Health and Fitness program.

Greenwich Wind Project

In November 2011, Enbridge and Renewable Energy Systems Canada Inc. (RES) completed construction of the 99-MW Greenwich Wind Energy Project, which is located on Crown lands near Thunder Bay, Ontario, and the project began commercial operation. Throughout the earlier regulatory process, two local First Nations, the Red Rock Indian Band and the Fort William First Nation, had been engaged, culminating in the conclusion of agreements that provide sustainable benefits flowing from the project to each of the First Nations. The project hired community members during construction in 2011, and First Nations members provided almost 7,500 hours of labour to the project during that year. Also in 2011, Greenwich Wind contracted with a First-Nation-owned company to provide road maintenance services to the project in 2011-12. These services are being provided to the project on an ongoing basis by First Nation contractors.

The Greenwich limited partnership had also concluded agreements with local Métis organizations in relation to the project. In 2011, the project provided financial support to facilitate communication regarding the project between three local Métis community councils and their members, and to support Métis community development, as deemed appropriate by each of the community councils. In addition, in response to concerns expressed by the Métis Nation of Ontario, the project has agreed to prohibit the use of chemical-herbicide sprays in vegetation clearing activities during the operation of project transmission-line corridors, access roads and turbine-tower sites.

Lac Alfred Wind Project
In 2011, Enbridge acquired a 50 per cent interest in the 300-MW Lac Alfred Wind Farm, which is currently under construction in the Gaspé region of Quebec. During the regulatory process, project developers had engaged with the Mi'qmaq and Malecite First Nations communities in the Gaspé to ascertain their concerns regarding the project. First Nations members have also been employed in construction of the project.

Conference Sponsorship
Beginning in 2010 and continuing in 2011 and 2012, Enbridge has been a sponsor of the annual "Powering Up Aboriginal Energy" conference, held in Toronto. This conference, which is primarily directed at Aboriginal communities, discusses issues related to Aboriginal participation in the renewable energy industry.

U.S. – MAJOR PROJECTS AND LIQUIDS PIPELINES OPERATIONS
Enbridge engages with Native American communities in the U.S. regarding new projects and ongoing operations. These sovereign nations play an important role in Enbridge's planning, consultation and construction processes, with tribal environmental staff having an ongoing role on a consultative basis both during construction of a pipeline and when construction is complete and the pipeline is operational.

The U.S. federal government consults with recognized Native American tribes on a government-to-government basis, which is required under Section 106 of the National Historic Preservation Act. Enbridge also works directly with the tribes whose lands are being crossed by the company's construction projects. The tribal governments and the U.S. Bureau of Indian Affairs have to approve agreements with Enbridge to build on any tribal-owned tracts of land. In addition, the tribes are concerned with any construction or maintenance activity taking place on reservations so, as a courtesy, it is important that Enbridge keep tribal governments informed of any such plans.

Lastly, all Native American reservations have a Tribal Employment Rights Ordinance (TERO), which states that companies, such as Enbridge, will give Native Americans hiring preference on all work within reservations.

In the U.S., Enbridge Native American Affairs provided scholarships to the following:

- Leech Lake Tribal College – $2,500
- Fond du Lac Tribal and Community College – $2,500

In February 2011, the Mandan, Hidatsa and Arikara Nation (MHA) in New Town, North Dakota, hosted the International Energy Oil and Gas Summit. The Fort Berthold Indian Reservation of the MHA is experiencing rising oil production from the Bakken formation, which is resulting in unprecedented wealth for the tribe, but is also taking a toll on roads, safety and culture. The summit provided a venue for the oil industry to understand concerns and work with the tribe toward solutions. Enbridge was a sponsor of the Summit and participated in a panel discussion with other industry representatives regarding the future of oil and gas on the Fort Berthold Indian Reservation. Although Enbridge does not currently have assets or projects in this area, opportunities may exist there in the future.

Tabletop Exercise with the Fond du Lac Tribe
On February 18, 2011, Enbridge participated in a tabletop exercise hosted by the Fond du Lac Tribe in Cloquet, Minnesota. In addition to representatives from tribal emergency management and Enbridge, the exercise included approximately 40 representatives from the U.S. EPA, Coast Guard, National Weather Service, Cloquet Fire Department, Culver Volunteer Fire District, and TransCanada Pipelines. So as to form a complete incident command structure, Enbridge participants included individuals from operations, pipeline maintenance, engineering, right-of-way, compliance, public affairs, safety and environment.

The day-long event involved a scenario of an oil spill on tribal land. Each participating group provided insight on how the response would be handled for the first 72 hours—from first responders to boom deployment, road closures and public notifications.

A "lessons learned" discussion was held following the exercise, providing participants and observers the opportunity to comment. Feedback from observers focused on establishing procedures with the Fond du Lac emergency management on how a spill would be handled and the steps that would be taken by the tribe in order to function as the lead agency during an actual emergency response.

Integrity Dig Meetings with the Bad River Band
On November 10, 2011, Enbridge Native American Relations staff, in conjunction with the company's Integrity Digs Project group, met with representatives from the Bad River Band of northern Wisconsin. The band requested information and details on Enbridge's emergency response capabilities because the company's Line 5 crosses through sensitive and culturally significant areas. The meeting also focused on integrity-dig procedures for a scheduled dig on tribal land. Background materials on these processes were provided to share with other interested

band members. Enbridge representatives were able to address the band's questions, resolve immediate concerns and establish processes for on-going communication. As a result, the Bad River Band issued a permit for the dig, which took place without incident on November 21, 2011.

CROSS-BORDER PROJECT – MONTANA-ALBERTA TIE LINE

In 2011, Enbridge acquired Tonbridge Inc. and assumed management of the Montana-Alberta Tie Line (MATL) project, a bi-directional power line project between Great Falls, Montana, and Lethbridge, Alberta. The project will provide power transmission for wind energy projects under development in northern Montana.

The MATL project crosses land in Montana that is of historic and cultural interest to the Blackfeet Tribe. The tribe is partnering with MATL in the identification and protection of any archeological, historic or cultural artifacts or areas that could be affected by the project. The tribe is providing a trained cultural resource monitor familiar with tribal history and pre-history in the project area, and Enbridge contributed over $30,000 in 2011 to support the work of the monitor. The full-time monitor helps to identify tribal sensitive cultural resources and ensures appropriate treatment of these resources. The tribal monitor has been working in Montana since late fall 2011 when construction restarted and will continue through 2012 as construction progresses south from the U.S.-Canada border.

In Canada, Enbridge has engaged with the Kainai First Nation and the Piikani First Nation in southern Alberta to introduce Enbridge as the new project proponent and to provide updated project information. Enbridge is committed to continuing to meet and we look forward to developing positive long-standing relationships with these First Nations.

COMMUNITY PARTNERSHIPS AND INVESTMENTS

Strategy

Directed by our social vision statement, Enbridge in 2011 helped build communities across our operating regions in Canada and the U.S. that are sustainable, with solid infrastructure and programming in the company's six focus areas:

- Lifelong Learning
- Community Leadership
- Natural Legacy
- Arts & Culture
- School Plus
- Safe Community

By investing in each of these key areas with our dollars, partnerships and human capital, Enbridge is able to support organizations that contribute to the economic and social development of communities near the company's operations. Enbridge believes these investments are essential to being a good neighbour and are a contributing factor in maintaining the company's social license to operate. Please see below for more details on the six focus areas.

Enbridge partners with charitable and non-profit organizations in our various geographic regions in Canada and the U.S. that have the skills and expertise to effect change. The criteria and guidelines for Enbridge's Community Partnerships & Investments Program are outlined under the heading 'Policy' of this Society section.

In the year ended December 31, 2011, Enbridge's actual enterprise-wide Community Investment expenditure totaled $13 million, which the company invested in more than 550 charitable, non-profit, and community organizations. This investment amount is growing with corporate earnings, and represents over one per cent of Enbridge's profits.

Following are details about Enbridge's approach to its six community investment focus areas.

Lifelong Learning

Investing in educational programs in the regions where Enbridge's employees live and work helps to build strong, sustainable communities. Enbridge understands that today's students are tomorrow's leaders, and the company is committed to helping young people advance their education to achieve their greatest potential.

Through a commitment to educational opportunities for students and adults, we focus our investments on scholarships for higher education, programs that improve literacy, and skills in math and science.

Community Leadership

Enbridge demonstrates community leadership by investing in innovative, leading edge initiatives in social services, health, volunteerism and leadership. In addition to civic investments, Enbridge also supports social development initiatives through employee-led United Way campaigns across the company.

Natural Legacy

Enbridge's Natural Legacy Program provides the company with an opportunity to demonstrate its ongoing commitment to environmental stewardship, habitat remediation and protection. Enbridge does this through initiatives such as elementary educational programs, and the planting and care of native trees and plants throughout urban and rural areas along the company's rights-of-way.

Enbridge operates the program with environmental/conservation partners and employee volunteers dispersing the funding across Canada and the U.S. In 2011, Enbridge invested $1.3 million in the program.

Arts & Culture

The development and sustainability of cultural institutions is an investment in the vibrancy and diversity of a community. Enbridge supports arts and culture initiatives that make communities in which it operates brighter, warmer, and more interesting places to live.

School Plus

Enbridge's School Plus Program—one of Enbridge's flagship community investment programs—was designed to encourage young Canadian Aboriginal students to stay in school. Established by Enbridge in partnership with the Assembly of First Nations, the School Plus Program supports enrichment programming and extra-curricular activities in First Nations schools near major Enbridge pipeline routes from Alberta to Quebec and the company's wind farm in Ontario. With funding from Enbridge, teachers have the means to find creative ways to make education more enticing to kids who are at risk of dropping out.

Safe Community

Another one of Enbridge's flagship community investment programs, the Safe Community Program provides monetary support to:

- police agencies;
- fire fighters, including volunteer fire-fighting organizations in rural communities;
- Emergency Medical Services (EMS); and
- other related health providers who respond to emergency situations in the communities where Enbridge operates.

In 2011, the Safe Community Program provided over $1.2 million in grants to 425 first-responder organizations in right-of-way communities in Canada and the U.S. Grants given through this program allow eligible organizations to acquire such support as new safety equipment, obtain professional training, and deliver safety educational programs in their neighbourhoods. By helping first responders, Enbridge is making its neighbourhoods safer and building sustainable communities.

Volunteers in Partnership (VIP) Program

Enbridge encourages its employees to actively participate in their communities. Through Enbridge's Volunteers in Partnership (VIP) Program, the company recognizes employee contributions of time and dollars to charitable organizations by providing additional support in terms of paid volunteer time and top-up financial contributions. Enbridge supports employee volunteer opportunities by:

- providing grants of $500 to non-profit organizations where employees have volunteered at least 40 hours or more of service per year outside of business hours in countries where Enbridge has operations; or providing grants to match an employee's individual fundraising efforts for one event per year up to a maximum of $500;
- matching donations up to $10,000 for employee contributions to the United Way during the campaigns of individual Enbridge business units;
- providing the opportunity for employees to take one paid day or eight hours off per year to volunteer at a non-profit organization of their choice in countries where Enbridge has operations; and
- providing one paid day or eight hours off per year for supervisor-led team-building volunteer activities in countries where Enbridge has operations.

Through this support, Enbridge gains a better understanding of the communities in which it operates, the challenges they face and the ways the company can best contribute.

Benchmarking and Assessment

To help Enbridge ensure that its community investments are achieving the maximum results possible, the company has been working with London Benchmarking Group (LBG) Canada, of which Enbridge is a founding member. LBG

Canada comprises a group of companies that are using the “LBG model” to improve their management, measurement, and reporting of community involvement initiatives.

LBG Canada focuses on companies’ voluntary community contributions and applies consistent accounting principles to value their total investments. Companies value financial donations, as well as a full range of other contributions—including staff time, in-kind contributions, and management costs—that a company could make to a community.

In this regard, Enbridge’s enterprise-wide community contributions in 2011 totaled $23.5 million.

The LBG Canada approach provides a process for assessing the results that the company and the community realize from contributions.

SiMPACT Strategy Group, facilitator of LBG Canada, worked with Enbridge to determine the true community value of the company’s 2011 Canadian community investments.

Leak on July 26, 2010, on Enbridge’s Line 6B near Marshall, Michigan – Community Investment and Community Enhancement Projects

In July 2010, Enbridge experienced the worst spill in our history near Marshall, Michigan.

Since the beginning of the incident in Marshall, Enbridge has committed to cleaning up the Kalamazoo River and to restoring the area as close as possible to its pre-existing condition. We have worked hard to deliver on that commitment, and we will continue until the job is complete.

By spring 2012, cleanup, under the direction of the U.S. Environmental Protection Agency, had progressed to the point that the Kalamazoo River and Morrow Lake had been reopened for recreational use.

Enbridge’s commitment to the communities of Marshall, Battle Creek and areas along the Kalamazoo River extends much further than the cleanup itself. Enbridge recognizes how important the Kalamazoo River is to area residents. The river is a recreational hub, providing area residents with ample opportunity for fishing, kayaking, canoeing, and simply enjoying its beauty. Enbridge has committed to supporting community investment programs that will provide a long-lasting benefit to the community by enhancing recreational opportunities.

Based on input from local residents, community leaders and recreation groups, much of Enbridge’s community investment efforts are focused on increasing access to the Kalamazoo River. Enbridge has created or improved five river access sites to encourage recreational opportunities along the river.

Enbridge has also committed to a $200,000 donation to the Kalamazoo River Valley Trail (KRVT) group in support of a walking/biking path that parallels the Kalamazoo River. On April 17, 2012, Enbridge’s then CEO Pat Daniel participated in a cheque presentation and groundbreaking ceremony with the KRVT group near Marshall. We believe that the KRVT group’s plan to extend the pathway through the county and along the river will provide a long-lasting recreational benefit to the area. The community-building and community-enhancing nature of this project is clear. It provides a way for residents and visitors to enjoy the natural beauty of the area and to connect with one another in a way that promotes active living. It also connects communities. The KRVT initiative is part of the Great Lake-to-Lake Trail that will traverse across the state and connect Lake Michigan to Lake Huron.

In addition, Enbridge has and will continue to support other programs in the Marshall region that align with its corporate community investment initiatives to help build sustainable communities. As at June 30, 2012, Enbridge had contributed over US$600,000 to organizations in the area, including, among several others: the Marshall (Michigan) Historical Society; Wilder Creek Conservation Club; United Ways of Battle Creek, Marshall and Kalamazoo; the Red Cross of South Central Michigan; the Food Bank of South Central Michigan; and Michigan Envirothon.

PARTNERSHIP PROFILES

LIFELONG LEARNING

Enbridge recognizes that education is one of the most powerful gifts you can give, which is why we are proud to support educational opportunities that help students in all stages of life get ahead. Through a commitment to educational opportunities for students and adults, we focus our investments on scholarships for higher education, programs that improve literacy and skills in math and science.

Following are reports about some of the key lifelong learning initiatives we support.

Enbridge Inc.

Enbridge Centre for Corporate Sustainability – On March 27, 2012, Enbridge and the University of Calgary's Haskayne School of Business inaugurated the Enbridge Centre for Corporate Sustainability, which will be a hub for thought leadership in the area of corporate social responsibility. Enbridge has donated $2.25 million over 10 years for

the Centre, whose mandate is to advance corporate practices that help sustain our planet's people, environment and economy. To meet its mandate, the Centre will fund innovative graduate student and faculty research, and will invite renowned academics and business leaders to come and share their knowledge. Based on its research and knowledge-gathering work, the Centre will develop business practices focused on advancing sustainability, corporate citizenship and CSR. The Centre will also oversee the Enbridge Research in Action seminar series, which will bring together leading academics and industry experts from a variety of disciplines, institutions and organizations to raise the level of dialogue on CSR-related topics. As an incubator for future business leaders, the Centre will also help Enbridge and other companies in their recruitment efforts.

Scholarships and bursaries – In 2011, Enbridge contributed over $95,000 through more than 60 endowed scholarships and bursary awards to 20 post-secondary institutions across Canada. By focusing on areas such as engineering, Aboriginal leadership, non-profit studies, and environmental sustainability leadership, Enbridge is actively supporting the development of the next generation of business and community leaders in a number of key areas.

Calgary Stampede Foundation – Enbridge partnered with the Calgary Stampede Foundation in support of The Enbridge Citizens of Tomorrow Program to provide equal opportunity programming for Calgary's youth. This program promotes western heritage while supporting leadership and character-building activities. In 2011, Enbridge provided 13 post-secondary scholarships to youth who were selected based on their achievements throughout their time at the Young Canadians School of Performing Arts or as part of the International Youth Livestock Show.

Liquids Pipelines Canada

NAIT – Through Enbridge's financial support, the Northern Alberta Institute of Technology (NAIT) received funding for five annual student awards in the areas of Alternative Energy Technology and Biological Sciences Technology. The Enbridge Alternative Energy Technology Program at NAIT's new Centre for Sustainable Energy Technology is a diploma program that provides students with solid technical knowledge of solar, geothermal, wind, bio fuel, fuel cell, carbon capture, small hydro, and hybrid energy system applications required to support and promote Alberta's sustainable energy industry.

Enbridge Biological Sciences Technology Renewable Resources program – This Enbridge-funded program at NAIT specializes in training natural resources technologists to have a wide range of field skills and knowledge. The program provides students with a solid ecological foundation in the applied life sciences. Students gain a working knowledge of disciplines such as wildlife biology, botany, limnology, fisheries, entomology, soils, field sampling, environmental education, and resources skills management. Through laboratory work and lectures, the students learn about collecting and preserving biological soil and water samples for analysis, applying methods for the handling and management of plant and animal populations, and preparing chemical solutions for laboratory and field use.

Adult Learning Centre Regina (ALC) – ALC received funding from Enbridge to support the hiring of at-risk adults aged 19-30 as employees/apprentices during a 43-week program. The ALC uses an entrepreneurial business model approach to solve the social issues inherent in marginalized young adults. Through learning, healing and meaningful work, the ALC assists young adults in developing personal, social and employment skills needed to become independent, self-supporting and contributing members of society. The ALC provides an environment of understanding and counseling. It also provides a challenge for program participants, and reinforces in them the value of work, belonging and independence. Enbridge is a Platinum Sponsor for this program.

Alberta School of Business – Enbridge Pipelines Inc. renewed its partnership with the Alberta School of Business directed to Applied Business Research in Energy Sustainability, the Enbridge Professorship in Energy Policy, and the Enbridge Award in Energy and the Environment—all in support of continued research to find new ways for energy to be developed, transported and used in efficient and socially responsible ways while protecting the environment.

Pembina Valley Conservation District – Since Enbridge's 1992 donation to the Pembina Valley Conservation District supporting the purchase of a parcel of land known as Binney Siding Nature Preserve, Enbridge has continued to support the sustainability of this 30-acre marshland, meadow and grassland educational site in Manitoba. Through our support, we are helping to ensure the completion of an outdoor classroom/shelter and sponsoring the South Central Eco Institute's River Watch Program, which supports local students and teachers in monitoring the water quality of selected rivers and streams in the Red River Basin watershed. River Watch is an international program of river monitoring performed by various agencies. Students work alongside conservation professionals in this endeavour. This partnership is another excellent example of Enbridge's ongoing commitment to environmental stewardship.

Ducks Unlimited Canada – In 2011, Enbridge partnered with Ducks Unlimited Canada (DUC) to breathe new life into

an aging, but thriving wetland near the town of Killam in central Alberta. As part of a donation from Enbridge, DUC is providing maintenance and repairs to the Wetthuhn project to ensure 39 acres of wetlands remain healthy and natural. The Wetthuhn project is a perfect example of the work DUC is currently undertaking to maintain and restore wetlands throughout Alberta, and these much-needed repairs to the structure will ensure it continues to function effectively for the next 40 years.

Liquids Pipelines U.S.

Minot Public Schools Community Learning Centers (CLC) – Enbridge Pipelines partnered with the Minot Public Schools' after-school program to educate students in grades K-5 about pipeline operations. After-school presentations were held at eight different schools in the Minot, North Dakota, area, followed by a station tour during the summer CLC session in 2011.

Gas Transportation / Enbridge Energy Partners

Linda Lorelle Scholarship Fund – The Linda Lorelle Scholarship Fund is dedicated to providing college scholarships, support and guidance to Houston-area high school students in need of financial assistance whose potential may be unfulfilled due to other life circumstances.

The Keystone Center's Key Issues Institute – For the ninth consecutive year, Enbridge recruited middle school science teachers from areas of our U.S. operations to attend The Keystone Center's Key Issues Institute. Enbridge sponsored the participation of six teachers from Marshall and Battle Creek, Michigan, in the interdisciplinary program that provides educators with a balanced and non-biased process for teaching students the concepts of sustainability and investigating environmental issues.

Enbridge Gas Distribution (EGD)

Junior Achievement (JA) – EGD's support of JA Southern Ontario and JA Eastern Ontario is well aligned with the company's community investment goals. JA's Dollars with Sense program introduces students to personal financial management concepts. Students learn to assess personal goals, learn about money as a means of exchange, and explore various investment vehicles through role playing and investment simulation. In 2010/2011, as a result of Enbridge employee volunteerism, over 2,000 students benefited from the JA experience.

COMMUNITY LEADERSHIP

Enbridge's community investment focus on community leadership reflects our commitment to innovative initiatives that improve the quality of life for members of communities where we operate. We strive to promote leadership in these communities by supporting the United Way, health care institutions and health programs and social services organizations.

Following are reports about some of the key community leadership initiatives we support.

Enbridge Inc.

Enbridge Ride to Conquer Cancer – Enbridge is the National Title Sponsor of The Enbridge Ride to Conquer Cancer from 2011-2013, with events taking place in Alberta, British Columbia, Quebec and Ontario. The Enbridge Ride to Conquer Cancer is the largest cycling fundraiser in Canadian history. In 2011, more than 11,000 riders raised a total of $44 million to support cancer research, treatment and care. In addition to Enbridge's sponsorship role, Enbridge employees were active participants in the ride, with more than 200 employees, friends and family members raising more than $900,000.

Volunteers in Partnership (VIP) Program–The enterprise-wide Enbridge VIP Program supports the volunteer efforts our employees are making in communities where we operate through grants to match their time and their fundraising efforts. In 2011, the program reached a milestone—almost two years since its inception, the program has engaged over 1,100 employees from all over Canada and the U.S., and contributed $280,000 and over 4,500 hours to the community.

United Way Employee-led Campaign – Enbridge's Calgary office raised over $1 million during the city-wide United Way Campaign in 2011. Of this amount, $873,855 was donated to the United Way of Calgary and Area and $209,957 was donated to Aspen Family and Community Network Society's Families in Transition program. Over two-thirds of the company's Calgary-based employees were involved in the United Way campaign, through either a volunteer activity or a monetary donation.

Aspen Family and Community Network Society's Families in Transition Program – Enbridge's Calgary-based employees raised $209,957 through a silent auction with proceeds going directly to the Families in Transition

Program, an Enbridge-sponsored program of Aspen Family and Community Network. Now into its 13th year, this program helps to transition families at risk into more stable living conditions. Employees host these families throughout the year in various social activities, including organizing an annual “Back-Pack” program in August, providing necessary school supplies and gift certificates for clothing, food and entertainment.

4-H Canada – Enbridge proudly committed $260,000 to 4-H Canada as the National Sponsor of their 100th anniversary in 2013. To celebrate the upcoming milestone, a new anniversary logo was unveiled at the Calgary Stampede on July 13, 2011. Enbridge shares 4-H’s commitment to youth and understand how important the next generation is in helping to build, sustain and grow vibrant communities.

Timeraiser – Since 2006, Enbridge has partnered with the Framework Foundation in support of its Timeraiser events. The Timeraiser program is a comprehensive volunteer engagement process that makes it easier for individuals to find meaningful and relevant volunteer opportunities in their community. It also benefits non-profit and charitable organizations by connecting them with quality, skilled volunteers. The annual Timeraiser event facilitates connections between a variety of groups, including young citizens, businesses, charitable and not-for-profit agencies, and emerging artists. The event is part volunteer fair, part silent art auction and part night on the town, with people matching their skills with agencies and bidding volunteer hours for artwork. In 2011, Enbridge supported the 6th annual Timeraiser held in Calgary. With over 400 people in attendance and 26 non-profit agencies seeking skilled volunteers, a total of 7,115 volunteer hours were pledged, and $16,000 was invested in the careers of Calgary-based artists. Of the 26 works of art, 23 went for the maximum bid of 100 hours. Over 25 Enbridge employees attended the event in support of local artists and non-profit organizations. Enbridge was also the Presenting Sponsor of Edmonton’s Timeraiser event in 2011.

Famous 5 Foundation – As Presenting Sponsor of the Enbridge Famous 5 Foundation luncheons in Ottawa, Enbridge sponsored The Governor General's Persons’ Case Award luncheon on October 19, 2011, honouring prominent women as nation builders. The Famous 5 women opened the doors of the Senate of Canada to women with their petition, later known as the Persons’ Case. Enbridge is also the Presenting Sponsor of the Enbridge Famous 5 Speaker Series in Calgary, Edmonton and Fort McMurray, providing $75,000 annually in support of the Famous 5 Foundation’s community initiatives across Canada.

TELUS Spark - the new Calgary Science Centre – Enbridge has been a long-standing supporter of the Science Centre in Calgary and an instrumental partner in its transformation over the past few years. Enbridge is proud to be the underwriter of the Enbridge Volunteer in Partnership Program at TELUS Spark, a program that will allow people to contribute their time to meaningful pursuits. On October 29, 2011, TELUS Spark—Canada's first brand new Science Centre in more than 25 years—opened its doors to the public.

Canada’s History Forum – Enbridge was proud to be the Presenting Sponsor of Canada’s History Forum: Speaking of the Past: History Beyond the Classroom, on December 11, 2011, as well as a Supporting Partner of the 2011 Governor General's Awards for Excellence in Teaching Canadian History, the nation’s top teaching prize honouring teachers who excel at bringing history to life for their students.

Calgary Family Services – In partnership with Calgary Family Services, Enbridge Inc. presented the 2011 McKillop Award for Community Service to four individuals in the not-for-profit human services sector for their outstanding service to Calgarians. Each individual received a $2,500 award.

Cenovus TRTL: Technological Residence Traditional Living – Enbridge believes in supporting leaders in our communities by investing in innovative initiatives and as such, we proudly sponsored the University of Calgary’s entry into the U.S. Department of Energy’s Solar Decathlon 2011 in Washington, D.C., that ran from September 23 - October 2. The entry—called Cenovus TRTL: Technological Residence Traditional Living—is a safe, durable net-zero solar powered home that addresses critical issues in Aboriginal housing. The University of Calgary’s TRTL project members were the only Canadian entry in the 2011 solar home competition, which challenged 20 international student-led teams to design, build and operate the most attractive, efficient and affordable solar-powered dwelling. The Canadian team finished in 10th place.

Earthquake/Asia-Pacific Tsumani Crisis Relief – Enbridge’s Natural Disaster Response Policy was activated on March 15, 2011, in an effort to support those affected by the earthquake and tsunami in Japan and in response to internal inquiries from employees in all of our business units. Enbridge committed to a corporate donation of $25,000 to the Red Cross and matched individual employee donations, up to $1,000, to the Canadian and American Red Cross Japan Earthquake/Asia-Pacific Tsunami Fund. Enterprise-wide, 446 employees donated $72,065. With Enbridge’s match of employee donations, the total contribution to the Red Cross was $169,130 .

East Africa Humanitarian Crisis Relief – In accordance with Enbridge’s Natural Disaster Response Policy and in

response to the humanitarian crisis in the Horn of Africa in 2011, Enbridge matched employee's donations, up to $1,000, to the Canadian and American Red Cross East Africa relief fund efforts. Enterprise-wide, 321 employees donated a total of $58,460.75. With Enbridge's match of employee donations, the total contribution to the East Africa relief efforts was $116,921.50.

Liquids Pipelines Canada

United Way Employee-led Campaign – Enbridge Pipelines' Alberta Capital Region campaign collected contributions of over $1.2 million for the 2011 campaign period. Of this amount, $50,000 was directed specifically to the Welcome Home program, which provides companionship to individuals and families that have made the journey from homelessness, to help them retain their housing.

Timeraiser – In 2011, Enbridge Pipelines, which is a founding sponsor of Edmonton's Timeraiser, participated in the sold-out event, which raised over 4,100 volunteer hours for the 25 participating charities. Over $11,000 was contributed to 20 local artists who received fair market value for their artwork entered into the event.

Dow Youth Centre for Excellence – Since 2008, Enbridge has supported this centre's efforts to provide quality programs to children and youth from a variety of socio-economic groups and backgrounds living in Sarnia-Lambton in Ontario. The programs strengthen the social, physical and emotional health of the children and youth—a vital element in building a healthy, caring and progressive community. The Dow Centre for Youth is coordinating an unprecedented collaboration of agencies that will provide as many services as possible to as many children and youth as possible. By housing youth-oriented agencies under one roof, the centre is promoting greater synergies and cost savings that can be diverted back into programs.

Liquids Pipelines U.S.

Supporting Red Cross in Disaster Relief – When disaster struck last summer—in Joplin, Missouri, in the form of a strong tornado and in and around Minot, North Dakota, in the form of devastating floods—the Red Cross stepped in to help in the recovery efforts, and Enbridge stepped up to help the Red Cross.

In May 2011, a large tornado killed approximately 125 people in Joplin, making it the eighth deadliest tornado in U.S. history. Government officials said that 8,000 structures were damaged or destroyed, along with 1,800 acres within the city limits, affecting everyone in the community of 50,000 people. Joplin High School and two elementary schools were a total loss, with estimated damages of $200 million to the school system. It is estimated that 300 businesses in Joplin were destroyed, including St. John's Hospital. Just a few days later, a contingent of Enbridge employees, contractors and family members were on the ground in Joplin, unloading donations and handing out water and food.

Enbridge also donated $20,000 to the American Red Cross Greater Ozark Chapter and $10,000 to American Red Cross of Central Oklahoma, an area that also was impacted by tornadoes in May.

In June and July 2011, the Souris (Mouse) River flood devastated Minot and the surrounding area. More than 4,100 homes were inundated by flood waters, forcing an evacuation of more than 10,000 people. While Enbridge's North Dakota pipeline system continued to operate normally, our employees in the Minot office found more than a few ways to help their fellow neighbours. Enbridge contributed $60,000 to the Red Cross Mid-Dakota Chapter—$10,000 in the spring and an additional $50,000 after the Souris had breached the dike system. Enbridge's offices were closed in Minot on June 24, 2011, so that employees could assist with evacuation and sandbagging efforts, and several continued to contribute their time serving food at the local Red Cross shelter, caring for displaced pets, and helping in any way they could. Our employees continued their support for the community on July 19 when they hosted a free community-wide barbeque. More than 400 community members stopped to take a break from rebuilding to enjoy a meal of hamburgers and bratwurst grilled by more than 20 Enbridge employees from the Minot office and terminal. Numerous volunteers from our Minot office also distributed free water to residents who had been placed under a boil order starting on June 25.

Gas Transportation / Enbridge Energy Partners

United Way – In 2011, Enbridge donated more than $500,000 to United Way organizations across the U.S. The company hosted workplace-giving campaigns in all office locations.

Houston Zoo – Enbridge's funding of the Houston Zoo supports five education efforts that bring Science Technology Engineering and Math (STEM) programs to under-served students throughout greater Houston, linking Texas Essential Knowledge and Skills (TEKS) principles to the programs taught.

Trees For Houston – Enbridge sponsored a second tree planting with Trees For Houston and engaged employees and their families. The donation also funded tree maintenance due to the drought that the state of Texas experienced in 2011. Trees For Houston is a non-profit organization dedicated to planting, protecting and promoting trees.

Enbridge Gas Distribution (EGD)

True Patriot Love Foundation – EGD has invested $200,000 in support of the True Patriot Love Foundation, which supports and honours members of the Canadian military and their families. On August 18, 2011, the Foundation in partnership with the Government of Ontario unveiled a bronze plaque to commemorate the sacrifices made by Canadian soldiers and their families. The plaque has been placed on 26 bridges along the Highway of Heroes. The money raised through the plaque sponsorship will support military families through programs that help send children to summer camp, provide psychological counseling, retrofit homes and cars for soldiers returning with injuries or amputations, and rehabilitate wounded soldiers through sport.

Niagara Health System (NHS) Foundation – EGD is partnering with the NHS Foundation, helping them meet the growing health-care needs of the Niagara Region, specifically as it relates to access to cancer, cardiac, mental health and kidney dialysis treatment.

York Central Hospital Foundation (YCHF)–York Central Hospital is a large, full-service community hospital with over 80,000 visits annually to its Emergency Department, serving a population of more than 400,000 in Southwest York Region and beyond. Located in one of Canada's fastest growing communities, the hospital is on a capacity-building journey that focuses on using the best available practices, newest technologies and innovative models of service to provide superior patient care. Enbridge has provided important philanthropic dollars, and our employees have played key volunteer roles in helping the Foundation fulfill its mission and mandate. EGD's commitment of $120,000 to the York Central Hospital Foundation over the next four years will help support the purchase of much-needed medical technology in the Endoscopy Department, which provides important diagnostic services for a wide variety of disorders. Enbridge has also committed to sponsor two York Central Hospital signature events.

United Way – EGD and its employees exceeded its goal of $1.8 million, raising an outstanding $2,204,100 to support the United Way 2011 Campaign. Employee pledge participation increased by 8 per cent over the previous year, with 375 new donors and a total increase of 22 per cent in dollars pledged. Of these employees, 180 donated at the Leadership Level of $1,000 or more, which is a 16 per cent increase over last year, with 45 new Leadership Donors.

CN Tower Climb – As the proud Title Sponsor of the Enbridge CN Tower Climb for United Way for the past decade, 232 EGD employees, as well their family members and friends joined Team Enbridge to raise the highest amount for an event—over $65,000. This year's Climb also helped set a new EGD fundraising record, with over $2.2 million raised to support United Way. Since Enbridge's first year as title sponsor, the Climb has raised more than $13 million.

Winter Warmth Program – To help Ontario households stay warm, EGD, together with the United Way, launched the 2011-2012 Winter Warmth Program. Winter Warmth provides support to low-income customers and is coordinated by a network of community-based agencies through the United Way. In 2011, over 1,300 Ontario households received support with their Enbridge natural gas bills. Since Winter Warmth started in 2004, it has helped over 7,500 households with their Enbridge bill. In addition to Winter Warmth, Enbridge works with individual customers who are having difficulty paying their bills to make payment arrangements—programs such as the Enhanced TAPS program and home weatherization that reduce costs in the long-term, golden age service for seniors, and a budget billing plan to help manage energy bills and payment arrangements. In 2011, EGD contributed $600,000 towards the Winter Warmth fund. As part of EGD's annual Winter Warmth drive, EGD employees participated in numerous community events, including the 7th Annual Winter Warmth Drive across the Greater Toronto Area, the Salvation Army Ottawa Booth Centre, as well as the E.T.A. Vaughn Women's Centre and the Salvation Army Family Life Resource Centre in Brampton, Ontario, which provide emergency housing and support services to women and children who are victims of abuse. Employees donated items to one of 12 families that their departments adopted as part of the drive.

Eva's Initiatives – EGD sponsors Eva's Initiatives' Home for Life fundraising event, which focuses on supporting innovative and award-winning programs that assist homeless youth to leave the streets permanently and make the transition from being homeless to becoming self-sufficient members of the community. Eva's Initiatives operates three unique shelters in the Greater Toronto Area that daily feed 114 youths aged 16 to 24. With cutting-edge services and distinctive programming, the shelters provide a continuum of services not available elsewhere in Canada. Nationally, Eva's Initiatives works to build innovative long-term solutions to youth homelessness. In 2011, Eva's Initiatives was able to open the doors of its three shelters to 1,763 residents and 2, 598 non-residents. For the second year in a row, Eva's Initiatives was selected as one of Canada's Outstanding Charities by Charity Intelligence, making Eva's Initiatives one of only 33 charities across Canada identified for leadership, cost-efficiency and most importantly, bottom-line results in getting the job done in helping clients.

Enbridge Gas New Brunswick (EGNB) Fix It In 5 Community Improvement Initiative: 9 Projects in 9 Communities in 5 Days – Nine projects came out on top in EGNB's first ever Fix It In 5 Community Improvement Initiative. For three weeks, individuals and groups from each of Enbridge Gas New Brunswick's nine service areas submitted fix-up project proposals, and community members had the opportunity to vote on which project they wanted to see completed in their community. The projects were selected based on the highest number of votes. From June 13-17, 2011, volunteers from each of the organizations joined EGNB employee volunteers to improve their community spaces, for a contribution value totaling over $15,000.

NATURAL LEGACY

At Enbridge, we take our responsibility to the environment seriously, and recognize that the way we treat the planet is our natural legacy. Because of this, we invest in programs that promote environmental stewardship, conservation, habitat remediation, habitat protection and environmental education.

Following are reports about some of the key natural legacy initiatives we support.

Enbridge Inc.

The Calgary Awards – Enbridge is the Platinum Sponsor of the Calgary Awards in the 'Environmental Achievement' category, which recognizes an environmental not-for-profit organization. The Calgary Awards, presented by The City of Calgary, honour members of the community who have made a significant contribution toward improving the quality of life for Calgarians. At an award ceremony on June 15, 2011, Green Calgary received the 2010 Not-for-Profit Environmental Achievement Award in recognition of their Healthy Homes Program, a holistic in-home consultation that addresses environmental and community issues in Calgary, including waste reduction, water conservation, energy efficiency, toxic cleaning products and sustainable food choices.

Liquids Pipelines Canada

Ducks Unlimited Canada (DUC) – In partnership with DUC, Enbridge's funding has contributed to a rebuild and enhancement initiative at the McKell Wascana Park in Regina, Saskatchewan, including the naming of the Enbridge Trail (Trail #1).

Enbridge's funding of DUC also supported the updating and improvement of the Wawanosh Wetlands Conservation Area in Sarnia, Ontario, including work on the dyke, trails and interpretive signs and improving access to ensure continued public use of the area and creating a much needed field-trip destination for DUC's Project Webfoot. This conservation area consists of substantial wetland and surrounding upland habitat and trails. The St. Clair Region Conservation Authority maintains ownership and management of Wawanosh, which includes facilities to support outdoor education and recreation. A 2.5-kilometre nature trail winds along the marsh and is complete with interpretive signs to help visitors find out more about wetlands and how we depend on them.

Alberta Emerald Foundation – In 2011, Enbridge contributed to a new initiative in support of the Alberta Emerald Foundation's work of recognizing those committed to protecting, preserving, enhancing and sustaining our environment. We were the Media Sponsor of a television campaign (in Edmonton and Calgary) depicting the great work of recipients of the Emerald Awards. Through our support, Enbridge was able to help the Emerald Foundation share more of *Alberta's Green Success Stories* with a broader audience than ever before, while also building on the video vignettes creation project that Enbridge began in 2007.

Gas Transportation / Enbridge Energy Partners

The Nature Conservancy of Texas – Enbridge sponsored The Nature Conservancy of Texas' Houston luncheon to bring awareness to the needs of conservation in this area of the world.

The Nature Conservancy of Louisiana – Enbridge again contributed to The Nature Conservancy of Louisiana's Fund for Gulf Coast Restoration to support their work to restore flows of freshwater and sediments to the marshes, rebuild oyster reefs, restore sea-grass beds and coral reefs, and protect coastal habitats.

Gathering Waters – In 2011, Enbridge fulfilled its pledge of US$15,000 to Gathering Waters in recognition of the organization's 15th anniversary in 2010. Gathering Waters supports land trust organizations throughout the state of Wisconsin and has land trusts in almost all of the areas where Enbridge operates its pipelines.

Hartley Nature Center – Enbridge contributed US$2,000 to the Hartley Nature Center in Duluth, Minnesota, to support its youth environmental education programs and its annual Youth Outdoor Expo.

Enbridge Gas Distribution (EGD)

Pollution Probe – Enbridge is a proud sponsor of Pollution Probe's Clean Air Commute, a charitable environmental organization dedicated to achieving positive and tangible environmental change. Now in its 19th year, the 2011 Clean Air Commute is a week of friendly competition among workplaces, with the goal of reducing the pollutants in our air and our lungs. In 2011 alone, 14,000 employees from more than 150 workplaces prevented more than 500 tonnes of air pollutants from being released. They carpooled, biked, walked and took public transit. During the Clean Air Commute Campaign each June, EGD and its employees find cleaner ways to commute to and from work to reduce smog. EGD employees are encouraged to participate through employee events, information sessions and contest giveaways. Thanks to the high participation rate of our employees, EGD's smog savings during the 2011 campaign totaled 12 tonnes.

St. Clair Region Conservation Authority – In 2010, Enbridge announced plans to partner with the St. Clair Region Conservation Authority to plant trees on close to 200 acres of EGD-owned property near Courtright, Ontario. The five-year partnership will see the creation of forest areas, upland habitat and wetlands to create habitat for a variety of species, including migratory waterfowl. Work commenced in 2011 with the planting of 13,150 trees and the construction of a wetland on one of the two EGD properties involved. 2011 was a particularly wet year and despite the delays to the spring planting, the results have been among the best that the Conservation Authority has experienced. The work is expected to continue over the next two to three years, with an estimated 50,000 trees and areas of tallgrass prairie still to be planted. The program will see an additional 10,000 of these trees planted in the spring of 2012.

ARTS & CULTURE

Enbridge delivers more than the energy you count on. We deliver on our promise to make communities better places to live by investing in visual and performing arts, and other organizations that contribute to culturally vibrant communities. For us, theatre, dance, music, visual arts and, in fact, all forms of expression provide communities with a unique identity—and all of us with sources of inspiration and beauty.

Following are reports about some of the key arts and culture initiatives we support.

Enbridge Inc.

Governor General's Performing Arts Awards – As the second year Presenting Sponsor of the Governor General's Performing Arts Awards (GGPAAs) in Ottawa, an Enbridge contingent was hosted by the Governor General at Rideau Hall on May 13, 2011. The GGPAAs are Canada's most prestigious honour in the performing arts, with a long and successful history. The awards celebrate, recognize and inspire the arts community across the country, and Enbridge is proud to support the nurturing of Canadian talent.

25th Annual Enbridge playRites Festival of New Canadian Plays – Enbridge was the Title Sponsor of the 25th Annual Enbridge playRites Festival of New Canadian Plays. For 25 years, the Enbridge playRites Festival of New Canadian Plays has been an incubator and showcase for new work. Many of the plays produced during the festival go on to be produced around the world. The festival also offers readings, special events, awards and a platform for emerging artists and student work.

National Arts Centre's Prairie Scene – Enbridge was proud to be the Major Partner of Prairie Scene, the fifth National Arts Centre's series of Scene Festivals. Prairie Scene is a diverse, multi-disciplinary arts festival featuring 500 of the best established and emerging artists from Saskatchewan and Manitoba. From April 26-May 8, 2011, the festival presented 80 different events in music, theatre, dance, visual and media arts, literature, film and culinary arts in more than 30 venues in Ottawa-Gatineau.

Liquids Pipelines Canada

Art Gallery of Alberta (AGA) – Enbridge Pipelines invested in a new three-year initiative titled *Enbridge Presents: Contemporary and Modern Art* at the Art Gallery of Alberta, helping the AGA to secure prestigious exhibits, including the internationally touring exhibition *ANDY WARHOL: Manufactured*. Support of this initiative mirrors our recognition and understanding of the importance of cultural energy in the communities in which we operate.

Enbridge Conductor in Residence Program – Since 2010, Enbridge has supported the Enbridge Resident Conductor program of the Edmonton Symphony Orchestra. The program addresses the needs of the orchestral music industry to develop artistic leaders who are equipped with the essential musical, administrative and leadership qualities necessary to lead an orchestra in the 21st century. An effective conductor and music director is one who can master the music, and adopt an appreciation and understanding of the delicate balance between art and business, and their responsibility to audiences and the community at large. This program helps foster sustainability in the arts, ensuring

that the time-honoured tradition of mentorship is afforded to emerging leaders at the highest professional level.

Nextfest – In Edmonton, Enbridge sponsors the Theatre Network's Nextfest, a multi-disciplinary emerging- artists festival dedicated to the development and exposure of professional artists at the beginnings of their careers. Specifically, we fund the Enbridge Emerging Artist Awards and the Enbridge High School Mentorship Program, which is designed to provide a practical educational experience to high school drama students through a mentoring relationship so they receive guidance and develop the skills necessary to meet their full potential. These emerging artists then actively learn and engage in a professional festival setting, getting the chance to curate and perform on the main stage.

The Works International Visual Arts Society – Enbridge continued as a Sponsoring Partner of The Works International Visual Arts Society education initiatives, specifically: The Works to Work Summer Internship, Certification, Education, and Scholarship Program; and The Places, Art & Design in Public Places Internship Program. The Works to Work programs offer both theoretical and hands-on learning to participants during full-time, paid internships with The Works Art & Design Festival. Participants benefit from working with experienced arts presenters, as well as world-class artists, designers, curators and educators. To support on-going skill development, Works to Work allows for participants to return every summer for three years to progress from Assistant to Coordinator to a Supervisor level. Once participants have completed the program, their skills are transferable to galleries, museums, educational institutions and other non-profit charitable organizations in Edmonton and countrywide.

Liquids Pipelines U.S.

Roosevelt Park Zoo – The Roosevelt Park Zoo in Minot, North Dakota, recently received its most significant contribution yet in support of the zoo's new entrance building when Enbridge Pipelines (North Dakota) LLC presented the zoo with a donation of $25,000 for the facility in 2011. The $25,000 contribution is a joint effort of Enbridge Pipelines (North Dakota) LLC and Enbridge US.

Duluth Air Show – Enbridge continued its support of the semi-annual Duluth Air Show in 2012. A US$10,000 contribution sponsored the Canadian Forces Snowbirds demonstration and performance.

Gas Transportation / Enbridge Energy Partners

Alley Theatre – Enbridge supported Houston's Alley Theatre for the ninth consecutive season by serving as the Lead Sponsor of one production during the 2011-2012 season – *Noises Off*. Enbridge also sponsored the Alley Theatre Playwriting 360° Showcase, which presents plays written by young adults from schools who participate in the program. The program introduces students to dramatic writing as a creative outlet.

Houston Public Radio – For the ninth consecutive year, Enbridge served as an underwriter of local programming on 88.7 KUHF, Houston Public Radio hosted by the University of Houston.

Enbridge Gas Distribution (EGD)

Shaw Festival Theatre – For the past decade, Enbridge Gas Distribution has been a proud supporter of the Shaw Festival Theatre, which is one of Canada's leading cultural organizations. Since 2002, Enbridge has donated over $100,000 to the Shaw Festival Theatre, a registered charity and a prominent tourism driver for southern Ontario, generating over $100 million in local activity annually.

SCHOOL PLUS

We believe in investing in the leaders of tomorrow by supporting enrichment programs and extra-curricular activities for Canadian Aboriginal school children located near our major pipeline routes and facilities. Through our School Plus Program, we provide Canadian Aboriginal youth in grades K-12 with enrichment programs to engage them in the education process, encouraging them to remain in school. We value educational opportunities that will ultimately contribute to the growth and learning of Canadian Aboriginal school children.

For a full report on our recent School Plus investments and other major Aboriginal community investment initiatives, please see 'Recent Initiatives and Significant Events' in the Aboriginal & Native Americans section of this SO1 chapter.

SAFE COMMUNITY

With operations and employees in communities across Canada and the U.S., we believe it is essential to be involved in those communities to help make them healthy, vibrant and ultimately, better places to live. The safety of the communities in which we operate and the people who live and work along our pipeline system remains our highest priority, which is why we are proud to support the organizations that help to keep our communities safe.

Through our Safe Community program, we provide grants to local first responders in areas of Enbridge operations to help with equipment, training, public awareness and volunteer recognition. Additionally, we support safety initiatives that are important in the communities where we operate.

Following are reports about some of our key Safe Community initiatives in 2011.

Liquids Pipelines Canada

Enbridge Pipelines presented a $150,000 cheque to the Regional Municipality of Wood Buffalo in Alberta. The Municipality used the donation to purchase resources needed to deliver emergency services and to support the delivery of emergency preparedness programs to residents in the Municipality's communities of Fort Chipewyan, Anzac, Fort McKay, Conklin and Saprae Creek, reinforcing publicly that the safety of the communities in which we operate, the lands our pipelines traverse and the people who live and work along our system is our highest priority.

Gas Transportation / Enbridge Energy Partners

Enbridge awarded a total of $288,701 to more than 315 emergency first responder organizations in areas of our U.S. operations. Eligible organizations include police, fire and EMS departments.

Enbridge Gas Distribution (EGD)

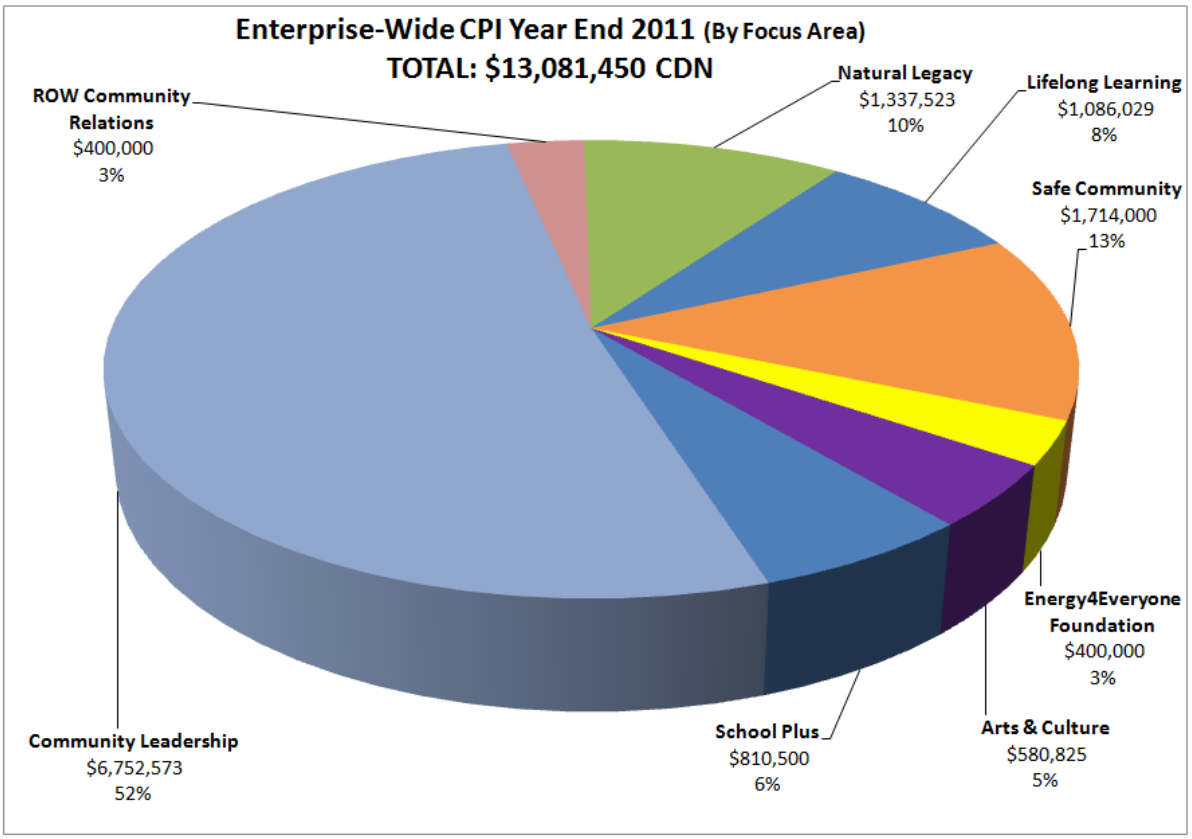
Project Zero – EGD has developed a strong relationship with the Fire Marshal's Public Fire Safety Council, which addresses public safety issues and distributes information to local fire departments in Ontario that in turn reach out to their respective communities. As a members of the Council, EGD is a strong supporter of fire- and life-safety education and is proud to provide funding support to programs like Project Zero, which was launched by Toronto Fire Services in 2009 and now includes a total of 21 Ontario municipalities. Project Zero's goal is to reduce residential fire and carbon monoxide deaths to zero. EGD's donation in 2011 will allow more than 2,700 combination smoke and carbon monoxide alarms to be installed in Ontario homes in Collingwood, Grimsby, Kemptville, Mississauga, Newmarket, Pembroke, Peterborough, Smiths Falls, St. Catharines, Vaughan and Welland. The alarms are distributed to homes in neighbourhoods where the number of residential fires and fire-related deaths and injuries have been higher than average. Enbridge's support of Project Zero builds on its ongoing efforts to educate customers about carbon monoxide safety.

ENTERPRISE-WIDE COMMUNITY PARTNERSHIPS AND INVESTMENTS (CPI) SPENDING

YEAR-END 2011 – ACTUAL

CAD: $11,643,943
USD: $1,437,507

Total: CAD $13,081,450



1 For information on the energy4everyone Foundation, which supports the delivery of affordable, reliable and sustainable energy to communities that do not have it, please see the GRI Performance Indicator report 'EC8' in the Economic Performance section of this 2012 CSR Report.

CORRUPTION

SO2

Percentage and total number of business units analyzed for risks related to corruption.

Enbridge analyzes each of its business units annually for potential corruption risks. The analysis tools the company uses include the general control evaluation procedures that were established to ensure that Enbridge meets the requirements of the Sarbanes-Oxley Act (SOX) and its own Statement on Business Conduct. Each employee must review and confirm their compliance with the Statement on Business Conduct annually.

SO3

Percentage of employees trained in organization's anti-corruption policies and procedures.

As a condition of employment, all new employees are required to read and provide written acknowledgement of their agreement to follow Enbridge's Statement on Business Conduct. Thereafter, all employees must certify their compliance with the Statement on Business Conduct each year. The annual certification process for each employee includes the completion of mandatory Statement on Business Conduct refresher training, which is coordinated and rolled-out each January on an enterprise-wide basis.

The Statement of Business Conduct applies to Enbridge Inc. and to each of its subsidiaries or controlled entities. It emphasizes Enbridge's commitment to specific standards of conduct expected of each of its directors, officers, employees, consultants and contractors in all of the countries where Enbridge does business.

SO4

Actions taken in response to incidents of corruption.

Enbridge's Statement on Business Conduct and Whistle Blower Procedures outline the procedures Enbridge would follow in response to allegations of corruption.

Strict adherence to the Statement on Business Conduct and all other Enbridge policies is mandatory for all Enbridge employees. Failure to comply may result in disciplinary action up to and including termination.

Enbridge management is not aware of any incidents of corruption during 2011.

PUBLIC POLICY

SO5

Public policy positions and participation in public policy development and lobbying.

Enbridge supports the democratic process in the jurisdictions in which the company conducts business. It does so in accordance with the letter and spirit of all applicable laws of the countries in which it operates. As such, all of Enbridge's activities pertaining to public policy development, lobbying and political donations comply with the country, provincial and state laws governing those activities, as well as with the company's Statement on Business Conduct.

Enbridge does not have a formal policy on public policy development or lobbying, but its Statement on Business Conduct addresses political contributions by stating that, "no funds or assets of Enbridge shall be contributed to any political party or organization, or any candidate for public office, except where such contribution is permitted by applicable law and authorized by senior management or the Board of Directors."

In Canada, the *Federal Accountability Act* prohibits corporate political donations at the federal level. Laws governing corporate political donations to provincial entities vary by province. Enbridge strictly adheres to them.

Although U.S. federal law and the laws of most states prohibit corporate political donations, companies that establish political action committees (PACs) may contribute amounts up to the limits set by the governments in whose jurisdiction they lie. However, Enbridge does not have a federal or state PAC and does not make corporate political donations, even in those states where corporate contributions are allowed.

SO6

Total value of financial and in-kind contributions to political parties, politicians and related institutions by country.

In 2011, Enbridge contributed approximately $91,000 to provincial political parties in Canada. It did not contribute to federal political parties or politicians in Canada.

Enbridge did not make any contributions to political parties, politicians or related institutions in the U.S.

ANTI-COMPETITIVE BEHAVIOUR

SO7

Total number of legal actions for anti-competitive behaviour, anti-trust and monopoly practices and their outcomes.

In 2011, Enbridge was not subject to any legal actions for anti-competitive behaviour, or for anti-trust or monopoly practices.
Regarding competition and anti-trust legislation, Enbridge's Statement on Business Conduct states that:

- Enbridge and its employees must comply with all applicable Canadian, U.S. or other foreign competition and antitrust legislation.
- Behaviour which is prohibited under such legislation includes activities such as agreements with competitors to allocate markets or customers, price fixing or agreements to control prices, the boycotting of certain suppliers or customers, bid-rigging, misleading advertising, price discrimination, predatory pricing, price maintenance, refusal to deal, exclusive dealing, tied selling, delivered pricing and the abuse of dominant position.
- Situations constituting potential breach of such legislation or circumstances requiring direction should be immediately reported to the employee's supervisor or the Law Department.

COMPLIANCE

SO8

Monetary value of significant fines and total number of non-monetary sanctions for non-compliance with laws and regulations.

Enbridge did not receive any fines in 2011 for anti-competitive behaviour.

Enbridge did not receive any non-monetary sanctions for non-compliance with laws and regulations pertaining to anti-competitive behaviour in 2011.

SOCIAL PERFORMANCE: PRODUCT RESPONSIBILITY

GOALS AND PERFORMANCE

Enbridge is committed to excellence in implementing product responsibility standards that not only comply with legislated requirements, but also respond to the social, economic and environmental expectations of communities, customers, shareholders, government and the public.

This commitment is an integral part of all planning and operations initiatives carried out corporately, as well as those carried out by Enbridge's business units.

Enbridge strives for zero incidents and injuries and believes that prevention of incidents and injuries benefits everyone and delivers increased value to our stakeholders.

PRODUCT RESPONSIBILITY PERFORMANCE INDICATORS

CUSTOMER HEALTH AND SAFETY

PR1

Life cycle stages in which health and safety impacts of products and services are assessed for improvement, and percentage of significant products and services categories subject to such procedures.

Enbridge is a transporter of energy, primarily in the form of liquid petroleum products and natural gas. Enbridge does not produce these commodities, but transports them from source to end users.

While Enbridge does not specifically conduct life-cycle reviews of the products that it transports through its systems, it does thoroughly review its systems to ensure that the products it transports are delivered in a manner that is safe and reliable. These reviews pertain to the design, construction, operation and maintenance of the transport systems. They are conducted on all of Enbridge's systems.

Enbridge Liquids Pipelines implements a New Service Request and New Commodity Approval process prior to movement of new products on its pipeline system. These processes require shippers to provide product quality information and material safety data sheets when requesting to ship a product on the pipeline for the first time. These processes further set out the requirements for ongoing periodic testing of all products once approved for transport on the pipeline. Enbridge also requires shippers to provide updated material safety data sheets every three years in accordance with regulations. This information is used to assess the health and safety impacts of any new products being introduced to the pipeline system and any changes in characteristics that may impact health and safety during the product lifecycle.

In addition to these processes, Enbridge Liquids Pipelines has an industrial hygiene program that sets out requirements for regular air sampling and monitoring of its operations and maintenance activities to assess worker exposures to airborne contaminants and potential impacts to worker health and safety. This information is used to validate the effectiveness of controls utilized to protect workers, including engineering controls, administrative controls and personal protective equipment.

For details on Enbridge's pipeline and system integrity practices and performance, please see the section "Environmental Performance – GRI Performance Indicators – Products and Services – EN26 and EN27" of this report.

Enbridge is also expanding its interests in renewable and alternative energy technologies, including wind and solar energy, geothermal, waste heat recovery, hybrid fuel cells, and carbon dioxide sequestration. Enbridge takes its responsibility as an energy producer very seriously. We pursue this commitment by:

- managing all of our operations and new facilities with respect for our neighbours and their land;
- consulting with the individuals who live and work in the vicinity of these operations, as well as those who may become our neighbours as our renewable energy portfolio grows;
- maintaining our projects to the highest possible standards; and
- keeping neighbours, community residents and officials informed about our activities.

Enbridge is committed to protecting the public and the environment, and we build safety into every step of our operations.

PR2

Total number of incidents of non-compliance with regulations and voluntary codes concerning health and safety impacts of products and services during their life cycle, by type of outcomes.

Within the Enbridge companies in 2011, there were no non-compliance incidents concerning the health and safety impacts of Enbridge's products and services.

For information on regulatory notifications, please see the section "Environmental Performance – GRI Performance Indicators – Compliance – EN28" of this report.

PRODUCT AND SERVICE LABELING

PR3

Type of product and service information required by procedures, and percentage of significant products and services subject to such information requirements.

Enbridge's Liquids Pipelines and Gas Transportation business units, as well as Enbridge Gas Distribution (EGD), are required to indicate with pipeline location markers including labels with the company name and contact information, any pipeline that is situated within a right-of-way. Although Enbridge is not required to label pipelines that run through streets or properties, it is illegal to excavate within streets or properties without obtaining "locates," which provide information on underground pipelines, etc. In Ontario, for example, home and property owners and contractors are responsible for obtaining "locates" before they dig and can obtain them by calling Ontario One Call. Ontario One Call is a call centre with which both EGD and Enbridge Liquids Pipelines contract to handle such inquiries within the province of Ontario.

In addition, the Workplace Hazardous Materials Information System (WHMIS) requires EGD to provide Material Safety Data Sheet (MSDS) information to all of its natural gas customers. EGD maintains updated French and English copies of the sheet pertaining to natural gas on its website. EGD also emails copies of the sheet to customers on a scheduled frequency basis. Liquids Pipelines also maintains MSDSs that are representative of the various products it ships on the pipeline system and makes these MSDSs available to employees, contractors working on the

pipeline system, and also to the public upon request.

Enbridge's right-of-way at its wind farms includes the footprint of the wind turbines themselves, as well as buried high-voltage cables located anywhere within the leased area. The right-of-way at Enbridge's solar farms is contained within the fenced solar farm itself and on Enbridge property outside the fence.

Even though buried high-voltage cables are identified above-ground by power-line markers, the marker may not necessarily be directly over the power line. To protect people and ensure their safety, federal and provincial/state laws require anyone planning to excavate near the right-of-way to call their local toll-free one-call number in advance of any excavation.

Enbridge makes landowners and the general public in the vicinity of its wind farms aware that buried high-voltage power lines are located both inside and outside the perimeter of the wind farms. (At Enbridge's solar farms, buried high-voltage power lines are contained only within the fenced perimeter of the solar farm. There are no buried power lines outside the fenced perimeter.)

Also integral to Enbridge's wind and solar farms are high-voltage sub-stations, which are located on leased or Enbridge-owned land near the farms. These sub-stations are fenced and no public entry is permitted.

PR4

Total number of incidents of non-compliance with regulations and voluntary codes concerning product and service information and labeling, by type of outcomes.

Enbridge's Liquids Pipelines, Gas Transportation, and Gas Distribution and Services businesses were in full compliance with regulations pertaining to product and service information or labeling in 2011.

PR5

Practices related to customer satisfaction, including results of surveys measuring customer satisfaction.

In 2011, Enbridge Gas Distribution (EGD) responded to just under three million customer inquiries and issued approximately 24 million residential utility bills.

Customer service and satisfaction are important to EGD and, as a result, measurement of these areas is important. EGD uses a third-party market research supplier to conduct monthly telephone interviews with residential customers. EGD uses the study to monitor customers' expectations about, perceptions of and satisfaction with EGD based on various interaction points. Customers are said to be satisfied if they responded excellent or very good (top-2 boxes), when asked three key satisfaction questions on a seven-point scale ranging from excellent to poor. As part of the study, benchmarking questions compare EGD to local telephone companies, electric companies and natural gas marketers in the EGD franchise area. During 2011, EGD led in the five areas measured, including overall value, image quality, choose again, overall billing and customer communication quality.

In 2005, EGD instituted an Office of the Ombudsman to resolve customer issues that the call centre was unable to resolve. In 2011, 8,891 issues were escalated to the Customer Ombudsman's office.

EGD uses a variety of information, including all of the sources of information outlined above, to identify opportunities to improve customer satisfaction.

MARKETING COMMUNICATIONS

PR6

Programs for adherence to laws, standards and voluntary codes related to marketing communications, including advertising, promotion, and sponsorship.

A thorough process is in place to review marketing communications pieces prior to distribution. This process includes review by Enbridge's legal department.

PR7

Total number of incidents of non-compliance with regulations and voluntary codes concerning marketing communications, including advertising, promotion and sponsorship by type of outcomes.

In 2011, Enbridge complied with applicable laws, regulations and voluntary codes concerning marketing communications.

CUSTOMER PRIVACY

PR8

Total number of substantiated complaints regarding breaches of customer privacy and losses of customer data.

In 2011, one minor incident of misdirected customer information was reported to the Privacy Office of Enbridge Gas Distribution (EGD) and was resolved. No complaints were referred to the Privacy Commissioner in 2011.

COMPLIANCE

PR9

Monetary value of significant fines for non-compliance with laws and regulations concerning the provision and use of products and services.

Enbridge Gas Distribution (EGD) was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25 per cent Victim Fine Surcharge, the total amount payable by EGD was $875,000.

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Aboriginal Relations ERG
Teresa Homik (Group Lead)
Jamie Honda-McNeil
Cheryl Levy
Lorraine Little
Maria MacAulay
Whitney Plaizier
Lori Sokoluk
Larry Springer
Jan Whitney
Jody Whitney

Community Investment ERG
Dan O'Grady (Group Lead)
Sonia Fazari
Katie Haarsager
Gina Jordan
Roshan Kastrinos
Aly Lang
Jason Manshum

Lennina Pavon Cardoso
Michele Perret
Lorna St. Thomas
Katherine Seheult
Larry Springer

Community & Landowner Relations ERG
Gina Jordan (Group Lead)
Theresa Doolittle
Katie Haarsager
Aly Lang
Cheryl Levy
Lorraine Little
Anne McIntosh
Jason Manshum
Jeff Paetz
Michele Perret
Todd Romaine
Irene Smith
Manny Sousa
Larry Springer

Economic Benefits ERG
Jonathan Gould (Group Lead)
David Trang

Environment & Climate Change ERG
Paul Hunt (Group Lead)
Tim Adamson
Edwin Makkinga
Greg Milne
Trey Moeller
Jennifer Murphy
Lynn Ross
Kevin Underhill

Governance ERG
Alison Love (Group Lead)
Bonnie Andriachuk
Vas Antoniou
Mark Boyce
Rob Carpenter
Colleen Galenzoski

Health & Safety ERG
Mike Koby (Group Lead)
Annette Abramyk
Scott Brummet
Sean Evans
Barry Goulah
Jennifer MacCarl
Mike McCollum
Scott McEachern
Richard Oleschuk

Boris Visnjevac
Eric Williams

Human Resources ERG
Molly Thompson (Group Lead)
Lori Campbell
Joan Gay
Jane Haberbusch
Deb Kaloudis
Stacy Parker

Systems Integrity ERG
Steve Irving (Group Lead)
Jeff Holden
Melanie Hosey
Scott Ironside
Glen Jessup
Lisa Lawler
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David Coglon, Coglon Corporate Communications Inc.
Anne Georg
Ian Fraser, Fraser Communications Inc.
Kristy Jensen
Mike Laurette
D'Arcy Levesque
Leandra Shrag
WAX Partnership Inc.

Enbridge's CSR Reporting Team:

Laura Badiyan-Eyford
Paul Hunt
Marie Jurcevic
MaryAnn Kenney
David Leinster
Aja Obin
Jennifer Varey
Cam Wood

CONTACT INFORMATION

If you have questions comments or requests for more information, please contact:

MaryAnn Kenney
Editor-in-Chief
Tel: (403) 508-6563 or (888) 992-0997
E-mail: maryann.kenney@enbridge.com

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Upper Canada Transmission, Inc. (o/a NextBridge)
East-West Tie Designation Application
Appendix 1

OMERS 2011 Annual Report

TAB A1e

2011 ANNUAL REPORT

FOCUS:
OUR STRATEGY
YOUR FUTURE



















OMERS

OMERS was established in 1962 as the pension plan for employees of local governments in Ontario. On June 30, 2006, the *Ontario Municipal Employees Retirement System Act, 2006* (the OMERS Act) came into effect. The OMERS Act continued the Ontario Municipal Employees Retirement Board as the OMERS Administration Corporation (OAC) and created the OMERS Sponsors Corporation (SC) to replace the Ontario government as Plan sponsor. Sponsors (such as Plan members and employers, through their unions, associations and other organizations) appoint the Board Members of the SC and, since June 30, 2009, the SC appoints OAC Board Members.

OMERS Sponsors Corporation

OMERS Sponsors Corporation is the Plan sponsor of the OMERS Pension Plans and consists of 14 Members: seven Plan member representatives and seven employer representatives.

The SC is responsible for:

- determining Plan design for benefits to be provided by the OMERS Pension Plans
- setting contribution rates for members and participating employers
- establishing or changing a reserve to stabilize contribution rates
- setting compensation levels and appointment protocol of SC and OAC Board Members.

OMERS Administration Corporation

OMERS Administration Corporation Board has 14 Members and is the administrator of the OMERS Pension Plans.

The OAC Board is responsible for:

- appointing and overseeing the OAC management team
- establishing investment and funding policies, asset allocation and investment management of OMERS Pension Plans' assets
- overseeing pension services, administration and Plan valuation
- appointing the OAC auditors and the actuary for the OMERS Pension Plans.

OMERS AC Management

OAC Management conducts the affairs of the OAC and has been delegated broad responsibilities for ensuring that OMERS discharges its statutory and related responsibilities to Plan members, including:

- administering the OMERS Pension Plans
- providing for the actuarial valuation of the OMERS Pension Plans
- investing the OMERS Pension Plans' assets
- providing technical and administrative support to the SC.

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The OMERS Administration Corporation team is charting a course for the long-term strength of the OMERS Pension Plans. With a strategy now underway to expand our global footprint and create new investment options, OMERS is making its mark on the worldwide investment stage.

Our service team is also committed to delivering excellent service to our members and we continue to explore new ways to provide even better efficiency. The pension landscape is shifting. The recent economic recession and future pension reforms will change the way traditional pension plans operate and invest.

These are times of opportunity. OMERS has established a course for the future — with continued focus on the long-term viability of the OMERS Pension Plans and the delivery of the pension promise.

FOCUS: OUR STRATEGY YOUR FUTURE

2011 HIGHLIGHTS

ENHANCING OPTIONS FOR OUR MEMBERS:

Additional Voluntary Contributions (AVCs) Begin

Since January 1, 2011, OMERS members are permitted to open an additional voluntary contribution (AVC) account. This concept, developed in response to member requests, enables members to invest in the OMERS Fund. Active members are permitted to transfer all or part of their funds from their existing RRSPs, registered pension plan or deferred profit sharing plan into the AVC account. They can also make automatic biweekly or monthly contributions through the year, which, like RRSP contributions, are tax deductible. By year end, 5,100 OMERS members had contributed $93 million to the AVC program.

AVCs are similar to a registered retirement savings plan, but they are part of the OMERS Primary Plan and have different withdrawal options. Through AVCs, members can have access to a well-managed, balanced global portfolio, including private market investments. Interest in AVCs continues to be strong.



GROWING OUR OXFORD PROPERTIES REAL ESTATE PORTFOLIO:

Through significant acquisitions:

In Canada – the iconic Metro Toronto Convention Centre

Oxford Properties Group enhanced its already significant profile in Toronto's business core with the September acquisition of the Metro Toronto Convention Centre. The Complex includes the Metro Toronto Convention Centre (MTCC), the 277 Front Street office tower, the InterContinental Hotel and a 1,200 stall parking facility.

In the U.K. – Consistent with our strategy to acquire large scale high quality assets, Oxford Properties completed the purchase of Green Park in Reading, U.K. As the most recent acquisition for our growing U.K. portfolio, Green Park is a complement to MidCity Place, Watermark Place and the office development project at 122 Leadenhall. Covering a total of 190 acres, Green Park occupies a prime location on the M4. One of the largest developments of its type in Europe, Green Park offers 1.3 million square feet of Grade A office space and first class amenities. Green Park benefits from a wide-ranging sustainability agenda that is aligned with Oxford Properties' own Sustainable Intelligence program, and includes the reduction of waste and emissions, the promotion of biodiversity, recycling and a green travel plan.



Watermark Place, U.K.



Hudson Yards

Through significant development:

In Canada – RBC WaterPark Place, AAA LEED Gold Development and Oxford Properties are joint venturing with CPP Investment Board in a major new office and retail development overlooking Toronto's waterfront. The tower will be the national headquarters for the Canadian banking business of the Royal Bank of Canada, building on Oxford's 50-year relationship with the RBC.

In the U.S. – Hudson Yards

Our New York presence is underscored by strategic relationships such as our joint venture with Related Properties in the 12 million square foot Hudson Yards redevelopment. In 2011, luxury leather goods company Coach Inc. chose Hudson Yards for its global corporate headquarters.

Without enlarging our carbon footprint:

Global Real Estate Sustainability Benchmark recently placed Oxford among the world's top ten private real estate companies for sustainability practices. This will only be enhanced with every new development. RBC WaterPark Place will join Oxford's award-winning Sustainable Intelligence program as the most cost-effective building in the Oxford portfolio.

GROWING OUR ASSETS THROUGH OMERS PRIVATE EQUITY:

In Canada – Husky International

In joint partnership with Boston-based private equity firm Berkshire Partners, OMERS Private Equity (OPE) acquired Husky International, a leading global supplier of injection molding equipment and services to the plastics industry. Described as a "Canadian success story," the Ontario-headquartered company has manufacturing plants in Canada, the U.S., Luxembourg and China, serving customers in over 100 countries through more than 40 service and sales offices. Its equipment is used to make an array of products from beverage bottles and food containers to medical devices and consumer electronics parts.



In the U.K. – V.Group Limited

The world leader in the robust and growing segment of outsourced ship management was acquired by OMERS Private Equity in September. V.Group is also a leading player in crew provision and related marine services. The profitable, U.K.-based company runs and maintains over 700 vessels and operates via 70 international offices in 34 countries. Combined with OMERS extensive international network, V.Group's experienced and talented management team will be able to pursue further growth in emerging markets.

In the U.S. – Accelerated Rehabilitation Centers and Great Expressions Dental

OMERS Private Equity acquired a leading U.S. regional network of outpatient physical rehabilitation services in July. Accelerated Rehabilitation Centers operates 223 clinics in eight states. With over 1,300 employees, it offers an industry-leading range of services, including pre- and post-operative care, treatment for orthopedic disorders, sports-related injuries and rehabilitation for injured workers.

Headquartered in Bloomfield Hills, MI, Great Expressions is a leading dental practice management company, with 152 affiliated dental offices in seven states across the Midwest, South and Northeast. With over 1,800 employees, Great Expressions' affiliated dental offices provide all facets of dental services, including general and preventative care.

OMERS PRIVATE EQUITY IS A 2011 WINNER OF THE CANADIAN DEALMAKERS PROGRAM

For the second consecutive year, OMERS Private Equity is a winner of the Canadian Dealmakers program. The Dealmakers Mid Market Private Equity Award was presented to OPE in recognition of its acquisition of two platform companies in the North American outpatient rehabilitation sector: CBI Health Group (CBI) and Accelerated Rehabilitation Centers (ARC).

The awards honour Canadian organizations and individuals who have made a significant contribution to the mergers and acquisitions market through measures including innovation, growth, establishment of best practices and value creation.

OMERS Private Equity partnered with management to purchase CBI, one of the largest providers of integrated health care services in Canada, in January 2011. Similarly, OPE partnered with management to acquire Accelerated Rehabilitation Centers, a leading provider of outpatient physical rehabilitation services in the U.S. Midwest in July 2011.



EXPANDING OPPORTUNITIES FOR OUR ORGANIZATION:

Official New York Office Opens

In October 2011, OMERS Worldwide officially opened an office at 320 Park Avenue in New York City, a permanent home to our team of 30 investment professionals in real estate, infrastructure, private equity and capital markets. This followed the launch of a fully staffed London U.K. office in 2008, in addition to existing offices in Toronto and Calgary.

OMERS Ventures

OMERS Ventures Launched

The launch of OMERS Ventures in October created one of Canada's largest venture capital investment groups. An initiative of OMERS Strategic Investments (OSI), OMERS Ventures is positioned to provide seed investment or growth capital as well as adding value through mentoring or guidance from its team of seasoned investment and operational professionals and an experienced advisory board.

2011 HIGHLIGHTS
CONT'D

OBJECTIVE ACCOLADES FROM OUR AUDIENCES:

From our employees:
One of Canada's 50 Best Employers

For the fourth year in a row, OMERS employees placed our organization among the 50 Best Employers in Canada, as surveyed by Aon Hewitt and published in the October 2011 edition of *Maclean's* magazine. OMERS ranked 16th among more than 260 organizations. In November, OMERS also ranked 11th among larger employers for Best Employers in the Greater Toronto Area – the only pension plan on the list.

WORLD FINANCE

From the investment community:
Pension Fund of the Year, Canada

For the second consecutive year, *World Finance* magazine has named OMERS Pension Fund of the Year, Canada. The judges look for a company demonstrating financial stability, a prudent approach to risk and corporate governance, and opportunities for employee development.

88%

From our members:
2011 Member Satisfaction Surveys

This year's annual survey of our members' satisfaction with OMERS level of service showed an average satisfaction rate of 88 per cent – marking the eighth straight year that our rate exceeded 85 per cent.

OUR PRINCIPLES

1

ENSURE THE QUALITY OF OUR BALANCE SHEET
Our assets and liabilities are fairly valued. Our assets are prudently invested and deliver a return that meets our pension needs within an appropriate risk profile.

2

ENSURE THAT THE RIGHT ORGANIZATIONAL STRUCTURE IS IN PLACE TO MEET OUR OBJECTIVES
Our organization is aligned with clear lines of accountability and clarity of purpose – everyone knows what is expected of them and of others. This structure allows active, hands-on management of our assets and provides value for the cost.

3

ENSURE THAT OUR MEMBERS' NEEDS ARE UNDERSTOOD AND MET
We understand the needs of all our members. We deliver what our members want, where, when and how they want it, and at a price that represents value for them.

4

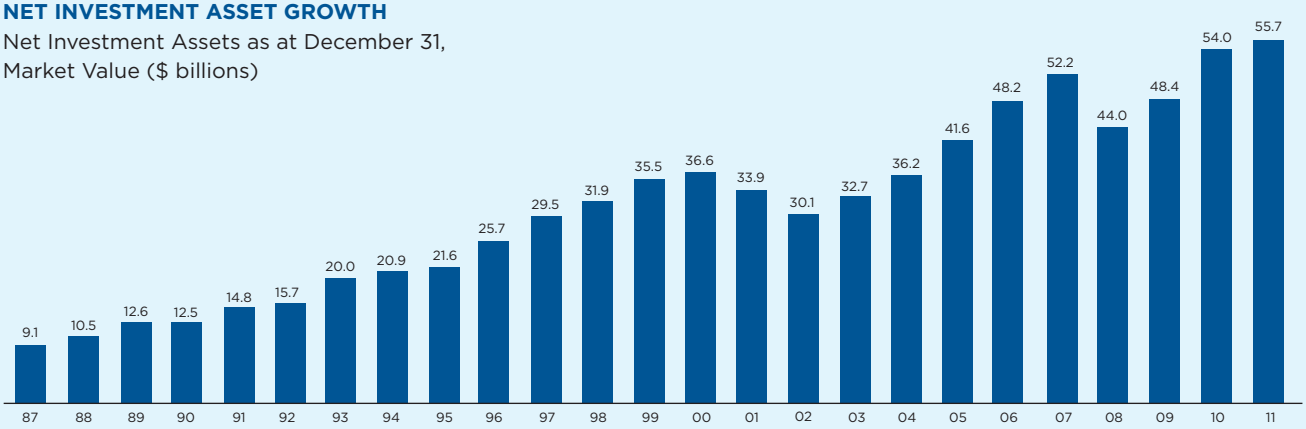
ENSURE THAT WE HAVE THE RIGHT PEOPLE IN THE RIGHT POSITIONS
Our business is organized around our primary asset: individuals taking ownership for decisions that they make. Our people are motivated, engaged and have the knowledge they need to achieve our goals. Our compensation programs reward performance.

5

ENSURE WE HAVE ACCESS TO THE RIGHT MANAGEMENT INFORMATION
We have information that is timely, accurate and actionable to manage our business. This information is universally understood throughout our organization.

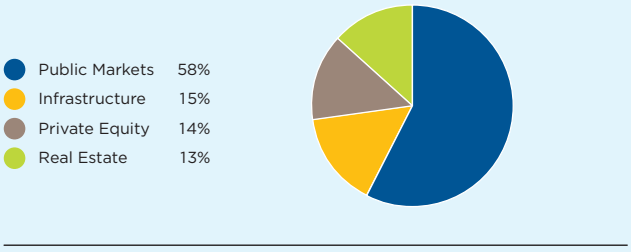
NET INVESTMENT ASSET GROWTH

Net Investment Assets as at December 31,
Market Value ($ billions)



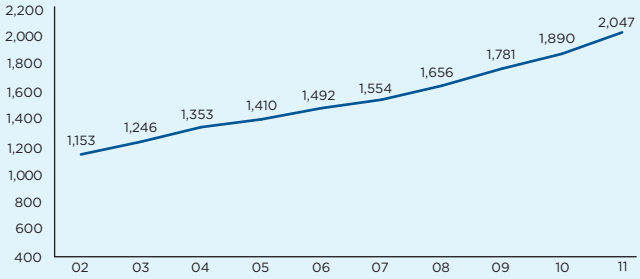
ASSET MIX

Net Investment Assets as at December 31, 2011



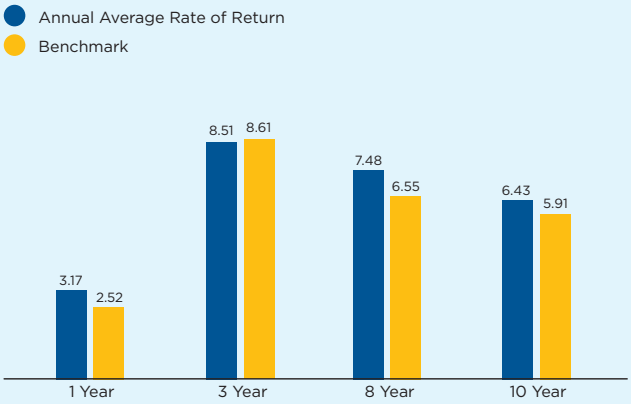
GROWTH IN MEMBERS' PENSION PAYMENTS

($ millions)



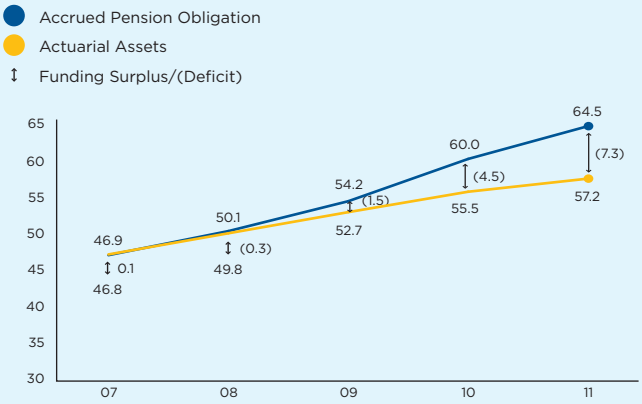
RATE OF RETURN AND BENCHMARK

(%)



ACTUARIAL ASSETS AND ACCRUED PENSION OBLIGATION — OMERS PRIMARY PENSION PLAN

As at December 31,
($ billions)



MESSAGE FROM THE CHAIR

OMERS IS "YOUR PLAN FOR THE FUTURE"



JOHN SABO Board Chair
OMERS Administration Corporation

Your future security always comes first and the OAC Board's prime stewardship responsibility is our commitment to keeping the pension promise. As the individuals with this accountability, Board members work closely with Management to develop the long-term strategy to ensure that happens, and then constantly monitor the present to help navigate around obstacles that may arise.

My four years as OAC Board Chair have provided me with a unique perspective. After six years as a Board member, I was honoured to have been given the opportunity to serve as Chair beginning in 2008 – a year of challenge on a global level but also a year of major transformation at OMERS.

In looking back, when the first signs of global economic collapse emerged in 2007, OMERS was already developing and implementing an investment strategy that would help stabilize our returns and give us a better balance in our asset mix of public and private investments. In 2003, private assets represented only 18 per cent of our investment portfolio. By a series of strategic and prudent moves over the intervening years, private market investments as of 2011 represent approximately 42 per cent – very close to our strategic goal of an asset balance of 47 per cent in private markets and 53 per cent in public markets, which we believe will provide OMERS with more predictable, consistent returns for the long term.

We followed this shift with a change in the way we manage our investments. The direct-drive approach we adopted means having our own people in major financial centres where we conduct business to assume hands-on investment management and to ultimately reduce overall costs. An example of this initiative was the opening of an OMERS Worldwide office in London, England in 2008, which now oversees a significant amount of private market investments.

In the fall of 2011, we launched an official New York office for OMERS Worldwide, a significant milestone in increasing our global profile and building our international investment relationships. Having experienced professionals in these centres to identify opportunities as they arise is essential to

"BEING WATCHFUL OF YOUR FUTURE INCLUDES NOT ONLY ENSURING THE LONG-TERM SECURITY OF THE PLAN BUT GOING FURTHER TO EXCEL IN SERVING OUR MEMBERS."

our investment strategy. With almost $10 billion invested in U.S. public and private markets, our expanded office was welcomed and acknowledged by our partners as a real commitment to the region.

Our global presence is just one aspect of the OMERS 2011–2015 Enterprise-wide Strategic Plan, which serves as a road map for our organization. However, our strategic plan is a living document, continuously and jointly monitored and adjusted when required by the Board and Management to ensure we stay on track with a clear vision for the future. It was developed through a consultative process and involves, as a matter of routine, much discussion and analysis of the issues we face currently and are projected to face in the future. This includes the Plan's funding position and our role in addressing the current deficit position.

Being watchful of your future includes not only ensuring the long-term security of the Plan but going further to excel in serving our members. This year, for example, the Board worked closely with Management to establish a new Member Services Committee to oversee Plan administration and funding.

The successful delivery of the OMERS pension promise is only possible because the Boards of the OMERS Administration Corporation and OMERS Sponsors Corporation work cooperatively with Management toward a common goal. This can be seen in our unified approach to adopting best practices in governance and ongoing joint communication initiatives where appropriate. We each play an important role in ensuring the ongoing health and success of the OMERS Plans and I would like to acknowledge and extend my thanks to the Sponsors Corporation Board for their commitment and decision making this past year that supports this goal.

Developing, implementing and monitoring industry leading governance practices has been and continues to be a focus of the OAC Board. In 2012 the external governance review mandated by the *OMERS Act, 2006* is scheduled to take place and the Board is committed to supporting the Ontario government in its review.

Under our CEO Michael Nobrega and his enterprise senior leadership team we have a highly engaged workforce which has earned OMERS recognition as a Best Employer in Canada for the fourth consecutive year.

This engaged workforce not only speaks well of our operations in terms of the commitment of our employees to the well-being of our Pension Plan but has translated into a continuously growing commitment to corporate citizenship. Since 2007 our employee response to community needs through volunteerism and fund raising has grown exponentially. As tangible evidence of efforts made, the OMERS family in 2011 raised in excess of $1.0 million for the United Way and provided approximately 2,200 volunteer hours in support of various charitable initiatives. These are very important statistics of which we all should be very proud.

I would like to congratulate Rick Miller who replaces me as OAC Chair. Rick's experience has prepared him exceedingly well for this role, beginning with his appointment to the OMERS Board in 1997 and for the many contributions he has made during his 15 years of dedicated service. Appreciation and our thanks for exceptional service are also given to John Goodwin who retired from the OAC Board on December 31, 2011. On behalf of the Board, I also want to pay tribute to Michael Power, who passed away in January 2012. Michael was a highly respected member of the OAC Board for 7 years during which time he served as Chair of the Governance Committee for 4½ years and was the key driving force behind the Governance Reform Project which was initiated in 2007 to assist the OAC Board in achieving its Governance Mission and Vision. He will be greatly missed and warmly remembered.

In closing, it has been an honour and privilege to have served as the OMERS Administration Corporation Chair over the past four years, and I can attest to the fact that your Board and Management remain focused on ensuring that OMERS will be "your plan for the future."



John Sabo
Board Chair

MESSAGE FROM THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

DEVELOPING A SUCCESSFUL STRATEGY

2011 was a reminder that no institution is immune to the continuing turbulence in the global credit and equity markets.



MICHAEL NOBREGA
President and Chief Executive Officer
OMERS Administration Corporation

Many sovereign governments, major financial institutions and corporations in the developed world were penalized for fiscal mismanagement and excessive debt through credit downgrades, higher borrowing costs and depressed stock prices. OMERS, with its triple "A" credit rating, navigated the global market turbulence and posted positive earnings for 2011.

OMERS achieved these goals by being a responsible long-term investor which includes being a very prudent user of debt. OMERS recognizes that one-year investment results are not a reliable measure of this commitment. With a multi-decade payout obligation, our goal is to achieve long-term performance at an acceptable level as we press forward with a strategy that anticipates over a five-year planning cycle, how disruptive market changes could impact our future.

Looking first at 2011, the Pension Plan earned a gross investment return of 3.17 per cent, or $1.7 billion in total investment income, following two years of strong returns that generated $9.7 billion in net investment income. Our substantial private market investments in infrastructure, real estate and private equity earned 8.20 per cent or total investment income of $1.8 billion. Our strategy to shift capital from public to private markets is working in accordance with our Strategic Plan's goal to achieve diversification in its asset mix. Our fixed income and real return bond portfolios comprising government bonds, corporate bonds and mortgages within Canada earned impressive returns of 9.13 per cent for fixed income and 17.84 per cent for real return bonds, or total investment income of $1.4 billion. Public equities were the weak spot, incurring a negative return of 11.29 per cent for Canadian public equities and negative 4.96 per cent for non-Canadian public equities, and a total investment loss of $1.5 billion. Sudden sharp declines in global equity

"OUR STRATEGIC PLAN HAS ACCOMPLISHED A GOOD DEAL THAT WILL PAY OFF IN THE YEARS AHEAD."

markets in the second half of 2011 reminded us once again that stock markets can be fickle. There are many reasons why equity returns weakened – the sovereign debt crisis emanating from Europe, U.S. and European government deficits, a slowdown in growth in leading Asian economies, softer demand for commodities and the threat of global recession. Developing a successful strategy to manage volatility in global equity markets continues to be a top priority in 2012.

One-year returns tell an incomplete story. Our financial contract with almost 420,000 Plan members is to deliver pension benefits over their retirement years. To stabilize performance at a level that fully funds the Plan, we began to shift capital from public to private markets in 2004, when 82 per cent of our total assets were invested in publicly traded stocks, bonds and related securities with the rest in privately owned assets. By 2011, the Plan was much better balanced with 58 per cent invested in public and 42 per cent in private market assets. In the past eight years, we have increased our investment in real estate, infrastructure and private equity transactions primarily in Canada, the United Kingdom and the United States by almost $18 billion.

This capital shift to private markets is designed to reduce exposure to volatile stock markets by acquiring private investments that generate reliable and rising cash flows to pay pensions. We continuously monitor the allocation of capital to various asset classes, particularly exposure to unpredictable stock markets. The Board and Management are currently conducting our regular triennial asset/liability study that takes the long view on the rising cost of pension benefits and the adjustments that may be necessary to the asset mix policy.

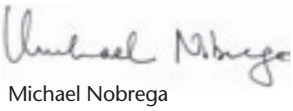
Our continuing challenge is to address the Plan's funding deficit. We are still paying the price of the damage caused by the 2008 global credit crisis and stock market meltdown. As investment gains and losses above and below the funding requirement are smoothed over five years, the Plan continues to recognize losses from 2008 and has not yet recognized all of the gains from 2009 and 2010. This contributed to the Primary Plan funding deficit widening in 2011 to $7.3 billion from $4.5 billion in 2010. We expect that it will widen further by the end of 2012, at which point all of the losses suffered in 2008 will be recognized. The funding position of the defined benefit component of the Primary Plan is also affected by the costs of liabilities which rose by $4.5 billion to $64.5 billion in 2011.

While temporary contribution rate increases and benefit reductions should eliminate the deficit over time, our goal is to get back to surplus sooner by achieving net returns in the 7 per cent to 11 per cent range. Over the last eight years we have earned close to a 7.5 per cent gross annual average return, adding $24.8 billion to net assets.

Our Pension Services group continues to score well with plan members and employers in the quality of plan administration and product innovation. A visible innovation is the Additional Voluntary Contributions program that enables plan members to contribute to or transfer funds from their registered retirement savings plans (RRSP) and other registered savings plans and receive the OMERS net return on investments. The program was first offered beginning in January 2011. Approximately 5,100 plan members joined the program during 2011. I am pleased to disclose that I was among them and transferred my RRSP savings to OMERS care because I believe in the soundness of our long-term investment strategy.

Our Strategic Plan, initiated in 2007, has accomplished a good deal that will pay off in the years ahead. For the third consecutive year, OMERS was independently ranked as one of Canada's top employers and most successful pension funds. We have the beginnings of a global footprint with offices in London and New York that enable our investment professionals to find attractive investment opportunities. We have introduced OMERS to institutional investors around the world as a potential co-investment partner. We have persuaded governments to remove unnecessary regulatory barriers for which compliance is expensive and which inhibit investment choices. And by increasing the internal investment management rather than paying third-party fund managers, we will save significant costs to the Fund.

We are confident that our strategic initiatives and innovations described in OMERS Strategic Plan and the risk measures embedded in our enterprise-wide investment approach will enable OMERS to successfully manage the continued turbulence in the global markets and underpin the security of the pension promise to our Plan members.



Michael Nobrega
President and Chief Executive Officer

GOVERNANCE OMERS ADMINISTRATION CORPORATION

Under the *Ontario Municipal Employees Retirement System Act, 2006* which was proclaimed into law in June 2006, OMERS Administration Corporation (OAC) is responsible for pension administration, valuation of the accrued pension obligation and investment of the pension funds.

CORPORATE AND BOARD GOVERNANCE

Effective and transparent pension plan governance is the foundation that allows OMERS to fulfill its pension promise to its members. Throughout its 50-year history, OMERS has continuously sought to achieve high standards in governance, as evidenced by its Governance Vision and Mission.

> Governance Vision

The OAC Board will be publicly recognized as an industry leader in corporate and pension governance.

> Governance Mission

The purpose of governance is to ensure effective board and management decision-making through the use of processes and controls to ensure the OMERS Pension Plans are administered in the best interests of the members and beneficiaries.

KEY BOARD RESPONSIBILITIES

The OAC Board of Directors (OAC Board) has many important responsibilities, as outlined in the OAC Board Mandate which can be found on our website. The key responsibility of the OAC Board is to set the overall course of OAC, including its investment direction and objectives and to ensure that the pension services for which it is responsible are executed effectively and efficiently. It also actively oversees financial reporting and actuarial matters such as the annual valuation of the OMERS Pension Plans' liabilities. The OAC Board approves the strategic planning process followed by OAC as well as the Strategic Plan prepared by the Management team. The OAC Board delegates to Management responsibility for strategy development and day-to-day business activities, as well as a number of other important functions such as compliance, internal controls and talent management. With respect to these delegations, the role of the OAC Board is to monitor Management and to ensure that its activities remain consistent with the longer term vision, objectives and directional framework set by the OAC Board.

Key specific responsibilities also include identifying and appointing the Chief Executive Officer (CEO) of OAC as well as assessing the performance of the CEO. Compensation of Management is also a key Board responsibility.

BOARD GOVERNANCE

Many policies and practices are in place to support OAC's commitment to leading governance practices and Board performance, including:

- a Governance Manual that is available on our website;
- a comprehensive Board development program that includes external director certification and an internal orientation in Board operations and governance;
- an external auditor independence policy;
- a detailed Code of Conduct, covering areas such as conflict of interest, fiduciary duties and privacy and confidentiality;
- a personal and insider trading policy which requires Board members and senior managers to pre-clear their personally directed securities trades;
- a requirement that members of the Audit Committee meet the standard of financial literacy; and
- transparency and accountability processes, including regular meetings with Plan participants and other stakeholders, as well as timely and accurate print and electronic communication of developments. Summaries of OAC Board and Committee decisions are published on the OMERS website.

In 2011, the OAC Board spent considerable time reviewing enterprise risk management programs at OAC, assuming direct responsibility for this activity, which had previously been undertaken by the Audit Committee. Also in 2011, the OAC Board approved a new Special Transactions Review Policy. This policy is the final deliverable in the Board's Governance Reform Project. It establishes additional rules regarding transactions with current or former directors and officers and their families, with sponsor organizations, or other parties who have a close relationship with OMERS, as the Board recognized that these kinds of transactions require additional scrutiny to ensure that any steps taken are in the best interests of plan members. The policy is available in the Governance section of our website. When the OAC Board approved the policy, it directed that we report annually on any transactions subject to the policy. There were no such transactions in 2011.

We expect that in 2012, the OAC Board will be spending considerable time on the province's review of OMERS contemplated by the *OMERS Review Act*, which was passed in 2006 and which requires a general review to take place in 2012.

Further details on OAC's governance practices can be found in the Governance Manual that is available on www.omers.com.

BOARD MEMBERSHIP

In 2009 OMERS Sponsors Corporation enacted SC By-law No. 13 which names specific sponsor organizations that have the right to nominate individuals to be considered by the SC for appointment to the OAC Board. According to SC By-law No. 13, the OAC Board is comprised of 14 members who are proposed by the following organizations:

- Association of Municipalities of Ontario (2 members)
- Canadian Union of Public Employees (Ontario) (2 members)
- City of Toronto (1 member)
- Electricity Distributors Association (1 member)
- Ontario Association of Children's Aid Societies (1 member)
- Ontario Association of Police Services Boards (1 member)
- Ontario Professional Fire Fighters Association (1 member)
- Ontario Public Service Employees Union (1 member)
- Ontario Secondary School Teachers' Federation (1 member)
- Police Association of Ontario (1 member)
- Retiree groups (1 member)
- School boards (1 member) (rotation between public and Catholic boards).

BOARD APPOINTMENTS

The OAC Board appoints the CEO, who is not a member of the Board, as well as the Corporation's independent auditor and external actuary responsible for Plan valuation and related matters. The Board has its own independent external counsel to provide legal advice to the Board when conflict matters arise.

BOARD PRACTICE

The OAC Board has regular in camera meetings without Management present. The Board also conducts regular evaluations of its performance at the end of meetings as well as annually. It conducts regular analysis of required Board competencies to serve the interests of Plan members.

OAC BOARD REMUNERATION AND EXPENSES

The remuneration paid to OAC Board members is determined by SC By-law No. 6. The SC's by-law provides for the Chair to receive total compensation of $70,000 per annum while the Chairs of Committees receive an annual retainer of $17,800 per annum and other members receive an annual retainer of $12,800. In addition, all Board members, with the exception of the Board Chair, receive a meeting fee of $750 to a maximum of 24 meetings per year.

Hearings of the OAC Appeals Sub-Committee, which meets when required to deal with appeals filed by Plan members, are not subject to, or counted in calculating, the 24 meeting per year limit.

The table on page 14 includes remuneration paid to OAC Board members for OAC Board and Committee meetings as well as other eligible expenses in 2011, with comparable numbers for 2010.

BOARD COMMITTEES

In 2011, the OAC Board had four standing committees which assisted the Board in discharging its responsibilities.

The OAC Board also uses sub-committees from time to time to deal with special situations.

INVESTMENT COMMITTEE (COMMITTEE OF THE WHOLE)

The purpose of the Investment Committee is to enable the OAC Board to meet its fiduciary oversight and related obligations in relation to OAC's investment policies and strategies and to enable the OAC Board to discharge its related monitoring, compliance and risk mitigation oversight responsibilities on behalf of the OAC Board. The Investment Committee also approves all major transactions.

GOVERNANCE COMMITTEE

The Governance Committee annually reviews the mandates of the OAC Board and its committees. It has oversight of the OAC Board Orientation and Education Program. It is also responsible for implementing an annual internal assessment of the Board's performance. It recommends changes to OAC governance where required to address effectiveness issues arising out of the assessments; assesses the competency requirements of the OAC Board and recommends skills and experience needs for the Board. The Committee is also responsible for reviewing relevant policies relating to governance, including an OAC external communications policy.

AUDIT COMMITTEE

The Audit Committee assists the OAC Board in fulfilling its oversight responsibilities for the:

- integrity of the financial reporting process and financial statements;
- system of internal control and the review of the disclosure of financial information;
- system of risk management and fraud risk management;
- internal audit process;
- external audit of the financial statements;
- organizational processes for monitoring compliance with laws and regulations and the Code of Conduct; and,
- Ethics Hotline (whistle-blower process) and special investigations.

LEADERSHIP RESOURCES AND COMPENSATION COMMITTEE (LRCC)

The purpose of the Leadership Resources and Compensation Committee is to assist the OAC Board in meeting its fiduciary oversight and related obligations by:

(i) attracting, retaining and motivating excellent leaders at the senior executive level who are committed to the OAC Mission Statement and Core Values;

(ii) overseeing a robust succession planning process for the position of CEO; and

(iii) overseeing senior executive performance, compensation and compensation policies.

MEMBER SERVICES COMMITTEE

In December 2011, the OAC Board established a new Member Services Committee, effective January 1, 2012, to assist the Board in ensuring that plan administration and actuarial valuation issues are fully addressed.

APPEALS SUB-COMMITTEE

The Appeals sub-committee serves as an appeals tribunal for Plan members who are appealing decisions of the President and CEO (or his delegates) regarding their pension benefit entitlements. The Appeals sub-committee hears evidence and renders decisions in these appeals. It retains independent external counsel to assist it in its deliberations.

OAC JOINT COUNCIL SUB-COMMITTEE (JCSC)

This sub-committee was formed following the execution of the Framework Agreement with the SC in 2009 as a venue in which to address matters of importance to either party with respect to oversight and governance of the OMERS Pension Plans including the Framework Agreement.

OAC BOARD ATTENDANCE

OAC Board and committee meeting attendance in 2011 is as detailed on page 15.

OAC BOARD REMUNERATION AND EXPENSES

For the year ended December 31,	2011		2010	
	Remuneration	Expenses[i]	Remuneration	Expenses[i]
John Sabo (Chair)	$ 70,000	$ 39,076	$ 70,000	$ 28,524
Bill Aziz	30,800	13,352	30,800	7,675
Frederick Biro[ii]	6,200	1,146	-	-
David Carrington	33,800	3,788	30,800	2,959
Richard Faber	35,800	24,496	35,800	21,632
John Goodwin	39,550	7,890	37,300	17,250
Rick Miller	35,800	42,125	35,800	46,418
Laurie Nancekivell[iii]	31,550	7,594	23,300	14,079
David O'Brien	35,800	17,389	35,800	8,615
James Phillips	30,800	8,293	30,800	8,937
Michael Power[iv]	23,850	27,860	32,800	46,799
Eugene Swimmer	36,550	17,787	32,300	27,523
Leslie Thompson	31,550	3,923	31,550	17,995
Sheila Vandenberk	30,800	20,914	31,550	28,432
John Weatherup	30,800	5,389	30,800	9,923
Other Expenses[v]	-	149,871	-	91,049
Total	$ 503,650	$ 390,893	$ 489,400	$ 377,810

(i) Includes reimbursement for normal out-of-pocket business expenses including education, meeting and communication expenses incurred on behalf of the OAC. These Board expenses by Director are reported to the Audit Committee annually.
(ii) Joined OAC Board effective September 23, 2011.
(iii) Remuneration to Laurie Nancekivell was paid directly to her sponsor organization.
(iv) Left OAC Board effective September 23, 2011.
(v) Other expenses include Board group meeting expenses not allocated by individual.

2011 BOARD/COMMITTEE MEETINGS

	Board (16)		Investment (11)		Audit (6)		Governance (5)		LRCC (5)		Joint Council (6)		Total (49)		
Board Member	Attended	Total	Attended	Total	Attended	Total	Attended	Total	Attended	Total	Attended	Total	Attended	Total	%
Bill Aziz	15	16	11	11	-	-	-	-	5	5	-	-	31	32	97%
Frederick Biro[i]	4	4	1	1					1	1	-	-	6	6	100%
David Carrington	16	16	11	11	-	-	-	-	5	5	-	-	32	32	100%
Richard Faber	13	16	10	11	6	6	-	-	-	-	-	-	29	33	88%
John Goodwin	16	16	9	11	5	6	-	-	-	-	-	-	30	33	91%
Rick Miller	16	16	11	11	-	-	-	-	5	5	6	6	38	38	100%
Laurie Nancekivell	16	16	11	11	-	-	5	5	-	-	-	-	32	32	100%
David O'Brien	14	16	9	11	-	-	4	5	-	-	5	6	32	38	84%
James Phillips	12	16	11	11	6	6	-	-	-	-	-	-	29	33	88%
Michael Power[ii]	9	12	7	10	-	-	-	-	3	4	-	-	19	26	73%
John Sabo[iii]	16	16	11	11	4	6	5	5	4	5	6	6	46	49	94%
Eugene Swimmer	16	16	11	11	-	-	5	5	-	-	-	-	32	32	100%
Leslie Thompson	16	16	11	11	5	6	5	5	-	-	-	-	37	38	97%
Sheila Vandenberk	16	16	10	11	6	6	-	-	5	5	-	-	37	38	97%
John Weatherup	16	16	10	11	-	-	5	5	-	-	6	6	37	38	97%
Overall Attendance	**94%**		**94%**		**89%**		**97%**		**93%**		**96%**		**94%**		

(i) Joined OAC Board on September 23, 2011.
(ii) Left OAC Board on September 23, 2011.
(iii) *Ex officio* member for Audit, Governance and LRCC Committees.

OAC Directors also attended other discretionary meetings such as the Spring and Fall Information Sessions, Joint Education Sessions with the SC, site visits to several of our Investee Companies and in-house education sessions.

PROXY VOTING

We own shares in numerous publicly traded companies around the world. Share ownership carries with it important rights and responsibilities, including the right to vote shares at company meetings.

The proxy vote is an important asset of a pension fund. We exercise our ownership rights by voting proxies diligently in a manner intended to maximize the long-term value of our investments.

We believe that well-managed companies with strong governance practices will generally contribute positively to long-term investment returns. Conversely, poorly-managed companies with poor governance practices are more likely to increase the risk of a long-term investment.

Our proxy voting guidelines contain general statements about how OMERS is likely to vote on an issue. These are not completely rigid positions, and we may consider extenuating circumstances that might call for a different vote than a specific guideline suggests. This may include taking into account different regulatory or corporate governance regimes and customary practices in different jurisdictions.

Our proxy voting guidelines, and our voting record for the Canadian and U.S. markets, can be found on our website.

PROXY VOTING GUIDELINES

OMERS understands the different roles and responsibilities of shareholders, directors and management in the corporate governance system. Accordingly, when OMERS exercises its voting rights, it does not seek to manage the companies in which it owns shares. However, OMERS considers its vote an important way in which it can influence management and the board of directors and express its view with the way in which the corporation is being managed and overseen.

Our proxy voting guidelines are based on a number of key principles, including:

Board of Directors

Good corporate governance practices should be followed to encourage effective and independent boards.

Executive and Director Compensation

Executive compensation should be reasonable, performance-based and structured in a manner that aligns management with the long-term interests of shareholders.

Takeover Protection

Shareholder rights plans should permit the board and management to respond to takeover offers in a manner that enhances long-term shareholder value.

Shareholder Rights

Share structures should support the basic principle linking voting to equity ownership on the basis of "one share, one vote".

Environmental, Social and Governance

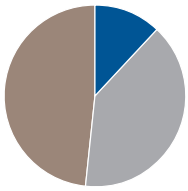
Well-managed companies that demonstrate high ethical and environmental standards and respect for their employees, human rights and the communities in which they do business contribute to long-term financial performance.

PROXY VOTES

During 2011, we voted on a total of 18,878 items covering 1,660 shareholder meetings globally. In Canada, we voted on 2,261 items in 216 shareholder meetings. Outside of Canada, we voted on 7,520 items in the U.S. and 9,097 items outside of North America at 1,444 shareholder meetings.

PROXY ITEMS VOTED

Canada	2,261
U.S.	7,520
Non North America	9,097



SENIOR MANAGEMENT TEAM

Corporate Management Team



Michael Nobrega
President and
Chief Executive Officer



Warren Bell
Executive Vice President and
Chief Human Resources Officer



Jennifer Brown
Executive Vice President
and Chief Pension Officer



G. Blair Cowper-Smith
Executive Vice President,
Corporate Affairs and
Chief Legal Officer



Patrick Crowley
Executive Vice President
and Chief Financial Officer



Rodney Hill
Executive Vice President
and Chief Auditor



Michael Latimer
Executive Vice President and
Chief Investment Officer



John Macdonald
Executive Vice President and
Chief Operating Officer
(retired December 31, 2011)

Investment Management Team



Jacques Demers
President and CEO,
OMERS Strategic Investments



James Donegan
President and CEO,
OMERS Capital Markets



Wendy Forsythe
President, OMERS
Investment Management
(retired December 31, 2011)



Blake Hutcheson
President and CEO,
Oxford Properties Group



Paul G. Renaud
President and CEO,
OMERS Private Equity



Michael Rolland
President and CEO,
Borealis Infrastructure

BOARD OF DIRECTORS

For biographies of the OAC Board of Directors visit omers.com.



John Sabo
Chair



Bill Aziz



Frederick Biro
(joined September 23, 2011)



David Carrington



Richard Faber



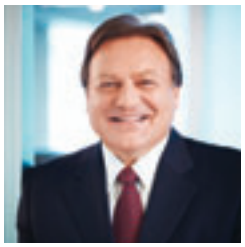
John Goodwin
(retired December 31, 2011)



Rick Miller



Laurie Nancekivell



David O'Brien



James Phillips



Michael Power
(retired September 23, 2011)



Eugene Swimmer



Leslie Thompson



Sheila Vandenberk



John Weatherup

2011 MANAGEMENT'S DISCUSSION AND ANALYSIS

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OMERS Administration Corporation ("OAC") is the administrator of the OMERS pension plans (the "OMERS Pension Plans" or the "Plans") as defined in the *Ontario Municipal Employees Retirement System Act, 2006* (the "OMERS Act"). The OMERS Pension Plans include OMERS Primary Pension Plan (the "Primary Plan" or the "Plan"), the Retirement Compensation Arrangement (the "RCA") associated with the Plan and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (the "Supplemental Plan"). Additional Voluntary Contributions ("AVCs") are offered to Plan members as part of the Primary Plan. The OAC is responsible for managing the funds of the Plan, the RCA and the Supplemental Plan (collectively, the "Fund" or the "Funds"). The Funds are managed by the following entities: OMERS Capital Markets (public markets, mortgages and private debt), OMERS Private Equity (private equity), Borealis Infrastructure (infrastructure), Oxford Properties Group (real estate) and OMERS Strategic Investments (strategic investments from any asset class) (collectively "the Investment Entities"). This management discussion and analysis is the responsibility of management of the OAC ("Management") and contains Management's analysis of the OAC's financial condition, operational results and the environment in which it operates as of February 22, 2012. This section should be read in conjunction with the OAC Consolidated Financial Statements. The Audit Committee and Board of Directors of the OAC (the "Board") have reviewed and approved the contents of this Management Discussion and Analysis.

In addition to historical information, this section contains forward-looking statements with respect to Management's strategy, objectives, outlook and expectations. Forward-looking statements can be identified by use of words such as "believe", "expect", "may", "could", "intend", "continue" or "estimate" or variations of such words and phrases or states that certain actions, events or results "may", "could", "would", "might", "will" be taken or achieved. By their very nature, those statements are subject to risks and uncertainties, which may cause actual results to differ from the expectations expressed in the forward-looking statements. Forward-looking statements made in this section represent Management's views at the date of this report and the OAC does not undertake to update or revise any forward-looking statements as a result of new information, future events, or otherwise.

VISION

We have one clear and overriding goal — to keep the pension promise to our current and future retirees.

We work as a team in pursuit of outstanding performance that will enable us to meet this objective, including:

- generating sufficient returns over the long term through the investment of the Funds; and
- providing excellent pension administration services to our members and employers, the most important of which is to pay monthly pensions to retirees.

Our vision focuses on four key areas which are integrated into our strategies and decisions:

LEAD

Be the leader in the pension industry.
We want to be nothing less than the leader in the pension industry. We will earn this status if we rank in the top quartile of investment performance over the long term and if we set the industry standard for service to members and employers.

PERFORM

Provide first-in-class investment management.
We recognize the importance of earning superior risk-adjusted returns in the long term. This means superior returns while being conscious of the actions we are taking to keep pensions secure.

SERVE

Deliver superior pension services to our members and employers.
Services to Plan members are one of our top priorities and one of our key strengths.

GROW

Attract investment partners and employers through our leadership.
Growth is an objective not for its own sake but because it will expand the range and size of investment opportunities we can pursue and allow us to improve our services for the benefit of all members.

ENTERPRISE-WIDE STRATEGIC PLAN

The OMERS 2011-2015 Enterprise-Wide Strategic Plan is the joint product of the Board and Management of OAC. It has evolved as a shared vision from a consultative strategic planning process.

The Strategic Plan reflects research and industry-leading initiatives developed by Management. It is influenced by open and transparent conversations between Board members and Management that occur at least six times per year when detailed update reports are formally presented to the Board. The focus on strategy is a matter of routine during ongoing liaison between the Board Chair and OAC CEO.

In 2011, collaboration between the Board and Management continued to be at a high level of engagement, consistent with leading governance practices. In February 2011, Board members identified the broad issues that would guide the 2011 strategic planning discussions, including OMERS funding position, global macroeconomic trends and their implications for OMERS investment strategy and the impact and opportunities of potential pension reform in Canada.

In April 2011, the Board devoted a significant amount of time to discussing a draft of the Strategic Plan and approved the final version in June 2011.

The Strategic Plan is a living document. New and revised initiatives and issues arise each year while other initiatives are removed from the plan based on research and due diligence. In addition, events beyond our control at home and abroad influence the content and tone of our strategy. Throughout the year, the Board receives informational updates and is called upon for approval, allowing Management to implement specific initiatives.

The major initiatives of the Strategic Plan include:

1. ASSET MIX POLICY

Our asset allocation policy is based on our belief that over the long term, an asset mix with greater exposure to private market investments positions the Plan to generate strong, predictable returns and consistent cash flows with reduced risk to meet its funding requirements. This Board-approved policy sets targets and ranges of public and private markets investments. Our investment strategy over the long term is to maintain our asset mix exposure to public market investments, such as public equities and interest bearing investments, at approximately 53 per cent of the Plan's net investment assets with the remaining 47 per cent representing exposure to private market investments, such as private equity, infrastructure and real estate.

At the end of 2011, the Plan's public markets investments represented 57.6 per cent of net investment assets and private markets investments represented 42.4 per cent of net investment assets. The investment in private markets is up from 38.3 per cent at December 31, 2010. Depending on the relative 2012 investment returns in public versus private market asset classes and investment opportunities in the private market asset classes, the Plan may be close to achieving its target allocations by the end of 2012.

2. DIRECT DRIVE ACTIVE ASSET MANAGEMENT

We are making significant progress in actively managing an increasing proportion of OMERS investments internally to enhance returns and reduce investment costs. The principal drivers are increased direct drive management of foreign publicly traded equities and private equity investments. Our long-term goal is to have 90 per cent of total Fund assets directly managed by 2015. This is expected to result in net savings of over $275 million over the next four years. As at December 31, 2011, total Fund assets managed internally were 83.8 per cent as compared with 85.6 per cent at the end of 2010. The decrease is due to a temporary shifting of funds to an external manager as part of a tactical decision to mitigate portfolio risk in capital markets investments.

3. ACCESS TO DOMESTIC CAPITAL

Accessing domestic capital to build a larger capital base that will enable us to pursue attractive investments continues to be a key priority. OMERS Investment Management (OIM) was established in 2009 with the principal objective of raising domestic capital from other pension plans, and other eligible clients. OIM has built significant awareness of OMERS investment capabilities, particularly in its private market strategies and is in advanced discussions with parties interested in gaining exposure in their funds to the performance of all or part of the annual investment return of the OMERS Primary Plan.

The Additional Voluntary Contributions (AVCs) initiative was successfully launched on January 1, 2011. At its first anniversary, AVCs had accumulated $94 million.

We are continuing our efforts to pursue traditional and associated employers to either join OMERS or, if they have existing plans, to outsource management of their funds to OMERS.

4. ACCESS TO FOREIGN CAPITAL

OMERS Strategic Investments (OSI) is leading our efforts to form a Global Strategic Investment Alliance (GSIA) to pursue large investments attractive to both OAC and like-minded investors in the United States, Europe, Asia and the Middle East. These efforts have resulted in considerable interest from many prospective partners, including foreign pension plans and superannuation funds. OMERS is currently engaged in a mutual due diligence process with several of these organizations. We expect that a first close of the GSIA will occur in 2012.

5. STRATEGIC INVESTMENT OPPORTUNITIES

The OMERS Worldwide brand has been established through OSI to assist the Investment Entities in sourcing global investments. We are in the process of creating a global investment footprint by (i) establishing a network of offices in major financial centers, (ii) building awareness of the OMERS Worldwide brand via a pro-active media strategy, participation in leading business conferences and building relationships with business and government leaders and (iii) creating awareness about our GSIA initiative. A new and expanded New York office with representatives of all the Investment Entities was opened in 2011. We launched OMERS Ventures in 2011 with a mandate of making venture capital investments in response to the pent up demand for new sources of venture capital in Canada.

6. BARRIERS TO GROWTH

In 2011 progress was made to remove restrictive rules that act as barriers to OMERS growth in two areas. First, the *Pension Benefits Act (Ontario)* (PBA) was amended to clarify that pension plans entering into investment arrangements with OMERS where the return is based on the performance of all or part of the Plan will not violate the rule that limits a pension plan to having no more than 10 per cent of its assets in any one investment. The change clarifies that such a fund will be able to rely on OMERS compliance with the 10 per cent rule. Second, certain sections of the PBA relating to the solvency funding exemption for Jointly Sponsored Pension Plans and other related provisions were proclaimed during 2011. Accordingly, the Primary Plan is exempt from solvency funding.

Also in 2011, the Canadian Minister of Finance announced the federal government's intention to move forward with Pooled Registered Pension Plans (PRPPs). OAC continues to monitor the development of PRPPs to ensure that OMERS is not disadvantaged or deprived of the opportunity to be an eligible provider of PRPPs.

OAC SUMMARY

REVIEW OF 2011 RESULTS

INVESTMENT OBJECTIVE	MANAGEMENT APPROACH	2011 PERFORMANCE
Our investment objective is to meet the pension promise and add surplus wealth. To fulfill the pension promise to our current and future retirees we must produce investment returns that generate 6.5 per cent (4.25 per cent real return plus 2.25 per cent inflation rate) or more in net annual returns on the asset classes in which we invest within an acceptable risk tolerance.	Define an asset mix strategy and investment strategy to meet the Plan's investment objectives.	Total Plan return of 3.17 per cent compared to 2.52 per cent for the benchmark. RCA Investment Fund return of negative 2.42 per cent compared to negative 2.43 per cent for the benchmark.

2011 ECONOMIC OVERVIEW

The solid performance that markets experienced in 2009 and 2010 with the broad S&P 500 Index and the S&P/TSX Composite almost doubling uninterrupted from the lows reached in March 2009 to the index highs in April 2011 came to a halt due to a number of macro-economic events. The latter half of 2011 saw a return to the type of daily volatility in equity markets reminiscent of the most recent recession. Most equity markets in developed countries ended the year in negative territory, including the S&P/TSX Composite that ended 2011 down 8.7 per cent. The only exception was the S&P 500 Index, which managed to post, in local terms, a positive 2.1 per cent return in 2011 largely buoyed by better than expected earnings produced by many U.S. corporations.

The financial crisis and recession during 2007–2009 saddled many governments (in particular, the U.S. and those in Europe) with unprecedented levels of debt as they attempted to stabilize the financial system and stimulate growth. While there were many events that impacted the global economy, including a massive earthquake that caused a tsunami and subsequent nuclear incident in Japan and the Arab Spring which saw civil uprisings in many countries in North Africa and the Middle East, financial headlines were dominated by the sovereign debt crisis emanating out of Europe.

OMERS has continued the overweight fixed income strategy to preserve capital in light of global economic uncertainty and to maintain adequate liquidity to meet the funding requirements for private market investments. This strategy has partially mitigated the losses which have occurred in the public markets in the latter half of 2011.

INVESTMENT PERFORMANCE OVERVIEW

Through our Investment Entities, we invest in several asset classes – public markets, private equity, infrastructure and real estate – both in Canada and around the world.

Investment Entity	Primary Asset Class
OMERS Capital Markets	Public markets, including interest bearing securities, commercial mortgages, real return bonds and public equities
OMERS Private Equity	Private equity through both direct and indirect (funds) investments
Borealis Infrastructure	Direct infrastructure-related investments
Oxford Properties Group	Real estate direct investments
OMERS Strategic Investments	Direct strategic assets of any asset class that are considered outside the strategy of the other Investment Entities but are still considered to be in the best interest of the Fund

Our Investment Entities are described more fully beginning on page 38 of this Annual Report.

Investment returns for the Plan and RCA for 2011 and 2010, based on investment income before external manager performance fees and investment management expenses, were as follows:

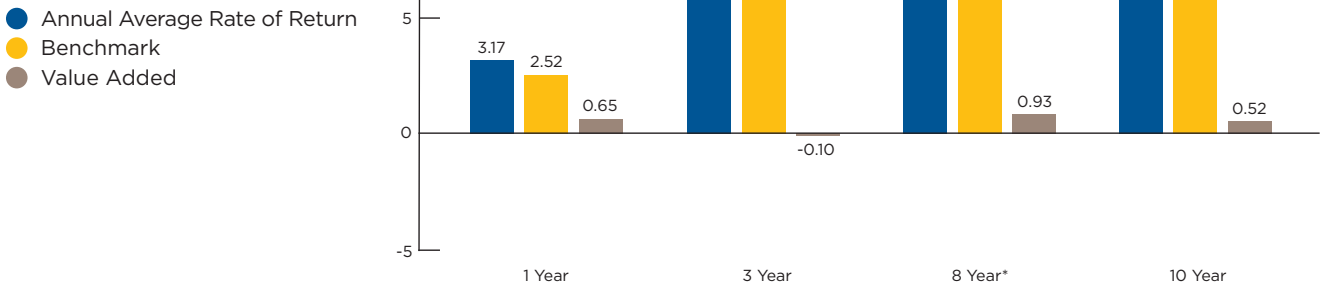
For the year ended December 31,	2011		2010	
	Rate of Return	Benchmark	Rate of Return	Benchmark
OMERS Capital Markets	**-0.22%**	**1.26%**	11.04%	10.11%
OMERS Private Equity	**7.23%**	**-5.58%**	22.21%	28.05%
Borealis Infrastructure	**8.79%**	**8.00%**	10.10%	8.50%
Oxford Properties Group	**8.40%**	**6.83%**	7.51%	6.65%
OMERS Strategic Investments	**7.24%**	**6.90%**	7.65%	7.00%
Total Private Markets	**8.20%**	**4.50%**	11.84%	12.39%
Total Primary Plan Fund[(i)]	**3.17%**	**2.52%**	12.01%	11.47%
RCA Investment Fund[(ii)]	**-2.42%**	**-2.43%**	7.99%	10.09%

(i) Results of the Primary Plan Fund's currency overlay hedging program and the costs of hedging certain private market investments are included in the total return only.
(ii) Excludes the RCA refundable tax balance with the Canada Revenue Agency. Including the refundable tax balance, the RCA rate of return was -1.25 per cent (2010: 4.31 per cent).

The Primary Plan achieved a 3.17 per cent total investment return in 2011, exceeding the benchmark of 2.52 per cent by 65 basis points while the RCA Investment Fund earned negative 2.42 per cent compared with the benchmark of negative 2.43 per cent.

High volatility in public markets has impacted OMERS Capital Markets results with a return of negative 0.22 per cent, 148 basis points below the benchmark of 1.26 per cent. Total private markets returns of 8.20 per cent exceeded the benchmark by 370 basis points across all private market investments demonstrating the effectiveness of the asset mix and direct drive management components of the Strategic Plan. In 2004, we adopted an asset mix policy of allocating a greater portion of our asset mix to private markets investments. Since that time, the Plan has earned $24.8 billion in total investment income and an average annual investment return of 7.48 per cent despite significant losses sustained in 2008 and the mostly negative returns in public equity markets in 2011. Our returns over this eight year period exceeded the benchmark returns adding $3 billion in value to the Fund. The rate of return, benchmark and the value added by our investment professionals over the past one, three, eight and ten-year periods is shown in the table below:

RATE OF RETURN AND BENCHMARK RETURNS
(%)



* Period since adoption of asset mix policy in 2004.

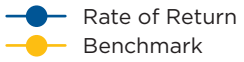
BENCHMARK RETURNS

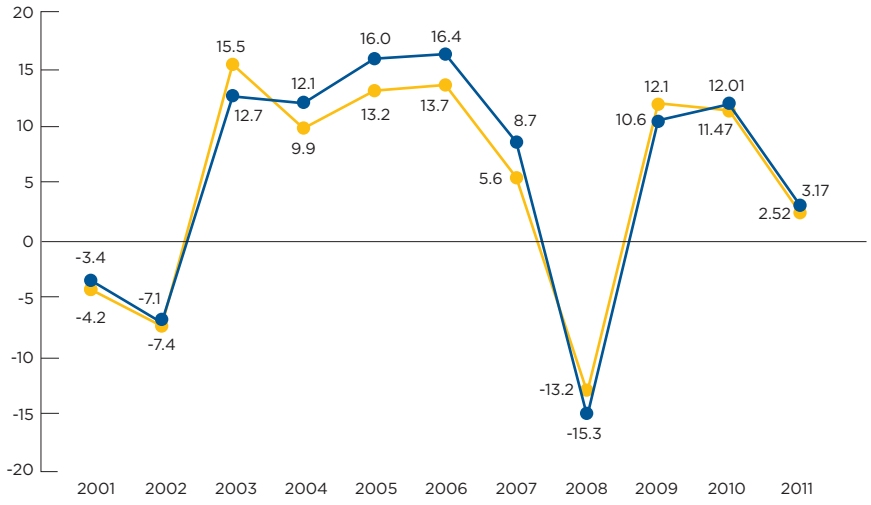
We measure the performance of each of OMERS Capital Markets asset classes and OMERS Private Equity against market benchmarks set by the Board that reflect the results of markets in which we invest and for Borealis Infrastructure, Oxford Properties and OMERS Strategic Investments, performance is measured against an absolute return benchmark set at the beginning of each year by the Board. We develop a benchmark for total investment activities by aggregating and weighting the individual benchmarks for each entity. Our benchmarks are reviewed and approved by the OAC Board. Our goal is to earn returns that equal or exceed these benchmarks. When we exceed the benchmark, our investment managers are adding value to the portfolio above the targeted return for the asset class or the return generated by the markets through passive investments. The benchmarks used are as follows:

Entity	Benchmark
OMERS Capital Markets	
- Fixed income	Blended DEX 30 day Treasury Bill Index and DEX Universe Bond Index
- Real return bonds	DEX Real Return Bond Index
- Canadian public equities	S&P/TSX Composite Index
- International equities	Blended MSCI All World excluding Canada and U.S. and MSCI All Cap U.S. Index
OMERS Private Equity	Aggregate of Global Russell indices adjusted for geographic and sector exposures plus an illiquidity and leverage premium; mezzanine debt based on an absolute return benchmark
Borealis Infrastructure, Oxford Properties and OMERS Strategic Investments	Absolute return set at the beginning of each year based on operating plans approved by the Board
Total Fund[(i)]	Weighted Average blend of Entity benchmarks including a 50 per cent hedge in International Equity
RCA Investment Fund	Weighted Average blend for the RCA Investment Fund is 5 per cent DEX 30-Day T-Bill + 23.75 per cent S&P/TSX 60 Composite + 23.75 per cent MSCI EAFE (Mid/Large Cap) + 47.50 per cent MSCI USA All Cap

(i) The Total Fund return is measured against a Canadian dollar denominated composite benchmark produced by aggregating returns from each of the policy entity benchmarks, using the Fund's asset mix policy weight.

ANNUAL RATE OF RETURN AND BENCHMARK
(%)
For the year ended December 31,





NET ASSETS OF THE PLANS

OAC net assets at December 31, 2011 were $55,083 million which includes net investment assets of $55,702 million, net pension-related assets of $209 million less the amount due to administered funds of $828 million.

NET ASSETS

(millions)

As at December 31,	2011	2010
Net investment assets	$ 55,702	$ 53,965
Net pension related assets	209	193
Due to administered funds	(828)	(809)
Net Assets	$ 55,083	$ 53,349

Net assets increased by $1,734 million, or 3.3 per cent, compared with an increase of $5,517 million, or 11.5 per cent in 2010. The increase in 2011 was driven primarily by investment returns from private markets investments and the excess of contributions over benefits payments and pension administration expenses. These increases were partially offset by negative returns in OMERS Capital Markets. The returns from Canadian and global equity markets, which experienced strong growth in 2009 and 2010, did not continue the momentum and were mostly negative in 2011.

CHANGES IN NET ASSETS

(millions)

For the year ended December 31,	2011	2010
Net assets, beginning of year	$ 53,349	$ 47,832
Changes due to investment activities	1,363	5,384
Changes due to pension activities	371	133
Net Assets, end of year	$ 55,083	$ 53,349

INVESTMENT MANAGEMENT AND PENSION ADMINISTRATIVE EXPENSES

Administrative expenses are incurred for direct pension administration, direct investment management and corporate services. Direct pension administrative expenses are incurred to provide direct services to OMERS members and employers. Direct investment management expenses represent those of the Investment Entities managing OMERS investments. Corporate services expenses primarily include corporate information systems, accounting, legal and other governance expenses incurred to support either the pension administration or the investment management functions. These are allocated between pensions and investments based on an estimate of the use of resources.

Investment management expenses were $279 million in 2011 compared to $268 million in 2010 – an increase of 4.1 per cent. Investment management expenses, including external manager performance fees recorded in investment income, represent an investment management expense ratio of 58 basis points (51 basis points excluding performance fees) for the year ended December 31, 2011 compared to 64 basis points (55 basis points excluding performance fees) for 2010. Pension administrative and related corporate support expenses were $59 million for the year, compared with $54 million for the previous year – an increase of 9.3 per cent. The increase in administrative expenses is primarily due to the introduction of the Harmonized Sales Tax and the increased staffing and systems costs related to the management of an increasingly larger, more complex and sophisticated Plan.

DEBT

OAC has maintained an "AAA" credit rating from two leading credit rating agencies. This has enabled us, where appropriate, to obtain debt financing at preferred rates to support our investment strategy. Recourse debt includes $1,538 million of debentures and $1,788 million of commercial paper issued through OMERS Finance Trust. The debentures and commercial paper are guaranteed by OAC supported by OAC's "AAA" credit rating. Other OAC debt is secured by specific investments.

PLAN ASSET MIX

As discussed in the investment strategy section, one of our investment strategies is to maintain a long-term asset allocation weighted 53 per cent to public market investments and 47 per cent to private market investments. At the end of 2011, private market investments comprised 42.4 per cent of our asset mix compared with 38.3 per cent at the end of 2010. As illustrated in the table on page 28, the market value of our net investment assets with exposure to private equity, infrastructure and real estate grew to $23,591 million, an increase of $2,935 million, or 14.2 per cent, over 2010.

Given the inherent volatility and the related impact of the global equity markets on the value of our public market investments, our investment professionals constantly manage our asset mix exposure, monitoring our long-term targets in each asset class so that the Plan is positioned for future growth. In order to facilitate this management process, the OAC Board approves the allocation of the Plan net investment asset exposure between the public and private markets and within these two market classifications our investment professionals manage the asset mix allocation to the individual asset classes. The actual asset mix allocation is reported regularly to the Board. The actual asset mix as at December 31, 2011, compared to the long-term asset mix target, is as follows:

ASSET MIX – ACTUAL VS. TARGET

As at December 31,	Actual 2011	Actual 2010	Long-Term Public/Private Market Allocation
Public Markets			
Interest bearing[(i)]	**28.6%**	22.3%	
Real return bonds	**3.9%**	2.7%	
Canadian public equities	**6.8%**	15.1%	
Non-Canadian public equities	**18.3%**	21.6%	
	57.6%	61.7%	53.0%
Private Markets			
Private equity	**13.9%**	12.3%	
Infrastructure	**15.3%**	14.2%	
Real estate	**13.2%**	11.8%	
	42.4%	38.3%	47.0%

(i) Includes short-term deposits, bonds and debentures, mortgages and private debt.

Asset Class Allocation

In determining the Plans' asset mix exposure, the market value of cash and other investment-related assets and liabilities included in net investment assets per the Consolidated Financial Statements are allocated to the individual asset classes. In addition, derivative exposure and other items, including transactions and balances between Investment Entities, are allocated to arrive at the Plans' ultimate exposure by asset class. Net investment assets based on the holdings per the Consolidated Financial Statements and after all allocations are as follows:

ASSET MIX – EXPOSURE

(millions)

As at December 31,	2011			2010		
	Holdings	Exposure	Asset Mix (%)	Holdings[ii]	Exposure	Asset Mix[iii] (%)
Public Markets						
Interest bearing[i]	$ 17,988	$ 15,926	28.6%	$ 16,632	$ 12,041	22.3%
Real return bonds	1,743	2,199	3.9%	1,472	1,475	2.7%
Total interest bearing	19,731	18,125	32.5%	18,104	13,516	25.0%
Canadian public equities	2,177	3,787	6.8%	6,994	8,133	15.1%
Non-Canadian public equities	10,246	10,199	18.3%	9,025	11,660	21.6%
	32,154	32,111	57.6%	34,123	33,309	61.7%
Private Markets						
Private equity	7,753	7,764	13.9%	6,633	6,634	12.3%
Infrastructure	9,635	8,490	15.3%	9,593	7,681	14.2%
Real estate	14,516	7,337	13.2%	12,599	6,341	11.8%
	31,904	23,591	42.4%	28,825	20,656	38.3%
Investment related assets	707	-	-	645	-	-
Investment related liabilities	(9,063)	-	-	(9,628)	-	-
Net Investment Assets	$ 55,702	$ 55,702	100.0%	$ 53,965	$ 53,965	100.0%

(i) Includes short-term deposits, bonds and debentures, mortgages and private debt.
(ii) Holdings for 2010 adjusted consistent with OAC Consolidated Financial Statements' (Note 2) transition to Canadian Institute of Chartered Accountants (CICA) Handbook Section 4600.
(iii) 2010 asset mix adjusted in accordance with the current year presentation. Previously the cumulative realized and unrealized gains and losses from hedging private markets foreign currency denominated holdings were recorded in the private markets asset class. Effective 2011, private markets exposure is only impacted by the unrealized hedging gains/losses.

INTERNAL CONTROLS REVIEW

The OAC maintains systems of internal control that are designed to ensure the integrity and fairness of the data presented in the Consolidated Financial Statements and elsewhere in this Annual Report, that transactions are duly authorized and that assets are adequately safeguarded. Consistent with our commitment to strong corporate governance and accountability, we complete an annual internal review of internal controls over financial reporting and disclosure controls using the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). This review is conducted under the oversight of the Audit Committee on a basis consistent with the requirements for public companies in Canada while taking into account the unique characteristics of a pension plan. The operating effectiveness of key controls is tested by OAC Audit Services and our external auditors. We have reported to the Audit Committee that based on our 2011 review we found no material issues with our internal controls over financial reporting and disclosure controls.

ENTERPRISE RISK MANAGEMENT

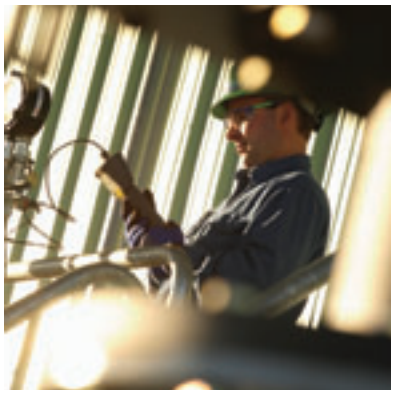
Our Enterprise Risk Management program (ERM) enhances our overall governance framework and is intended to identify and manage risk on an integrated basis; to apply consistent risk standards, concepts and policies across the organization; and to make the concept of risk assessment and management an integral and sustainable part of business operations. The ERM program is based on a modified Enterprise Risk Management-Integrated Framework issued by COSO.

The primary oversight responsibility for risk management rests with the Board. The 2011 ERM Risk Assessment Report was submitted to the Board in December 2011. The Board receives quarterly communications from Management on the status of the investment risk program.

OMERS PENSION PLANS







OMERS PRIMARY PENSION PLAN

The OMERS Primary Pension Plan is a multi-employer pension plan whose members consist primarily of employees of Ontario municipalities, local boards, public utilities and non teaching workers at the school boards. The Plan is a jointly sponsored defined benefit pension plan financed by equal contributions from participating employers and employees as well as by investment earnings of the Plan. The Plan has 419,007 members which is an increase of 2.3 per cent over 2010. The Plan also has 947 participating employers which is an increase of 16 employers over 2010.

During 2011, OMERS launched the Additional Voluntary Contributions (AVCs) component of the Plan. AVCs are a voluntary retirement savings arrangement available to the members of the Plan.

The Plan's defined benefit component pension payments are integrated with the Canada Pension Plan as the benefit formula includes a "bridge" benefit if the member retires before age 65. Including this bridge benefit, the benefits paid under the Plan are calculated by multiplying two per cent of the member's average annual earnings for the highest paid five consecutive years ("pensionable earnings") times years of credited service to a maximum of 35 years. At age 65, the bridge benefit of 0.675 per cent of the pensionable earnings (or 0.675 per cent of the average of the yearly maximum pensionable earnings (YMPE) in the year of retirement and the four preceding years, if this amount is less than 0.675 per cent of the pensionable earnings) is subtracted for integration with the Canada Pension Plan.
The Plan also provides members with:

- full inflation protection up to 6 per cent per year with any inflation amount above that carried forward to subsequent years;
- early retirement options;
- disability protection in the event a contributing member becomes disabled and is unable to work;
- survivor benefits to protect a member's family when a member dies; and
- portability to continue to be a Plan member with 947 employers across Ontario.

RETIREMENT COMPENSATION ARRANGEMENT

In addition to the Plan for all members, the RCA provides pension benefits for members whose pension benefits under the Plan are limited by ceilings imposed by the *Income Tax Act*. The RCA provides a means to enable retirement savings and contributions on members' total earnings. As the RCA is not a registered pension plan, a 50 per cent refundable tax is levied by the Canada Revenue Agency (CRA) on all contributions made to the RCA as well as on investment income received and realized investment gains. The refundable tax is held by the CRA and earns no investment income for the RCA. The refundable tax is refunded on the basis of one dollar for every two dollars of realized losses or benefits paid out. The RCA is consolidated in the OAC's financial statements and is accounted for separately from the Plan. OAC invests the RCA assets, excluding the refundable tax and a small cash balance, in public equities separate from the Plan. Net assets of the RCA were $68 million at December 31, 2011 and $59 million at December 31, 2010. The RCA financial statements are set out in Note 8 to the Consolidated Financial Statements on page 99 of this Annual Report.

OMERS SUPPLEMENTAL PENSION PLAN FOR POLICE, FIREFIGHTERS AND PARAMEDICS

The OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (the Supplemental Plan) became effective on July 1, 2008, pursuant to the requirements of the OMERS Act. The Supplemental Plan is a separately funded stand-alone multi-employer pension plan that provides supplemental pension benefits that "top up" those available under the Plan for members who are employed in the police and fire sectors which, as defined in the OMERS Act, includes paramedics.

The Supplemental Plan is a contributory defined benefit pension plan funded by equal contributions from participating employers and members and by the investment earnings of the Supplemental Plan assets. Participation in the Supplemental Plan is effective only upon agreement between employee groups and their employer. As at December 31, 2011, the Supplemental Plan had no assets (December 31, 2010 – no assets) and no members.

PLAN FUNDING STATUS

Each year an independent actuary determines the Plan's funded status by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. On December 31, 2011, the estimated accrued pension obligation for all members (including survivors) of the defined benefit component of the Plan was $64,548 million, compared with $60,035 million a year earlier. The increase of $4,513 million was primarily due to interest accrued on the pension benefit obligation plus new benefits accrued during the year, partially offset by benefits paid in 2011. The pension benefit obligation also increased by $560 million due to the net impact of actual economic and Plan demographic factors being less favourable than what was assumed for 2011. For the AVC component of the Plan, the accrued pension obligation is equal to the AVC net assets.

The Plan reports a surplus/deficit position both for accounting purposes and for the actuarial funding of the Plan. For accounting purposes, the surplus/deficit position is based on the fair value of assets compared to the accrued pension obligation. In arriving at the actuarial funding surplus/deficit, changes in the fair value of net assets above or below the long-term nominal actuarial rate of return assumption are deferred and amortized over five years to "smooth out" the peaks and valleys in an individual year's investment returns caused by market volatility. Smoothing is a common practice accepted by the actuarial profession and pension regulators to reduce the effect of short-term market fluctuations on pension plan funding. The annual actuarial smoothing adjustment is based on the difference between the current year's actual net return and the long-term return expectation (expected inflation of 2.25 per cent plus 4.25 per cent, equivalent to 6.50 per cent in 2011) which is deferred and recognized over five years, adjusted for the recognition of equivalent amounts from the four preceding years. This approach is in keeping with the long-term nature of the Plan and assists in maintaining stable contribution rates.

The market value of the Plan's defined benefit component net assets as at December 31, 2011 was $54,921 million compared with the smoothed actuarial value of $57,258 million. The resulting actuarial smoothing adjustment account represents unrecognized net losses of $2,337 million as at December 31, 2011 which will be recognized in the actuarial value of net assets over the next four years. After application of the required actuarial rate of return, which is essentially the interest on the unrecognized losses from prior years (as discussed in Note 7 of the Consolidated Financial Statements on page 95 of this Annual Report) and before recognizing any future year's investment income above or below the long-term actuarial rate of return, the impact of the unrecognized net losses on the Plan's surplus/deficit position by year of recognition will be as follows:

(millions)

For the year ending December 31,	Net gains/(losses)
2012	$ (2,530)
2013	$ 452
2014	$ 75
2015	$ (543)

Based on the fair market value of the Plan's net assets, the deficit as at December 31, 2011 was $9,627 million compared with a deficit of $6,745 million at December 31, 2010, an increase of $2,882 million.

The Plan defined benefit component had an actuarial value of net assets of $57,258 million at the end of 2011 compared with $55,568 million in the prior year. The resulting funding deficit was $7,290 million as at December 31, 2011 compared with a funding deficit of $4,467 million last year.

DEFICIT BASED ON FAIR VALUE VS. ACTUARIAL VALUE OF NET ASSETS

(millions) As at December 31,	2011	2010
Fair value of net assets of the Plan, excluding AVCs	$ 54,921	$ 53,290
Accrued pension benefit obligation	64,548	60,035
Plan deficit based on fair value of net assets	(9,627)	(6,745)
Actuarial value adjustment	2,337	2,278
Plan deficit based on actuarial value of net assets	$ (7,290)	$ (4,467)

CURRENT YEAR CHANGE IN FUNDING DEFICIT

(millions) For the year ended December 31,	2011	2010
OMERS Primary Pension Plan		
Deficit, beginning of year	$ (4,467)	$ (1,519)
Increase in net assets available for benefits, excluding AVCs	1,631	5,506
Change in actuarial smoothing adjustments	59	(2,672)
Increase in actuarial value of net assets available for benefits	1,690	2,834
Less: increase in accrued pension benefit obligation	(4,513)	(5,782)
Deficit, End of Year	$ (7,290)	$ (4,467)

The funded ratio (actuarial value of net assets divided by accrued pension benefit obligation) at December 31, 2011 is 88.7 per cent compared with 92.6 per cent a year earlier.

FUNDING OUTLOOK

Pension plan funding is made up of two components – the amount required to fund the cost of benefits earned by active members in respect of the current year, which is the normal actuarial cost, and the amount required to eliminate any funding deficits that have emerged.

The SC is responsible for Plan design changes and setting the Plan's contribution rates to ensure the adequacy of funding as well as determining when an actuarial valuation of the Plan should be filed, subject to the requirements under regulations. Under Ontario provincial regulations, a pension plan must file an actuarial valuation report at least once every three years and at that time must take measures to eliminate any going-concern and solvency deficits. The Plan's December 31, 2010 actuarial valuation was filed with the Ontario pension regulator in 2011 and the next required filing is the December 31, 2013 actuarial valuation, although the SC has the discretion to file earlier.

For current service, employer contributions equal member contributions under the Plan. During 2010, the SC approved temporary increases to the contribution rates to fund the actuarial deficit under the Plan; these increases averaged 1.0 per cent for 2011, 1.0 per cent for 2012 and 0.9 per cent for 2013 for both members and employers.

The resulting contribution rates for members with normal retirement age (NRA) 60 and 65 for 2011 and 2012 are shown in the table below with 2010 rates provided for comparison. The 2013 contribution rates will be set by the SC following receipt of recommendations from an independent actuarial firm with regard to the allocation principles.

	2012	2011	2010
NRA 65			
- Up to YMPE[(i)]	8.3%	7.4%	6.4%
- Above YMPE[(i)]	12.8%	10.7%	9.7%
NRA 60			
- Up to YMPE[(i)]	9.4%	8.9%	7.9%
- Above YMPE[(i)]	13.9%	14.1%	13.1%

(i) YMPE is the Yearly Maximum Pensionable Earnings as set by the Canada Revenue Agency. For the years above, YMPE was as follows: 2012: $50,100; 2011: $48,300; 2010: $47,200.

Although the Plan has a funding deficit of $7,290 million at the end of 2011 (2010: $4,467 million), the defined benefit component net cash inflow from contributions less benefit payments and pension administrative expenses for 2011, was $269 million (2010: $124 million) which is expected to increase in future years as a result of the temporary contribution rate increases discussed above. Further, with our expected investment returns, combined with post-2012 benefit changes, we expect the Plan will return to surplus within 10 to 15 years.

ACTUARIAL ASSUMPTIONS

In calculating the funded position and the ongoing normal actuarial cost to ultimately provide benefits for active members, the actuary makes various demographic and long-term economic assumptions. Demographic assumptions are used to project the future benefits payable to members and beneficiaries and include assumptions about mortality rates, termination rates and patterns of early retirement. Each of these assumptions is updated periodically, based on a detailed review of the experience of the Plan and on the expectations for future trends. Economic assumptions about future investment returns, i.e., the discount rate, assumptions about inflation and member salary increases affect both the projected benefits and the present value of those future benefits. The actuary's major economic assumptions included in the going-concern funding valuation and normal actuarial cost as at December 31, 2011, which were approved by the Board, are summarized as follows:

- **Inflation Rate**

  The Plan has used an inflation rate assumption of 2.25 per cent per annum for future years in the calculation of future indexing adjustments, as a component of the nominal discount rate for estimating liabilities and the anticipated salary increases, consistent with 2010. Any variation in the actual inflation rate from this assumption will result in experience gains (lower inflation than assumed) or losses (higher inflation than assumed) to the Plan.

- **Discount Rate**

  The Plan's annual nominal rate of return and discount rate for future years is assumed to be 6.50 per cent, the same as 2010. This is based on the 2.25 per cent assumed inflation and a real investment return assumption, based on the Plan's asset mix, of 4.25 per cent, consistent with 2010. A decrease/increase of 50 basis points in the real discount rate, with no change in other assumptions, would result in an approximate increase/decrease of $4,900 million in the total accrued pension obligation of the Plan.

  The real investment return assumption used in 2011 is unchanged from that used in 2010. It includes a conservative margin to account for potential adverse investment experience, so that over the long term there is a greater chance of actuarial gains than losses arising from the Plan's assets. This assumption includes an estimate of the returns expected to be earned over the long term on the Plan's assets, based on the current asset mix. In comparison to some other public sector plans, the Plan has a higher ratio of active members to retired members and our asset mix has a higher proportion of non-fixed income investments. This results in a relatively lower fixed income component in the asset mix and results in a relatively higher real discount rate.

- **Salary Increases**
  The estimated value of the actuarial liability includes an assumption about future increases in the salaries of active members. The salary increase assumption uses an age-based scale which allows for increases in productivity as well as merit and promotion-related earnings increases. For members with normal retirement age of 60, the assumption also includes service-related increases. The assumed average real salary increase (increase in excess of inflation) for the December 31, 2011 valuation is as follows:

	NRA 60		NRA 65	
	Up to 2014	After 2014	Up to 2014	After 2014
Average annual real salary	1.4%	1.9%	1.1%	1.6%

RETIREMENT COMPENSATION ARRANGEMENT

The RCA is funded using a modified pay-as-you-go approach, where inflows from contributions, investment income and the reimbursement of the refundable tax from CRA are used to pay the current benefits to members. The excess of current contributions and investment income over current benefit payments are accumulated for future years' benefit payments. As a consequence of this modified pay-as-you-go funding policy, the RCA's assets will remain small relative to its liability. A relatively small increase in the number of terminations and retirements at higher income levels can increase actual benefit payments from, and decrease actual contributions to, the RCA; however, our actuary estimates that if contributions to the RCA continue as projected, the annual cash inflow will be sufficient to cover benefit payments and the RCA's assets will continue to grow for the near term. Effective January 1, 2012, the funding of the RCA will be managed and monitored to ensure that the current RCA net assets together with future contributions and earnings will be sufficient to provide for the projected benefit payments over the 20-year period following each valuation date. The RCA accrued pension obligation is also sensitive to changes in assumptions and experience gains and losses.

Current Year Change in Deficit

The accrued pension obligation for the RCA increased from $468 million in 2010 to $504 million at the end of 2011. The change was due to new benefits earned in the year, interest on the accrued pension obligation, experience gains/losses and the monthly benefit and lump sum payments made in the year. The RCA had an estimated funding deficit of $436 million at December 31, 2011 compared with a deficit of $409 million at December 31, 2010 as shown below:

CHANGE IN RCA DEFICIT

(millions) For the year ended December 31,	2011	2010
Deficit, beginning of year	$ (409)	$ (438)
Increase in net assets	9	11
(Increase)/decrease in accrued pension obligation	(36)	18
Deficit, End of Year	$ (436)	$ (409)

PENSION BENEFITS AND CONTRIBUTIONS

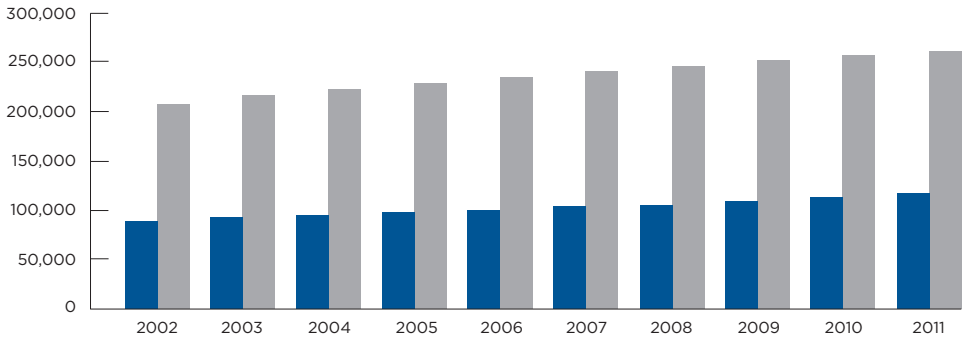
In 2011, the Plan ended the year with over 118,300 retired members and survivors receiving pension benefits. Benefits paid from the Plan's defined benefit component in 2011 were $2,375 million, an increase of $254 million over 2010. The increase reflected new retirements, the adjustment of benefits for inflation and higher pension values for new retirees compared with those already receiving benefits, as well as an increase in transfers to other registered plans and commuted value payments. Benefits paid from the RCA in 2011 were $7 million, an increase of $2 million from 2010.

Contributions to the Plan's defined benefit component in 2011 were $2,702 million compared with $2,299 million in 2010. The increase reflects an increase in the contribution rates, an increase in active members of 1.5 per cent and increased members' salaries. Contributions to the Plan's AVC component were $93 million in 2011, the first year of the AVC program. Contributions to the RCA in 2011 were $18 million, an increase of $4 million over 2010.

The chart below compares the growth in the number of pensioners versus active members over the past 10 years. The ratio of active members to pensioners was 2.22 at December 31, 2011 compared with 2.28 at December 31, 2010.

GROWTH IN NUMBER OF PENSIONERS AND ACTIVE MEMBERS

- Number of Pensioners
- Number of Active Members



OMERS PENSION SERVICES

Our mandate is to provide excellent service to our members and employers.

OMERS Pension Services is the primary communications link with our members and employers. Through a keen focus on customer satisfaction, we ensure rapid response times and excellent service to our members and employers. A flexible, expert pension team gives us the capacity to innovate and grow – to develop new pension services and features, to drive broader growth opportunities and to be on the forefront of pension reform.

Our growth and innovation initiatives support OMERS strategic objective to raise domestic capital. Ultimately this benefits all plan members, employers and retirees. A larger discretionary capital base affords large-scale investments that can generate stable long-term returns and supports the growing demands of changing demographics, an aging membership and the resulting pressure on liabilities.

Three strategies are at the core of our mandate as a professional service organization:

- enhancing internal capabilities;
- responding to external drivers; and
- supporting effective plan governance.

Enhancing Internal Capabilities

To meet the needs of our membership, we continue to build our internal capabilities – by enhancing our internal structure, systems and processes and by fostering a culture of leadership and collaboration. In 2011:

- OMERS Pension Services continued to make improvements to its organizational structure by launching a multi-functional operations group and by introducing a Quality and Resource Management department to focus on special projects to improve the efficiency and quality of our services to members and employers;
- we successfully re-engineered our pension service "buy-back" processes to provide individual OMERS members, who have employment service not originally covered by the OMERS pension, with information on the additional contributions required for them to buy back such service in the Plan. This has resulted in a significant reduction in turnaround times for these members and total funds coming into the Plan from buy-backs reached $36 million in 2011, consistent with 2010; and

- we began a three-year program to redevelop our internal technology systems to accommodate increased Plan complexity and to increase our flexibility.

Both our people and our systems will be positioned to support OMERS strategic initiatives, to address deficit management programs and to pursue pension reform over the next several years. We will foster leadership through core skills development and clear lines of accountability. Action plans will ensure we maintain strong employee engagement and a collaborative culture. To innovate and grow, we will build a business intelligence platform to identify customer segments and develop new service-focused systems architecture.

Responding to External Drivers

By responding quickly and strategically to the external drivers that affect our business, we can be instrumental in influencing the pension landscape in Ontario to better meet the needs of our members.

Our performance in 2011 against our demanding service standards and a growing number of transactions confirms that we are meeting the challenge of providing excellent pension services. In each month during 2011, we met or exceeded our targets for our key service standards by processing all key business activities within an average of three business days while addressing continued growth in client requests, and by answering 80 per cent of incoming calls to Client Services within 100 seconds in a year that saw OMERS Client Services handle 137,600 incoming calls compared to 121,300 in 2010.

Our membership is diverse and the need to deliver outstanding service continues to grow.

- As illustrated in Charts A and B on page 37, we now serve 947 employers and a total of 419,007 members – a 2.3 per cent increase over 2010. In addition, as a group our active member population is aging. As active members near retirement, they become more interested in the services provided by OMERS. Pension estimates and pre-retirement information sessions become more important to them. The number of active members 45 years of age and older has increased from 48 per cent of total active members in 2003 to 58 per cent in 2011. The fact that the membership is aging results in an increase in the normal cost (i.e. contributions required to fund the retirement benefit earned in the current year) for the Plan.

- Members of the OMERS Pension Plans belong to a wide variety of unions and associations. Chart C on page 37 shows a breakdown of our active membership by their affiliation as at December 31, 2011.

- As illustrated in Chart D on page 37, the number of individuals receiving an OMERS pension continues to grow. In 2011, we delivered retirement and disability pension payments totaling $2,047 million to our retirees and survivors, compared with $1,890 million in 2010 – keeping the pension promise. In addition, where individuals transferred to other registered pension plans, received death benefits or chose to leave the Plan and forego its guaranteed monthly pension benefit, payments of $336 million were made in 2011 (2010: $236 million).

- We received requests for approximately 81,400 retirement and termination estimates, representing a 20 per cent increase over last year. For the most part, these estimates were initiated and completed from beginning to end by OMERS members using the on-line estimate tool now available through OMERS secure member channel myOMERS, which is available on omers.com. In addition, we managed approximately 18,000 retirement, termination, disability, and pre-retirement death benefits queries, an increase of more than 10 per cent over 2010, approximately 80 per cent of which were initiated through the employer e-access channel or myOMERS.

- OMERS introduced a new web analytics tool with new tracking methodology. Using this industry standard analytics tool, OMERS had 771,000 visits to our website in 2011.

- Communication is a critical element of our service. In addition to the detailed information available on our website, we continued our practice of serving our members and building our relationship with employers through approximately 1,200 on-site visits in 2011, making presentations to members at information and pre-retirement sessions and providing technical support to employers.

- At year-end 2011, myOMERS had recorded approximately 57,000 total registrations since it went live in December 2009. Our members appreciate the fast and secure access to their pension information, the option to receive e-statements, as well as the on-line Retirement Income Estimator and Buy-back Calculator tools available through myOMERS.

- In 2011, e-access continued to be the preferred means of communicating with employers as 900 employers (or 95 per cent of employers covering 99 per cent of active members) are now registered for our e-access program. The most significant e-access application for both employers and OMERS Pension Services is the e-Form 119 application, through which employers report annual member data directly and securely to us online. More than 99 per cent of all annual pension statements were issued to members by June 30, 2011, which exceeded our target of 90 per cent in that time frame. We also handled 9,600 e-correspondence requests in 2011.

Not only do we serve many individual members on a timely basis, but the results of our annual independent survey to assess how we are doing at meeting the needs of members and employers (Chart E on page 37) reveals that we continue to do it well. The 2011 survey results showed an average satisfaction rate of 88 per cent for the overall level of service, which demonstrates continuing recognition of our high standards. 2011 is the eighth straight year that our satisfaction rate exceeded 85 per cent.

While maintaining outstanding service for our core activities, OMERS Pension Services continues to develop new services and options for Plan members and respond to pension reform opportunities during 2011.

- Over 5,100 OMERS members contributed to the Additional Voluntary Contributions program resulting in a total accumulation of funds (including investment earnings) of $94 million in its first year. The AVC component of the Plan provides members with a new optional retirement savings program that is similar in some respects to Registered Retirement Savings Plans (RRSPs). AVCs enable members to earn the net investment returns generated by OMERS diverse global portfolio on their personal retirement savings, in addition to the defined benefit provided by the Plan. Active members can voluntarily contribute additional funds and all members can transfer funds from their RRSPs, locked-in retirement account, registered pension plan or deferred profit sharing plan to the AVC program.

- To support the AVC program, the myOMERS portal was improved to give members additional opportunities to access the AVC program including on-line sign-up, maintenance and view features, and over 200,000 "outbound" phone calls were made to OMERS members to provide information on the new program.

- We readied ourselves to support our members through legislative changes effective January 1, 2012 related to the distribution of pension benefits in instances of marriage breakdown.

- OMERS continued to be an active participant in provincial and federal pension reform solutions and offered our knowledge and expertise to support government discussions related to improved retirement solutions for Canadians.

Supporting Effective Plan Governance

An effectively governed pension plan helps to ensure that we will grow, innovate and deliver on our pension promise to members. In 2011, Pension Services worked closely with members of the OMERS Administration Corporation Board to support the Board in the introduction of a new Member Services Committee.

Under the OMERS Act, the OMERS Sponsors Corporation is responsible for pension plan design and contribution rates. In 2011, Pension Services provided information and analysis to the SC and supported the implementation of SC decisions including:

- the introduction of a Statement of Plan Design Objectives and Strategy;

- a change requiring an annual review of the RCA to ensure that, on an ongoing basis, the RCA Fund is of sufficient size that it would not be expected to be fully depleted for at least 20 years; and

- the increase in contribution rates for members and employers effective the first full pay in 2012.

Going forward, we will continue to prepare our systems and documents to implement the 2013 contribution rates as determined by the SC, as well as the post-2012 benefit changes.

Most importantly, we will maintain our focus on OMERS core objective – providing pensions to current and retired employees in more than 940 municipalities, school boards, libraries, police and fire departments, and other local agencies across Ontario.

CHART A
MEMBER PROFILE

As at December 31, 2011

Active	263,059
Retired/Survivor	118,310
Inactive	24,299
Deferred	13,339
Total	**419,007**

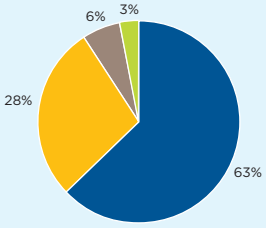


CHART B
ACTIVE MEMBERS BY AGE

As at December 31,

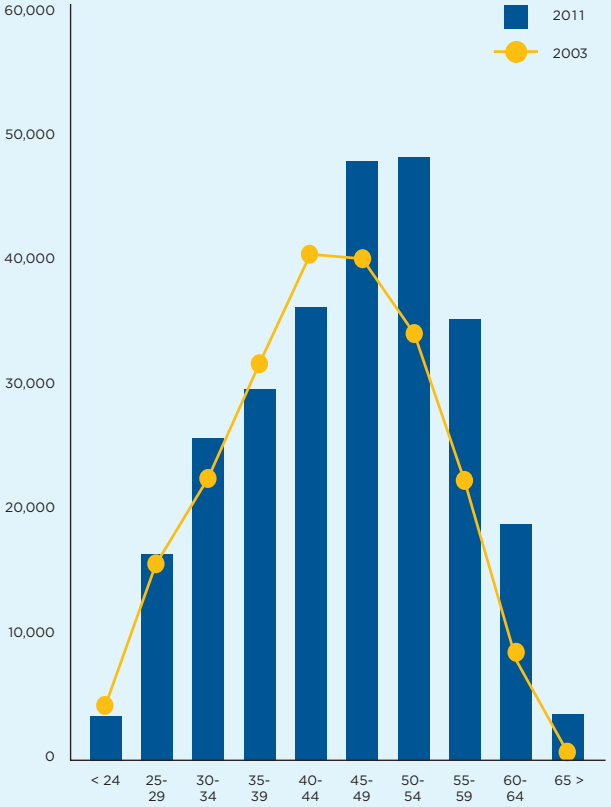


CHART C
ACTIVE MEMBER AFFILIATION

As at December 31, 2011

Canadian Union of Public Employees	45%
Management/non-union	21%
Police associations	10%
Ontario Professional Fire Fighters Association	4%
Ontario Secondary School Teachers' Federation	4%
Ontario Public Service Employees Union	4%
Other	12%

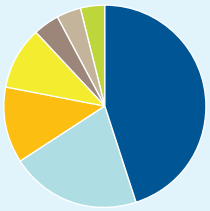


CHART D
NUMBER OF NEW PENSIONERS

For the year ended December 31,

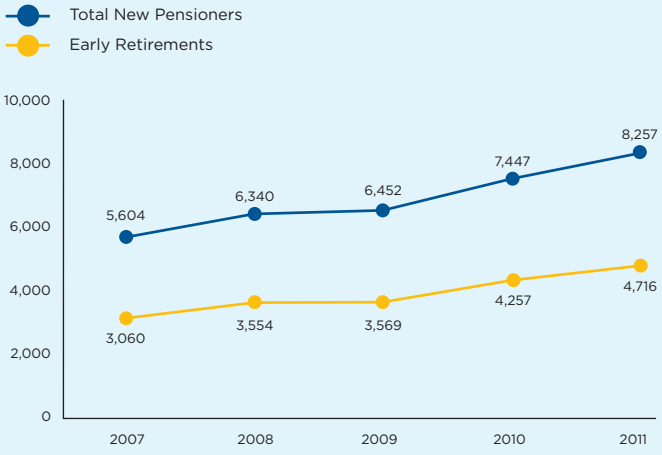
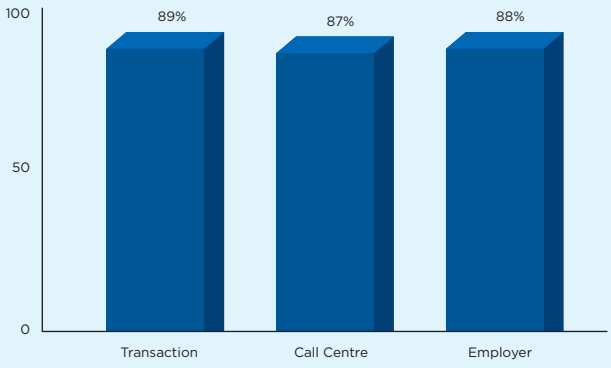


CHART E
SATISFACTION SURVEYS

For the year ended December 31, 2011

Percentage of respondents who rated OMERS 4 out of 5 or 5 out of 5 for service excellence



THE FUNDS





The Funds had net investment assets of $55,702 million at December 31, 2011. To meet the pension promise to over 419,000 members of the Plan, we must earn a 6.5 per cent annual return over the long term (or 4.25 per cent real rate of return when anticipated inflation is excluded). This expected return assumption is set by an independent actuary retained by the Board and is based on the asset mix policy set by the Board.

The long-term asset mix policy is to invest 53 per cent in public markets and 47 per cent in private markets. At the end of 2011, 57.6 per cent was invested with exposure to public markets and 42.4 per cent with exposure to private markets. Public market assets are predominantly publicly traded equities and interest bearing securities. Private market investments are private equity assets and income-producing infrastructure and real estate assets.

The investment target and asset mix policy are reviewed formally at least once a year by the Board with input on future liability changes, economic assumptions and investment expectations from actuarial, financial and economic specialists. The goal is to ensure that the value of invested assets, accumulated through investment income and net contributions from employers and plan members, matches or exceeds the present value of accrued pension obligations over multiple decades during which markets will go through many positive and negative cycles.

The Board has delegated responsibility for achieving the target return and achieving the Board-approved public/private market asset mix to Management. Management has developed a Board-approved rolling five-year enterprise-wide strategic plan that, among other things, is committed to creating surplus wealth for the Plan above the long-term investment target. The Board is updated on the progress of the initiatives of the strategic plan at each board meeting with a thorough and extended review conducted at an annual strategic planning session.

INVESTMENT STRATEGY

Two cornerstones of the investment strategy are to invest directly in the ownership of public and private market assets and to actively manage these ownership interests to mitigate risks and optimize long-term returns.

The Board believes that active asset management produces superior risk-adjusted returns compared with passive fund investing. This involves originating investments through proprietary research; purchasing assets at prices that should result in long-term value and strong predictable cash flows; developing relationships with like-minded business and investment partners for private market investments; structuring ownership interests in private assets in innovative and regulatory-compliant ways; financing these investments with non-recourse loans or utilizing our treasury competencies to finance investments with recourse loans backed by the OAC's "AAA" credit rating; and managing all investments to mitigate risk and maximize returns.

Mitigating risk and maximizing returns require Management to pay attention to diversifying investments by asset class, economic sector and geographic market. About 67.5 per cent of the OMERS investment exposure is currently in Canada. The value of listed market capital in Canada represents less than three per cent of global market capitalization. While Canada continues to offer exceptional long-term investment opportunities, prudence and related risk management practices make it necessary to diversify investments to global economies with different growth profiles. This is readily accomplished in the case of public market investments due to their liquidity and ease of trading in organized markets. In the past two years, we have increased our internal capabilities in global equity research and direct, active and worldwide trading.

The challenge of diversification is different and potentially more complex in the case of private investments. Relationships with investors, business owners and governments are critical to understanding markets and finding suitable investments. Typically, investments in private markets require a large single infusion of capital, are not easily traded and must be held for several years. Research confirms that size matters in earning superior risk-adjusted returns due to economies of scale, securing the necessary concentration of expertise at the operating level and achieving governance efficiencies.

Large-scale private market investments require as much as $500 million for private equity and $3 billion to $10 billion for commercial real estate portfolios and infrastructure assets. The Fund does not generally make investments of this size on its own for risk management reasons. Consequently, a strategic objective is to augment the Fund's capital with third-party capital. The OAC has built an expert team which now has a multi-decade history of leading or co-leading investor consortia. Our teams in each of the private market entities also possess the negotiating skills to complete due diligence and acquire influential equity positions in assets and companies on behalf of the Fund and its investment partners.

THE OMERS INVESTMENT ORGANIZATION

The OAC today has a deep investment management organization comprised of professional teams dedicated to managing defined asset classes and subclasses led by OMERS Chief Investment Officer (CIO). The CIO is responsible for the investment strategy and operational leadership of OMERS Investment Entities. OMERS Capital Markets manages all public market investments and Oxford Properties Group, OMERS Private Equity and Borealis Infrastructure manage private market investments. These organizations are discussed in greater detail on pages 40 to 54 of this Annual Report.

In addition, three corporate investment-related entities support the activities of the Investment Entities – OMERS Strategic Investments, OMERS Investment Management Inc. and OMERS Finance Trust.

OMERS Strategic Investments

OMERS Strategic Investments, founded in 2008, is leading certain corporate strategic initiatives and building a portfolio of strategic investment platforms. Its mandate is discussed on page 55 of this Annual Report.

OMERS Investment Management

OMERS Investment Management (OIM) was established in 2009 following legislative authority granted to the OAC to provide investment management services and products through an authorized subsidiary. Eligible clients include Canadian public and private sector pension plans, governments and their agencies, colleges, universities and their endowments, and Canadian registered charities. OMERS Investment Management offers investment arrangements that provide eligible clients with access to all or parts of the annual investment return of the OMERS Primary Plan.

OMERS Finance Trust

Established in 2010, OMERS Finance Trust is responsible for the management of all recourse debt of OAC and refinances existing public market debt as needed. In doing so, it follows prudent leverage practices and carries the OMERS brand in capital markets. Guaranteed debt securities currently issued by OAC are rated "AAA" by two credit rating agencies. All OAC guaranteed commercial paper is now issued through OMERS Finance Trust.

OMERS CAPITAL MARKETS





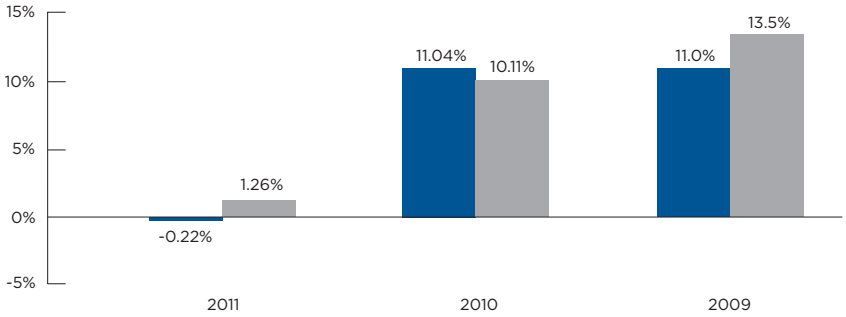
OMERS Capital Markets (OCM) manages OMERS public markets investment portfolio of bonds and other interest-bearing assets, publicly traded equities in Canadian and global financial markets as well as currency positions.

RETURNS AND BENCHMARKS

For the year ended December 31,

- Rate of Return
- Benchmark

-0.22%
The overall OMERS Capital Markets investments return in 2011 was -0.22%. The return is below the benchmark of 1.26%.



A summary of public market performance returns by portfolio is discussed below:

For the year ended December 31,	2011		2010	
	Rate of Return	Benchmark	Rate of Return	Benchmark
Interest bearing	**9.13%**	**9.22%**	6.72%	6.42%
Real return bonds	**17.84%**	**18.35%**	11.04%	11.09%
Canadian public equities	**-11.29%**	**-8.71%**	18.31%	17.60%
Non-Canadian public equities	**-4.96%**	**-4.23%**	9.90%	8.04%

The OMERS Capital Markets' return of negative 0.22 per cent is below the benchmark of 1.26 per cent largely driven by under performance in Canadian public equities. OMERS Capital Markets generated a net investment loss of $296 million in 2011 compared with net investment income of $3,036 million a year earlier. Asset allocation shifts were made in 2011 resulting in an underweight position against the benchmark in public equities and an overweight position against the benchmark for interest bearing investments and real return bonds.

At December 31, 2011 OMERS Capital Markets net investment assets were $30,357 million compared with $30,654 million at the end of 2010.

INTEREST BEARING INVESTMENTS

Interest bearing investments provide low-risk returns that offset the more volatile nature of publicly traded equities. As a result, they are a natural fit for a pension plan.

The interest bearing investments, excluding real return bonds, generated total investment income of $1,083 million compared to $733 million in 2010. Of this total in 2011, $25 million (2010: $nil) relates to debt held by Oxford Properties and $40 million (2010: $53 million) relates to mortgages managed by OMERS Capital Markets on behalf of OMERS Strategic Investments. The 2011 return of 9.13 per cent, calculated based on exposure to interest bearing investments, is below the benchmark of 9.22 per cent and is higher than the 2010 return of 6.72 per cent. The increase in income is primarily due to the overweight position in interest bearing investments and the decline in interest rates in 2011, which resulted in strong valuation gains in 2011 of $590 million compared with gains of $302 million in 2010. Real return bonds generated total investment income of $270 million compared with $167 million in 2010 due to declining real interest rates in 2011, which produced valuation gains in 2011 of $232 million compared with $121 million of valuation gains in 2010.

Including assets of other OAC Investment Entities, interest bearing investments include federal and provincial government bonds and corporate bonds of institutional investment grade, mortgages and private debt and cash and short-term cash equivalent securities. Interest bearing investments had a fair value of $19,731 million at December 31, 2011 including $17,988 million in cash and short-term deposits, nominal bonds, and mortgages and private debt (2010: $16,632 million) and $1,743 million in the real return bond portfolio (2010: $1,472 million).

Interest bearing investments are used as part of our interest bearing investment portfolio, as collateral received from securities lending activities and as assets backing our derivatives program. At December 31, 2011, our exposure to interest bearing investments (excluding real return bonds) totaled $15,926 million compared with $12,041 million as at December 31, 2010 as follows:

(millions) As at December 31,	2011	2010
Interest bearing investments holdings	$ 17,988	$ 16,632
Interest bearing investments backing equity derivatives	(2,774)	(3,075)
Cash collateral for securities lending and exposure from/(to) other programs	712	(1,516)
Interest bearing investments exposure	$ 15,926	$ 12,041

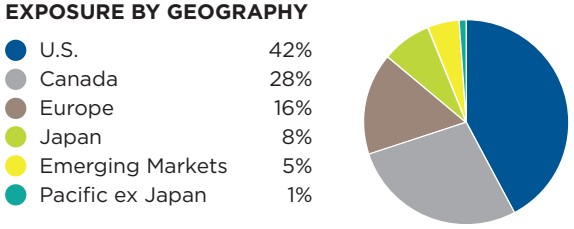
Our exposure to real return bonds was $2,199 million at December 31, 2011 compared to $1,475 million at the end of 2010 as follows:

(millions) As at December 31,	2011	2010
Real return bonds holdings	$ 1,743	$ 1,472
Real return bond exposure in other programs	456	3
Real return bonds exposure	$ 2,199	$ 1,475

PUBLIC EQUITIES

At December 31, 2011, the Plan had exposure of $3,787 million (2010: $8,133 million) to Canadian public equities and $10,199 million (2010: $11,660 million) to non-Canadian public equities including both actively managed and non-derivative, quantitatively managed portfolios across various industry sectors and geographies. Approximately 95 per cent of public equity holdings are in dividend paying stocks. Our total exposure to public equities by geography is illustrated in the following graph.

PUBLIC EQUITIES
EXPOSURE BY GEOGRAPHY



With respect to our exposure in Europe, we are well diversified and have minimal direct financial sector holdings in the European countries which have the greatest economic concerns (Portugal, Ireland, Italy, Greece and Spain). Also, in aggregate we are below the benchmark weight for Europe excluding U.K.

Canadian Equity Portfolio

The Canadian public equity holdings which are actively managed generated a total investment loss of $1,120 million in 2011 compared to a gain of $1,128 million in 2010. The 2011 return of negative 11.29 per cent, calculated based on exposure to Canadian equities, is below the benchmark of negative 8.71 per cent and the return of 18.31 per cent in 2010. In 2011, the Canadian equity portfolio returns were below the benchmark by 258 basis points in part due to the under performance of the active Core Fund. Going forward, investments in Canadian public equities will be managed through our quantitative investment program and global programs.

Our exposure to Canadian public equities is as follows:

(millions) As at December 31,	2011	2010
Canadian equity holdings	$ 2,177	$ 6,994
Non-equity assets backing equity derivatives	1,433	956
Canadian equity exposure from other programs	177	183
Canadian public equities exposure	$ 3,787	$ 8,133

The decline in investments in Canadian equities resulted from asset mix allocation shifts made during the year.

Non-Canadian Public Equity Portfolio

Non-Canadian public equities generated a total investment loss of $338 million compared to a gain of $1,175 million in 2010. The 2011 return of negative 4.96 per cent, calculated based on exposure to non-Canadian public equities, is below the benchmark of negative 4.23 per cent and the 2010 return of 9.90 per cent. Performance in non-Canadian equities was affected by several significant events in 2011, including the earthquake and tsunami in Japan, the ongoing European sovereign debt crisis, and the debt ceiling debates in the United States. These events contributed to the worst annual performance in global equity markets since the financial crisis of 2008.

Participating in global equity markets increases our portfolio diversification and lowers overall risk. As discussed below, active management of our non-Canadian public equity portfolio has been a focus of our strategy in the past few years, while at the same time, we continue to leverage the expertise offered by external managers in global markets. The non-Canadian equity portfolio also includes assets in absolute return and other similar hedge fund strategies.

Our exposure to non-Canadian equities is summarized below:

(millions) As at December 31,	2011	2010
Non-Canadian public equity holdings	$ 10,246	$ 9,025
Non-equity assets backing equity derivatives	1,292	2,122
Non-Canadian equity exposure from/(to) and other programs	(1,339)	513
Non-Canadian public equities exposure	$ 10,199	$ 11,660

The decline in exposure to non-Canadian public equities portfolio resulted from asset mix shifts made during the year to respond to the high level of volatility in global equity markets.

As discussed on page 21 of this Annual Report, our long-term investment strategy is to increase direct active management of our investments. Over the past three years OMERS Capital Markets has been building its team of investment professionals and its investment information systems to increase its capability to internally manage a larger portion of its non-Canadian equities. This gives us greater control over our non-Canadian investments and is expected to substantially reduce the costs of managing these investments. While we are continuing with this strategy, in 2011 tactical decisions were made to place funds with certain external managers. Since the program started three years ago, we have repatriated a net amount of $3.7 billion from external managers.

DERIVATIVE FINANCIAL INSTRUMENTS

In order to manage risk and enhance returns, we enter into a variety of widely used industry standard derivative contracts. These contracts are used in combination with other investment assets. The objective of their use is to provide a cost-efficient means to improve returns by mitigating uncompensated risks and to add flexibility in asset mix management. Notional values of various categories of derivatives held include:

(millions) As at December 31,	2011	2010
Interest rate contracts	$ 3,382	$ 1,524
Equity contracts	7,302	4,556
Commodity contracts	286	-
Foreign exchange forward contracts	19,038	13,887
	$ 30,008	$ 19,967

Interest Rate Derivatives

We use interest rate derivatives to enhance investment yields and to manage the duration of our interest bearing investments and our fixed versus floating interest rate exposure. Types of interest rate derivative contracts used include interest rate swaps, bond index swap contracts, bond futures contracts and bond options. At the end of 2011, interest rate derivatives with a notional value of $3,382 million were outstanding compared to a notional value of $1,524 million at December 31, 2010.

Equity Derivatives

We use equity derivative contracts to replicate Canadian and non-Canadian equity index returns. This exposure to the indices of major equity markets is achieved primarily through the use of equity index futures and equity index swap contracts and complements the Canadian equities portfolio and global equity portfolios managed both internally and externally. At December 31, 2011, we had public equity derivative exposure of $7,302 million (2010: $4,556 million), representing the notional value of derivatives as follows:

- $3,553 million in derivative portfolios that provide exposure to the S&P 500 index;
- $1,518 million in derivative portfolios that provide exposure to the S&P/TSX Composite, the S&P/TSX 60 index; and
- various derivative portfolios totaling $2,231 million that provide diversified exposure to major equity indices throughout the world.

Commodity Derivatives

We use commodity derivatives to enhance investment yields.

Foreign Exchange Derivatives

We use foreign exchange forward contracts to manage our exposure to currencies other than the Canadian dollar and to generate returns through active trading. At December 31, 2011, $18,702 million (2010: $19,546 million) or 34 per cent (2010: 36 per cent) of our net investment assets were exposed to foreign exchange risk before hedging. We hedge approximately 50 per cent of our exposure to public investments denominated in 12 major currencies, narrowing their volatility relative to the Canadian dollar. In addition, for non-Canadian private market investments we hedge foreign currency exposure up to 100 per cent.

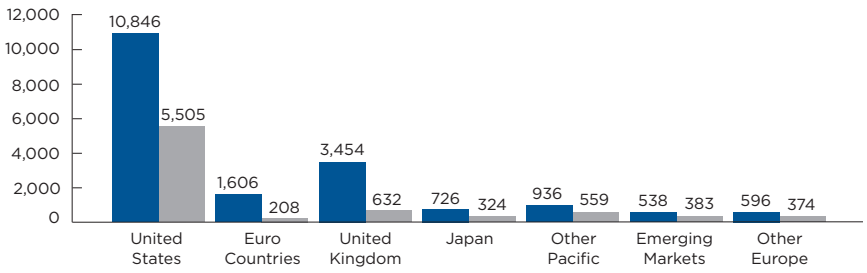
Since our currency hedging program was implemented, it has produced a net gain of $1,811 million offsetting the currency losses experienced on our foreign currency assets. This is largely a result of the appreciation of the Canadian dollar against most major currencies over this period.

Our net foreign currency exposure after accounting for our foreign currency management and trading programs at December 31, 2011 was $7,985 million (2010: $7,974 million). Our gross and net foreign currency exposure is allocated as shown in the chart below:

GROSS AND NET FOREIGN CURRENCY EXPOSURE

As at December 31, 2011
(millions of CDN Dollars equivalent)

- Gross Foreign Currency Exposure
- Net Foreign Currency Exposure



Credit Risk

The credit risk exposure for derivatives is the unpaid amount receivable from counterparties. We follow prudent risk management policies, limiting our derivative credit risk exposure to less than five per cent of total fund net investment assets. We require that all counterparties have a minimum "A" credit rating. At December 31, 2011, the credit risk exposure was 0.6 per cent of net investment assets or $343 million.

Top 10 Stock Holdings

OMERS Capital Markets' top 10 stock holdings include:

- Pargesa Holding SA
- Royal Bank of Canada
- Toronto-Dominion Bank
- Total SA
- Bank of Nova Scotia
- Exxon Mobil Corp.
- Microsoft Corp.
- Apple Computer Inc.
- Suncor Energy Inc.
- Goldcorp Inc.

OMERS PRIVATE EQUITY





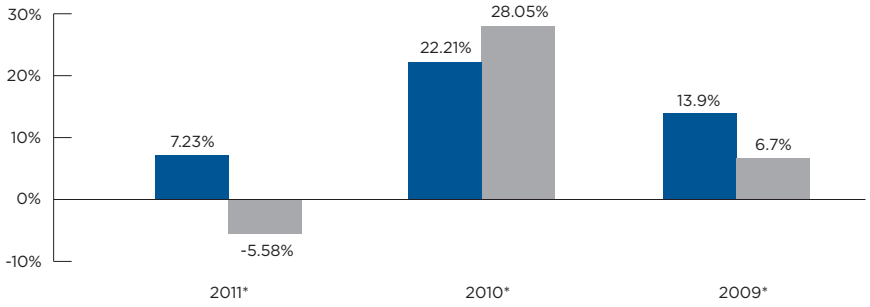
OMERS Private Equity (OPE) manages private equity investments through direct investments in private companies and through third-party funds.

RETURNS AND BENCHMARKS

For the year ended December 31,

- Rate of Return
- Benchmark

7.23%
OMERS Private Equity return in 2011 was 7.23% compared to the one-year benchmark of -5.58%.

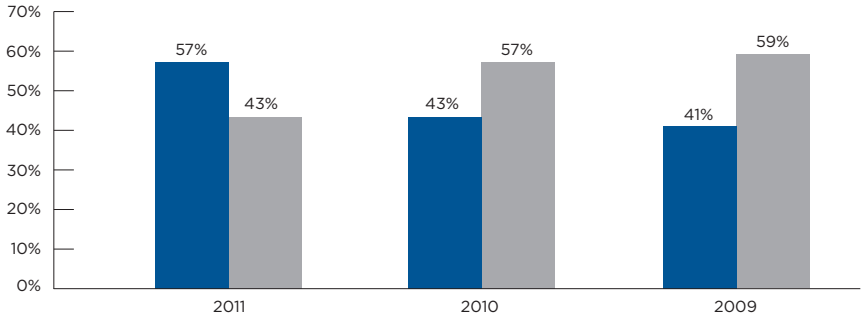


* Benchmark based on absolute return in 2009 and relative returns in 2010 and 2011.

OMERS Private Equity's investment strategy focuses on acquiring the majority control of a company with an enterprise value between $200 million to $1.5 billion. We will consider other ownership structures, including joint control and/or having significant influence with trusted like-minded partners as long as we have the governance rights commensurate with our investment. Our investment approach is premised on a long-term, active partnership with talented management teams. Our investment mandate is flexible to capitalize on the prevailing market conditions and financial markets and to invest in a broad range of industries in various geographical markets. We firmly believe in direct financial alignment of interest amongst ourselves, the management team of our investments and our investment partners. Our strategic shift toward direct investing that began in 2008 is on track to achieve our target of having over 80 per cent of our assets invested in direct investments by 2015. The chart below illustrates the consistent progress made by OMERS Private Equity's shift toward directly held and actively managed portfolio over the last three years.

DIRECT VS. FUND INVESTMENTS

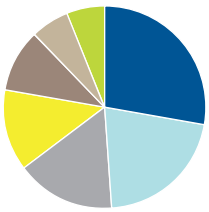
- Direct Investments
- Fund Investments



Our geographical focus is currently Canada, the United States and Europe, with a particular emphasis on the United Kingdom. Our direct investments can take a variety of forms, including private market transactions, secondary transactions from private equity funds and corporate carve-outs. The objective remains to have a well diversified investment portfolio, both by industry and by geography.

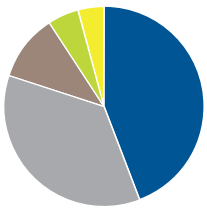
TOTAL ASSETS BY SECTOR

Industrials	28%
Consumer Discretionary	21%
Health Care	16%
Information Technology	13%
Financials	10%
Consumer Staples	6%
Other	6%



TOTAL ASSETS BY GEOGRAPHY

U.S.	44%
Canada	36%
U.K.	11%
Europe	5%
Other	4%



In evaluating investment opportunities, the key criteria that we consider are the current market position and the market outlook for the company's products and services; the quality and depth of the company's management team and their willingness to invest along with us; an assessment of the company's strategy for growth and our expected return based on the purchase price to acquire the business. Our role is to work closely with the management team and bring the necessary resources to bear so that the business can achieve sustainable, profitable growth.

When measured against our benchmark, OMERS Private Equity had generated a return of 7.23 per cent versus a benchmark return of negative 5.58 per cent. The negative benchmark reflects the turmoil experienced by the global public equity markets which had negative returns this year. The valuation of our investments is generally based on the operating performance of the individual companies and the returns of comparable publicly traded entities. As such, public equity market returns impact OPE investment valuations. The rate of return this year is much lower than the 22.21 per cent reported last year which was impacted by the continued recovery in the global equity markets following the financial crisis that occurred in 2008. Over the three-year period ending December 31, 2011, OMERS Private Equity generated a return of 14.30 per cent versus its benchmark of 8.86 per cent, with net investment income of $354 million in 2011, compared to $941 million in 2010. The strong financial performance from a number of our direct portfolio investments contributed to the positive performance against the benchmark this year.

During 2011, OMERS Private Equity's net investment assets increased to $6,333 million from $5,568 million in 2010, reflecting both an increase in the market value of existing investments and net new investments made in 2011. A record $1.6 billion of capital was deployed in 2011. Of this, $1.3 billion was deployed in direct investments in five new platform investments and one follow-on investment; the balance was spent on capital calls from various fund commitments. The five direct investments in the year include the acquisition of:

(i) a 44 per cent ownership interest in Ontario-based Husky International Ltd., a global supplier of highly engineered systems solutions and related aftermarket services and components for the plastics injection molding equipment industry and the leading supplier to the PET (PolyEthylene Terephthalate) Preform packaging industry;

(ii) Accelerated Rehabilitation Centers, which is a leading provider of traditional and specialty outpatient physical rehabilitation services in the U.S. midwest;

(iii) Great Expressions Dental, which is a leading dental practice management company, with 152 affiliated dental offices in seven states across the midwest, south and northeast U.S.;

(iv) V.Group Limited, a global market leader in outsourced ship management and a leading player in crew provision and related marine services; and

(v) the January 4, 2011 closing of the acquisition of the CBI Health Group that had been agreed to in the latter part of 2010.

The follow-on investment was the acquisition of Consolidated Utility Services in the U.S. by United States Infrastructure Corporation to further consolidate the company's position in certain markets.

OMERS Private Equity also had a record amount $1.2 billion of capital returned through realizations. The majority of this came through realizations from the private equity funds in the first half of the year when credit conditions were much more buoyant.

A continuation of the public equity market volatility experienced in 2011 would present a risk to the 2012 earnings performance of both the direct and fund portfolios. OPE will continue our "direct drive" active management strategy. We will work with the management of our direct investments in achieving their strategic and financial goals.

OMERS Private Equity's significant direct investments, other than the ones noted above, include:

- **Affinia Group Inc.** – a leading manufacturer and distributor of aftermarket components for cars, trucks and off-highway vehicles. Affinia's broad range of brake, filtration and chassis products are sold in North and South America, Europe and Asia;
- **Cengage Learning** – delivers highly customized learning solutions for colleges, universities, instructors, students, libraries, government agencies, corporations and professionals around the world;
- **Constellation Software Inc.** – an international provider of market leading software and services to the public and private sectors. Constellation acquires, manages and builds vertical market software businesses that provide custom mission-critical software;
- **Give and Go Prepared Foods Corp.** – a Toronto-based wholesale bakery producing Two-Bite Brownies™, Cinnamon Crunchies™, Butter Tarts and Two-Bite Coffee™ Cakes. Give and Go products are sold throughout Canada and in the U.S.;
- **Golf Town** – Canada's leading retailer of golf merchandise from leading manufacturers together with teaching academies, golf simulators and pro shop services. Golf Town also provides logo services on apparel and equipment for corporate tournaments and events;
- **Haymarket Financial LLP** – an independent finance company providing focused lending products to corporate clients and investment management services to institutional clients;
- **Marketwire** – a leading provider of newswire services, with one of the largest distribution platforms in North America. Based in Toronto, Marketwire has partnerships worldwide to distribute news and has offices in the U.S. and the U.K.;
- **Maxxam Analytics** – the largest privately owned analytical laboratory in Canada, providing analytical testing services to government and major companies in the environment, food, oil and gas, health, forensics and genetic markets;
- **Logibec** – a market leader in North America specializing in information systems for the health and social services sector;
- **Nelson Education** – Canada's leading education publisher from kindergarten to university and college levels. Nelson offers customized educational solutions for core disciplines such as mathematics, science and language arts;
- **Nordco** – a leading designer and manufacturer of products and services for the maintenance of railroad infrastructure, serving North American railroads, public transit systems, contractors and equipment leasing companies; and
- **Public Mobile** – a new entrant within Canada's wireless voice and data services market serving customers in Ontario and Quebec.

BOREALIS INFRASTRUCTURE







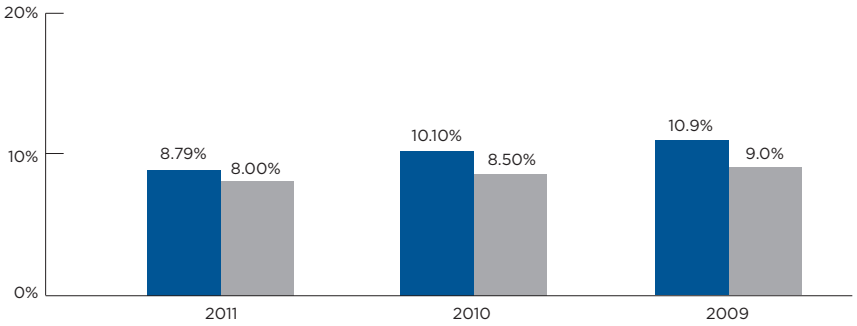
Borealis Infrastructure (Borealis) manages infrastructure investments for the OAC and ranks as one of the world's largest infrastructure investors. Borealis has a proven track record in identifying, investing and managing infrastructure investments around the world, consistently outperforming its benchmark for the last seven years.

RETURNS AND BENCHMARKS

For the year ended December 31,

- Rate of Return
- Benchmark

8.79%
The overall Borealis Infrastructure return in 2011 was 8.79% compared with a benchmark of 8.00%.



Infrastructure investing generally involves direct investments in inflation-sensitive assets that are crucial to the long-term success of a modern industrial economy. Some infrastructure investments are subject to regulatory establishment of rates, service delivery levels or both. Individual investments generally require large up-front or near term capital commitments and typically generate strong inflation-linked cash returns – a perfect fit in meeting our long-term pension obligations.

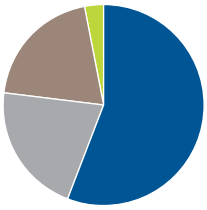
Borealis employs a direct-drive active management strategy in originating and managing infrastructure assets that exhibit strong underlying, inelastic demand with predictable, stable cash flows supported by regulation or long-term contracts with low-risk counterparties. We actively manage our investments through majority or significant minority positions and bring to investee companies the experience gained through managing a large infrastructure asset portfolio as well as the relationships developed with governments, lenders, other investors and members of the business community. Borealis also plays an active role in ensuring that each of its investments has the right management team in place with meaningful incentives that promote alignment with shareholders. In instances where we do not hold a majority interest in an investment, we partner with like-minded investors with aligned interests such as other pension, corporate and government investors as well as strong operating partners that can bring operational expertise to the investment, both in evaluating its potential and in managing and improving its performance.

Our investments are located in Canada, the United Kingdom and the United States. Given the breadth of opportunities and low political and regulatory risk that exists in its current markets, Borealis expects that infrastructure assets located in North America and Western Europe will remain the focus of its efforts for the near term; however, we continue to look opportunistically at infrastructure assets in other jurisdictions or geographies which exhibit stable and strong political and regulatory environments.

Borealis' investments can be grouped into four primary sectors and two main geographic regions as illustrated below.

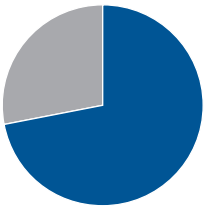
TOTAL ASSETS BY SECTOR

Energy	56%
Transportation	21%
Government Regulated Services	20%
Institutional & Other	3%



TOTAL ASSETS BY GEOGRAPHY

North America	72%
U.K.	28%



The energy sector includes investments in regulated utilities, power generation and oil pipelines. We adhere to a patient and disciplined investment approach and continue to prudently diversify our portfolio by industry sector, geography, size and stage of development while pursuing higher probability, lower execution risk opportunities.

Borealis' investments generated net investment income of $674 million in 2011, compared with $693 million a year earlier. The 2011 gross rate of return before investment management expenses was 8.79 per cent, compared with 8.00 per cent for the benchmark and 10.10 per cent in 2010. In addition, Borealis' investments generated a cash yield of 5.6 per cent (7.4 per cent based on operating assets) in 2011 compared to 5.4 per cent (7.1 per cent based on operating assets) in 2010. The strong, stable returns and consistent cash flow generated by Borealis' investments over the past three years illustrates that OAC's allocation of a significant portion of its investment portfolio to infrastructure investments continues to be a successful strategic initiative.

During 2011, Borealis' net investments increased to $8,997 million from $8,184 million in 2010. While it did not make any significant new acquisitions during 2011, the increase over 2010 is attributable to increases in the market value of its existing investments as well as follow-on capital injections in existing investments. Also, during the year, two significant debt refinancing arrangements were completed for Teranet and Associated British Ports. The Associated British Ports' refinancing was accomplished despite the challenging debt market conditions in Europe. Both transactions illustrate the high quality of these investment assets.

In 2012, we expect refurbishment of Bruce Power's Units 1 and 2 to be complete. This project required a significant investment of development capital over the past few years without generating a corresponding operating return. Once refurbishment is completed, Bruce Power will be the world's largest nuclear facility, generating approximately 25 per cent of Ontario's electricity needs. Bruce Power is in a much different situation than the Fukushima Daiichi nuclear facility in Japan that was impacted by the earthquake and tsunami in 2011 (i.e. geologic location, type of reactors, etc.), however, as with all nuclear operators around the world, Bruce Power believes that the events in Japan require a critical assessment of its own related systems. Bruce Power has already implemented a number of measures to enhance their response capability and has received approval for other minor design changes from the Canadian Nuclear Safety Commission. These additional measures and safeguards will further enhance Bruce Power's already robust disaster plans, consistent with their objective of operating to the highest nuclear standards.

Other significant investments made in prior years include interests in:

- **Ciel Satellite** – a wholesale communications satellite that offers telecommunication broadband capacity to the North American market;
- **Confederation Bridge** – a 12.9 kilometre bridge that links Prince Edward Island and New Brunswick and operates under a concession agreement with the Government of Canada until 2032;
- **Detroit River Tunnel** – a railway tunnel that operates as one of the largest trade corridors in the world;
- **Enwave Energy Corporation** – a company that owns the largest deep lake water cooling service in the world and provides environmentally friendly heating and air conditioning to Toronto's downtown office core;
- **Express Pipeline** – a 2,800 kilometre pipeline that transports crude oil from Alberta to the United States and serves refineries in six western and mid-western states;
- **HS1 Limited** – a company that operates, manages and maintains the United Kingdom's only high-speed rail line connecting St. Pancras International Station in central London to the Channel Tunnel;
- **LifeLabs** – Canada's largest provider of laboratory services that provides more than 50 million diagnostic tests to more than 10 million patients through nearly 20,000 physicians each year;
- **Oncor** – a leading electricity transmission and distribution company in Texas; and
- **Scotia Gas Networks** – a company that operates the Scotland and South of England gas distribution networks, comprising approximately 73,000 kilometres of gas lines serving approximately 5.6 million customers.

OXFORD PROPERTIES GROUP





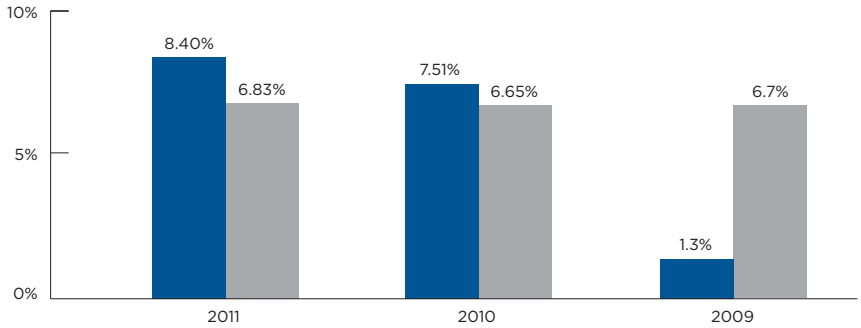
Oxford Properties Group (Oxford) is one of North America's largest commercial real estate investment, development and management organizations. Oxford oversees and manages approximately $19 billion (2010: approximately $17 billion) of real estate for itself and on behalf of its co-owners and investment partners as at December 31, 2011.

RETURNS AND BENCHMARKS

For the year ended December 31,

- Rate of Return
- Benchmark

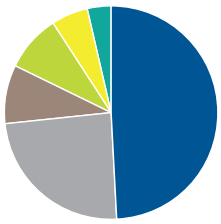
8.40%
The overall real estate return in 2011 was 8.40% compared with a benchmark of 6.83%.



Oxford's focus is to build a global platform for real estate investment, providing superior risk-adjusted returns and secure, sustainable and growing cash flows for the Plan. Oxford's strategy focuses on the ownership, development and active management of significant assets, diversified by property type, geographic market, partner relationship and risk-reward profile. A diversified real estate portfolio of this nature generates predictable cash flows, facilitating our ability to meet both current and future pension benefit obligations. Furthermore, actively managed real estate generally appreciates in capital value over time which helps to offset the inflation exposure of our pension liabilities.

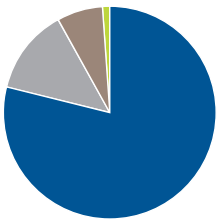
TOTAL ASSETS BY SECTOR

Office	49%
Retail	24%
Hotel	9%
Residential	9%
Industrial	6%
Other	3%



TOTAL ASSETS BY GEOGRAPHY

Canada	79%
Europe	13%
U.S.	7%
Other	1%



At December 31, 2011, Oxford's direct real estate portfolio consisted of 118 properties located primarily in Canada, the U.S., the U.K. and Germany, with a total leasable area of 46.3 million square feet, 3,511 hotel rooms and 21,111 residential units.

Oxford's office portfolio, with the exception of three assets located in the U.K., is diversified geographically in Canada across six major markets: Toronto, Vancouver, Calgary, Edmonton, Ottawa and Montreal. The largest concentration is in the Greater Toronto Area representing approximately 44 per cent of the market value of the office portfolio. The most significant office properties are:

- TD Canada Trust Tower, the Richmond-Adelaide Complex and a 50 per cent interest in Royal Bank Plaza in Toronto;
- Centennial Place and a 50 per cent interest in Bow Valley Square in Calgary;
- Watermark Place and a 50 per cent interest in MidCity Place in London, U.K.; and
- Green Park Business Park in Reading, U.K.

The retail portfolio is comprised of 14 properties, primarily super regional and regional shopping centres, totaling 14.2 million square feet. The properties are located across Canada and the United States but are predominantly located in the Greater Toronto Area. The more significant properties include:

- a 50 per cent ownership interest in Yorkdale Shopping Centre, Square One Shopping Centre, Scarborough Town Centre and Hillcrest Mall in the Greater Toronto Area;
- Upper Canada Mall in Newmarket, Ontario;
- Southcentre Mall in Calgary; and
- various regional shopping centres in the U.S.

The hotel portfolio includes major Canadian landmark resort properties located in Banff, Lake Louise and Jasper, Alberta; Whistler, British Columbia; Montebello, Quebec and two urban centre hotels in Vancouver, British Columbia and Toronto, Ontario.

Oxford's multi-family residential portfolio consists of 23 properties located in Ontario, Quebec, Nova Scotia, the southern U.S. and Germany. The industrial use assets include 22 properties in the Greater Toronto Area, Calgary and Edmonton markets.

In addition, Oxford's real estate portfolio includes properties held for/under development which form the basis of its active development program which currently includes the development of three office towers in Toronto and Vancouver, an office tower in London, U.K. and industrial properties in Edmonton and Calgary. Oxford is also continuing the co-development of Hudson Yards, a mixed use office, retail and residential project in Manhattan, New York, U.S.

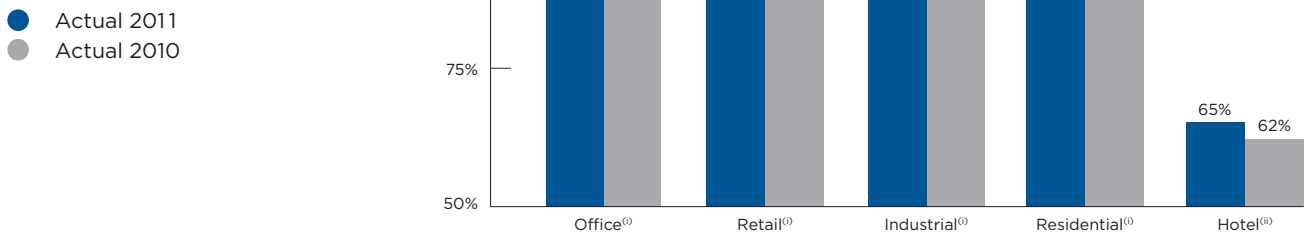
Oxford is actively pursuing a global investment strategy in targeted international markets to diversify its portfolio and enhance returns. In 2011, in addition to continuing its U.K. and U.S. development projects, Oxford acquired Green Park Business Park, an office complex in Reading, U.K. and a 50 per cent interest in MidCity Place, a landmark office building in Midtown, London, U.K. Oxford's long-term strategic plans are for continuing sector and geographic diversification.

Oxford's current European exposure is limited to its investments in London office assets and residential properties in Germany. The London office investments represent 10 per cent of Oxford's total gross asset value and the German residential properties represent less than 3 per cent of Oxford's total gross asset value.

Oxford's net investment income increased from $487 million in 2010 to $610 million ($585 million excluding income from mortgage investments) in 2011. Net investment income is primarily comprised of net operating income and unrealized gains and losses resulting from changes in the market value of the real estate assets and liabilities, and other realized gains and losses.

Excluding the impact of transaction costs and income from mortgage investments, Oxford's net operating income increased by $49 million in 2011 primarily due to the net impact of acquisitions and the completion of development projects, as well as higher occupancy throughout the portfolio as shown in the table below.

OCCUPANCY
(%)



(i) As at December 31
(ii) Based on average occupancy for the year

Net gains in 2011 were $177 million ($167 million excluding gains relating to mortgage investments), compared with $70 million in 2010. The 2011 net gain is mainly due to an unrealized gain in the value of investments of $211 million (2010: gain of $157 million) partially offset by a mark-to-market loss of $52 million on debt obligations (2010: loss of $79 million). Unrealized valuation gains in investments were primarily in the Canadian office and retail portfolios.

In late 2010, Oxford began executing on its strategy to invest in U.S. debt instruments that yield a strong risk-adjusted return and are secured by high quality real estate assets, which are consistent with its property ownership strategy. This debt investments portfolio contributed $25 million of net investment income in 2011 which consisted of net operating income of $15 million and $10 million of net gains.

The overall Oxford Properties return increased to 8.40 per cent in 2011 compared to a benchmark return of 6.83 per cent and a 7.51 per cent return in 2010.

Oxford's total owned real estate assets were valued at $14,679 million (including mortgage investments of $163 million) as at December 31, 2011 compared to $12,782 million (including mortgage investments of $183 million) as at December 31, 2010, representing an increase of $1,897 million. The increase is mainly due to the market value appreciation of the real estate portfolio and net investment activity during the year. In addition to the new investments in the U.K. noted earlier, other major acquisitions during 2011 included:

- Metro Toronto Convention Centre Complex in Toronto;
- a 50 per cent interest in Hillcrest Mall in the Greater Toronto Area;
- Golden Gate Apartments in Toronto;
- an additional 47.5 per cent interest in the Williams Multi-family residential portfolio in the U.S.; and
- 2600 North Park Drive, an industrial property in the Greater Toronto Area and development lands in Burnaby, Vancouver.

Oxford also holds and manages a portfolio of indirect investments that were valued at $445 million as at December 31, 2011, an increase of $27 million from $418 million at December 31, 2010, primarily due to additional investments made during the year.

Oxford's real estate portfolio is partially funded by $6,160 million in mortgages, debentures and commercial paper as at December 31, 2011 compared to $5,319 million as at December 31, 2010. The net increase in debt of $841 million in 2011 is primarily due to new borrowings related to acquisitions made in the year.

OMERS STRATEGIC INVESTMENTS





OMERS Strategic Investments (OSI) has a broad mandate to lead certain corporate strategic initiatives and to build strategic investment platforms that do not logically fit under the mandates of OMERS existing Investment Entities, which will position OMERS as a leading global pension-based investment enterprise.

OSI has the following overarching objectives:

- to build long-term strategic relationships and co-investment alliances to enable OMERS to raise capital for OMERS Investment Entities;
- to build and manage a portfolio of strategic investment platforms that provide OAC with footholds in key markets around the world which may ultimately be transferred to the Investment Entities, established as standalone platforms, or be sold to third party investors; and
- to establish OMERS global footprint through a network of offices and to communicate the depth and breadth of expertise behind the OMERS Worldwide brand to strategically important investors and operating businesses around the world.

A key part of OSI's mandate is to build long-term strategic relationships with like-minded global institutional investors and form strategic alliances that will enable OAC to leverage its capital alongside new sources of co-investment capital. In executing this mandate OSI is in the process of forming a Global Strategic Investment Alliance (GSIA) with institutional investors in Europe, the United States, Asia and the Middle East. Such an alliance will enhance OMERS ability to secure preferred large-scale private market investments while leveraging OMERS investment management expertise. Relationships have been initiated with many organizations, some of whom are in the advanced stages of forming our initial GSIA.

OSI is actively building a portfolio of specialized strategic investment platforms that will expand our capacity to generate attractive investment opportunities and build global business relationships for the benefit of all the Investment Entities. An overview of OSI's investment platforms and key investments is as follows:

- The first platform is based on the resource/commodities sector which is a major driver of Canada's long-term economic prosperity. OSI investments in this area include:
  - **OMERS Energy/OMERS Energy Services** – is a Calgary-based oil and natural gas acquisition, exploration, development and production company with oil and gas wells throughout western Canada; and
  - **CEDA International** – is a leading industrial, mechanical and electrical services company which is well established in the Alberta Oil Sands.

- The second platform is in entities that help leverage proprietary expertise and knowledge in engineering, innovation and technology to provide OMERS with additional access to investments and expertise. OSI's investments in this space include:

  - **MMM Group** – is a Canadian-based international engineering company that provides engineering, project management, environmental and advisory services in Canada and abroad in more than 40 countries on five continents. MMM Group is recognized as an industry leader in the provision of quality, cost-effective and technically excellent multidisciplinary solutions for a diverse range of assignments; and

  - **OMERS Ventures** – invests in technology, media, telecommunications, clean tech and life sciences sectors in Canada throughout the lifecycle of a company, starting with small investments in the early stages and then, based on success, followed with larger amounts to drive a company's growth, when substantial value can be harvested.

- The emerging/growth markets platform has been established to enter emerging/growth economies where OAC has not invested directly in the past, primarily in Latin America, South America and Asia, in a cost-effective manner. OSI's investment in this space includes:

  - **ADC & HAS Airports** – OSI has formed a partnership with HAS Development Corporation, an affiliate of the Houston Airport System, and Airport Development Corporation focused on the operation and, where required, the development of airports in growing and important markets around the world. This partnership brings together the operational, technical and financial expertise of the Houston Airport System, the Airport Development Corporation and OSI. Through this partnership we are able to invest and conduct operations in countries where OAC does not have an investment presence at a reasonable cost, opening the door to future investments by OSI and the other Investment Entities in such countries.

OSI is establishing OAC's global footprint through promoting and leveraging the intellectual capital of the entire enterprise under the OMERS Worldwide brand and ensuring that OAC has a presence in and knowledge of global markets through business relationships and a network of OMERS Worldwide offices. In 2011, OSI opened a new OMERS Worldwide office in New York after opening offices in London, England and Calgary in previous years.

In 2011, OSI generated net investment income of $121 million for a gross investment return of 7.24 per cent compared with the benchmark of 6.90 per cent and net investment income of $128 million in 2010. The lower income in 2011 is in part due to the transfer of the portion of OMERS mortgage portfolio previously held by OSI to OCM.

OSI's net investment assets decreased from $2,143 million at December 31, 2010 to $1,644 million at December 31, 2011. The decrease primarily reflects the transfer of the portion of OMERS mortgage portfolio previously held by OSI to OCM.

RISK MANAGEMENT

We are committed to providing secure pensions to our members by investing in a broad range of assets in a manner that strives to earn superior returns without taking undue risk and is consistent with our risk tolerance. OMERS seeks to ensure that the value of the net assets of the Funds is sufficient to pay all pensions promised to members of the OMERS Pension Plans.

For a given contribution rate, our ability to meet this objective is affected by two factors:

- fluctuations in the value of the investment portfolio, which are driven by changes in investment markets (primarily market, credit and liquidity risk); and
- changes in the value of the Plan's accrued pension obligation, which are driven by both economic and demographic factors.

Risk management is an essential part of our corporate and investment strategy as it can mitigate the negative impact of the above factors on the investment portfolio and the accrued pension obligation. Risk management is supported by our system of internal controls, programs such as enterprise risk management and investment risk management and our corporate policies including our Code of Conduct and Statement of Investment Policies and Procedures. We continually strive to improve our enterprise-wide approach which involves our Board, Management and employees within all areas of OAC and our Investment Entities. All employees are required to adhere to policies, procedures and standards that a prudent person would reasonably exercise when managing the assets of others.

The economic value of the Plan's accrued pension obligation is sensitive to movements in Canadian interest rates and inflation rates similar to changes in the value of a portfolio consisting of real return bonds and long-term Canada bonds; however, the Plan invests in a combination of equities, infrastructure, real estate and a broad range of interest bearing instruments in various currencies. While this investment strategy diversifies the investment portfolio and assists in maintaining stable and cost-effective contribution rates, it produces a mismatch between the economic characteristics of the accrued pension obligation and the investment assets. This exposes the Plan to various risks that must be closely monitored and managed.

RISKS AFFECTING THE OMERS PENSION PLANS

The Enterprise Risk Management program has identified four categories of risk that could potentially have an adverse effect on the OMERS Pension Plans:

- investment risks (market, credit and liquidity risk) that are an inherent part of investing in capital markets;
- an array of operational risks that we face as an operating business;
- strategic risks inherent in the execution of our long-term plan including funding risk; and
- legal and compliance risks that we deal with in the management and administration of the OMERS Pension Plans under the laws of Canada as well as laws and regulations of the various countries where we invest.

INVESTMENT RISK

The future values of OMERS investment assets and liabilities are not known with certainty and change over time. Investment risk (i.e. market, credit and liquidity risk) reflects the possibility that the value of the Funds' investments will deviate from the actuarially assumed long-term rate of return as a result of changes in market conditions, whether those changes are caused by factors specific to the individual investment or factors affecting all investments traded in the market.

The fund will incur investment risk in order to meet the Plans' benefit obligations at a reasonable cost. The goal of investment risk management is not to eliminate risk but to find a balance between expected returns and the risks needed to generate those returns. Further, it is generally accepted that expected investment returns (positive or negative) increase with the amount of risk taken. The higher the risk involved in an investment, the higher the expected return (or potential loss) from that investment. Investment risk is neither good nor bad – a certain amount is needed to generate the investment returns required to maintain stable and cost-effective contribution rates. Through various policies, delegations and the long-term strategic asset mix, the OAC Board defines the amount of investment risk to be taken by the Funds. OAC utilizes analytical and reporting tools including enterprise-wide and Investment Entity specific policies; asset/liability studies and actuarial valuations; risk measurement and reporting; and due diligence and internal direct drive asset management processes to manage investment risk at the enterprise and Investment Entity (public market and non-public market) levels.

OAC ensures that OMERS Pension Plans' investments are well diversified across assets, industry sectors and geographic regions in order to have different segments of the investment portfolio exposed to different investment risks. This reduces the overall volatility of returns and insulates the investment portfolio from the negative impact of adverse returns in any one asset class, industry or region.

The OAC Board receives an annual comprehensive Enterprise Risk Management (ERM) report which includes a risk assessment of all Investment Entities and all functional areas within OAC. In 2011 the consolidated reporting of the investment risks and exposures facing the Fund was enhanced through the development of forward looking liquidity risk models used to assess the impact of tactical and strategic initiatives on Fund liquidity.

Market, credit and liquidity risks are discussed in our Consolidated Financial Statements starting on page 86 of this Annual Report.

OPERATIONAL RISK

Operational risk is the risk of loss arising either directly or indirectly from operational error due to failure in processes, systems, technology, actions of personnel or due to unforeseen external events. Our framework of policies and procedures is designed to identify and manage operational risks through the implementation of controls over data integrity, information processing, and management of information technology. Further, our human resources practices are designed to mitigate people risk including the risk of loss of key personnel. These controls are independently reviewed through internal audits and the annual review of our internal controls over financial reporting and disclosure controls discussed on page 28 of this Annual Report. As OMERS implements its direct drive strategy and repatriates assets from external fund managers, continuing to manage people risk remains a focused priority for the Board and Management.

STRATEGIC RISK

Strategic risk is the risk of not achieving our long-term strategic goals and objectives. The Board and the CEO manage the achievement of our strategic goals by overseeing our policies and the planning and achievement of our long-term goals. The CEO is accountable to the Board for decisions relating to the day-to-day management of the OMERS Pension Plans and the Funds including funding policy, investment strategies, and investments pursued, investment management styles and operating results. To manage this risk, we have established a governance framework, a business strategy development process and performance measures. In addition, the OAC conducts a formal asset/liability study at least every three years. This study identifies the optimum asset mix based on the identified asset classes and their corresponding market volatility and the required liquidity of the Plan. The next asset liability study will be undertaken in 2012.

The OMERS Pension Plans' funding is a significant strategic risk as discussed in funding risk below.

Funding Risk

Inappropriate policies or decisions related to asset allocation or actuarial methodologies and valuation processes can impact funding of the OMERS Pension Plans. Our ability to pay pensions is not only subject to investment risks but is also subject to the risks associated with the assumptions used in the valuation of the Plan's accrued pension obligation. The major assumptions that go into the valuation of the accrued pension obligation include long-term economic conditions (i.e., inflation, the real return on investments and the rate of member future salary increases) and membership demographics (i.e., mortality, disability, termination and early retirement rates and marital status). The risk arises in two ways: (i) actual market conditions and member demographics differ significantly from the assumptions used in the valuation of the accrued pension obligation; and (ii) unforeseen changes in other major assumptions.

To manage these risks, the Board appoints an independent actuary to value the accrued pension obligation annually based on economic and demographic assumptions recommended by the independent actuary, reviewed by Management and approved by the Board. The validity of all assumptions is monitored each year against actual experience and the assumptions may be adjusted as appropriate.

Legal and Compliance Risk

Legal and compliance risks arise from changes in or non-compliance with legal and/or regulatory requirements and/or other ethical standards which can undermine the OAC's ability to achieve its objectives. The Board and Management, with the assistance of the Legal Division (including the Compliance Office) and independent expert advisors, monitor situations affecting regulatory compliance that could result in regulatory action. We have established processes to keep abreast of applicable regulatory developments and to advocate for changes where they are in the best interest of Plan members.

Through our governance framework and established policies and procedures, including our Code of Conduct and Personal and Insider Trading Policy for directors and employees, we strive to ensure that values and behavioral expectations are well understood and integrated throughout the organization so as to minimize these risks.

CRITICAL ACCOUNTING POLICIES

As of January 1, 2011, financial statements of pension plans such as OAC must be in compliance with the requirements of the Canadian Institute of Chartered Accountants (CICA) Handbook Section 4600 – Pension Plans ("CICA Section 4600"). The recognition, measurement and disclosure contained in the 2011 year end Consolidated Financial Statements are in compliance with the requirements of CICA Section 4600.

CICA Section 4600 requires that in selecting or changing accounting policies that do not relate to its investment portfolio or pension obligations, a pension plan shall comply on a consistent basis with either International Financial Reporting Standards (IFRS) in Part I of the Handbook or accounting standards for private enterprises in Part II of the Handbook, to the extent that those standards do not conflict with the requirements of Section 4600. OAC has chosen to comply on a consistent basis with the International Financial Reporting Standards.

The adoption of CICA Section 4600 had no impact on OAC's net assets available for benefits, the accrued pension obligations and deficits or total investment income as reported in prior years' financial statements. Consistent with CICA Section 4600, investment assets are presented on a non-consolidated basis even when the investment is in an entity over which OAC has effective control. Earnings of such entities are recognized as interest is earned, dividends are declared or as real estate rental revenue is earned. OAC total investment income includes valuation adjustments required to adjust the carrying of investments to their fair value.

An explanation of how the transition to Section 4600 and IFRS has affected OAC's financial statements disclosure is set out in Note 2 to the Consolidated Financial Statements on page 76 of this Annual Report.

Consistent with CICA Section 4600 and International Financial Reporting Standards, certain of our accounting policies require subjective or complex judgments and estimates relating to matters that are inherently uncertain. The use of different judgments and estimates could result in materially different amounts being recorded under different conditions or by using different assumptions. As a result, actual results could materially differ from our estimates and assumptions applied in the Consolidated Financial Statements. Significant estimates included in the Consolidated Financial Statements relate to the valuation of private market investments and the valuation of our accrued pension obligation.

Our policy is to record all investments at fair value; however, the assessment of fair value involves considering many factors for each type of investment held by the Funds. Fair value is based on quoted market prices, where available, and excludes transaction costs which are expensed as incurred. For private market investments where quoted market prices are not available, fair value is generally based on internal or external valuations using generally accepted valuation methods. The fair value of private market investments acquired within the current fiscal year may be held at cost, where cost is considered the best estimate of fair value based upon events since acquisition. For private equity funds, the fair value is generally based on the valuation provided by the fund's general partner subject to information available to OAC's investment management. As a result, fair values for private market investments are based on estimates which are inherently uncertain. Our policy is to obtain independent support of valuations for significant investments through review by accredited independent appraisers at least once every three years, or whenever the valuation changes by more than 15 per cent from the prior year for private market direct investments and through annual audited financial statements for fund investments.

Actuarial assumptions used in determining the accrued pension obligation reflect Management's estimates of future economic factors such as the Plans' nominal rate of return and discount rate, rate of pensionable earnings increase and inflation, and non-economic factors such as mortality, withdrawal and retirement rates of Plan and RCA members. This process is supported by our independent actuary. The Plan and RCA's actual experience could differ from these estimates. Differences are recognized as experience gains or losses in future years.

A summary of our significant accounting policies is presented in Note 2 to the Consolidated Financial Statements starting on page 76 of this Annual Report.

COMPENSATION DISCUSSION AND ANALYSIS

REPORT OF THE LEADERSHIP RESOURCES AND COMPENSATION COMMITTEE

The Leadership Resources and Compensation Committee of the Board (LRCC) is responsible for OMERS executive compensation across the enterprise.

LEADERSHIP RESOURCES AND COMPENSATION COMMITTEE MANDATE

The purpose of the LRCC is to assist the Board in meeting its fiduciary oversight and related obligations by: (i) attracting, engaging and retaining excellent leadership at the senior executive level who are committed to the Enterprise Leadership Principles, Mission Statement and Core Values; (ii) overseeing a robust succession management process for the position of the OAC President & Chief Executive Officer (CEO); and (iii) overseeing senior executive performance, compensation and compensation policies.

The LRCC's key responsibilities include:

- oversight of an annual performance appraisal process for the CEO;
- making recommendations to the Board for compensation arrangements for the CEO;
- succession management process for the CEO;
- recommending to the Board the recruitment of and the proposed compensation for the Enterprise Senior Leadership Team;
- approving the compensation strategy, policy structure and framework for short-term and long-term compensation plans for the Enterprise Senior Leadership Team;
- reviewing human resources management policies, compensation and benefits plans to ensure appropriate strategic linkages and risk mitigation; and
- reviewing and providing guidance with respect to significant organizational structure changes to ensure alignment with enterprise-wide strategic plans.

The LRCC regularly reviews and recommends amendments to its mandate to the Governance Committee.

KEY ACTIVITIES FOR FISCAL 2011

In 2011, the LRCC engaged in all of the above key responsibilities including reviewing new compensation plans for OMERS Capital Markets, Oxford Properties and OMERS Strategic Investments (OMERS Ventures) businesses. The Committee also reviewed a new comprehensive succession management process designed to ensure OMERS is well positioned with the right talent for the future.

EXTERNAL ADVISORS

To assist in executing its responsibilities, the LRCC engages an external advisor, Global Governance Advisors (GGA), to provide independent advice. During 2011, GGA's scope of services included the following: (i) provided independent executive compensation advice pertaining to the Enterprise Senior Leadership Team (i.e. compensation philosophy, performance management, comparator groups, competitive pay positioning and pay mix); (ii) ensured the Committee understood and were comfortable with the current compensation program for the Enterprise Senior Leadership Team; (iii) assisted and counselled the Committee on any recommendations made by Management; (iv) conducted board education sessions that provided the Board with an overview of emerging trends and best practices; (v) assisted in any succession planning initiatives; and (vi) assisted with any other items that the LRCC requested.

The LRCC has sole authority to approve the amount of the external advisor's fees. For its services provided to the Board in 2011, GGA received $138,500. GGA did not provide any non-Board approved services to the organization during 2011.

COMMITTEE COMPOSITION

The LRCC is comprised of at least five members of the OAC Board and meets a minimum of four times annually. Members of the LRCC are appointed by the Board from amongst the Board's members and are independent of Management. It conducts in camera sessions at the end of every meeting, without Management present.

Members of the LRCC for 2011 were:

Chair: Rick Miller

Vice Chair: Sheila Vandenberk

Members: Bill Aziz
David Carrington
Michael Power *(until September 23, 2011)*
Frederick Biro *(after September 23, 2011)*
John Sabo *(ex-officio)*

LEADERSHIP RESOURCES AND COMPENSATION COMMITTEE MESSAGE FROM THE CHAIR

OMERS is committed to maintaining full transparency with our stakeholders on all facets of our executive compensation program. As part of this commitment, our goal is to provide information that is clear, relevant and appropriate. The Compensation Discussion and Analysis section highlights OMERS 2011 performance, reviews our executive compensation program in detail and describes the compensation awards for the Named Executive Officers. The Named Executive Officers include the OAC Chief Executive Officer (CEO), OAC Chief Financial Officer (CFO) and the three highest paid members of the Enterprise Senior Leadership Team.

Talent Management

The potential growth of OMERS over the next five years will require significant talent development. It is critical that the approach to compensation is integrated with the talent strategy to continue to attract highly qualified and capable people in all jurisdictions. It will be equally important to enhance our people development capability in continuing to grow our own talent at all levels leading to senior management roles across OMERS as part of our succession management strategy.

Approach to Compensation

We are committed to providing performance-based incentives to continue to attract, engage and retain high performing people. Our compensation program strongly links executive pay to actual performance achieved and aligns employee interests with that of Plan members. Our compensation plans are designed to motivate executives to achieve OMERS strategic objectives prudently, while ensuring an appropriate balance between risk and reward.

2011 Performance and Compensation

When determining compensation, the committee considers a number of quantitative and qualitative performance measures that were selected due to their alignment with OMERS five-year strategic plan. This year, investment performance results were below our expectations given the realities of the financial markets. Substantial progress was realized, however, in executing the five-year enterprise-wide strategic plan, which included achievements in moving toward a more balanced weighting between public market and private market assets and significant advancement in securing additional capital to invest for the benefit of OMERS members. Additionally, important and substantial advancement was made in how OMERS supports members directly from our Pension Operations group including the launch of the Additional Voluntary Contribution (AVC) program to allow members to save even more for retirement while sharing in the OMERS investment returns. The committee believes that the compensation awarded to the Named Executive Officers appropriately reflects overall performance during the year.

Risk Management and Compensation

Effective risk management is an important component of OMERS culture and business strategy. We believe that our compensation programs encourage prudent and appropriate risk taking by: (i) providing a mix of short-term and long-term compensation, which encourages executives to take a balanced view; (ii) providing at-risk compensation which can result in payouts as low as zero if minimum levels of performance are not met; and (iii) capping the amount that can be earned in any incentive plan, even in the case of extraordinary performance. We are continuously working to improve how we factor risk management into compensation decisions to incent management to achieve our desired investment results with due regard for effective risk management.

Preparing for 2012

Effective 2011, executive perquisites were discontinued across the enterprise, replaced by a perquisite cash allowance which will be reviewed regularly by the LRCC. Salary increases were not granted to employees in executive positions. Given the current market conditions an enterprise-wide salary increase budget of 2.1 per cent was approved for 2012.

Conclusion

We are confident that our approach to compensation, which includes strong governance practices, achieves the appropriate balance between effectively paying for performance and ensuring compensation programs do not incent excessive risk taking, and also attracts and retains talented leadership. The LRCC remains committed to being a leader in compensation governance among pension funds and will continue to provide clear and transparent disclosure to our Plan members and stakeholders.



Rick Miller
2011 Chair, Leadership Resources and Compensation Committee

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis describes the compensation philosophy, policies and programs and discusses the compensation provided in 2011 to the CEO, CFO and the three other most highly compensated members of the Enterprise Senior Leadership Team.

APPROACH TO COMPENSATION

OMERS is committed to a pay-for-performance approach to compensation for all employees, including the senior leaders. This philosophy supports the execution of the five-year enterprise-wide strategic plan and the commitment to ensure the sustainability of the Plan's funding by delivering realistic risk-adjusted returns over the long term.

As a result, the total compensation programs are designed to attract, engage and retain high performing people and ensure they are motivated to pursue OMERS overall investment goal of earning sustainable returns that meet or exceed the Plan's long-term requirements. OMERS recognizes that this must be done with an acceptable level of risk and the LRCC is responsible for ensuring our compensation policies and practices do not encourage undue risk taking. As a result, OMERS has a clear set of incentives that are aligned with the long-term investment strategy and investment risk limits, measured against pre-established Board approved benchmarks, and are communicated to and understood by Management and employees.

COMPENSATION PRINCIPLES

The objective of the compensation strategy is to attract, engage and retain high performing people to focus on the long-term viability of the Pension Plan and delivery of the pension promise. To achieve this objective, the executive compensation program is based on the following principles:

1. **Align with the interests of Plan members** – Align employee interest with the interests of the Plan members through effective policy and plan design.

2. **Align with OMERS strategy** – Focus employee efforts on critical investment/performance targets and reward for superior performance in achieving results.

3. **Pay for Performance** – Promote a pay-for-performance culture and reward employees for superior performance on results and adjust compensation when performance falls below targets.

4. **Effective Risk Management** – Ensure compensation plan design does not create an incentive for excessive risk taking and review each compensation plan regularly to ensure that it is operating as intended.

5. **Pay Competitively** – Reward employees in a manner consistent with competitive market practice to improve the organization's ability to attract, engage and retain high quality professionals. Base salary and target level performance for short-term and long-term incentive plans are benchmarked to the median in the marketplace and superior level performance for short-term and long-term incentive plans are benchmarked to the 75th percentile in the marketplace.

6. **Good Corporate Governance** – Strive to be a leader on governance issues and continually review and incorporate appropriate compensation practices that align with evolving best practices. The pay philosophy is approved annually by the LRCC and is an integral component of the compensation strategy.

COMPARATOR GROUPS USED TO SET COMPETITIVE PAY

OMERS has identified different comparator groups for its various lines of business in setting competitive compensation to closely reflect the competitive market for our workplace. The comparator groups are reviewed on a regular basis and approved by the LRCC. Typical considerations include other organizations that compete for similar talent, industry specific organizations and organizations with similar financial measures. Within these comparator groups, OMERS reviews compensation levels of comparable positions and assesses relative performance and size of the comparator institutions.

ELEMENTS OF THE EXECUTIVE COMPENSATION PLAN

Executive compensation for 2011 consists of six main elements: base salary, short-term incentives, long-term incentives, benefits, perquisite cash allowances and pensions. These elements provide a total compensation package designed to attract highly qualified individuals, provide strong incentive to align efforts with OMERS objectives and motivate to deliver performance that creates sustainable results for OMERS members.

Salary

The compensation philosophy aims to pay competitive base salaries as defined by the comparator group. Salaries are reviewed annually at the beginning of each year and any increases are generally granted when an executive assumes greater responsibilities, deepens knowledge and expertise, or when there is a significant change in the compensation levels of comparable roles in the comparator group. The LRCC considers and approves base salaries of the Enterprise Senior Leadership Team, while the OAC Board approves the CEO's base salary based on the LRCC's recommendations.

In order to reward executives for performing in the interests of Plan members, their compensation is split into two parts. Annual performance is rewarded immediately through the short-term incentive plan and to ensure that performance is sustained, a long-term incentive plan is in place.

Short-term Incentive Plan

The Short-term Incentive Plan (STIP) is designed to attract, engage and retain high-performing executives by providing competitive, performance-based compensation targets. The STIP has been designed to align compensation with key performance and strategic objectives and individual performance. The LRCC reviews short-term incentive targets for the Enterprise Senior Leadership Team each year as well as upon hire, promotion or when there are significant changes in responsibilities.

At the beginning of each year, the LRCC approves the key areas of focus, performance measures, weightings and targets against which performance will be evaluated. The corporate performance component is based on a scorecard comprised of: (i) investment performance; (ii) pension services performance; and (iii) objectives aligned with OMERS five-year enterprise-wide strategic plan. There is also an individual component that assesses and rewards leadership behaviours demonstrated by the executives in the achievement of their key performance objectives and how well they have met their overall job performance expectations.

STIP awards are determined as follows for the CEO and corporate senior executives:

STIP AWARD	Salary	x	Short-term Incentive Target (%)	x	[	Investment Performance	+	Pension Services Performance	+	Strategic Plan Objectives	+	Individual Objectives]

Investment entity leaders have a similar STIP based on performance of their specific business.

Long-term Incentive Plan

Long-term Incentives are designed to: (i) encourage and reward executives for the achievement of superior and sustained investment performance; and (ii) align the interests of executives with those of Plan members.

The Long-term Incentive Plan (LTIP) rewards overall investment return performance results, with emphasis on consistent value-added performance over the three-year period. The awards vest and mature on the third anniversary of the award date.

LTIP awards are determined as follows for the CEO and corporate senior executives:

LTIP AWARD	Salary	x	Long-term Incentive Target (%)	x	[	Investment Performance Total Public Markets • Value Add	+	Total Private Markets • Value Add • Absolute Return	]	x	OMERS Total Fund Absolute Return Multiplier	

Investment entity leaders have a similar LTIP based on performance of their specific business. The CEO is also eligible for an award under the long-term performance plan (LTPP) which is based on value-add generated from growth of assets under management.

BENEFIT, PERQUISITE AND PENSION PROGRAMS

All employees participate in benefits that include vacation, life and disability insurance, health and dental benefits, our employee assistance program and pension plan. In 2011, executive perquisites were discontinued for the Enterprise Senior Leadership Team and replaced by a perquisite cash allowance which will be regularly reviewed by the LRCC.

ALIGNMENT TO FINANCIAL STABILITY BOARD PRINCIPLES – FOR EFFECTIVE GOVERNANCE OF COMPENSATION

The LRCC has taken steps to further strengthen our approach to compensation, including incorporating the Financial Stability Board Principles for Sound Compensation Practices and the associated Implementation Standards. These principles and standards, established in 2009, are intended to ensure effective governance of compensation, alignment of compensation with prudent risk taking, effective supervisory oversight and stakeholder engagement in compensation. The following paragraphs discuss how OMERS approach to compensation is aligned with these principles and standards.

The LRCC is composed entirely of independent directors and meets on a regular basis to discuss various compensation and human resources matters. They are responsible for approving compensation plans and policies for the Enterprise Senior Leadership Team, including base salary and incentive compensation. The LRCC has a formal and comprehensive process for approving the design of compensation plans across the organization. On an annual basis, the LRCC approves the performance measures, weightings and targets at the beginning of the year. At the end of the year, the results are evaluated to determine actual payouts.

Executives have a competitive mix of base salary, variable and deferred compensation. The mix varies by position and level within the organization, with a higher weighting of variable and at risk compensation at higher executive levels. All STIP and LTIP award payouts are dependent on performance results based on pre-determined LRCC approved measures and the level of risk taken in achieving results versus OMERS risk framework. Executives receive a meaningful portion of their compensation in LTIP awards, subject to performance and vesting requirements. All compensation plans reviewed or designed after 2010 include a comprehensive review of risk measures to determine the impact on compensation awards. The LRCC uses both quantitative measures and judgment in determining risk adjustments. The risk adjustments account for all types of risk which include but are not limited to asset allocation and concentration risk, active risk, regulatory breaches, operational risk and people risk.

OMERS continues to ensure effective governance of compensation and alignment of compensation with prudent risk taking. The LRCC remains committed to being a leader in compensation governance among Canadian pension funds and will continue to strive for improvements in disclosure to our Plan members and stakeholders.

2011 PERFORMANCE AND EXECUTIVE COMPENSATION

Incentive compensation for the CEO and corporate senior executives is based on performance against pre-determined investment performance results, pension services performance, and performance against OMERS five-year enterprise-wide strategic plan. This section highlights the performance during the year and how it translates into the compensation awarded to the Named Executive Officers.

2011 Corporate Performance

Under Mr. Nobrega's leadership, OMERS continues to evolve as a strategic leader with innovative programs and services in the pension industry and investment community.

OMERS performed strongly against the five-year strategic plan objectives by continuing to implement the long-term asset mix policy and the initiatives to gain access to domestic and foreign capital, as well as identifying strategic investment opportunities and removing barriers to OMERS growth. These strategic initiatives are discussed in the MD&A section of this Annual Report.

Pension Services met or exceeded all the targets to ensure our members and employers receive excellent service by continuing to enhance our internal capabilities, focusing on excellent execution, supporting effective plan governance and successfully launching the Additional Voluntary Contribution (AVC) program, which allows Plan members to save further for retirement while sharing in the OMERS investment returns.

Investment performance is critical to fulfill the pension promise to our current and future retirees as OMERS must produce investment returns that exceed the actuarially assumed rate of return, within an acceptable risk tolerance. At the start of every year the OAC Board approves benchmarks for the asset classes in which OMERS invests. The total Fund return for 2011 was below expectations given the realities of the financial markets. For Borealis Infrastructure, Oxford Properties and OMERS Strategic Investments, benchmarks are based on projected absolute returns and met or exceeded expected performance levels for 2011. For OMERS Capital Markets and OMERS Private Equity, benchmarks are based on a market benchmark. OMERS Capital Markets returns were below the benchmark, while OMERS Private Equity was above its benchmark. Results for each entity are further discussed in the MD&A section of this Annual Report.

Compensation Decisions

When determining compensation, the LRCC ensures there is a strong link between executive compensation and actual performance achieved. Given the 2011 performance results, the LRCC approved the STIP performance factor of 120.7 per cent for the CEO, which resulted in actual STIP awards reported in the charts below. For the 2009 LTIP award that matured on December 31, 2011, the three-year pre-determined performance measures resulted in a payout below target, which recognized the investment returns over the three year period. The LRCC believes that the compensation awarded to the Named Executive Officers closely reflects the actual performance of OMERS and continues to emphasize executive retention as well as supports the OMERS pay-for-performance philosophy.

SUMMARY COMPENSATION TABLE

The table below represents disclosure of salary, short-term incentive plan, long-term incentive plan, employer portion of pension contributions and other compensation paid to or earned by each Named Executive Officer during the three most recently completed financial years.

			Non-Equity Incentive Compensation				
Name and Principal Position	Year	Salary	Annual Incentive Plan	Long-Term Incentive Plan[i]	Pension Value[ii]	All Other Compensation[iii]	Total Compensation
Michael Nobrega	**2011**	**$ 515,000**	**$ 777,263**	**$ 790,364**	**$ 145,715**	**$ 95,652**	**$ 2,323,994**
President & CEO	2010	$ 515,000	$ 1,179,496	$ 1,191,259	$ 276,707	$ 90,573	$ 3,253,035
	2009	$ 475,000	$ 1,051,210	$ 1,362,110	$ 200,097	$ 143,158	$ 3,231,575
Patrick G. Crowley	**2011**	**$ 438,000**	**$ 600,000**	**$ 353,584**	**$ 95,261**	**$ 29,462**	**$ 1,516,307**
Executive Vice President	2010	$ 438,000	$ 613,200	$ 532,932	$ 152,824	$ 31,531	$ 1,768,487
and Chief Financial Officer	2009	$ 425,000	$ 510,000	$ 232,800	$ 96,034	$ 31,582	$ 1,295,416
R. Michael Latimer	**2011**	**$ 500,000**	**$ 1,000,000**	**$ 549,120**	**$ 112,009**	**$ 105,186**	**$ 2,266,315**
Executive Vice President	2010	$ 500,000	$ 1,100,000	$ 1,762,128	$ 214,257	$ 122,638	$ 3,699,023
and Chief Investment Officer	2009	$ 640,000	$ 228,480	$ 1,978,086	$ 57,600	$ 93,908	$ 2,998,074
Michael Rolland	**2011**	**$ 438,000**	**$ 812,769**	**$ 1,845,563**	**$ 22,000**	**$ 49,066**	**$ 3,167,398**
President & CEO,	2010	$ 438,000	$ 841,377	$ 1,958,516	$ 21,000	$ 46,537	$ 3,305,430
Borealis Capital Corporation	2009	$ 425,000	$ 820,250	$ 1,639,463	$ 20,000	$ 46,496	$ 2,951,209
Paul Renaud	**2011**	**$ 438,000**	**$ 798,985**	**$ 1,384,438**	**$ 22,450**	**$ 78,278**	**$ 2,722,151**
President & CEO,	2010	$ 438,000	$ 810,300	$ 1,364,260	$ 22,000	$ 73,360	$ 2,707,920
OMERS Private Equity	2009	$ 425,000	$ 569,500	$ 800,000	$ 21,000	$ 70,725	$ 1,886,225

(i) The amount reported for a given year reflects the total earned from the LTIP performance period that matured at the end of that year.
(ii) Represents the employer contributions to the Plan and employer contributions to third-party providers of defined contribution pension plans.
(iii) Includes insurance, benefits and other allowances.

INCENTIVE PLAN AWARDS

Long-term Incentive Plan (LTIP) awards are granted at the start of the fiscal year and paid out at the end of the vesting period. The following table presents the outstanding LTIP awards for each Named Executive Officer.

Name	Year	Type of Award	Award Target Value	Maximum Value at Payout
Michael Nobrega	**2011**	**LTPP**	**$ 386,250**	**$ 579,375**
President & CEO	**2011**	**LTIP**	**1,287,500**	**2,575,000**
	2010	LTPP	386,250	579,375
	2010	LTIP	1,287,500	2,575,000
Patrick G. Crowley	**2011**	**LTIP**	**547,500**	**1,095,000**
Executive Vice President and Chief Financial Officer	2010	LTIP	547,500	1,095,000
R. Michael Latimer	**2011**	**LTIP**	**1,250,000**	**2,500,000**
Executive Vice President and Chief Investment Officer	2010	LTIP	1,250,000	2,500,000
Michael Rolland	**2011**	**LTIP**	**1,095,000**	**2,190,000**
President & CEO, Borealis Capital Corporation	2010	LTIP	1,095,000	2,190,000
Paul Renaud	**2011**	**LTIP**	**1,095,000**	**2,190,000**
President & CEO,	2010	LTIP	1,095,000	2,190,000
OMERS Private Equity	2010	LTIP	1,095,000	2,190,000

The 2009 LTIP awards matured at the end of 2011 and were paid out, leaving the 2010 and 2011 LTIP awards outstanding. All LTIP awards vest and mature on the third anniversary of the award date, with the exception of Paul Renaud's additional 2010 LTIP award, which vests and matures on the fourth anniversary of the award date. The LRCC approved a 2012 LTIP award for each member of the Enterprise Senior Leadership Team. The minimum value of the long-term incentive awards is zero, based on the achievement of performance targets.

PENSION PLANS

The table below represents disclosure of estimated pension information for the Named Executive Officers as at December 31, 2011.

Name	Number of Years Credited Service	Annual Benefits Payable		Opening Present Value of Defined Benefit Obligation	Compensatory Change	Non-Compensatory Change	Closing Present Value of Defined Benefit Obligation
		At Year End	At Age 65				
Michael Nobrega President & CEO	4.808	$ 222,270	n/a	$ 2,700,423	$ 69,245	$ 270,659	$ 3,040,327
Patrick G. Crowley Executive Vice President and Chief Financial Officer	8.910	$ 92,625	$ 204,627	$ 1,038,652	$ 219,885	$ 139,046	$ 1,397,583
R. Michael Latimer Executive Vice President and Chief Investment Officer	6.843	$ 93,786	$ 211,897	$ 1,369,434	$ 278,527	$ 183,268	$ 1,831,229
Paul Renaud President & CEO, OMERS Private Equity	2.153	$ 25,967	$ 41,924	$ 435,126	$ -	$ 35,393	$ 470,519

CONCLUSION

All OMERS employees are committed to delivering realistic risk-adjusted returns over the long term to deliver the pension promise to Plan members. The approach to executive compensation motivates executives to achieve OMERS strategic objectives prudently by encouraging an appropriate balance between risk and reward. OMERS remains committed to ensuring our compensation policies and programs support our talent management strategy to continue to attract, engage and retain high performing people who will produce the results that deliver value to our Plan members.

RESPONSIBILITIES OF MANAGEMENT, THE ACTUARY AND INDEPENDENT AUDITORS

The OMERS Administration Corporation (the "OAC") is the administrator of the OMERS pension plans (the "OMERS Pension Plans") as defined in the *Ontario Municipal Employees Retirement System Act, 2006* (the "OMERS Act"). The OMERS Pension Plans include OMERS Primary Pension Plan (the "Plan"), which includes the Defined Benefit and the Additional Voluntary Contribution components, and the Retirement Compensation Arrangement (the "RCA") associated with the Plan and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (the "Supplemental Plan"). The OAC is responsible for managing the funds of the Plan, the RCA and the Supplemental Plan (collectively, the "Funds"). As at December 31, 2011, membership in the Supplemental Plan was nil.

The consolidated financial statements of the OAC have been prepared by management and approved by the Board of the OAC (the "OAC Board"). Management is responsible for the contents of the consolidated financial statements and the financial information contained within the Annual Report.

Management maintains systems of internal controls and supporting procedures that are designed to ensure the integrity and fairness of the data presented, that transactions are duly authorized and that assets are adequately safeguarded. These controls include clear division of responsibilities, accountability for performance, timely communication of policies and procedures throughout the organization and high standards in the hiring and training of employees. In addition, Corporate Audit Services reviews the OAC's systems of internal controls to determine whether these controls are appropriate and operating effectively.

The OAC Board is responsible for approving the annual consolidated financial statements. The Audit Committee, which is comprised of directors who are not officers or employees of the OAC, assists the OAC Board in executing this responsibility. The Audit Committee meets regularly with management and the internal and external auditors to review the scope and timing of their respective audits as well as to review any internal control or financial reporting issues and their resolution. The Audit Committee reviews the annual consolidated financial statements and recommends them to the OAC Board for approval.

The independent actuary is appointed by the OAC Board. It is the independent actuary's responsibility to carry out annual valuations of the accrued pension obligations of the OMERS Pension Plans in accordance with accepted actuarial practice and to report thereon to the OAC Board. The Audit Committee assists the OAC Board in executing this responsibility. The results of the independent actuary's valuation are set out in the Actuarial Opinion. In performing the valuation, the independent actuary values the benefits provided under the OMERS Pension Plans using appropriate assumptions about future economic conditions (such as inflation, salary increases, and investment returns) and demographic factors (such as mortality, termination rates and retirement ages). These assumptions take into account the circumstances of the OAC and its active, inactive and retired members.

The independent auditors are also appointed by the OAC Board. Their responsibility is to report to the OAC Board whether in their opinion the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of changes in net assets available for benefits and the statements of changes in pension obligations for the years ended December 31, 2011 and 2010 present fairly in all material respects, the financial position, the changes in net assets available for benefits and changes in pension obligations in accordance with Canadian accounting standards for pension plans. The independent auditors have full and unrestricted access to management and the Audit Committee to discuss any findings arising from their audit related to the integrity of financial reporting and the adequacy of internal control systems on which they rely for the purposes of their audit. The auditors' report outlines the scope of their examination and opinion.

Based on my knowledge, the Annual Report does not contain any untrue statement of a material fact, or omit to state a material fact, that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by this Annual Report.

Based on my knowledge, the annual financial statements, together with the other financial information included in this Annual Report, fairly present in all material respects the financial position, changes in net assets available for benefits and changes in pension obligations of OAC as of the date and for the periods presented in this Annual Report.



Michael Nobrega
President and Chief Executive Officer



Patrick G. Crowley
Executive Vice President and Chief Financial Officer

Toronto, Canada
February 22, 2012

ACTUARIAL OPINION

We conducted actuarial valuations as at December 31, 2011 of the OMERS Primary Pension Plan (the "Primary Plan") and the Retirement Compensation Arrangement for the OMERS Primary Pension Plan (the "RCA") administered by OMERS Administration Corporation (the "OAC"). The Primary Plan consists of a defined benefit component and an additional voluntary contribution ("AVC") component. The purpose of the valuations is to fairly present the actuarial funded status of the Primary Plan and the RCA as at December 31, 2011, for inclusion in this Annual Report in accordance with Section 4600 of the Canadian Institute of Chartered Accountants Handbook Part IV.

The results of the actuarial valuation of the Primary Plan disclosed total going concern actuarial liabilities of $64,642 million in respect of benefits accrued for service to December 31, 2011 (comprising $64,548 million with respect to the defined benefit component and $94 million with respect to the AVC component). The actuarial assets at that date were $57,352 million (comprising $57,258 million with respect to the defined benefit component and $94 million with respect to the AVC component), indicating a going concern actuarial deficit of $7,290 million. Ongoing adequacy of the Primary Plan's contribution rates will need to be monitored to ensure that future contributions, together with the Primary Plan assets and future investment earnings thereon, will be sufficient to provide for its future benefits.

The RCA provides for pension benefits in excess of the maximum pension benefits under the Primary Plan. The RCA is not fully pre-funded. The actuarial liability in respect of RCA benefits accrued for service to December 31, 2011 (determined using assumptions consistent with those used for the Primary Plan except that the discount rate is adjusted to approximate the effect of the 50 per cent refundable tax under the RCA), net of the RCA assets, was $436 million. Contributions, based on the top-tier Primary Plan contribution rates, are payable to the RCA on the excess of earnings over the maximum contributory earnings recognized under the Primary Plan. The funding of the RCA is managed on a modified pay-as-you go basis and, effective January 1, 2012, monitored to ensure that the fund will have sufficient assets to provide for the projected benefit payments over the 20-year period following each valuation date.

The actuarial valuations of the Primary Plan and the RCA as at December 31, 2011 were conducted using the Unit Credit Actuarial Cost Method with projection of earnings, and membership data as at December 2, 2011 and financial information as at December 31, 2011 supplied by the OAC. The December 2, 2011 membership data was adjusted, among other things, for the following:

- actual inflationary increases to pensions in payment and deferred pension payments effective January 1, 2012;
- estimated credited service accruals in 2011; and
- estimated earnings for 2011.

We reviewed the data for reasonableness and consistency with the data provided in prior years. In our opinion,

- the membership data are sufficient and reliable for the purpose of the valuations;
- the assumptions adopted were set with reference to the Primary Plan's funding policy and with allowance for refundable taxes under the RCA, and are appropriate for the purpose of the valuations; and
- the methods employed in the valuations are appropriate for the purpose of the valuations.

The future experience of the Primary Plan and the RCA may differ from the actuarial assumptions, resulting in gains or losses which will be revealed in future valuations.

The valuations were prepared and our opinions are given in accordance with accepted actuarial practice in Canada.

Respectfully submitted
Towers Watson Canada Inc.



Ian Markham
Fellow, Canadian Institute of Actuaries



Philip Morse
Fellow, Canadian Institute of Actuaries

Toronto, Canada
February 22, 2012

INDEPENDENT AUDITOR'S REPORT

TO THE BOARD OF OMERS ADMINISTRATION CORPORATION

We have audited the accompanying consolidated financial statements of OMERS Administration Corporation and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010, and January 1, 2010, and the consolidated statements of changes in net assets available for benefits and changes in pension obligations for the years ended December 31, 2011 and 2010, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian accounting standards for pension plans, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of OMERS Administration Corporation as at December 31, 2011, December 31, 2010, and January 1, 2010, and the changes in its net assets available for benefits and changes in its pension obligations for the years ended December 31, 2011 and 2010, in accordance with Canadian accounting standards for pension plans.

PricewaterhouseCoopers LLP/s.r.l./s.e.n.c.r.l.

Chartered Accountants, Licensed Public Accountants

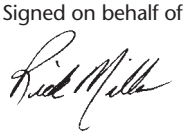
Toronto, Ontario
February 22, 2012

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(millions) As at,	December 31, 2011	December 31, 2010	Opening Balance January 1, 2010
Net Assets Available for Benefits			
Assets			
Investments (note 3)	$ 64,058	$ 62,948	$ 57,287
Other investment assets (note 5)	332	263	235
Amounts due from pending trades	375	382	311
Contributions receivable			
- Members	114	99	90
- Employers	114	100	91
Other assets	65	66	50
Total Assets	65,058	63,858	58,064
Liabilities			
Investment liabilities (note 6)	8,802	9,392	9,293
Due to administered funds	828	809	734
Amounts payable from pending trades	261	236	151
Other liabilities	84	72	54
Total Liabilities	9,975	10,509	10,232
Net Assets Available for Benefits	$ 55,083	$ 53,349	$ 47,832
Accrued Pension Obligations and Deficit			
Primary Plan (note 7)			
Defined benefit component			
Accrued pension obligation	$ 64,548	$ 60,035	$ 54,253
Deficit			
Funding deficit	(7,290)	(4,467)	(1,519)
Actuarial value adjustment of net assets	(2,337)	(2,278)	(4,950)
	(9,627)	(6,745)	(6,469)
	54,921	53,290	47,784
Additional Voluntary Contributions Component			
Pension obligation	94	-	-
	55,015	53,290	47,784
Retirement Compensation Arrangement (note 8)			
Accrued pension obligation	504	468	486
Deficit	(436)	(409)	(438)
	68	59	48
Accrued Pension Obligations and Deficit	$ 55,083	$ 53,349	$ 47,832

The accompanying notes are an integral part of these consolidated financial statements.

Signed on behalf of OMERS Administration Corporation



Rick Miller
OAC Chair



Jim Phillips
Chair, Audit Committee

CONSOLIDATED STATEMENT OF CHANGES IN NET ASSETS AVAILABLE FOR BENEFITS

(millions)

For the year ended December 31,	2011	2010
Changes Due to Investment Activities (note 9)		
Investment income	$ 1,988	$ 1,912
Changes in fair values of investment assets and liabilities and derivatives	(246)	3,641
Investment management expenses (note 13(b))	(279)	(268)
Gain/(loss) from currency hedging	(79)	182
Income allocated to administered funds	(21)	(83)
	1,363	5,384
Changes Due to Pension Activities		
Contributions (note 11)		
- Employers	1,317	1,121
- Members	1,362	1,165
- Transfers in	41	27
- Additional voluntary contributions	93	-
	2,813	2,313
Benefits (note 12)		
- Payments	(2,193)	(1,992)
- Transfers out	(190)	(134)
	(2,383)	(2,126)
Pension administrative expenses (note 13(a))	(59)	(54)
	371	133
Total Increase	1,734	5,517
Net assets available for benefits, beginning of year	53,349	47,832
Net Assets Available for Benefits, End of Year	$ 55,083	$ 53,349

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENT OF CHANGES IN PENSION OBLIGATIONS

(millions) For the year ended December 31,	2011	2010
OMERS Primary Pension Plan (note 7)		
Defined Benefit Component		
Accrued pension obligation, beginning of year	$ 60,035	$ 54,253
Interest accrued on benefits	3,904	3,601
Benefits accrued	2,434	2,211
Benefits paid (note 12)	(2,375)	(2,121)
Experience losses	560	491
Changes in actuarial assumptions and methods	(10)	1,600
Accrued pension obligation, end of year	64,548	60,035
Additional Voluntary Contributions Component		
Additional voluntary contributions obligation, beginning of year	-	-
Contributions	93	-
Withdrawals	(1)	-
Attributed net investment income	2	-
Management/administration fee	-	-
Additional voluntary contributions obligation, end of year	94	-
	$ 64,642	$ 60,035

(millions) For the year ended December 31,	2011	2010
Retirement Compensation Arrangement (note 8)		
Accrued pension obligation, beginning of year	$ 468	$ 486
Interest accrued on benefits	15	16
Benefits accrued	24	24
Benefits paid (note 12)	(7)	(5)
Experience losses	4	5
Changes in actuarial assumptions and methods	-	(58)
Accrued pension obligation, end of year	$ 504	$ 468

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Year ended December 31, 2011

NOTE 1

DESCRIPTION OF PLANS ADMINISTERED BY OMERS ADMINISTRATION CORPORATION

The OMERS Administration Corporation (the "OAC") is a corporation without share capital under the *Ontario Municipal Employees Retirement System Act, 2006* (the "OMERS Act"). OAC is the administrator of the OMERS pension plans (the "OMERS Pension Plans") as defined in the OMERS Act. The OMERS Pension Plans include OMERS Primary Pension Plan (the "Plan" or the "Primary Plan"), the Retirement Compensation Arrangement (the "RCA") associated with the Plan and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (the "Supplemental Plan"). OAC is responsible for managing the funds of the Plan, the RCA and the Supplemental Plan (collectively, the "Funds"), in accordance with the *Pension Benefits Act* (Ontario) (the "PBA"), the *Income Tax Act* (Canada) (the "*Income Tax Act*"), and the OMERS Act. Under the OMERS Act, the OMERS Sponsors Corporation (the "SC") is the sponsor of the OMERS Pension Plans. The Ontario Municipal Employees Retirement System ("OMERS") represents the combined retirement system comprised of the SC, the OAC, the Plan, the RCA and the Supplemental Plan.

The accrued pension obligations of any of the OMERS Pension Plans cannot be funded by the assets of either of the other two OMERS Pension Plans. As at December 31, 2011, membership in the Supplemental Plan was nil.

OMERS PRIMARY PENSION PLAN

The Plan is a multi-employer jointly sponsored pension plan, created in 1962 by an Act of the Ontario Legislature, whose members are mainly employees of Ontario municipalities, local boards, public utilities and non-teaching school board staff. The Plan is governed by the OMERS Act and the benefit provisions and other terms of the Plan are set out in the plan text. The Plan consists of both the defined benefit component and the Additional Voluntary Contributions ("AVCs") component.

The Plan is registered with the Financial Services Commission of Ontario ("FSCO") under Registration #0345983 and the Canada Revenue Agency ("CRA").

a) **Funding** – The defined benefit component of the Primary Plan is a jointly sponsored defined benefit pension plan funded by equal contributions from participating employers and members and by the investment earnings of the Plan assets. Contribution rates for the defined benefit component are set by the SC based on the actuarial valuation, and are determined in accordance with the OMERS Act, the ITA and the PBA, according to the actuarial needs of the Plan.

b) **Pensions** – The normal retirement age ("NRA") is 65 years for all Plan members, except police officers and firefighters, who generally have a normal retirement age of 60 years. The normal retirement pension is calculated using a member's years of credited service and the average annual earnings during the member's highest sixty consecutive months of earnings. The Plan benefits are integrated with the Canada Pension Plan.

c) **Death Benefits** – Death benefits are available to a surviving spouse, eligible dependent children or designated beneficiary upon the death of a member. Depending upon eligibility requirements, the benefits may be paid in the form of a survivor pension, lump sum payment or both.

d) **Withdrawals and Transfers from the Plan** – Subject to lock-in provisions, a member that has terminated employment prior to eligibility to retire has the option to withdraw or transfer his/her benefits from the Plan to another retirement savings vehicle.

e) **Escalation of Pensions** – Pension benefits are increased for inflation through an annual adjustment equal to 100 per cent of the increase in the average Consumer Price Index ("CPI") from the prior year. This is subject to a limit of six per cent in any one year. If the increase in the average CPI exceeds the six per cent limit, any excess is carried forward to future years.

f) **Disability Pensions** – A disability pension is available at any age to a member who becomes totally disabled as defined by the Plan. The pension is calculated using a member's years of credited service and the average annual earnings during the member's highest 60 months of consecutive earnings consistent with a standard pension. Disability pensions continue until normal retirement or until the member is able to return to work.

NOTE 1

DESCRIPTION OF PLANS ADMINISTERED BY OMERS ADMINISTRATION CORPORATION (continued)

g) **Income Taxes** – The Plan is a Registered Pension Plan as defined in the *Income Tax Act* and as such is not subject to income taxes for contributions or investment income received. The operations of certain entities holding private equity, infrastructure or real estate investments may be taxable.

h) **Additional Voluntary Contributions Component** – The Plan also contains a component enabling members to make additional voluntary contributions on which the member receives the net investment return of the defined benefit component of the Plan. For the AVC component of the Plan the only liability of the OAC is the members' contributions plus/minus the net investment return of the Plan funds.

Funds in an AVC account can be fully withdrawn when members retire or leave their OMERS employer (subject to any locking-in requirements); however, while a member is active, withdrawals are limited to a maximum of 20 per cent of the previous year-end balance, subject to a minimum of $500. As well, withdrawals are permitted only from March 1 to April 30 of each year.

RETIREMENT COMPENSATION ARRANGEMENT

The RCA was established to provide pension benefits based on full earnings for those members with earnings exceeding the amount that generates the maximum pension allowed by the *Income Tax Act* (ITA). The determination of the value of these benefits is made on the basis of an annual actuarial valuation. The RCA net assets available for benefits are invested and accounted for separately from the Plan and the Supplemental Plan and the accrued pension obligation of the RCA is valued separately from the Plan and Supplemental Plan accrued pension obligations.

OMERS SUPPLEMENTAL PENSION PLAN FOR POLICE, FIREFIGHTERS AND PARAMEDICS

The Supplemental Plan became effective on July 1, 2008, pursuant to the requirements of the OMERS Act. The Supplemental Plan is a separately funded, jointly sponsored, multi-employer pension plan that provides supplemental pension benefits that "top up" those available under the Plan for members of the Plan who are employed in the police and fire sectors which, as defined in the OMERS Act, includes paramedics. The Supplemental Plan is governed by the OMERS Act and the benefit provisions and other terms of the Supplemental Plan are set out in the plan text. The Supplemental Plan is registered with FSCO and CRA. The Supplemental Plan is registered under Registration #1175892.

The Supplemental Plan is a contributory defined benefit pension plan funded by equal contributions from participating employers and members and by the investment earnings of the Supplemental Plan assets. Contribution rates are set by the SC. Participation in the Supplemental Plan is effective only upon agreement between an employee group and an employer. As at December 31, 2011, the Supplemental Plan had no assets (December 31, 2010 – no assets) and no members.

Neither the Plan nor the RCA is permitted to pay costs for the Supplemental Plan. As such, until March 31, 2018, unless the Supplemental Plan has sufficient funds based on the administrative portion of contributions, any administrative costs of the Supplemental Plan are funded through a start up grant from the province of Ontario.

NOTE 2

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

As of January 1, 2011, OAC has implemented the requirements of the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 4600 – Pension Plans. This standard is the basis for Canadian accounting standards for pension plans. The recognition and measurement of OAC assets and liabilities are consistent with the requirements of CICA Section 4600.

CICA Section 4600 requires that in selecting or changing accounting policies that do not relate to its investment portfolio or pension obligations, a pension plan shall comply on a consistent basis with either International Financial Reporting Standards in Part I of the Handbook, or accounting standards for private enterprises in Part II of the Handbook, to the extent that those standards do not conflict with the requirements of Section 4600. OAC has chosen to comply on a consistent basis with the International Financial Reporting Standards.

The adoption of CICA Section 4600 had no impact on OAC's net assets available for benefits, the accrued pension obligations and deficits or total investment income. Consistent with CICA Section 4600, investment assets are presented on a non consolidated basis even when the investment is in an entity over which OAC has effective control. Earnings of such entities are recognized as interest and real estate rental income is earned and dividends are declared. OAC total investment income includes valuation adjustments required to bring the investment to its fair value. OAC total investment income of prior years is unchanged as investments continue to be stated at fair value.

Transition to CICA Section 4600 and IFRS

In preparing its first financial statements in accordance with CICA Handbook Section 4600 – Pension Plans and IFRS, the OAC has adjusted amounts that were previously reported in accordance with CICA Handbook Section 4100. An explanation of how the transition has affected the OAC's financial position is set out in the following table and the note that accompanies the table.

	As at January 1, 2010			As at December 31, 2010		
(millions)	Reporting Under CICA Section 4100	Effect of Transition to CICA Section 4600 and IFRS	Reporting under CICA Section 4600 and IFRS	Reporting Under CICA Section 4100	Effect of Transition to CICA Section 4600 and IFRS	Reporting under CICA Section 4600 and IFRS
Net Assets Available for Benefits						
Assets						
Investments[(i)]	$ 60,554	$ (3,267)	$ 57,287	$ 69,139	$ (6,191)	$ 62,948
Other investment assets[(i)]	862	(627)	235	1,109	(846)	263
Amounts due from pending trades	311	-	311	382	-	382
Contributions receivable						
- Members	90	-	90	99	-	99
- Employers	91	-	91	100	-	100
Other assets	50	-	50	66	-	66
Total Assets	61,958	(3,894)	58,064	70,895	(7,037)	63,858
Liabilities						
Investment liabilities[(i)]	13,084	(3,791)	9,293	16,327	(6,935)	9,392
Due to administered funds	734	-	734	809	-	809
Amounts payable from pending trades[(i)]	254	(103)	151	338	(102)	236
Other liabilities	54	-	54	72	-	72
Total Liabilities	14,126	(3,894)	10,232	17,546	(7,037)	10,509
Net Assets Available for Benefits	$ 47,832	$ -	$ 47,832	$ 53,349	$ -	$ 53,349

(i) Prior to the adoption of CICA Handbook Section 4600 – Pension Plans and IFRS, investments in an entity controlled by OAC were presented on a consolidated basis. The changes resulting from the adoption of CICA Section 4600 are summarized in the Basis of Presentation section above. The effect of transition to the new standards requires an adjustment in investment assets, other investment assets and investment liabilities to reflect the fact that investments in such assets are no longer consolidated.

NOTE 2

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

CONSOLIDATION

The consolidated financial statements include the financial position, changes in net assets available for benefits and changes in pension obligations of OAC. OAC investments are managed by the following entities: OMERS Capital Markets (which is primarily responsible for investing in publicly traded interest bearing and equity investments as well as commercial mortgages and private debt investments); OMERS Private Equity (which manages private equity investments); Borealis Infrastructure (which manages infrastructure investments); Oxford Properties Group (which manages real estate assets) and OMERS Strategic Investments (which manages strategic investments across all asset classes) (collectively the "Investment Entities"). In accordance with CICA 4600, the consolidated financial statements present the assets and liabilities of the Investment Entities on a consolidated basis and the fair value of investments, on a non consolidated basis even where OAC has effective control over the operations of that investment.

Inter-company transactions and balances between OAC and the Investment Entities of OAC are eliminated in arriving at the consolidated financial statements.

USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with CICA Section 4600 and International Financial Reporting Standards requires management to make estimates and assumptions that affect the reported values of assets and liabilities, income and expenses, accrued pension obligations and related disclosures. Actual results could differ from these estimates. Significant estimates included in the consolidated financial statements relate to the valuation of private market investments and the determination of the accrued pension obligation.

INVESTMENTS

The Funds' investments consist of the following major asset classes: public markets (which include public equities and interest bearing investments such as treasury bills, bonds, mortgages and private debt), private equity, infrastructure and real estate.

During 2011, the CICA introduced International Financial Reporting Standard 13 – Fair Value Measurement. This standard defines fair value and sets out a framework for measuring fair value. It is effective for annual periods beginning on or after January 1, 2013, however, early adoption is permitted. OAC has chosen to early adopt the requirements of IFRS 13 for the period beginning January 1, 2011.

All investment transactions are recorded at the point when the risks and rewards of ownership are transferred. Purchases and sales of publicly traded investments are recorded as of the trade date.

Investments are stated at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It is best evidenced by a quoted closing market price in an active market, if one exists, which is the most representative of fair value. The determination of fair value is based on market conditions at a specific point in time and may not be reflective of future fair values.

Fair value may be determined by reference to a market index, publicly observable market data or through the use of valuation techniques and models which utilize assumptions based on information that is not publicly observable. Where a public market price in an active market is not available for an investment asset or liability, a suitable method of valuation is used annually by Management to determine fair value. Valuation techniques used include the use of discounted cash flows, earnings multiples, prevailing market rates for instruments with similar characteristics or other pricing models, as appropriate. In these cases the fair value may differ significantly when varying assumptions are used. Accredited external appraisers are required to perform a review of Management's valuations to determine the reasonableness of the valuations for each significant private market investment at least once every three years or in any year where the valuation changes by more than fifteen per cent from the prior year.

The difference between the value of an asset or liability at the time it was acquired and its current fair value takes into account changes in market rates and credit risk of the issuer that have occurred since original acquisition. Unrealized appreciation/depreciation in the fair value of investments is the change in fair value adjusted for cash flows accrued and received during the year and is reflected in net investment income/loss in the consolidated statement of changes in net assets available for benefits.

NOTE 2

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

INVESTMENT INCOME/LOSS

Investment income/loss includes accrued interest, dividends, and real estate rental income. Gains and losses that have been realized on the disposal of investments, and the unrealized appreciation/depreciation required to adjust investments to their fair value are added to investment income to arrive at total investment income.

Income is recognized as interest and real estate rental income is earned, as dividends or distributions are declared and as investments are adjusted to their fair value.

TRANSACTION AND PURSUIT COSTS

Transaction and pursuit costs which include broker commissions, legal and other professional fees incurred as a part of the due diligence of a potential or completed transaction are expensed to investment income as incurred.

EXTERNAL MANAGER FEES

Base external manager fees for portfolio management are expensed in investment management expenses as incurred. Performance fees which are contractually due to external managers for superior investment returns and fees for pooled funds where OAC's investment return from the fund is net of fees are expensed in investment income as incurred.

INVESTMENT LIABILITIES

Investment liabilities include commercial paper, debentures, mortgages and other debt obligations incurred by OAC to acquire an investment, primarily in the real estate and infrastructure asset classes. Investment liabilities also include the Funds' liability to return cash collateral received in securities lending transactions. The fair value of investment liabilities is estimated using discounted cash flows based on current market yields, except for items that are short-term in nature, for which fair value is deemed to be the cost amount.

Liabilities incurred in entities in which OAC has invested are netted as part of investment assets, even when the investment is in an entity over which OAC has effective control or can exercise significant influence.

AMOUNTS DUE/PAYABLE FROM PENDING TRADES

For securities transactions, the fair value of amounts due from pending trades and amounts payable from pending trades approximate their carrying amounts due to their short-term nature. For derivative contracts, unrealized gains and losses are included in amounts due/payable from pending trades.

FOREIGN CURRENCY TRANSLATION

Certain investments are denominated in foreign currencies. The fair values of such investments are translated into Canadian dollars at the year-end rate of exchange. Unrealized foreign exchange gains and losses arising from this translation are included in net gain/loss on investments. Once a foreign currency denominated investment is sold, the realized foreign exchange gain or loss based on the settlement is recognized in realized gains/losses.

DUE TO ADMINISTERED FUNDS

Under contractual agreements and with the approval of the Government of Ontario, OAC invests funds on behalf of The Board of Trustees of Ryerson University, the Minister of Energy for the Province of Ontario (The Ontario Hydro Guarantee Fund) and the Transit Windsor Fund. The OAC is authorized under the terms of the various agreements to recover its expenses for administering such funds.

The amount due to administered funds is credited with income based upon their proportionate interest in the Plan's net investment income and the balance reflects the Plan's obligation to return funds to the administered funds.

NOTE 2

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

ACCRUED PENSION BENEFITS AND ACCRUED PENSION OBLIGATION

The value of the accrued pension obligation of the Plan's defined benefit component is based on a projected accrued benefits method (pro-rated on service) actuarial valuation prepared by an independent firm of actuaries. This accrued pension obligation is measured in accordance with accepted actuarial methods using actuarial assumptions and methods adopted by OAC for the purpose of establishing the long-term funding requirements of the Plan. The actuarial valuation included in the consolidated financial statements is consistent with the valuation for funding purposes.

The AVC pension obligation represents OAC's liability to repay AVC contributions including a pro-rata share of investment income or losses.

The valuation methodology used in the estimation of the accrued pension obligation of the RCA is developed on a basis consistent with the accrued pension obligation of the Plan's defined benefit component. The AVC pension obligation and the accrued pension obligation of the RCA are separate from the accrued pension obligation of the Primary Plan's defined benefit component.

ACTUARIAL VALUE OF NET ASSETS AND ACTUARIAL VALUE ADJUSTMENT

The actuarial value of net assets for the Plan is used in assessing the funding position of the Plan, including the determination of contribution rates. The actuarial value of net assets is determined by smoothing investment returns above or below the actuarial long-term rate of return assumption over a five-year period. The fair value of net assets is adjusted by the unrecognized actuarial value adjustment to arrive at the actuarial value of net assets.

SURPLUS/DEFICIT

For financial statement reporting, the surplus/deficit of the Plan is based on the difference between the fair value of the Plan net assets available for benefits and the Plan accrued pension obligation. For funding purposes, the Plan surplus/deficit is based on the difference between the Plan actuarial value of net assets and the Plan accrued pension obligation. For the RCA, the surplus/deficit for both financial statement reporting and funding purposes is based on the difference between the fair value of RCA net assets available for benefits and the RCA accrued pension obligation.

CONTRIBUTIONS

Contributions from employers and members due to the OMERS Pension Plans as at the end of the year are recorded on an accrual basis. Service purchases that include, but are not limited to leaves of absence, conversion of normal retirement age and contract adjustments and transfers from other pension plans are recorded and service is credited when the purchase amount is received. Contributions for AVCs are recorded when the contribution is received.

BENEFITS

Benefit payments to retired members are recorded as they are due, at the first of each month. Commuted value payments and transfers to other pension plans are recorded in the period in which OAC is notified. Accrued benefits for active members are recorded as part of the accrued pension obligation.

ADMINISTRATIVE EXPENSES

Administrative expenses are incurred for direct pension administration, direct investment management and corporate services and are recorded on an accrual basis. Direct pension administration expenses represent expenses to provide direct services to OMERS members and employers. Direct investment management expenses represent expenses of the Investment Entities managing OMERS investments. Corporate services expenses primarily include corporate information systems, accounting, legal and other governance expenses incurred to support either the pension administration or the investment management functions. These are allocated between pensions and investments based on an estimate of the use of resources.

APPROVAL OF THE FINANCIAL STATEMENTS

These financial statements were approved by the Board of Directors on February 22, 2012.

NOTE 3

INVESTMENTS

Total investments, before allocating the effect of derivative contracts, and investment related assets and liabilities are as follows:

(millions) As at,	December 31, 2011		December 31, 2010		Opening Balance January 1, 2010	
	Fair Value	Cost	Fair Value	Cost	Fair Value	Cost
Public Market Investments						
Interest Bearing Investments						
Cash and short-term deposits[i]	$ 6,120	$ 6,120	$ 5,573	$ 5,573	$ 5,009	$ 5,009
Bonds and debentures[ii]	10,173	9,522	9,177	8,923	8,117	8,042
Real return bonds	1,743	1,266	1,472	1,134	1,977	1,639
Mortgages and private debt[iii]	1,695	1,583	1,882	1,744	1,785	1,709
	19,731	18,491	18,104	17,374	16,888	16,399
Public Equity						
Canadian public equities	2,177	2,153	6,994	5,533	6,272	5,217
Non-Canadian public equities	10,246	9,750	9,025	8,173	7,859	7,349
	12,423	11,903	16,019	13,706	14,131	12,566
Total Public Market Investments	32,154	30,394	34,123	31,080	31,019	28,965
Private Equity[iv]						
Canadian private equities[v]	3,827	3,295	3,056	2,433	1,987	1,836
Non-Canadian private equities	3,926	4,114	3,577	3,687	2,988	3,380
Total Private Equity Investments	7,753	7,409	6,633	6,120	4,975	5,216
Infrastructure Investments[iv]	9,635	8,807	9,593	9,105	9,318	8,712
Real Estate Investments	14,516	13,014	12,599	11,369	11,975	10,699
Total Investments	64,058	59,624	62,948	57,674	57,287	53,592
Investment Related Assets						
Other investment assets (note 5)	332	501	263	440	235	283
Amounts due from pending trades	375	64	382	48	311	35
	707	565	645	488	546	318
Investment Related Liabilities						
Investment liabilities (note 6)	(8,802)	(8,560)	(9,392)	(9,264)	(9,293)	(9,246)
Amounts payable from pending trades	(261)	(73)	(236)	(102)	(151)	(33)
	(9,063)	(8,633)	(9,628)	(9,366)	(9,444)	(9,279)
Net Investment Assets	$ 55,702	$ 51,556	$ 53,965	$ 48,796	$ 48,389	$ 44,631

(i) Includes restricted cash of $86 million (December 31, 2010: $39 million, January 1, 2010: $15 million).
(ii) Includes non-Canadian bonds and debentures with a fair value of $289 million (December 31, 2010: $228 million, January 1, 2010: $230 million).
(iii) Includes mortgages with a fair value of $1,235 million (December 31, 2010: $1,216 million, January 1, 2010: $975 million).
(iv) Investment assets are net of long-term debt as presented in Note 6 (a).
(v) Includes resource properties with a total fair value of $660 million (December 31, 2010: $599 million, January 1, 2010: $422 million).

NOTE 3

INVESTMENTS (continued)

The Funds' net investment assets by Investment Entity responsible for managing the Funds' investments are as follows:

(millions) As at December 31, 2011	OMERS Capital Markets	OMERS Private Equity	Borealis Infrastructure	Oxford Properties Group	OMERS Strategic Investments	Total
Investment assets	$ 31,990	$ 6,230	$ 9,515	$ 14,679	$ 1,644	$ 64,058
Allocation of cash and other	(1,004)	94	674	223	13	-
Investment related assets	474	9	11	210	3	707
Investment related liabilities	(1,103)	-	(1,203)	(6,741)	(16)	(9,063)
Net Investment Assets	$ 30,357	$ 6,333	$ 8,997	$ 8,371	$ 1,644	$ 55,702

(millions) As at December 31, 2010	OMERS Capital Markets	OMERS Private Equity	Borealis Infrastructure	Oxford Properties Group	OMERS Strategic Investments	Total
Investment assets	$ 33,252	$ 5,364	$ 9,415	$ 12,782	$ 2,135	$ 62,948
Allocation of cash and other	(1,301)	201	813	273	14	-
Investment related assets	468	7	23	143	4	645
Investment related liabilities	(1,765)	(4)	(2,067)	(5,782)	(10)	(9,628)
Net Investment Assets	$ 30,654	$ 5,568	$ 8,184	$ 7,416	$ 2,143	$ 53,965

(millions) Opening Balance, January 1, 2010	OMERS Capital Markets	OMERS Private Equity	Borealis Infrastructure	Oxford Properties Group	OMERS Strategic Investments	Total
Investment assets	$ 30,369	$ 4,454	$ 9,240	$ 11,975	$ 1,249	$ 57,287
Allocation of cash and other	(762)	(7)	578	186	5	-
Investment related assets	392	5	13	132	4	546
Investment related liabilities	(2,126)	-	(2,338)	(4,971)	(9)	(9,444)
Net Investment Assets	$ 27,873	$ 4,452	$ 7,493	$ 7,322	$ 1,249	$ 48,389

NOTE 3

INVESTMENTS (continued)

INVESTMENT VALUATION PRACTICE

Fair values are based on quoted prices in an active market or where such pricing is not available, fair value is estimated using observable market inputs such as interest rates, quoted prices of comparable securities or unobservable inputs based on Management assumptions of investments. Fair values are determined as follows:

(i) Short-term deposits are recorded at amortized cost, which together with accrued interest income approximates fair value.

(ii) Bonds and debentures, real return bonds and public equities are valued at year-end quoted market prices, where available. For public equities the quoted market prices are based on exchange prices while bonds and real return bonds are based on quotes from industry standard sources. For public market investments where quoted market prices are not available such as mortgages and private debt, estimated values are calculated using discounted cash flows based on current market yields for comparable securities, independent asset appraisals, and financial analysis. Externally managed hedge funds where details of individual securities are not maintained by the Fund are valued based on values provided by the fund manager.

(iii) Private market investments include investments in private equity, infrastructure and real estate assets, held either directly or as a limited partner, which generally do not have a publicly available market price. For private market investments, the completion of a purchase or sale of an identical or similar investment is often the most objective determination of fair value. While not exact, appraisal or valuation procedures are able to provide estimates or identify likely ranges that a reasonable counterparty would pay for such assets. Such valuation procedures include one or a combination of the following:

- Discounting projected future cash flows of an investment using discount rates which reflect the risk inherent in the projected cash flows. Discount rates and projected cash flows are based on internal assumptions and external inputs.
- Assessing the investment assets against the value of comparable publicly listed entities.

The Funds' private market investments are valued as follows:

- the fair value of investments that have reasonably predictable future revenue streams or that derive their value based on property or commodity values is equal to the appraised amount;
- for non-operating and/or start-up directly held private investments, the value may be held at cost where cost is considered the best estimate of fair value, until there is evidence to support a change in valuation; and
- the fair value of a private fund investment where the OAC's ability to access information on underlying individual fund investments is restricted, such as under the terms of a limited partnership agreement, is equal to the value provided by the fund's general partner unless there is a specific and objectively verifiable reason to vary from the value provided by the general partner.

(iv) Fair value of derivatives, including swap, futures, option and forward contracts, are determined using quoted market prices, where available, or discounted cash flows using current market yields, where quoted market prices are not available.

Fair value measurements of investment assets and liabilities are based on inputs from one or more levels of a fair value hierarchy as follows:

Level 1 – Fair value is based on unadjusted quoted prices in active markets for identical assets or liabilities traded in active markets. Level 1 primarily includes publicly listed equity investments.

Level 2 – Fair value is based on valuation methods that make use of inputs, other than quoted prices included within Level 1, that are observable by market participants either directly through quoted prices for similar but not identical assets or indirectly through observable market information used in valuation models. Level 2 primarily includes debt securities and derivative contracts not traded on a public exchange and public equities not traded in an active market.

NOTE 3

INVESTMENTS (continued)

Level 3 – Fair value is based on valuation methods where inputs that are based on non-observable market data have a significant impact on the valuation. Level 3 primarily includes mortgages and private market investments valued based on discounted future cash flow models which reflect assumptions that a market participant would use when valuing such an asset or liability.

Net investment assets based on the valuation level within the fair value hierarchy are as follows:

(millions) As at December 31, 2011	Level 1	Level 2	Level 3	Total
Public Market Investments				
Interest Bearing Investments				
Cash and short-term deposits	$ 22	$ 5,094	$ 1,004	$ 6,120
Bonds and debentures	-	10,173	-	10,173
Real return bonds	-	1,743	-	1,743
Mortgages and private debt	-	-	1,695	1,695
	22	17,010	2,699	19,731
Public equity	9,400	-	135	9,535
Public fund investments	-	2,608	280	2,888
Total Public Market Investments	9,422	19,618	3,114	32,154
Private Equity Investments				
Direct investments	31	484	4,541	5,056
Fund investments	-	-	2,697	2,697
Total Private Equity Investments	31	484	7,238	7,753
Infrastructure Investments	-	-	9,635	9,635
Real Estate Investments	-	-	14,516	14,516
Total Investments	9,453	20,102	34,503	64,058
Investment Related Assets				
Other investment assets	-	99	233	332
Amounts due from pending trades[(i)]	54	321	-	375
	54	420	233	707
Investment Related Liabilities				
Debt	-	(3,100)	(4,139)	(7,239)
Payables under securities lending program	-	(845)	-	(845)
Other payables and liabilities	(50)	(10)	(658)	(718)
Amounts payable from pending trades[(i)]	(54)	(143)	(64)	(261)
	(104)	(4,098)	(4,861)	(9,063)
Net Investment Assets	$ 9,403	$ 16,424	$ 29,875	$ 55,702

(i) Includes fair value of derivatives.

NOTE 3

INVESTMENTS (continued)

(millions) As at December 31, 2010	Level 1	Level 2	Level 3	Total
Public Market Investments				
Interest Bearing Investments				
Cash and short-term deposits	$ 93	$ 4,183	$ 1,297	$ 5,573
Bonds and debentures	-	9,177	-	9,177
Real return bonds	-	1,472	-	1,472
Mortgages and private debt	-	-	1,882	1,882
	93	14,832	3,179	18,104
Public equity	15,080	-	96	15,176
Public fund investments	-	553	290	843
Total Public Market Investments	15,173	15,385	3,565	34,123
Private Equity Investments				
Direct investments	113	317	3,082	3,512
Fund investments	-	-	3,121	3,121
Total Private Equity Investments	113	317	6,203	6,633
Infrastructure Investments	-	-	9,593	9,593
Real Estate Investments	-	-	12,599	12,599
Total Investments	15,286	15,702	31,960	62,948
Investment Related Assets				
Other investment assets	-	89	174	263
Amounts due from pending trades[(i)]	37	345	-	382
	37	434	174	645
Investment Related Liabilities				
Debt	-	(3,175)	(4,111)	(7,286)
Payables under securities lending program	-	(1,566)	-	(1,566)
Other payables and liabilities	-	(11)	(529)	(540)
Amounts payable from pending trades[(i)]	(42)	(138)	(56)	(236)
	(42)	(4,890)	(4,696)	(9,628)
Net Investment Assets	$ 15,281	$ 11,246	$ 27,438	$ 53,965

(i) Includes fair value of derivatives.

NOTE 3

INVESTMENTS (continued)

The Level 3 classification includes all assets and liabilities related to investments valued based on non-observable market data. Where the investment asset is being valued as an entity, the Level 3 category includes the fair value of that entity. In addition, where the investment asset is hedged against foreign currency gains and losses, the impact of the hedging activity is included in the valuation.

The following table presents the changes in the fair value measurements in Level 3 of the fair value hierarchy:

(millions)	Fair Value Dec. 31, 2010	Total Gain/(Loss) Included in Net Income	Transfers In (Out)[i]	Contributed Capital	Capital Returned	Fair Value Dec. 31, 2011	Unrealized Gains/Losses Attributable to Investments Held at Dec. 31, 2011[ii]
Mortgages and private debt	$ 1,882	$ (25)	$ -	$ 104	$ (266)	$ 1,695	$ (25)
Public equity investments	96	18	-	56	(35)	135	35
Public fund investments	290	9	-	-	(19)	280	9
Private equity – direct investments	3,151	220	61	1,418	(301)	4,549	164
Private equity – fund investments	3,258	144	-	342	(953)	2,791	(61)
Infrastructure investments	8,363	683	(61)	595	(463)	9,117	288
Real estate investments	12,134	251	-	1,676	(137)	13,924	251
Real estate fund investments	418	(46)	-	85	(12)	445	(46)
Debt	(2,154)	(147)	-	157	(917)	(3,061)	(43)
Total	$ 27,438	$ 1,107	$ -	$ 4,433	$ (3,103)	$ 29,875	$ 572

(i) Represents amounts transferred between assets classes. The net amount transferred represents an infrastructure asset that was transferred to private equity during 2011.
(ii) Amount represents unrealized market value adjustments recorded during the year which are included in the valuation of assets held at year end only.

Level 3 financial instruments are valued using internal models and the resulting valuations are significantly affected by non-observable inputs, the most significant of which is the discount rate as the discount rate reflects both current interest rates as well as the uncertainty of future cash flows from the investment. The following hypothetical analysis illustrates the sensitivity of the Level 3 valuations to reasonably possible alternative discount rate assumptions for asset categories where such reasonably possible alternative assumptions would change the fair value significantly. The alternative discount rates below are based on the volatility of the respective asset classes. The impact to the valuation from such changes to the discount rate has been calculated independently of the impact of changes in other key variables. In actual experience, a change in the discount rate may be the result of changes in a number of underlying assumptions which could amplify or reduce the impact on the valuation.

As at December 31, 2011	Increase/Decrease in Discount Rate (basis points)	Increase/Decrease in Net Investment Assets (millions)
Private equity – direct investments	60	$ 230
Infrastructure investments	20	180
Real estate investments	25	300
Total Impact on Net Investment Assets		$ 710

As at December 31, 2010	Increase/Decrease in Discount Rate (basis points)	Increase/Decrease in Net Investment Assets (millions)
Private equity – direct investments	60	$ 160
Infrastructure investments	20	380
Real estate investments	25	250
Total Impact on Net Investment Assets		$ 790

NOTE 3

INVESTMENTS (continued)

The fair value of public market, private equity and real estate fund investments where OAC does not have access to the underlying investment information is based on the value provided by the general partner or other external manager and therefore, in the absence of specific information to support deviating from this value, no other reasonably possible alternative assumptions could be applied.

The Funds held investments, each having a fair value or cost exceeding one per cent of the fair value or cost of net investment assets as follows:

(millions)

As at December 31,	2011			2010		
	Number of Investments	Fair Value	Cost	Number of Investments	Fair Value	Cost
Public market investments	**3**	**$ 1,707**	**$ 1,662**	1	$ 686	$ 683
Private market investments	**14**	**12,011**	**11,158**	12	9,524	8,799
	17	**$ 13,718**	**$ 12,820**	13	$ 10,210	$ 9,482

Public market investments where the individual issue has a cost or fair value exceeding one per cent of the cost or fair value of net investment assets includes investments in Government of Canada interest bearing securities.

Private market investments having a cost or fair value exceeding one per cent of the cost or fair value of net investment assets include a limited partnership interest in Bruce Power; ownership interests in Teranet, Oncor, Associated British Ports, Scotia Gas Networks, LifeLabs and OMERS Energy Inc.; and real estate ownership interests in Yorkdale Shopping Centre located in Ontario, the Fairmont Banff Springs hotel located in Alberta, TD Canada Trust Tower located in Ontario, the Richmond Adelaide Complex located in Ontario, Centennial Place located in Alberta, Green Park Business Park located in Reading, England and Watermark Place located in London, England.

INVESTMENT RISK

OAC is exposed to a variety of investment risks as a result of its investment activities and has formal policies and procedures that govern the management of investment risk (market, credit and liquidity risk). The objective of investment risk management is to minimize unanticipated losses, to optimize the reward-risk trade-off for the Funds and to enhance the ability of the Plans to meet their respective obligations.

Portfolio investment and asset managers are responsible for understanding the investment risk in the various strategies and assets that they manage and invest in. Furthermore, they must ensure that the returns from those assets and strategies are commensurate with the risks involved. As a result, the Investment Entities are responsible for managing their investment risk and ensuring that the returns are commensurate with the amount of risk taken.

Investment risk is managed through various policies including entity level policies, OAC enterprise risk measurement policies, and investment policies which establish a target asset mix between public market and private market investments. Within public market investments, policies establish targets between interest bearing and public equity investments and within private markets investments, policies establish targets among private equity, infrastructure and real estate investments to ensure diversification across and within asset classes.

OAC utilizes analytical and reporting tools to manage investment risk and achieve its desired level of risk at the enterprise, public market and private market levels. In addition, derivative financial instruments are used, where appropriate, to assist in the management of these risks (note 4).

a) Market Risk

Market risk is the risk that the value of an investment will fluctuate as a result of changes in market conditions, whether those changes are caused by factors specific to the individual investment, or factors affecting all securities traded in the market. Market risk encompasses a variety of financial risks, such as foreign currency risk, interest rate risk and price risk. Significant volatility in interest rates, equity values and the value of the Canadian dollar against the currencies in which our investments are held can significantly impact the value of OAC investments and the funded status of the OMERS Pension Plans.

NOTE 3

INVESTMENTS (continued)

OAC uses various investment strategies such as diversification, hedging and the use of derivative instruments to mitigate the various forms of market risk. In addition, investment exposure in various assets and markets are monitored daily.

- **Foreign Currency Risk**

  Investments denominated in currencies other than the Canadian dollar expose the Funds to fluctuations in foreign exchange rates. Fluctuations in the relative value of the Canadian dollar against these foreign currencies can result in a positive or a negative effect on the fair value of investments. OAC has currency exposure management programs under which it hedges foreign currency exposure through the use of foreign exchange forward contracts. OAC also makes active investments in foreign currencies with the objective of adding value. The net exposure to foreign currencies represents 15 per cent (2010: 15 per cent) of net investment assets at December 31, 2011.

  OAC's total currency exposure before the impact of currency hedging and trading activities, the impact of hedging and trading activities and the net currency exposure are as follows:

(millions Canadian dollar equivalent) As at December 31,	2011 Fair Value By Currency				2010 Fair Value By Currency			
	Total Exposure[i]	Hedging Activities	Net Exposure	% of Total	Total Exposure[i]	Hedging Activities	Net Exposure	% of Total
Canada	$ 37,000	$ 10,717	$ 47,717	85%	$ 34,419	$ 11,572	$ 45,991	85%
United States	10,846	(5,341)	5,505	10%	10,264	(6,681)	3,583	7%
Euro Countries	1,606	(1,398)	208	0%	2,086	(1,532)	554	1%
United Kingdom	3,454	(2,822)	632	1%	3,208	(2,131)	1,077	2%
Japan	726	(402)	324	1%	939	(426)	513	1%
Other Pacific	936	(377)	559	1%	1,494	(402)	1,092	2%
Emerging Markets	538	(155)	383	1%	787	(175)	612	1%
Other Europe	596	(222)	374	1%	768	(225)	543	1%
	$ 55,702	$ -	$ 55,702	100%	$ 53,965	$ -	$ 53,965	100%

(i) Currency exposure before the impact of currency hedging and trading activities.

After giving effect to the impact of hedging and trading activities, a ten per cent increase/decrease in the value of the Canadian dollar against all currencies, with all other variables and underlying values held constant, would result in an approximate decrease/increase in the value of the Funds' net investment assets and an unrealized (loss)/gain of $799 million (2010: $797 million).

- **Interest Rate Risk**

  Interest rate risk refers to the effect on the fair value of the Funds' assets and liabilities due to fluctuations in interest rates. Due to the inflation indexing of benefit entitlements and the relatively long-term nature of pension benefits (notes 7 and 8), the accrued pension obligation is influenced by inflation and long-term rates of return. The impact to the Plan from a change in interest rates will be mitigated as the impact on the valuation of investment assets is generally opposite from the impact on investment liabilities and the accrued pension obligation. The interest bearing investment portfolio has guidelines on concentration and duration which are also designed to mitigate the risk of interest rate volatility.

NOTE 3

INVESTMENTS (continued)

The term to maturity classifications of interest bearing investments, based upon the contractual maturity of the securities, are as follows:

(millions) As at,	December 31, 2011					December 31, 2010		Opening Balance January 1, 2010	
	Term to Maturity								
	Within 1 Year	1 to 5 Years	Over 5 Years	Total	Average Effective Yield[i]	Total	Average Effective Yield[i]	Total	Average Effective Yield[i]
Cash and short-term deposits	$ 6,120	$ -	$ -	$ 6,120	1.07%	$ 5,573	1.10%	$ 5,009	0.37%
Bonds and debentures	165	4,127	5,881	10,173	1.76%	9,177	3.08%	8,117	3.47%
Real return bonds[ii]	-	50	1,693	1,743	0.26%	1,472	1.09%	1,977	1.51%
Mortgages and private debt	67	827	801	1,695	3.22%	1,882	4.20%	1,785	4.81%
	$ 6,352	$ 5,004	$ 8,375	$ 19,731	1.54%	$ 18,104	2.42%	$ 16,888	2.46%

(i) Average effective yield represents the weighted average rate required to discount future contractual cash flows to current market value.
(ii) Real return bond yields are based on real interest rates. The ultimate yield will be impacted by inflation as it occurs.

After giving effect to derivative contracts (note 4), OAC debt liabilities and amounts payable under the OAC securities lending programs (note 6), a one per cent increase/decrease in nominal interest rates, with all other variables held constant, would result in an approximate decrease/increase in the value of net interest bearing investments and an unrealized (loss)/gain of $579 million (2010: $367 million). Similarly, a one per cent increase/decrease in real interest rates would result in an approximate decrease/increase in the value of real return bonds and an unrealized (loss)/gain of $326 million (2010: $305 million).

- **Price Risk**

Price risk is the risk that the fair value of a financial instrument will fluctuate because of changes in market prices (other than those arising from foreign currency risk or interest rate risk) whether those changes are caused by factors specific to the individual financial instrument, its issuer, or factors affecting all similar financial instruments traded in the market. OAC is subject to price risk through its public equity investments and in addition to geographic, industrial sector and entity specific analysis, uses strategies such as diversification and the use of derivative instruments to mitigate the overall impact of price risk. OAC's private market investments are also subject to price risk as they are impacted by many general and specific market variables. After giving effect to derivative contracts, a ten per cent increase/decrease in the value of all public equity and private market investments, with all other variables held constant, would result in an approximate increase/decrease in the value of public and private market exposure and an unrealized gain/(loss) of $3,758 million (2010: $4,045 million).

b) Credit Risk

Credit risk is the risk of loss arising from the failure of a counterparty to fully honour its financial obligations with OAC, including its inability or unwillingness to pay borrowed principal, interest or rent when they come due. Credit risk can also lead to losses when issuers and debtors are downgraded by credit rating agencies, usually leading to a fall in the market value of the debtors' obligations. OAC has put in place investment policies and procedures that have established investment criteria designed to manage credit risk by setting limits to credit exposure from individual corporate entities and by requiring collateral where appropriate. The credit quality of financial assets is generally assessed by reference to external credit ratings, where available, or to historical information about counterparty default rates. Credit risk associated with derivative financial instruments is discussed in note 4.

NOTE 3

INVESTMENTS (continued)

OAC's most significant credit risk exposure arises from its interest bearing investments. The Funds' interest bearing investments exposed to credit risk are as follows:

(millions)

As at December 31,	2011		2010	
	Interest Bearing Investments	% of Total	Interest Bearing Investments	% of Total
Federal government	$ 6,233	32%	$ 5,551	31%
Provincial government	3,323	17%	2,848	16%
Municipal	22	0%	21	0%
Corporate				
Investment grade	8,570	44%	7,006	39%
Non-investment grade	461	2%	635	3%
Securities lending cash collateral	845	4%	1,566	9%
Cash on deposit	277	1%	477	2%
	$ 19,731	100%	$ 18,104	100%

OAC participates in a securities lending program where it lends securities that it owns to third parties for a fee. For securities lent, the Fund receives a fee and the borrower provides cash or readily marketable securities of higher value as collateral which mitigates the credit risk associated with the program. As at December 31, 2011, securities with an estimated fair value of $2,101 million (2010: $3,615 million) were loaned out, while collateral held had an estimated fair value of $2,182 million (2010: $3,750 million) of which $845 million (2010: $1,566 million) was cash collateral invested in short-term interest bearing investments.

c) Liquidity Risk

Liquidity risk describes the Fund's ability to manage financial liability related cash requirements in a timely and cost effective manner. OAC has developed forward looking liquidity risk models which are used on a periodic basis to assess the impact of tactical and strategic initiatives on Fund liquidity.

OAC's primary future liabilities include the accrued pension obligation of the Plan (note 7) and the RCA (note 8) and debt financing investments (note 6). The contractual undiscounted principal repayments and term to maturity of the investment liabilities are disclosed in note 6.

In the normal course of business, OAC enters into contracts that give rise to commitments for future payments which may also impact our liquidity (note 16).

The cash requirements related to these liabilities are managed using investment income from public and private investments (note 9), contributions made by both members and employers (note 11), and through investing in assets which may be efficiently converted to cash in both normal and stressed market conditions.

Another part of liquidity risk is OAC's ability to cover its commercial paper issuance. OAC is authorized to issue up to $3,100 million in commercial paper to help finance future investment opportunities. OAC holds at least 1.5 times the authorized size of the commercial paper program in high quality liquid assets.

NOTE 4

DERIVATIVE FINANCIAL INSTRUMENTS

Derivative financial instruments are financial contracts, the value of which is derived from changes in underlying assets or indices. Derivatives transactions are conducted in over-the-counter markets directly between two counterparties or on regulated exchange markets.

Derivative financial instruments are used, when appropriate, to manage the Funds' asset mix and to assist in the management of exposure to market risk, including foreign currency, interest rate and price risk, without directly purchasing or selling the underlying assets or currencies. In certain circumstances, derivatives are also used to increase returns or to replicate investments synthetically.

DERIVATIVE CONTRACTS

Types of contracts currently entered into by the Funds include:

Interest Rate Swaps

Interest rate swaps involve contractual agreements between two counterparties to exchange fixed and floating interest payments based on notional amounts.

Bond, Equity and Commodity Swaps

Bond, equity and commodity swaps involve contractual agreements between two counterparties to exchange a series of cash flows based on changes in the value of bond, equity instruments or a bond, equity or commodity index.

Bond, Equity and Commodity Options

Bond, equity and commodity options are contractual agreements where the seller (writer) gives the right but not the obligation to a counterparty to buy (call option) or sell (put option) a specified quantity of a financial instrument or commodity on or before a specified future date at a predetermined price. The instruments may include bonds, a bond index, equities or an equity or a commodity index. The seller receives a premium from the counterparty for this right. Options may be traded through an exchange or in the over-the-counter market.

Bond Forward Contracts

Bond forward contracts are contractual agreements to buy or sell bonds or a bond index at a specified price and date in the future. Forwards are customized contracts transacted in the over-the-counter market.

Equity Index and Commodity Futures Contracts

Futures contracts are agreements to either buy or sell specified equity indices at a specified price and date in the future. Futures are transacted in standardized amounts on regulated exchanges and are subject to daily cash settlement of changes in fair value.

Foreign Exchange Forward Contracts

Foreign exchange forward contracts are obligations in which two counterparties agree to exchange one currency for another at a specified price for settlement on a predetermined date in the future. Foreign exchange forward contracts are used to provide exposure to currencies other than the Canadian dollar, to hedge currency exposure and for active trading.

CREDIT RISK

The Funds are exposed to credit-related losses in the event of non-performance by counterparties to derivative financial instruments. In order to mitigate this risk, the Funds:

- deal only with highly rated counterparties, normally major financial institutions with minimum credit standard of "A" rating, as supported by a recognized credit rating agency; and
- arrange credit risk mitigation in the form of periodic prepayments of the fair value of contracts.

Credit risk represents the maximum amount that would be at risk as at the reporting date if the counterparties failed to perform under the contracts, and if the right of offset proved to be non-enforceable. Credit risk exposure on derivative financial instruments is represented by the replacement cost receivable of contracts with counterparties, less any prepayment collateral or margin received, as at the reporting date.

NOTE 4

DERIVATIVE FINANCIAL INSTRUMENTS (continued)

Credit risk on futures contracts is minimal as the counterparty is an exchange rather than a corporate entity and contracts are marked to market and margin receivables and payables are settled in cash daily.

The following summarizes the Funds' derivative portfolio and related credit exposure:

(millions) As at,	December 31, 2011			December 31, 2010			Opening Balance January 1, 2010		
		Fair Value[ii]			Fair Value[ii]			Fair Value[ii]	
	Notional Value[i]	Assets[iii]	Liabilities	Notional Value[i]	Assets[iii]	Liabilities	Notional Value[i]	Assets[iii]	Liabilities
Interest Rate Contracts									
Interest rate swap contracts	$ 2,332	$ 11	$ (66)	$ 847	$ 10	$ (58)	$ 1,137	$ 10	$ (110)
Bond index swap contracts	904	10	(2)	576	-	(4)	572	-	(5)
Bond futures	80	1	-	-	-	-	-	-	-
Bond options – purchased[iv]	66	1	-	101	-	-	196	10	-
	3,382	23	(68)	1,524	10	(62)	1,905	20	(115)
Equity Contracts									
Equity index futures contracts	5,167	20	(13)	3,642	1	(6)	2,416	2	(16)
Equity index swap contracts	663	10	(3)	914	27	(22)	305	7	-
Equity options written[v]	941	-	(18)	-	-	-	38	-	(1)
Equity options purchased[vi]	531	22	-	-	-	-	-	-	-
	7,302	52	(34)	4,556	28	(28)	2,759	9	(17)
Commodity Contracts									
Commodity futures contracts	48	1	-	-	-	-	-	-	-
Commodity swaps contracts	190	-	-	-	-	-	-	-	-
Commodity options written	25	-	-	-	-	-	-	-	-
Commodity options purchased[vii]	23	-	-	-	-	-	-	-	-
	286	1	-	-	-	-	-	-	-
Foreign Exchange									
Foreign exchange forward contracts	19,038	267	(109)	13,887	296	(42)	12,814	247	(85)
Total	$ 30,008	$ 343	$ (211)	$ 19,967	$ 334	$ (132)	$ 17,478	$ 276	$ (217)

(i) Notional value represents the contractual amount to which a rate or price is applied in order to calculate the exchange of cash flows and is therefore not recorded in the consolidated financial statements.

(ii) Fair value represents unrealized gains or losses from derivative contracts which are recorded in the consolidated statement of financial position based on the fair value of the derivative contract. Fair value represents the cost of replacing all outstanding contracts under current market conditions. Contracts with a positive fair value are recorded as part of amounts due from pending trades. Contracts with a negative fair value are recorded as part of amounts payable from pending trades.

(iii) The fair value of derivative contracts recorded as an asset represents the credit risk replacement cost or the loss to which the Funds are exposed should counterparties fail to perform under the derivative contracts. The amounts do not take into consideration legal contracts that permit offsetting of positions or any collateral which may be held.

(iv) The premium paid on bond options purchased in 2011 was $1 million (December 31, 2010: $2 million, January 1, 2010: $5 million).

(v) The premium received on equity options written in 2011 was $23 million (December 31, 2010: $nil, January 1, 2010: $2 million).

(vi) The premium paid on equity options purchased in 2011 was $29 million.

(vii) The premium paid on commodity options purchased in 2011 was $1 million.

NOTE 4

DERIVATIVE FINANCIAL INSTRUMENTS (continued)
The term to maturity based on notional value is as follows:

(millions) As at,	December 31, 2011					December 31, 2010				Opening Balance January 1, 2010			
	Interest Rate Contracts	Equity Contracts	Com-modity Contracts	Foreign Exchange Contracts	Total	Interest Rate Contracts	Equity Contracts	Foreign Exchange Contracts	Total	Interest Rate Contracts	Equity Contracts	Foreign Exchange Contracts	Total
Under 1 year	**$ 1,493**	**$ 7,302**	**$ 286**	**$ 19,038**	**$ 28,119**	$ 678	$ 4,538	$ 13,887	$ 19,103	$ 888	$ 2,759	$ 12,814	$ 16,461
1 to 5 years	**1,852**	**-**	**-**	**-**	**1,852**	120	18	-	138	327	-	-	327
Over 5 years	**37**	**-**	**-**	**-**	**37**	726	-	-	726	690	-	-	690
	$ 3,382	**$ 7,302**	**$ 286**	**$ 19,038**	**$ 30,008**	$ 1,524	$ 4,556	$ 13,887	$ 19,967	$ 1,905	$ 2,759	$ 12,814	$ 17,478

NOTE 5

OTHER INVESTMENT ASSETS
Other investment assets are comprised of operational accounts receivable, accrued income, and other assets related to private equity, infrastructure and real estate investments.

(millions) As at,	December 31, 2011	December 31, 2010	Opening Balance January 1, 2010
Investment receivables	**$ 197**	$ 176	$ 179
Deferred assets, prepaid and other	**135**	87	56
Other investment assets	**$ 332**	$ 263	$ 235

NOTE 6

INVESTMENT LIABILITIES
The liabilities incurred by OAC in investment related activities are as follows:

(millions) As at,	December 31, 2011	December 31, 2010	Opening Balance January 1, 2010
Debt (a)	**$ 7,239**	$ 7,286	$ 6,809
Payable under securities lending program (b)	**845**	1,566	1,960
Payables and other liabilities	**718**	540	524
Total	**$ 8,802**	$ 9,392	$ 9,293

NOTE 6

INVESTMENT LIABILITIES (continued)

(a) Debt is comprised of the following:

(millions) As at,	December 31, 2011			December 31, 2010			Opening Balance January 1, 2010		
	Fair Value	Cost	Weighted Average Interest Rate	Fair Value	Cost	Weighted Average Interest Rate	Fair Value	Cost	Weighted Average Interest Rate
Oxford Properties Group									
Secured debt[i]	$ 3,175	$ 3,092	3.81%	$ 2,222	$ 2,182	4.56%	$ 1,703	$ 1,756	5.57%
Series A debentures[ii]	520	500	1.49%	531	500	2.27%	540	500	2.65%
Series C debentures[iii]	414	400	1.56%	416	400	2.39%	415	400	2.93%
Series D debentures[iv]	226	200	2.51%	212	200	3.81%	202	200	4.63%
ORCH debentures[v]	188	170	2.15%	182	170	3.33%	177	170	4.01%
ORCH Two debentures[vi]	190	180	1.65%	188	180	2.70%	185	180	3.34%
Commercial paper[vii]	-	-	-	-	-	-	1,296	1,296	0.29%
	4,713	4,542	3.14%	3,751	3,632	3.72%	4,518	4,502	3.27%
Borealis Infrastructure									
Secured debt[viii]	738	735	2.50%	890	885	2.68%	792	787	1.71%
Commercial paper[ix]	-	-	-	-	-	-	1,499	1,499	0.29%
	738	735	2.50%	890	885	2.68%	2,291	2,286	0.78%
OMERS Finance Trust[x]									
Oxford Properties Group commercial paper	1,447	1,447		1,568	1,568		-	-	
Borealis Infrastructure commercial paper	341	341		1,067	1,067		-	-	
Other	-	-		10	10		-	-	
	1,788	1,788	1.10%	2,645	2,645	1.14%	-	-	-
Total[xi]	$ 7,239	$ 7,065	2.57%	$ 7,286	$ 7,162	2.70%	$ 6,809	$ 6,788	2.43%

(i) Includes mortgages and other secured debt with various terms to maturity up to 2027 with each debt instrument secured by a specific real estate asset.
(ii) OMERS Realty Corporation Series A 5.48% Debentures issued December 4, 2002, maturing December 31, 2012.
(iii) OMERS Realty Corporation Series C 4.09% Debentures issued May 8, 2008, maturing June 4, 2013.
(iv) OMERS Realty Corporation Series D 4.74% Debentures issued May 8, 2008, maturing June 4, 2018.
(v) OMERS Realty CTT Holdings Inc. Series A 4.75% Debentures issued May 5, 2009, maturing May 5, 2016.
(vi) OMERS Realty CTT Holdings Two Inc. Series A 4.05% Debentures issued May 5, 2009, maturing May 5, 2014.
(vii) OMERS Realty Corporation's Commercial Paper program was discontinued during 2010. Effective April 12, 2010 all OAC guaranteed Commercial Paper is issued through OMERS Finance Trust.
(viii) Includes mortgages and other secured debt with various terms to maturity up to 2042 with each debt secured by a specific infrastructure asset.
(ix) Borealis Finance Trust's Commercial Paper program was discontinued during 2010. Effective April 12, 2010 all OAC guaranteed Commercial Paper is issued through OMERS Finance Trust.
(x) OMERS Finance Trust's Commercial Paper program is authorized up to $3,100 million. Commercial Paper outstanding has maturities from January 3, 2012 to March 21, 2012.
(xi) Scheduled undiscounted principal and interest repayments for the five years subsequent to December 31, 2011 and thereafter are as follows:

(millions)	
2012	$ 3,607
2013	1,366
2014	448
2015	424
2016	1,063
Thereafter	912
	$ 7,820

NOTE 6

INVESTMENT LIABILITIES (continued)

Investment assets where OAC has effective control are presented in the Statement of Financial Position on a non-consolidated basis. The cost of debt (which is non-recourse to OAC) incurred in such investments is as follows:

(millions) As at,	December 31, 2011	December 31, 2010	Opening Balance January 1, 2010
Borealis Infrastructure	$ 5,998	$ 5,460	$ 2,634
OMERS Private Equity	1,381	664	438
OMERS Strategic Investments	181	167	121
Total	$ 7,560	$ 6,291	$ 3,193

Various derivative financial instruments are used by investment assets of OAC to assist in the management of exposure to interest rate risk in the debt identified above. The notional value of these interest rate swap agreements is $905 million as at December 31, 2011 (2010: $825 million).

(b) As part of the securities lending program, the Plan receives cash collateral that it invests in short-term interest bearing investments. The Plan is obligated to return the cash collateral upon termination of the arrangement. The securities lending agreements may be terminated at anytime and as such the collateral is repayable on demand.

NOTE 7

OMERS PRIMARY PENSION PLAN

A summary of the financial statements of the Primary Plan is as follows:

STATEMENT OF FINANCIAL POSITION

(millions) As at,	December 31, 2011	December 31, 2010	Opening Balance January 1, 2010
Net Assets Available for Benefits			
Investments	$ 64,026	$ 62,919	$ 57,267
Other investment assets	332	263	235
Amounts due from pending trades	375	382	311
Contributions receivable	227	198	180
Other assets	29	36	23
Investment liabilities	(8,802)	(9,392)	(9,293)
Due to administered funds	(828)	(809)	(734)
Amounts payable from pending trades	(261)	(236)	(151)
Other liabilities	(83)	(71)	(54)
Net Assets Available for Benefits	$ 55,015	$ 53,290	$ 47,784
Accrued Pension Obligation and Deficit			
Defined benefit component			
Accrued pension obligation	$ 64,548	$ 60,035	$ 54,253
Deficit			
Funding deficit	(7,290)	(4,467)	(1,519)
Actuarial value adjustment of net assets	(2,337)	(2,278)	(4,950)
	(9,627)	(6,745)	(6,469)
Additional voluntary contributions component			
Pension obligation	94	-	-
Total Primary Plan Accrued Pension Obligation and Deficit	$ 55,015	$ 53,290	$ 47,784

STATEMENT OF CHANGES IN NET ASSETS AVAILABLE FOR BENEFITS

(millions) For the year ended December 31,	2011	2010
Net investment income	$ 1,364	$ 5,382
Contributions	2,795	2,299
Benefits	(2,376)	(2,121)
Pension administrative expenses	(58)	(54)
Total Increase	1,725	5,506
Net assets available for benefits, beginning of year	53,290	47,784
Net Assets Available for Benefits, End of Year	$ 55,015	$ 53,290

NOTE 7

OMERS PRIMARY PENSION PLAN (continued)

ACTUARIAL VALUE OF NET ASSETS OF THE DEFINED BENEFIT COMPONENT

The actuarial valuation of the Plan was performed by Towers Watson Canada Inc. Under the PBA an independent actuarial valuation must be filed with FSCO at least once every three years. The Plan valuation was last filed for the December 31, 2010 year-end and, if not filed earlier, must be filed for the December 31, 2013 year-end.

The actuarial value of net assets of the Plan is established such that investment returns above or below the long-term return assumption in effect for the year, 6.50 per cent for 2011 (2010: 6.50 per cent) are recognized over 5 years to smooth fluctuations in the market value of net assets. For 2011, $1,686 million was debited to the actuarial valuation adjustment because the investment return was below the long-term rate of return assumption. This compares with 2010 when $1,816 million was credited to the actuarial valuation adjustment because the investment return was in excess of the long-term rate of return assumption.

As a result, at December 31, 2011, the Plan has $2,337 million in the actuarial valuation adjustment reserve representing the net unrecognized returns below the long-term rate of return assumption (2010: $2,278 million net unrecognized returns below the long-term rate of return assumption). The present value of unrecognized net investment returns by initial year they were established and the amounts to be recognized from 2012 through 2015, after application of the long-term return assumption, are as follows:

(millions)

Initial Year Earned	Actuarial Valuation Adjustment as at Dec. 31, 2011[i]	Unrecognized Investment Returns to be Recognized in 2012	2013	2014	2015	Actuarial Valuation Adjustment as at Dec. 31, 2010
2007	**$ -**	$ -	$ -	$ -	$ -	$ 167
2008	**(2,773)**	(2,954)	-	-	-	(5,209)
2009	**673**	359	382	-	-	948
2010	**1,449**	515	548	584	-	1,816
2011	**(1,686)**	(450)	(478)	(509)	(543)	-
	$ (2,337)	$ (2,530)	$ 452	$ 75	$ (543)	$ (2,278)

(i) For each initial year, amounts in the actuarial valuation adjustment reserve are escalated annually by the long-term return assumption. Reserve amounts are recognized in actuarial assets based on the number of years remaining in the five-year smoothing period.

The change in the actuarial adjustment is as follows:

(millions)

For the year ended December 31,	2011	2010
Expected interest on beginning actuarial valuation adjustment[i]	**$ (148)**	$ (321)
Current year returns in excess of/(below) the funding rate[i]	**(1,686)**	1,816
Prior years' returns below the funding rate recognized in the year	**1,775**	1,177
Increase/(Decrease)	**(59)**	2,672
Actuarial valuation adjustment, beginning of year	**(2,278)**	(4,950)
Actuarial Valuation Adjustment, End of Year	**$ (2,337)**	$ (2,278)

(i) Based on the funding rate in effect during the year, 2011: 6.50 per cent (2010: 6.50 per cent).

NOTE 7

OMERS PRIMARY PENSION PLAN (continued)

ACCRUED PENSION OBLIGATIONS OF THE DEFINED BENEFIT COMPONENT

The actuarial present value of the accrued pension obligation is an estimate of the value of pension obligations of the Plan in respect of benefits accrued to date for all active and inactive members. This obligation is measured using the same actuarial assumptions and methods adopted by OAC for determining the Plan's minimum funding requirements as set out under the PBA. As the experience of the Plan unfolds, and as underlying conditions change over time, the actual value of accrued benefits payable in the future could be materially different than the actuarial present value.

The projected benefit method pro-rated on service is used for the actuarial valuation. Under this method, the cost of providing benefits to an individual member will increase as the individual member ages and gets closer to retirement.

The following are the primary economic actuarial assumptions which have been used in the actuarial valuation of the Plan as at December 31:

	2011	2010
Assumed rate of inflation	**2.25%**	2.25%
Real rate of return assumed on Plan assets	**4.25%**	4.25%
Discount rate (rate of inflation plus real rate of return)	**6.50%**	6.50%

The assumed increases in the real rate of pensionable earnings (i.e. increase in excess of the assumed inflation rate) are dependent on the attained age of the members. These rates of increase were updated in 2009 to reflect recent experience of the Plan and current expectations for future years.

	2011				2010			
	NRA 60[(i)]		NRA 65[(i)]		NRA 60[(i)]		NRA 65[(i)]	
	Until 2014	After 2014	Until 2014	After 2014	Until 2014	After 2014	Until 2014	After 2014
Assumed real rate of pensionable earnings increases (weighted average of a table of age related increases)	**1.40%**	**1.90%**	**1.10%**	**1.60%**	1.40%	1.90%	1.10%	1.60%
Rate of pensionable earnings increases (assumed rate of inflation plus real rate of pensionable earnings increases)	**3.65%**	**4.15%**	**3.35%**	**3.85%**	3.65%	4.15%	3.35%	3.85%

(i) Normal Retirement Age of 60 and 65 years of age respectively.

In addition, demographic assumptions are used to estimate when future benefits are payable to members and beneficiaries, including assumptions about mortality rates, termination rates, and patterns of early retirement. Each of these assumptions is updated periodically, based on a detailed review of the experience of the Plan and on the expectations for future trends. During 2010, the early retirement assumption was updated to reflect the Plan's recent retirement experience and to account for an anticipated future trend towards older retirement ages.

The accrued pension obligation as at December 31, 2011 takes account of known changes in the Plan membership up to December 2, 2011, actual inflationary increases to pension payments and deferred pension payments to be implemented as at January 1, 2012 and estimated pensionable earnings and credited service accruals in 2011.

NOTE 7

OMERS PRIMARY PENSION PLAN (continued)

The deficit of the Plan's actuarial value of net assets available for benefits over accrued pension obligation is as follows:

(millions) As at December 31,	2011	2010
Primary Plan fair value of net assets available for benefits	$ 55,015	$ 53,290
Less additional voluntary contribution net assets	94	-
Defined benefit net assets available for benefits	54,921	53,290
Actuarial value adjustment	2,337	2,278
Actuarial value of net assets available for benefits	57,258	55,568
Accrued pension obligation	64,548	60,035
Funding deficit of actuarial value of net assets available for benefits over accrued pension obligation	(7,290)	(4,467)
Reversal of actuarial value adjustment	(2,337)	(2,278)
Deficit of net assets available for benefits over accrued pension obligation	$ (9,627)	$ (6,745)

As the Plan provides 100 per cent inflation protection, the accrued pension obligation is particularly sensitive to changes in the assumed real rate of pensionable earnings increases, which impacts future benefits, and the assumed real rate of return on Plan assets, which is used in the discounting of these future benefits. A 50 basis point change in the following assumptions (with no change in other assumptions) would have the following approximate effects on the accrued pension obligation:

50 Basis Point Decrease/Increase	Approximate Effect on Accrued Pension Obligation
Real rate of pensionable earnings increases	-/+$1,400 million
Real return on plan assets and discount rate	+/-$4,900 million

NOTE 8

RETIREMENT COMPENSATION ARRANGEMENT

The Retirement Compensation Arrangement provides pension benefits for those members with earnings exceeding the amount that generates the maximum pension allowed by the *Income Tax Act* with respect to service after 1991. Under the *OMERS Act*, OAC is the administrator of the RCA. The investments of the RCA are managed separate from those of the Plan.

The full earnings pension benefits provided by the RCA are not fully funded but are funded on a modified pay-as-you-go basis in order to minimize the impact of the 50 per cent refundable tax applicable to all RCA plans under the *Income Tax Act*. Contributions to the RCA are based on the top-tier Plan contribution rates and are currently payable to the RCA on the excess of earnings over a defined earnings threshold, which was $143,912 for 2011 (2010: $140,652). Effective January 1, 2012, this earnings threshold will be actively managed and monitored in such a way that future contributions to the RCA, together with the existing RCA Fund and future investment earnings, are expected to be sufficient to provide for projected benefit payments over the 20-year period following each annual valuation date. Benefits in excess of the maximum amounts payable from the Plan as allowed by the *Income Tax Act* will be paid from the RCA.

A summary of the financial statements for the RCA is as follows:

STATEMENT OF FINANCIAL POSITION

(millions) As at,	December 31, 2011	December 31, 2010	Opening Balance January 1, 2010
Net Assets Available for Benefits			
Net investment assets	$ 32	$ 29	$ 20
Other assets	36	30	27
Contributions receivable	1	1	1
Other liabilities	(1)	(1)	-
Net Assets Available for Benefits	$ 68	$ 59	$ 48
Accrued Pension Obligation and Deficit			
Accrued pension obligation	$ 504	$ 468	$ 486
Deficit	(436)	(409)	(438)
Accrued Pension Obligation and Deficit	$ 68	$ 59	$ 48

STATEMENT OF CHANGES IN NET ASSETS AVAILABLE FOR BENEFITS

(millions) For the year ended December 31,	2011	2010
Net investment income/(loss)	$ (1)	$ 2
Contributions	18	14
Benefits	(7)	(5)
Administrative expenses	(1)	-
Total Increase	9	11
Net assets available for benefits, beginning of year	59	48
Net Assets Available for Benefits, End of Year	$ 68	$ 59

NOTE 8

RETIREMENT COMPENSATION ARRANGEMENT (continued)

The actuarial assumptions used for the RCA are consistent with those used for the Plan except that the discount rate as at December 31, 2011 is 3.25 per cent (2010: 3.25 per cent), which approximates the effect of the 50 per cent refundable tax applicable to the RCA. A 50 basis point decrease/increase in the assumed rate (with no change in other assumptions) before reflecting the 50 per cent refundable tax would have a +/- $25 million (2010: +/- $25 million) impact on the accrued pension obligation.

Determination of the value of the RCA accrued pension obligation is made on the basis of an actuarial valuation. The deficit of net assets over accrued pension obligation as at December 31 is as follows:

(millions) As at December 31,		**2011**		2010
Fair value of net assets at end of year	**$**	**68**	$	59
Accrued pension obligation at end of year		**504**		468
Deficit of actuarial value of net assets over accrued pension obligation	**$**	**(436)**	$	(409)

NOTE 9

NET INVESTMENT INCOME/(LOSS)

The Funds' investments consist of the following major asset classes; public markets (which includes public equities and interest bearing investments such as treasury bills, bonds, mortgages and private debt), private equity, infrastructure and real estate.

Income from assets backing derivative financial instruments is reported in the particular investment category by major asset class. Realized and unrealized income from derivative financial instruments in 2011 is a loss of $626 million (2010: a gain of $1,087 million).

The Funds' investment income/(loss) by asset classes is as follows:

(millions)
For the year ended December 31, **2011**

	Investment Income[i][ii]	Net Gain/(Loss) on Investment Assets, Liabilities and Derivatives[iii]	Total Investment Income/(Loss)	Investment Management Expenses (note 13(b))[iv]	Net Investment Income/(Loss)
Public Market Investments					
Interest Bearing Investments					
Short-term deposits	$ 45	$ 29	$ 74		
Bonds and debentures	339	582	921		
Mortgages and private debt	109	(21)	88		
	493	590	1,083		
Real return bonds	38	232	270		
Public Equity					
Canadian public equities	95	(1,215)	(1,120)		
Non-Canadian public equities	228	(566)	(338)		
	323	(1,781)	(1,458)		
Total Public Market Investments	854	(959)	(105)	(126)	(231)
Private Equity					
Canadian private equities	217	131	348		
Non-Canadian private equities	51	128	179		
Total Private Equity Investments	268	259	527	(89)	438
Infrastructure Investments	437	287	724	(53)	671
Real Estate Investments[v]	429	167	596	(11)	585
	$ 1,988	$ (246)	$ 1,742	$ (279)	1,463
Gain/(loss) from currency hedging activities[vi]					(79)
(Income)/loss credited to administered funds					(21)
Net Investment Income/(Loss)					$ 1,363

NOTE 9

NET INVESTMENT INCOME/(LOSS) (continued)

(millions)

For the year ended December 31,	Investment Income[i][ii]	Net Gain/(Loss) on Investment Assets, Liabilities and Derivatives[iii]	Total Investment Income/(Loss)	Investment Management Expenses (note 13(b))[iv]	Net Investment Income/(Loss)
					2010
Public Market Investments					
Interest Bearing Investments					
Short-term deposits	$ 22	$ (4)	$ 18		
Bonds and debentures	339	249	588		
Mortgages and private debt	70	57	127		
	431	302	733		
Real return bonds	46	121	167		
Public Equity					
Canadian public equities	136	992	1,128		
Non-Canadian public equities	167	1,008	1,175		
	303	2,000	2,303		
Total Public Market Investments	780	2,423	3,203	(114)	3,089
Private Equity					
Canadian private equities	71	203	274		
Non-Canadian private equities	93	731	824		
Total Private Equity Investments	164	934	1,098	(99)	999
Infrastructure Investments	540	214	754	(44)	710
Real Estate Investments[v]	428	70	498	(11)	487
	$ 1,912	$ 3,641	$ 5,553	$ (268)	5,285
Gain/(loss) from currency hedging activities[vi]					182
(Income)/loss credited to administered funds					(83)
Net Investment Income/(Loss)					$ 5,384

(i) Investment income includes interest, dividends and real estate operating income accrued or received net of interest expense on liabilities incurred in investment related activities. Investment income is also net of transaction costs of $121 million (2010: $80 million) and net of external manager performance fees of $36 million (2010: $47 million).
(ii) Interest on investment related activities includes interest on real estate investment liabilities of $204 million (2010: $161 million), interest on infrastructure investment liabilities of $48 million (2010: $46 million).
(iii) Includes net realized gain of $698 million (2010: $2,412 million).
(iv) Investment management expenses relate to corporate activity.
(v) Real estate investment income includes Oxford Properties Group's operating expenses net of property management income of $14 million (2010: $23 million) which includes audit costs of $3.3 million (2010: $2.6 million) and legal costs of $5.6 million (2010: $5.6 million).
(vi) Represents the gain/(loss) on the Fund's passive foreign currency hedging activities.

NOTE 9

NET INVESTMENT INCOME/(LOSS) (continued)
The Funds' net investment income/(loss) by Investment Entity is as follows:

(millions)
For the year ended December 31, **2011**

	OMERS Capital Markets	OMERS Private Equity	Borealis Infrastructure	Oxford Properties Group	OMERS Strategic Investments	Total
Public market investments	**$ (296)**	**$ -**	**$ -**	**$ 25**	**$ 40**	**$ (231)**
Private equity investments	**-**	**354**	**-**	**-**	**84**	**438**
Infrastructure investments	**-**	**-**	**674**	**-**	**(3)**	**671**
Real estate investments	**-**	**-**	**-**	**585**	**-**	**585**
Net Investment Income/(Loss)[i]	**$ (296)**	**$ 354**	**$ 674**	**$ 610**	**$ 121**	**$ 1,463**

(millions)
For the year ended December 31, 2010

	OMERS Capital Markets	OMERS Private Equity	Borealis Infrastructure	Oxford Properties Group	OMERS Strategic Investments	Total
Public market investments	$ 3,036	$ -	$ -	$ -	$ 53	$ 3,089
Private equity investments	-	941	-	-	58	999
Infrastructure investments	-	-	693	-	17	710
Real estate investments	-	-	-	487	-	487
Net Investment Income[i]	$ 3,036	$ 941	$ 693	$ 487	$ 128	$ 5,285

(i) Before gain/(loss) from currency hedging activities and income/(loss) credited to administered funds.

NOTE 10

INVESTMENT RETURNS

Investment returns have been calculated in accordance with methods set forth by the CFA Institute.

The Plan's percentage returns by investment entity are as follows:

For the year ended December 31,	2011	2010
OMERS Primary Pension Plan Gross Returns by Entity		
OMERS Capital Markets[i]	**-0.22%**	11.04%
OMERS Private Equity	**7.23%**	22.21%
Borealis Infrastructure	**8.79%**	10.10%
Oxford Properties	**8.40%**	7.51%
OMERS Strategic Investments	**7.24%**	7.65%
Total OMERS Primary Pension Plan[ii]	**3.17%**	12.01%
Retirement Compensation Arrangement		
RCA Investment Fund[iii]	**-2.42%**	7.99%

The above gross returns are before the impact of external manager performance fees, and administrative expenses. The Plan net return after all investment costs for the year ended December 31, 2011 was 2.59 per cent (2010: 11.37 per cent).

(i) Returns for OMERS Capital Markets are before the impact of external manager performance fees and external manager fees related to public market fund investments (Note 9).
(ii) Total returns include the results of the Plan's currency hedging related activities.
(iii) Excludes the RCA refundable tax balance with CRA. Including the refundable tax balance, the RCA December 31, 2011 rate of return was negative 1.25 per cent (2010: 4.31 per cent).

NOTE 11

CONTRIBUTIONS

(millions) For the year ended December 31,	2011	2010
Current service required contributions[i]	$ 2,618	$ 2,227
Transfers from other pension plans	41	27
Past service contributions from members[ii]	53	52
Past service contributions from employers[ii]	8	7
Contributions before AVC contributions	2,720	2,313
AVC contributions	93	-
	$ 2,813	$ 2,313

(i) Current service contributions are funded equally by employers and members. For NRA 65 members, the 2011 contribution rate was 7.4 per cent (2010: 6.4 per cent) of earnings up to $48,300 (2010: $47,200) and 10.7 per cent (2010: 9.7 per cent) of earnings above that level. For NRA 60 members, the 2011 contribution rate was 8.9 per cent (2010: 7.9 per cent) of earnings up to $48,300 (2010: $47,200) and 14.1 per cent (2010: 13.1 per cent) of earnings above that level.

(ii) Past service contributions include amounts for leaves of absence, conversion of normal retirement age and contract adjustments.

For the year ended December 31, 2011, contributions to the Plan defined benefit component were $2,702 million (2010: $2,299 million) and to the Plan AVC component were $93 million (2010: $nil). Contributions to the RCA for the year ended December 31, 2011 were $18 million (2010: $14 million).

NOTE 12

BENEFITS

(millions) For the year ended December 31,	2011	2010
Retirement benefits	$ 2,021	$ 1,866
Disability benefits	26	24
Transfers to other registered plans	190	134
Death benefits	66	46
Commuted value payments and members' contributions plus interest refunded	80	56
	$ 2,383	$ 2,126

For the year ended December 31, 2011, total benefit payments from the Plan defined benefit component were $2,375 million (2010: $2,121 million) and from the AVC component were $1 million (2010: $nil). Benefit payments from the RCA for the year ended December 31, 2011 were $7 million (2010: $5 million).

NOTE 13

PENSION ADMINISTRATIVE AND INVESTMENT MANAGEMENT EXPENSES

(a) Pension administrative expenses[(i)]

(millions) For the year ended December 31,	2011	2010
Salaries and benefits	$ 35	$ 34
System development and other purchased services	5	4
Premises and equipment	4	3
Professional services[(ii)]	10	8
Travel and communication	5	5
	$ 59	$ 54

(b) Investment management expenses[(i)]

(millions) For the year ended December 31,	2011	2010
Salaries and benefits	$ 147	$ 130
System development and other purchased services	14	12
Premises and equipment	11	7
Professional services[(ii)]	22	22
Travel and communication	12	11
Investment management services[(iii)]	73	86
	$ 279	$ 268

(i) Includes allocation of corporate expenses.
(ii) Total professional services expenses include independent actuarial costs of $1.1 million (2010: $0.7 million), external audit costs of $0.9 million (2010: $0.9 million) and external legal costs of $6.2 million (2010: $7.2 million).
(iii) Includes external management and custody fees.

NOTE 14

RELATED PARTY DISCLOSURES

The OAC manages its real estate, infrastructure and private equity businesses through OAC Investment Entities as discussed in Note 1 and holds investments through a network of investment structures or subsidiary companies established in compliance with the OMERS Act, the Pension Benefits Act, the *Income Tax Act* and other statutory, regulatory and tax legislation governing the OAC.

The OAC's related parties include 947 employers whose employees are members of the Plan, the SC, members of OAC Board, key management personnel (defined below) and investments where OAC has controlling interest. Transactions with related parties include the following:

- The OAC, in the normal course of business, purchased bonds at the prevailing market prices that were issued by a municipal employer. The fair market value of the bonds outstanding at December 31, 2011 was $22 million (2010: $21 million).

- The OAC through its Oxford Properties Group paid property taxes to municipal employers for the year ended December 31, 2011 of $231 million (2010: $221 million). The amounts paid were based on normal levies by the individual municipal employers and were consistent with those that would be paid by a non-related party.

KEY MANAGEMENT PERSONNEL COMPENSATION

Key management personnel consist of members of the OAC's Board of Directors, Chief Executive Officer, Chief Financial Officer, Chief Investment Officer, Chief Pension Officer and the chief executive officers of OMERS Capital Markets, Oxford Properties Group, Borealis Infrastructure and OMERS Private Equity. The aggregate key management personnel compensation is shown below:

(millions) For the year ended December 31,	2011	2010
Salaries and short-term employee benefits	$ 14	$ 15
Post-employment benefits	1	1
Other long-term benefits	6	5
	$ 21	$ 21

The OAC had no other transactions with key management personnel during the year.

NOTE 15

CAPITAL

OAC defines its capital as the funded status (surplus/(deficit)) of each of the OMERS Pension Plans, as determined annually based on the fair value of the net assets of the OMERS Pension Plans, the actuarial value adjustment of net assets and the actuarial valuation prepared by the OAC's independent actuary on a going concern basis. The funded status of the Plan is discussed in Note 7 and the funded status of the RCA is discussed in Note 8. OAC's objective is to ensure that the Plan defined benefit component is fully funded over the long-term through the management of investments, contribution rates and benefits. Investments (Note 3), the use of derivatives (Note 4) and leverage (Note 6) are based on an asset mix and risk management policies and procedures that are designed to enable the Plan to meet or exceed its long-term funding requirement within an acceptable level of risk, consistent with the Plan's Statement of Investment Policies and Procedures as approved by the OAC Board.

The Plan AVC component pension liability is based on net contributions plus investment income and as such does not have a surplus/(deficit) position.

The RCA is funded on a modified pay-as-you-go basis in order to minimize the impact of the 50 per cent refundable tax applicable to all RCA plans. The RCA investments are based on an asset mix and Statement of Investment Policies and Procedures separate from those of the Plan.

The funded status of each plan and the related cash flows are also impacted by the level of contributions (Note 11) and benefits (Note 12). The SC is responsible for setting contribution rates above the minimum required to fund the plan, subject to compliance with legislation, and determining benefits for the OMERS Pension Plans.

The Plan and Supplemental Plan are subject to FSCO regulations which require the Plan to file an actuarial valuation report for a funding valuation at least once every three years. At that time, the Plan must take measures to eliminate any going concern funding deficits over a period not to exceed 15 years.

Where the funded status of the Plan is filed with a surplus position greater than ten per cent of the accrued pension obligation, the *Income Tax Act* requires contributions be reduced with the amount of the reduction increasing as the percentage surplus increases. Once the filed surplus reaches twenty-five per cent of the accrued pension obligation, regular contributions must be eliminated. The SC is responsible for determining when an actuarial valuation of the Plan and Supplemental Plan should be filed, subject to the requirements under the regulations. There are no similar filing requirements for the RCA as the RCA is not a registered pension plan.

NOTE 16

GUARANTEES, COMMITMENTS AND CONTINGENCIES

As part of normal business operations, OAC enters into commitments and guarantees related to the funding of investments. Future commitments to fund investments include, but may not be limited to, investments in infrastructure, real estate and private equity limited partnership agreements. The future commitments are generally payable on demand based on the capital needs of the investment. As at December 31, 2011, these future commitments totaled $4.2 billion (2010: $4.4 billion). The maximum amount payable under guarantees and standby letters of credit provided as part of investment transactions was $740 million as at December 31, 2011 (2010: $520 million). Guarantees and commitments are often provided as part of developing or holding an investment and as such often have no fixed expiration date.

OAC, in the normal course of business, indemnifies its and its subsidiaries' and affiliates' directors, officers, employees and certain others in connection with proceedings against them to the extent that these individuals are not covered under another arrangement. In addition, OAC may in certain circumstances in the course of investment activities agree to indemnify a counterparty. Under the terms of such arrangements, OAC and/or its subsidiaries and affiliates may be required to compensate these parties for costs incurred as a result of various contingencies such as changes in laws and regulations or legal claims. The contingent nature of the liabilities in such agreements and the range of indemnification prevent the OAC from making a reasonable estimate of the maximum amount that would be required to pay such indemnifications.

As at December 31, 2011, OAC was involved in certain litigation and claims. The outcome of such litigation and claims is inherently difficult to predict; however, in the opinion of Management, any liability that may arise from such contingencies would not have a significant adverse effect on the consolidated financial statements of OAC.

TEN-YEAR FINANCIAL REVIEW

($ millions)	2011	2010[i]	2009	2008	2007	2006	2005	2004	2003	2002
Net Assets Available for Benefits										
as at December 31,										
Public markets	**32,154**	34,123	31,336	28,763	43,291	43,533	39,338	30,283	30,168	23,823
Private equity	**7,753**	6,633	5,048	4,162	3,608	2,951	2,391	1,460	914	1,021
Infrastructure	**9,635**	9,593	12,195	12,140	8,412	5,585	3,719	2,314	1,426	349
Real estate	**14,516**	12,599	11,975	12,037	10,904	8,541	6,180	6,898	6,920	7,747
	64,058	62,948	60,554	57,102	66,215	60,610	51,628	40,955	39,428	32,940
Other investment assets	**707**	645	1,173	1,366	1,001	699	765	494	578	733
Investment liabilities	**(9,063)**	(9,628)	(13,338)	(14,474)	(15,029)	(13,088)	(10,772)	(5,267)	(7,297)	(3,540)
Net investment assets	**55,702**	53,965	48,389	43,994	52,187	48,221	41,621	36,182	32,709	30,133
Non investment assets/(liabilities)										
Due to administered funds	**(828)**	(809)	(734)	(672)	(800)	(741)	(639)	(553)	(496)	(440)
Other assets/(liabilities)	**209**	193	177	155	129	125	83	26	(120)	(188)
Net assets available for benefits	**55,083**	53,349	47,832	43,477	51,516	47,605	41,065	35,655	32,093	29,505
Accrued Pension Obligation and Surplus/(Deficit)										
as at December 31,										
OMERS Primary Pension Plan										
Defined Benefit Component										
Accrued pension obligation	**64,548**	60,035	54,253	50,080	46,830	44,167	41,123	37,774	35,466	33,034
Funding Surplus/(Deficit)	**(7,290)**	(4,467)	(1,519)	(279)	82	(2,382)	(2,784)	(963)	509	2,514
Actuarial value adjustment of net assets	**(2,337)**	(2,278)	(4,950)	(6,363)	4,567	5,791	2,707	(1,168)	(3,888)	(6,048)
	(9,627)	(6,745)	(6,469)	(6,642)	4,649	3,409	(77)	(2,131)	(3,379)	(3,534)
	54,921	53,290	47,784	43,438	51,479	47,576	41,046	35,643	32,087	29,500
Additional Voluntary Contributions Component										
Pension obligation	**94**	-	-	-	-	-	-	-	-	-
Net assets available for benefits	**55,015**	53,290	47,784	43,438	51,479	47,576	41,046	35,643	32,087	29,500
RCA										
Accrued pension obligation	**504**	468	486	285	236	172	157	149	69	63
(Deficit)	**(436)**	(409)	(438)	(246)	(199)	(143)	(138)	(137)	(63)	(58)
Net asset available for benefits	**68**	59	48	39	37	29	19	12	6	5
Total Accrued Pension Obligation and Deficit	**55,083**	53,349	47,832	43,477	51,516	47,605	41,065	35,655	32,093	29,505
Changes in Net Assets Available for Benefits										
for the year ended December 31,										
Net assets, beginning of the year	**53,349**	47,832	43,477	51,516	47,568[ii]	41,065	35,655	32,093	29,505	33,243
Changes Due to Investment Activities										
Total investment income	**1,663**	5,735	4,623	(7,910)	4,200	6,803	5,767	3,907	3,751	(2,358)
Investment management expenses	**(279)**	(268)	(246)	(227)	(201)	(169)	(160)	(147)	(158)	(103)
	1,384	5,467	4,377	(8,137)	3,999	6,634	5,607	3,760	3,593	(2,461)
(Income)/Loss credited to administered funds	**(21)**	(83)	(67)	124	(61)	(104)	(92)	(66)	(51)	28
Net investment income/(loss)	**1,363**	5,384	4,310	(8,013)	3,938	6,530	5,515	3,694	3,542	(2,433)
Changes Due to Pension Activities										
Contributions										
Current service	**2,618**	2,227	2,077	1,975	1,840	1,739	1,498	1,363	404	-
Other contributions	**195**	86	66	73	46	53	36	46	42	47
	2,813	2,313	2,143	2,048	1,886	1,792	1,534	1,409	446	47
Benefits										
Pensions paid	**(2,047)**	(1,890)	(1,781)	(1,656)	(1,554)	(1,492)	(1,410)	(1,353)	(1,246)	(1,153)
Commuted value and other payments	**(336)**	(236)	(269)	(371)	(279)	(252)	(193)	(145)	(110)	(149)
	(2,383)	(2,126)	(2,050)	(2,027)	(1,833)	(1,744)	(1,603)	(1,498)	(1,356)	(1,302)
Pension administrative expenses	**(59)**	(54)	(48)	(47)	(43)	(38)	(36)	(43)	(44)	(50)
Net assets available for benefits, end of year	**55,083**	53,349	47,832	43,477	51,516	47,605	41,065	35,655	32,093	29,505
Total Annual Rate of Return										
for year ended December 31,										
OMERS Primary Pension Plan										
Defined Benefit Component										
Time weighted return on market value	**3.17%**	12.01%	10.6%	-15.3%	8.7%	16.4%	16.0%	12.1%	12.7%	-7.1%
Benchmark	**2.52%**	11.47%	12.1%	-13.2%	5.6%	13.7%	13.2%	9.9%	15.5%	-7.4%
Additional Voluntary Contributions Component										
Time weighted net return on market value	**2.59%**	-	-	-	-	-	-	-	-	-
RCA Investment Fund[iii]										
Time weighted return on market value	**-2.42%**	7.99%	11.3%	-26.1%	8.7%	16.4%	16.0%	12.1%	12.7%	-7.1%
Benchmark	**-2.43%**	10.09%	16.6%	-27.3%	5.6%	13.7%	13.2%	9.9%	15.5%	-7.4%

(i) In preparing financial statements in accordance with CICA Handbook Section 4600-Pension Plans and IFRS for 2011, OAC has adjusted amounts for 2010 (which were previously reported in accordance with CICA Handbook Section 4100) for comparative purposes.
(ii) 2007 beginning of the year net assets were decreased by $37 million to reflect a change in accounting policy for transaction costs.
(iii) Excludes the RCA refundable tax balance with the Canada Revenue Agency.

GLOSSARY

Absolute Return Strategies Strategies expected to generate positive returns regardless of the movements of the financial markets due to their low correlation to broad financial markets. Absolute return strategies may be used with the objective of increasing the overall investment portfolio risk-adjusted return while contributing to the stability of the overall investment portfolio returns.

Accrued Pension Obligation The actuarial present value of future pension benefits earned to date.

Actuarial Smoothing A common practice accepted in the actuarial profession and by pension regulators to reduce the effect of short-term market fluctuations on pension plan funding by deferring and recognizing changes in net assets above or below the long-term funding objective over five years.

Actuarial Valuation Report A report issued by the OAC's actuary on the funded status of the OMERS Pension Plans. The actuarial valuation is based on a set of assumptions, as approved by the OAC Board, that include demographic and economic assumptions.

Additional Voluntary Contributions (AVCs) A new retirement savings opportunity for members of the OMERS Primary Pension Plan, effective January 1, 2011. AVCs will enable members and retirees (to age 70) to take advantage of OMERS investment returns by making additional contributions. Such contributions can include ongoing withdrawals from a bank account (for active members) as well as lump-sum transfers from other registered retirement vehicles (for active, retired and deferred members).

Basis Point One basis point equals 1/100th of one percentage point.

Benchmark A benchmark is a standard or point of reference against which performance of an investment is measured. It is generally a passive external index (e.g., the S&P/TSX Composite Index) or for the OAC's infrastructure and real estate investments a predetermined absolute return based on operating plans approved by the OAC Board.

Benefit Accrual The accumulation of pension benefits based on a formula using years of credited service, pensionable earnings and an accrual rate. This is expressed in the form of an annual benefit to begin payment at normal retirement age.

Bridge Benefit A temporary benefit provided to employees who retire prior to age 65. The bridge benefit supplements the pension income until age 65. The bridging benefit is not necessarily related to the size of the prospective government benefits.

Commercial Paper Short-term unsecured debt instruments issued by companies typically to meet short-term financing needs.

Commuted Value The lump sum payment made in lieu of a member's future pension amount based on the member's service and earnings to date. The commuted value fluctuates with changes in factors such as the member's age, current inflation and interest rates.

Currency Hedging A technique used to offset the risks associated with the changing value of currency.

Custom Benchmark A benchmark calculated based on the weighted average allocation to two or more underlying benchmarks (e.g., Blended DEX 30 day Treasury Bill Index and DEX Universe).

Debentures Bonds that are not secured by specific assets of a firm.

Defined Benefit Plan In a defined benefit plan members' benefits are determined by a formula usually based on years of service times earnings, rather than by the investment returns made on their pension contributions.

Derivative/Derivative Financial Instrument A financial contract that derives its value from changes in underlying assets or indices. Derivative transactions can be conducted on public exchanges or in the over-the-counter market using investment dealers. Derivative contracts include forwards, futures, swaps and options and are discussed in more detail in note 4 of the OAC Consolidated Financial Statements.

Direct-Drive Active Management Direct drive active management is where we have involvement in on-going decisions within the businesses we invest in with respect to strategy, major investment decisions, annual financial target setting and the monitoring of performance against these targets, risk management and governance oversight.

Discount Rate A discount rate is the interest rate used to compute the present value of anticipated future benefit payments.

Enterprise-wide This refers to the OAC, including OMERS Pension Group, OMERS Capital Markets, Borealis Infrastructure, OMERS Private Equity, Oxford Properties Group, OMERS Strategic Investments and corporate functions.

International Financial Reporting Standards (IFRS) are a set of principles-based accounting standards developed by the International Accounting Standards Board that is becoming the global standard for the preparation of public company financial statements.

Infrastructure Infrastructure investing involves direct investments in inflation sensitive assets that are critical to the long-term success of a modern industrial economy. Some infrastructure investments are subject to regulatory establishment of rates, service delivery levels or both.

Modified Pay-As-You-Go Funding Policy Promised retirement benefits are not fully pre-funded, instead contributions are paid to ensure that they are sufficient to fund current benefits. This variation of the funding method is used by the OAC for the RCA, in order to minimize the 50 per cent refundable tax applicable to RCA plans.

Nominal Bonds Bonds that pay interest and principal without contractual adjustments for inflation.

OAC Board The Board of Directors of the OMERS Administration Corporation.

OMERS Pension Plans or Plans Collectively, the OMERS Primary Pension Plan, the associated Retirement Compensation Arrangement and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics.

OMERS Primary Pension Plan or the Plan The primary registered pension plan administered by the OAC under the OMERS Act. This includes the defined benefit component and the AVC component.

Passive Management Investing in a manner that replicates the performance of a market index (eg. S&P/TSX Composite Index).

Plan Sponsor The organization or body, which has the final authority to create a pension plan and/or make revisions to an existing pension plan. Usually the plan sponsor is an employer, but it can also be a union, an association, the government, or a mixture. For the OMERS Pension Plans, the Sponsors Corporation is made up of employer and member representatives and acts as the sponsor.

Private Equity Private equity is the ownership of equity or equity-like securities in companies that do not generally trade publicly.

Proxy Voting Proxy voting is the process by which a shareholder expresses their views, on proposed corporate actions, by submitting their vote at a company's annual meeting.

Public Market Investments Investments in interest bearing (i.e., bonds, debentures and treasury bills) and equity securities (i.e., stocks, trust units, warrants and mutual fund units) traded on recognized public exchanges.

Real Rate of Return Nominal return adjusted to exclude the impact of inflation.

Real Return Bonds Interest bearing marketable bonds that pay a semi-annual coupon rate calculated based upon the sum of the principal amount and an inflation compensation component that adjusts for inflation.

Retirement Compensation Arrangement or RCA The plan for those of the OMERS Pension Plan members with earnings exceeding the amount that generates the maximum pension allowed by the *Income Tax Act*.

SC The OMERS Sponsors Corporation.

Secured Debt Debt backed or secured by collateral to reduce the risk associated with lending for creditors given that if the debtor defaults the creditor may seize the collateral as repayment of the debt.

Supplemental Plan The OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics is a stand-alone registered pension plan which offers benefits not available in the OMERS Primary Pension Plan and which is not funded from the OMERS Primary Pension Plan.

Unsecured Debt Debt which is not backed or secured by collateral property.

















OMERS
One University Avenue
Suite 400
Toronto, Ontario M5J 2P1
Tel **416.369.2444**
Toll-free **1.800.387.0813**
Email **client@omers.com**

For more information, please visit our website at www.omers.com

OMERS

2011 ANNUAL REPORT

FOCUS:
OUR STRATEGY
YOUR FUTURE















OMERS
Sponsors Corporation

OMERS was established in 1962 as the pension plan for employees of local governments in Ontario. On June 30, 2006, the *Ontario Municipal Employees Retirement System Act, 2006* (the OMERS Act) came into effect. The OMERS Act continued the Ontario Municipal Employees Retirement Board as the OMERS Administration Corporation (OAC) and created the OMERS Sponsors Corporation (SC) to replace the Ontario government as Plan sponsor. Sponsors (such as Plan members and employers, through their unions, associations and other organizations) appoint the Board Members of the SC and, since June 30, 2009, the SC appoints OAC Board Members.

OMERS Sponsors Corporation

OMERS Sponsors Corporation is the Plan sponsor of the OMERS Pension Plans and consists of 14 Members: seven Plan member representatives and seven employer representatives.

The SC is responsible for:

- determining Plan design for benefits to be provided by the OMERS Pension Plans
- setting contribution rates for members and participating employers
- establishing or changing a reserve to stabilize contribution rates
- setting compensation levels and appointment protocol of SC and OAC Board Members.

OMERS Administration Corporation

OMERS Administration Corporation Board has 14 Members and is the administrator of the OMERS Pension Plans.

The OAC Board is responsible for:

- appointing and overseeing the OAC management team
- establishing investment and funding policies, asset allocation and investment management of OMERS Pension Plans' assets
- overseeing pension services, administration and Plan valuation
- appointing the OAC auditors and the actuary for the OMERS Pension Plans.

OMERS AC Management

OAC Management conducts the affairs of the OAC and has been delegated broad responsibilities for ensuring that OMERS discharges its statutory and related responsibilities to Plan members, including:

- administering the OMERS Pension Plans
- providing for the actuarial valuation of the OMERS Pension Plans
- investing the OMERS Pension Plans' assets
- providing technical and administrative support to the SC.

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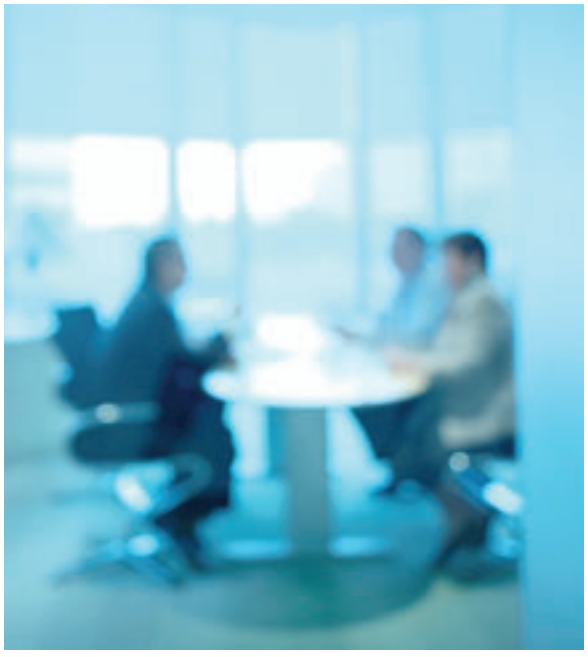


The OMERS Sponsors Corporation is responsible for pension plan design, setting contribution rates and filing the actuarial valuation. For many of our members, their pension is their single largest asset and safeguarding that investment is our primary responsibility. The focus of the Sponsors Corporation is to provide decision-making that supports the health and long-term viability of the OMERS Pension Plans.

We are committed to ensuring that our decisions are always in the best interests of our stakeholders and that we consider the long-term sustainability and growth of the Plan for future retirees in everything we do.

As we move forward we have a clear view of our needs today while focusing on your future.

FOCUS: OUR STRATEGY YOUR FUTURE

MESSAGE FROM THE CO-CHAIRS

FOCUSING ON YOUR FUTURE

Design and funding are crucial to ensuring affordable and sustainable plans that will fulfill the pension promise for the long term.



MARIANNE LOVE
Co-Chair

BRIAN O'KEEFE
Co-Chair

Our primary goal at OMERS Sponsors Corporation (SC) is to ensure that governance and decision-making practices support the health and long-term viability of the OMERS Pension Plans. Our outlook and horizon must consider the retirement of those who have been members for quite some time as well as those who are just starting their careers and will be retiring forty or fifty years from now.

FUNDING

Like most other pension plans, OMERS is currently dealing with a funding deficit in its Primary Plan that will continue through 2012 as we recognize the last of the losses incurred in 2008. In 2010, the SC established a strategy to address the funding deficit and, despite turbulent markets and the ongoing uncertainty in the U.S. and Europe, the strategy continues to support the Plan. Our plan calls for contribution increases averaging 2.9 per cent over three years and benefit changes in the final year for members who leave the Plan before they qualify for early retirement.

On January 1, 2011, we implemented the first phase of our strategy – increasing contributions to ensure the Fund received an additional one per cent in contributions from both members and employers. During 2011, decisions were made on the second phase of our plan and contribution rate increases were established for 2012. The final phase – determining the 2013 contribution rates – will be completed following a review of principles for allocating contribution rates. Raising contribution rates or changing benefits is a decision not taken lightly but, given the Primary Plan's funded position, these temporary changes are necessary.

A review of our other plans also resulted in changes to enhance the funding flexibility in our Retirement Compensation Arrangement (which pays benefits over and above the maximum payable under the Primary Plan) and changes to the contribution rates for the Supplemental Plan for Police, Firefighters and Paramedics. Additional stability was provided through the filing of the 2010 actuarial valuations.

"OUR MULTI-YEAR STRATEGY IS ON COURSE AND CONTINUES TO SUPPORT THE PLAN."

GOVERNANCE

We firmly believe that good governance is fundamental to ensuring long-term success. Following best practices in governance is an ongoing goal and, having just completed our fifth full year of operation, the SC undertook a number of initiatives to review and update its governance practices. For example, we reviewed our Board and committee structure, confirmed the existing Co-Chair structure and amended the way we appoint Committee Chairs to ensure appropriate balance and succession for the SC committees.

We updated our Board Member Orientation program to train and inform new Members as soon as they join the Board. Our ongoing training and education program for board members was also improved and updated to provide a robust, cost-effective program.

Recognizing the need to consolidate and articulate our internal governance structure, we also developed an "SC Governance, Mandates and Responsibilities" document which defines the SC structure, as well as the mandates and responsibilities of the Board, its Committees, individual Board Members, Co-Chairs, Committee Chairs and the CEO, respectively. You can find detailed information on our website at www.omerssc.com.

Effective governance also requires regular and periodic reviews of Board compensation to ensure it remains current and relevant. In 2011, we reviewed the compensation structure for OAC and SC Board Members. Considerations included a market and industry trend overview provided by an outside advisor, and, after significant discussion, we decided to maintain the current levels and structure.

This year, we reappointed two OAC Board Members, whose terms were set to expire, and appointed two new OAC Board Members who replace other outgoing Members.

WORKING TOGETHER – SC AND OAC

The Boards of the SC and OAC meet regularly, in their entirety as well as through a smaller Joint Council, to discuss issues of relevance to both organizations. These meetings help us develop and maintain a common understanding of issues of joint interest. Through our respective mandates, the two organizations are able to work together to ensure our focus remains on the OMERS Plans.

The SC and OAC also periodically conduct internal governance reviews to identify strengths as well as opportunities for improvement. This year, the Boards jointly reviewed OMERS decision-making processes, assisted by an external advisor. We are currently reviewing the results and developing an action plan to address the recommendations.

The SC receives significant technical support and information from the OAC to assist us in fulfilling our mandate and we would like to extend our appreciation and sincere thanks for the ongoing support.

IN CLOSING...

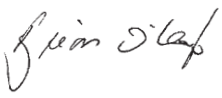
We will continue to monitor the Plan and the impact of investment returns on our strategy and, as always, the SC will continue to work in partnership with the OAC to keep your plans healthy and viable.

On behalf of the SC Board, we would like to thank Marnie Niemi Hood, who stepped down from the SC this year, for her significant contributions since the SC's inception. We welcome to the Board Diana Clarke from OPSEU.

We also want to thank John Poos for his hard work and dedication during his term of leadership with the OMERS SC. John left the SC to pursue other opportunities and Deb Preston has been promoted from her role as Director, Pension Policy and Communications, into the CEO role. Deb's understanding of pensions, OMERS and the industry will be invaluable as the SC moves forward.



Marianne Love
Co-Chair



Brian O'Keefe
Co-Chair

MESSAGE FROM THE CHIEF EXECUTIVE OFFICER

AN IMPORTANT TIME FOR PENSION PLANS

A sound strategy and vision are essential to our success.



DEB PRESTON
Chief Executive Officer

2011 was the fifth full year of operation by the SC. During the start-up period our priority was to develop the governance, infrastructure and processes for the organization. The second phase of growth involved building and developing a strategic direction with regard to plan funding. My predecessor, John Poos, was instrumental in helping the SC lay the foundation for future decisions with regard to contributions and benefits through the establishment of the Statement of Plan Design Objectives and Strategy for the Primary Plan. Work will continue throughout 2012 on further developing a strategic direction and vision.

Throughout 2011, pensions and pension reform remained in the headlines as governments continued to discuss how best to balance coverage and adequacy while managing costs. This is an important time for pension plans such as OMERS and, together with the OAC, we will continue to monitor and participate in these discussions to ensure OMERS is well represented.

As the pension and investment landscape continues to change, communication with our stakeholders becomes even more crucial. At our Spring and Fall Information Sessions, both Boards take the opportunity to update stakeholders. These sessions let us hear directly from our stakeholders and allow us to provide timely, relevant information. In 2011, both sessions were available by webcast which allowed stakeholders, regardless of geography, to participate in real time.

In 2011 we also undertook a full redesign of our website which now reflects industry standards and provides improved navigation. We regularly update our website to provide information on decisions and activities and, as a result, more groups and individuals are now providing input and comments on activities underway at the SC. Be sure to visit our website frequently to get the most up to date information.

"AS THE PENSION AND INVESTMENT LANDSCAPE CONTINUES TO CHANGE, COMMUNICATION WITH OUR STAKEHOLDERS BECOMES EVEN MORE CRUCIAL."

As noted by the Co-Chairs, the SC's primary focus in 2011 was ongoing implementation of the three-year plan to manage the funding of the Primary Plan, reviewing the sustainability of the Retirement Compensation Arrangement (RCA) and ensuring appropriate governance and best practices are in place as we move forward into 2012.

We expect market conditions will continue to be turbulent, requiring regular and ongoing monitoring of the Primary Plan's funded position. We also remain ever-mindful of the government's need to review the OMERS governance model in the upcoming year.

The SC will continue to work with the OAC to strengthen the OMERS Plans through a consultative and collaborative environment to help return the Plan to a fully funded position. As always, our goal is to work together to deliver an affordable, sustainable Plan for both members and employers.

I would like to thank the Co-Chairs and Board Members for their ongoing support throughout this past year, as well as our employees for the tremendous work they do. I am very pleased to be part of the SC leadership team and look forward to working with the SC and the OAC as we move forward through these challenging times.



Deb Preston
Chief Executive Officer

YEAR IN REVIEW

Many factors contributed to the funding deficit that was our priority in 2011.

The deficit is largely due to the 2008 market losses, but losses due to actuarial assumption changes and an aging population also have had an impact. We expect the effect on our funded position in the Primary Plan to continue through 2012, when the last of the 2008 market losses will be absorbed.

As of December 31, 2011, the Primary Plan defined benefit component has $54.9 billion in net assets available for benefits and its current funding deficit on a smoothed basis stands at $7.3 billion. Based on the year-end actuarial value of net assets, the Plan is approximately 89 per cent funded – that is, it has $89 in assets for every $100 of long-term pension obligations.

We have begun to implement our multi-year, phased approach to address the deficit, as approved by the SC Board in 2010. This included increasing contributions by an average of 2.9 per cent for both employers and members over three years, beginning January 1, 2011, as well as benefit changes for some members in the third year.

In 2011 the SC approved the second contribution rate increase in this strategy, affecting 2012 contributions. The SC also committed to review how future contributions would be allocated, and will make decisions on the 2013 contribution rates during its annual decision-making cycle.

Starting in 2013, there will be changes to the calculation of benefits members receive if they terminate employment before they are eligible for an early retirement pension – before age 55 (for normal retirement age 65 members) and before age 50 (for normal retirement age 60 members). The changes will only impact service entitlements accrued after 2012. These plan members will not receive pre-retirement inflation protection; nor will they receive subsidized early retirement. These changes will reduce the Plan's long-term liability cost.

There will be no change in the benefit entitlements of current retirees, member survivors or active members who stay in the Plan until their early retirement date.

In 2011, the SC also made changes to the funding of the OMERS RCA. The Primary Plan and the RCA are separate plans with separate funds. While the Primary Plan enjoys favourable treatment under the *Income Tax Act*, the RCA is subject to different taxation. The SC approved a change that would introduce a degree of flexibility into the RCA funding formula. An annual review will be undertaken to ensure there are sufficient funds to avoid depleting the RCA for at least 20 years from each review date. Effective January 1, 2012, the earnings level at which contributions are made to either the OMERS Plan or the RCA will vary each year based on actuarial projections (within a certain range). This change balances sustainability of the RCA with the tax inefficiency created under the *Income Tax Act*.

Other decisions in 2011 related to the Supplemental Plan contribution rates and the 2010 actuarial valuations. Under the Supplemental Plan an employer can provide additional benefits to Police, Firefighters and Paramedics, where negotiated. Based on revised assumptions, new contribution rates were set, effective January 1, 2011. The SC also decided to file the 2010 Primary Plan and Supplemental Plan valuations with the regulators, which means the next required filing will be the December 2013 valuation.

To ensure pension plan terms and conditions are current and easy to reference, it is good practice to regularly amend and restate Plan texts. The OMERS Primary Plan text was last amended and restated as of April 30, 2007 and, since then, the SC has made a number of amendments to the Plan. In March 2011, the SC approved amended and restated Plan texts for the OMERS Pension Plans which consolidates these amendments and include some additional minor amendments that help maintain the integrity of the Primary Plan, reflect compliance with the applicable governing legislation and provide clarity. Corresponding changes have been made to the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics.

The amended and restated Primary Plan text – effective January 1, 2011 – also includes a technical amendment to clarify the distribution of assets under administration by the OMERS Administration Corporation in the unlikely event that the Primary Plan is wound up.

More detail on the amendments and the updated Plan texts can be found on our website at www.omerssc.com.

SUMMARY

Over time, defined benefit pension plans such as OMERS will cycle through periods of surplus and deficit. Like many other pension plans, the Primary Plan continues to be affected by the 2008 market losses as well as the ongoing volatility of stock markets.

Our current strategy with regard to contribution and benefit changes, together with the OMERS AC investment strategy, is expected to return the Primary Plan to a fully funded position over time.

As always, we remain committed to ensuring the health, viability and sustainability of your pension plans.

GOVERNANCE OMERS SPONSORS CORPORATION

The *OMERS Act* created the SC to fulfill the role of plan sponsor, giving employers and employees more direct control over the pension plan.

The SC has committed itself to upholding OMERS long history of exemplary corporate governance through maintaining high standards of integrity, education, transparency and communication in carrying out its responsibilities.

GOVERNANCE

The SC strives to achieve best practice standards in corporate governance. To achieve this goal, the SC has developed policies and practices with input and advice from third-party advisors who are expert and experienced in the field. The governance structure includes:

- corporate by-laws and policies that support the commitment to a best practice standard;
- an education program for Members which includes learning opportunities in the areas of governance, pension administration, benefits strategies and pension plan trustee development, as well as mandatory orientation to the OMERS Pension Plans;
- a process for reviewing SC governance policies and processes to ensure ongoing efficiency and effectiveness of its practices; and
- transparency and accountability to OMERS Plan participants through regular meetings with plan participants and stakeholders, together with timely print and electronic communication carried out in conjunction with the OAC, as well as regular website updates and posting of by-laws, by-law amendments and information for submitting proposals for plan design changes.

In 2011, the SC also developed and published the "SC Governance, Mandates and Responsibilities." This document consolidates and articulates the SC governance structure, as well as the mandates and responsibilities of the Board, Committees, individual Board Members, Co-Chairs, Committee Chairs and the Chief Executive Officer.

KEY BOARD RESPONSIBILITIES

The SC's key responsibilities include:

- making decisions about the design of the OMERS Pension Plans, including benefits to be provided by, and contributions to be made;
- deciding whether to establish a reserve;
- deciding whether to file a valuation more frequently than is required under the *Pension Benefits Act*;
- establishing the composition, remuneration and expense reimbursement for the Boards of the SC and the OAC;
- appointing members to the OAC Board;
- appointing the SC auditor, legal and actuarial advisors and the CEO; and
- approving the Corporation's budget and audited financial statements.

The SC Members owe a fiduciary duty to the Corporation and must act in the best interests of the SC. The SC believes that:

The best interests of the Sponsors Corporation include governance and decision-making practices which support the health and long-term viability of the jointly-sponsored OMERS pension plans, and give due consideration to the interests of the stakeholders and other relevant circumstances.

BOARD MEMBERSHIP

The composition of the Board was established under legislation and confirmed by SC By-Law #4 and is based on a balanced formula reflecting plan membership. A review of SC composition was last undertaken in 2009 to ensure the SC continued to provide equitable representation of the participants in the OMERS Pension Plans.

The SC has a representative Board with seven pension plan member representatives and seven employer representatives. Members are appointed by their Sponsoring Organizations (as outlined in By-Law #4) for a three-year term. Terms are staggered to ensure ongoing continuity and effectiveness of the Board.

Employer Representatives

- Association of Municipalities of Ontario (AMO) – two members
- City of Toronto – one member
- School Boards, rotating between Public and Catholic Boards – one member
- Ontario Association of Police Services Boards – one member
- Ontario Association of Children's Aid Societies – one member
- Electricity Distributors Association (Ontario) – one member

Plan Member Representatives

- Canadian Union of Public Employees (CUPE Ontario) – one member
- Canadian Union of Public Employees rotating between Locals 79 and 416 – one member
- Police Association of Ontario – one member
- Ontario Professional Fire Fighters Association – one member
- Ontario Secondary School Teachers' Federation – one member
- Ontario Public Service Employees Union – one member
- Retiree Group – appointed from among the Municipal Retirees Organization Ontario, the Police Pensioners Association of Ontario, the Police Retirees of Ontario and the Retired Professional Fire Fighters of Ontario – one member

The Board is headed by Co-Chairs, one appointed by the pension plan member representatives and the other appointed by employer representatives. There are a total of 18 votes on the SC. The number of votes is equally split between employer and plan member representatives and is further proportionately distributed using a weighted voting system.

In accordance with its by-laws, the SC will be conducting a further review of Board composition in 2012. Many stakeholders have taken the opportunity to provide input which will be considered as the SC completes its review.

COMPENSATION AND EXPENSES

Compensation

SC Members are compensated through a combination of an annual retainer and meeting fees covering attendance at Board and committee meetings and at other meetings or events such as the SC's annual planning session and the Spring and Fall Information Sessions for stakeholders.

A Member's compensation may be paid directly to the Member or to the organization with which they are affiliated.

SC Member compensation was reviewed in 2011, resulting in no changes to the June 2009 structure, as follows:

	Annual Retainer	Meeting Fee*
Co-Chairs	$70,000	-
Committee Chair(s)	$17,800	$750
All Other Members	$12,800	$750

* Maximum number of compensable meetings is 24 and only one fee is paid per day.

Reimbursement of Expenses

SC Members are entitled to reimbursement of reasonable and necessary expenses incurred in connection with carrying out the business of the SC.

SC Members are also reimbursed for travel, tuition and other expenses incurred in attending pension and governance conferences, or other educational programs. By-Law #6 sets out the particulars of expense reimbursements.

BOARD COMMITTEES

The SC has four standing committees to assist the Board in discharging its responsibilities. In addition, the SC and OAC have established a Joint Council to address matters of importance to both boards.

Plan Design Information Committee (PDIC)

The Plan Design Information Committee assists with responsibilities relating to design of the OMERS pension plans including:

- co-ordinating and facilitating the process of gathering and considering information; and
- arranging for the referral of questions to OMERS Administration Corporation staff and legal, actuarial and other professionals engaged by the SC.

Human Resources and Compensation Committee (HRCC)

The Human Resources and Compensation Committee's responsibilities relate to:

- staff levels and succession planning;
- training, education and orientation programs for Members of the Corporation;
- compensation structure, including benefits, for employees of the Corporation;
- expense reimbursement policies in respect of employees of the Corporation;
- compensation and expense reimbursement policies in respect of SC Members and members of OMERS Administration Corporation Board; and
- a performance evaluation process for the Chief Executive Officer.

Corporate Governance Committee (CGC)

The Members of the SC are assisted by the Corporate Governance Committee with regard to:

- developing appropriate corporate governance practices, guidelines and benchmarks for the Corporation; and
- developing by-laws for the Corporation.

Audit Committee

The Audit Committee assists the Members in fulfilling their responsibilities of oversight and supervision of:

- the quality and integrity of the financial statements of the Corporation;
- the compliance by the Corporation with legal and regulatory requirements in respect of financial disclosure and reporting;
- the adequacy of the internal accounting controls and procedures of the Corporation; and
- the qualifications, independence and performance of the independent auditor of the Corporation.

OAC/SC Joint Council

The Joint Council is comprised of an equal number of Members from the SC and OAC Boards and is intended to discuss and address matters of importance to either Board with respect to the oversight and governance of the OMERS pension plans.

MEETING ATTENDANCE

There were 12 regular meetings of the Board and 23 meetings of standing committees, as well as six Joint Council meetings; 11 other information and planning meetings were also held, which Members attended at their discretion and as their obligations allowed. Overall attendance in 2011 was 96 per cent compared with 97 per cent in 2010.

BOARD REMUNERATION AND EXPENSES

For the year ended December 31,	2011		2010	
	Remuneration[i]	Expenses[ii]	Remuneration[i]	Expenses[ii]
Marianne Love (Co-Chair)	$ 70,000	$ 21,530	$ 70,000	$ 19,720
Brian O'Keefe (Co-Chair)	70,000	10,098	70,000	14,134
Wm. (Joe) Aitchison[iii]	35,800	7,222	35,800	9,717
Paul Bailey[iv]	30,800	9,625	13,150	10,393
Diana Clarke[v]	24,167	4,755	-	-
Mark Ferguson[iv]	30,800	2,342	14,650	2,349
John Fleming[iii]	35,800	7,077	35,800	10,942
Jack Jones	30,800	23,527	30,800	25,194
Charlie Macaluso	30,050	2,328	30,050	2,754
Wayne McNally[iv]	30,050	8,202	13,900	4,385
Bruce Miller[iii]	35,550	19,562	35,800	12,109
Marnie Niemi Hood[vi]	3,633	-	29,300	3,890
Garth Pierce[iii]	33,550	9,854	31,300	12,745
Frank Ramagnano	30,800	13,373	30,800	14,775
Bruce Stewart	30,800	3,858	29,300	3,036
Former Board Members[vii]	-	-	49,450	11,244
Other Expenses[viii]	-	43,599	-	51,123
Total	$ 522,600	$ 186,952	$ 520,100	$ 208,510

(i) Remuneration is in accordance with By-Law #6. Effective July 1, 2009, members receive a base retainer plus a per meeting attendance fee to prescribed maximum levels.
(ii) Includes reimbursement for normal out-of-pocket business expenses including education, meeting, and communication expenses incurred on behalf of the SC.
(iii) Committee Chairs
Joe Aitchison – CGC – Corporate Governance Committee
John Fleming – PDIC – Plan Design Information Committee
Bruce Miller – HRCC – Human Resources and Compensation Committee
Garth Pierce – Audit Committee
(iv) Term commenced July 1, 2010.
(v) Term commenced March 1, 2011.
(vi) Term ended February 28, 2011.
(vii) Term ended June 30, 2010.
(viii) Other expenses include Board meeting expenses not allocated to individuals.

2011 BOARD/COMMITTEE MEETINGS

Board Member	Board (12) Attended	Board (12) Total	PDIC (6) Attended	PDIC (6) Total	HRCC (8) Attended	HRCC (8) Total	CGC (5) Attended	CGC (5) Total	Audit (4) Attended	Audit (4) Total	Joint Council (6) Attended	Joint Council (6) Total	Other (11)(i) Discretionary	Overall (52) Attended	Overall (52) Total	Overall (52) %
Marianne Love (Co-Chair)(ii)	12	12	6	6	8	8	4	5	-	-	6	6	11	47	48	98
Brian O'Keefe (Co-Chair)(ii)	12	12	6	6	8	8	5	5	-	-	6	6	11	48	48	100
Wm. (Joe) Aitchison	10	12	-	-	8	8	5	5	-	-	-	-	7	30	32	94
Paul Bailey	12	12	-	-	8	8	-	-	4	4	-	-	10	34	34	100
Diana Clarke(iii)	10	10	-	-	-	-	-	-	-	-	-	-	11	21	21	100
Mark Ferguson	11	12	5	6	-	-	-	-	2	4	-	-	10	28	32	88
John Fleming	11	12	6	6	-	-	-	-	-	-	6	6	10	33	34	97
Jack Jones	12	12	6	6	-	-	5	5	-	-	-	-	10	33	33	100
Charlie Macaluso	9	12	6	6	-	-	3	5	-	-	-	-	7	25	30	83
Wayne McNally	11	12	-	-	8	8	-	-	4	4	-	-	9	32	33	97
Bruce Miller	12	12	1	1	8	8	-	-	-	-	6	6	10	37	37	100
Marnie Niemi Hood(iv)	1	2	-	-	-	-	-	-	-	-	-	-	1	2	3	67
Garth Pierce	12	12	-	-	-	-	-	-	4	4	-	-	10	26	26	100
Frank Ramagnano	11	12	6	6	-	-	5	5	-	-	-	-	10	32	33	97
Bruce Stewart	11	12	6	6	-	-	-	-	-	-	-	-	10	27	28	96
Total	**93%**		**98%**		**100%**		**90%**		**88%**		**100%**			**96%**		

(i) Other includes: stakeholder meetings, education/information sessions, mandatory orientation for new Members and a planning retreat which Members attended at their discretion and as their obligations allowed.
(ii) Co-Chairs are ex-officio members of all committees except the Audit Committee.
(iii) Term commenced March 1, 2011.
(iv) Term concluded February 28, 2011.

Note: Total meetings may vary by Member depending on commencement/conclusion of term dates

SPONSORS CORPORATION MEMBERS



Marianne Love, Co-Chair
Employer Representative
for Association of Municipalities
of Ontario



Brian O'Keefe, Co-Chair
Plan Member Representative
for CUPE Ontario



Wm. (Joe) Aitchison
Employer Representative
for Ontario Association of
Children's Aid Societies



Paul Bailey
Plan Member Representative
for Retiree Group



Diana Clarke
Plan Member Representative
for Ontario Public Service
Employees Union



Mark Ferguson
Plan Member Representative
for CUPE Local 416



John Fleming
Employer Representative
for the City of Toronto



Jack Jones
Plan Member Representative
for Ontario Secondary School
Teachers' Federation



Charlie Macaluso
Employer Representative
for Electricity Distributors
Association



Wayne McNally
Employer Representative
for Ontario Catholic School
Trustees' Association



Bruce Miller
Plan Member Representative
for Police Association
of Ontario



Garth Pierce
Employer Representative
for Ontario Association of
Police Services Boards



Frank Ramagnano
Plan Member Representative
for Ontario Professional
Fire Fighters Association



Bruce Stewart
Employer Representative
for Association of Municipalities
of Ontario

INDEPENDENT AUDITOR'S REPORT

TO THE BOARD OF OMERS SPONSORS CORPORATION

REPORT ON THE FINANCIAL STATEMENTS

We have audited the accompanying financial statements of OMERS Sponsors Corporation, which comprise the statement of financial position as at December 31, 2011 and the statement of operations and of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as Management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian Auditing Standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by Management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements present fairly, in all material respects, the financial position of OMERS Sponsors Corporation as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Norton McMullen & Co. LLP

Chartered Accountants, Licensed Public Accountants

Markham, Ontario
February 21, 2012

FINANCIAL STATEMENTS

STATEMENT OF FINANCIAL POSITION

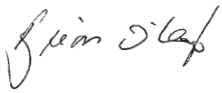
As at December 31,	2011	2010
Assets		
Cash and cash equivalents	$ 1,979,324	$ 1,866,949
OAC receivable	594,738	808,490
Prepaid expenses and other assets	6,272	7,899
	$ 2,580,334	$ 2,683,338
Liabilities		
Accounts payable and accrued liabilities	$ 137,336	$ 249,885
Net Assets		
Excess / (deficit) of revenues over expenses from operations		
Balance at beginning of year	2,433,453	2,437,851
Current year	9,545	(4,398)
Balance at end of year	2,442,998	2,433,453
	$ 2,580,334	$ 2,683,338

The accompanying notes to the financial statements are an integral part of these financial statements.

Signed on behalf of the Board of OMERS Sponsors Corporation



Marianne Love
Co-Chair



Brian O'Keefe
Co-Chair



Wayne McNally
Chair, Audit Committee

STATEMENT OF OPERATIONS

For the year ended December 31,	2011	2010
Revenues		
OAC expense reimbursement	$ 1,941,961	$ 2,012,958
Interest income	16,042	7,512
	1,958,003	2,020,470
Expenses		
Contract and administrative salaries, including payroll taxes and benefits	688,702	712,029
Legal	181,333	266,874
Audit	5,605	4,123
Actuarial	68,679	78,264
Professional advisors and other administrative (note 3)	203,512	147,137
Insurance	77,638	77,638
Board remuneration including payroll taxes and benefits (note 4)	536,037	530,293
Board expenses	186,952	208,510
	1,948,458	2,024,868
Excess / (Deficit) of Revenues over Expenses from Operations	$ 9,545	$ (4,398)

The accompanying notes to the financial statements are an integral part of these financial statements.

STATEMENT OF CASH FLOWS

For the year ended December 31,	2011	2010
Operating Activities		
Excess / (Deficit) of revenues over expenses	$ 9,545	$ (4,398)
Changes in non-cash working capital accounts		
OAC receivable	213,752	(220,096)
Prepaid expenses and other assets	1,627	(7,899)
Accounts payable and accrued liabilities	(112,549)	21,859
Increase / (Decrease) in Cash	112,375	(210,534)
Cash at Beginning of Year	1,866,949	2,077,483
Cash at End of Year	$ 1,979,324	$ 1,866,949
Supplemental disclosure of cash flows from operating activities:		
Interest income	$ 16,042	$ 7,512

The accompanying notes to the financial statements are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS

Year ended December 31, 2011

NOTE 1

DESCRIPTION OF PLANS SPONSORED BY OMERS SPONSORS CORPORATION

The OMERS Sponsors Corporation (the "SC") is a corporation without share capital under the *Ontario Municipal Employees Retirement System Act, 2006* (the "*OMERS Act*"). The SC is the sponsor of the OMERS Pension Plans (the "OMERS Pension Plans") as defined in the OMERS Act. The OMERS Pension Plans are administered by OMERS Administration Corporation (the "OAC") and include the OMERS Primary Pension Plan (the "Plan") and the Retirement Compensation Arrangement (the "RCA") associated with the Plan and the OMERS Supplemental Pension Plan for Police, Firefighters and Paramedics (the "Supplemental Plan"). The SC is responsible for making decisions about the design of the Plan, the RCA, and the Supplemental Plan, amendments to those plans, setting contribution rates, and the filing of the actuarial valuation as required under the *Pension Benefits Act*.

NOTE 2

SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These financial statements are prepared on a going-concern basis in accordance with Canadian generally accepted accounting principles, and present the information of the SC as a separate financial reporting entity independent of the employers, plan members and the OAC.

Government Grant Revenue Recognition and Net Assets

In previous years the SC received grants for operations from the Ministry of Municipal Affairs and Housing of the Ontario Government (the Ministry). These amounts receivable were recognized as income once the amount to be received could be reasonably estimated and collection was reasonably assured. The initial funding agreement with the Ministry, which was put in place during 2007, stated that any part of the grant funds that have not been used or accounted for by the SC at the time the agreement was to expire, on March 31, 2009, would belong to the Ministry.

In July 2008, following the establishment of, and agreement to, a joint SC/OAC protocol for SC expenditure reimbursement from the OAC and an Ontario Superior Court of Justice decision that confirmed that the OAC may lawfully reimburse the SC in accordance with the categories outlined in the protocol, the Ministry agreed to amend their initial agreement with the SC. The amended agreement authorizes the SC to use the remaining provincial funding for a period of up to five years (to March 31, 2014), to pay for the SC costs that, under the protocol, cannot be reimbursed from the OAC. Net assets consist of government grant funds received, net of expenditures not reimbursed by the OAC, plus interest earned. Interest income for operations is recognized as income in the year earned.

Income Taxes

The SC is not subject to corporate income tax.

Use of Estimates

The preparation of financial statements is in conformity with Canadian generally accepted accounting principles which require management to make estimates and assumptions that affect the reported values of assets and liabilities, income and expenses, and related disclosures. Such estimates include the OAC receivable, and accounts payable and accrued liabilities. Actual results could differ from these estimates.

Cash Equivalents

Cash equivalents are treasury bills which have been issued for terms not exceeding 180 days that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

NOTE 3

PROFESSIONAL ADVISORS AND OTHER ADMINISTRATIVE EXPENSES

Professional advisor and other administrative expenses consist primarily of various professional advisors for information technology and governance issues, training, and other administrative expenses.

NOTE 4

BOARD REMUNERATION AND EXPENSES

Board remuneration and board expenses are in accordance with SC By-Law #6.

NOTE 5

FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

Financial instruments of the Corporation consist of cash and cash equivalents, OAC receivable, and accounts payable and accrued liabilities. The carrying values of the above items approximate their fair value due to their short-term nature.

Credit Risk

The SC's cash is held at a major financial institution and cash equivalents are all Ontario treasury bills. The OAC receivable is due from an organization with a "AAA" rating and therefore there is virtually no credit risk.













OMERS SPONSORS CORPORATION
One University Avenue
Suite 400
Toronto, Ontario M5J 2P1
Tel **416.814.6565**
Toll-free **1.800.387.0813**
Email **board@omerssc.com**

For more information,
please visit our website at
www.omerssc.com

OMERS
Sponsors Corporation

Appendix 2: NextBridge Ontario Electricity Transmission License

A copy of the NextBridge Ontario electricity transmission license ET-2011-0222 discussed in Section 1.2 is attached.

Ontario Energy Board

Commission de lénergie de l'Ontario

EB-2011-0222

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an application under section 60 of the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B for an electricity transmission licence.

By delegation, before: Jennifer Lea

DECISION AND ORDER

BACKGROUND

Upper Canada Transmission Inc. ("Upper Canada") filed an application with the Ontario Energy Board (the "Board") on June 3, 2011, under section 60 of the *Ontario Energy Board Act, 1998* (the "Act") for an electricity transmission licence.

The Board issued a Notice of Application and Hearing on June 20, 2011. Intervention requests were filed by Hydro One Networks Inc. and Great Lakes Power Transmission L.P. Canadian Niagara Power Inc. requested observer status. The Board granted all the intervenor and observer status requests.

On July 8, 2011, the Board issued Procedural Order No. 1, pursuant to which Board staff and intervenors filed interrogatories on July 20, 2011. On July 28, 2011 Upper Canada filed a letter with the Board requesting an extension of time to file its responses to interrogatories. On August 2, 2011 the Board issued Procedural Order No. 2 granting the requested extension. Upper Canada filed its interrogatory responses on August 26, 2011. A submission was received from Board staff on September 8, 2011. No intervenor filed a submission. On September 22, 2011, Upper Canada filed its reply submission.

The record of the proceeding is available at the Board's offices and on the Board's website.

THE APPLICATION

Upper Canada, newly incorporated on April 19, 2011, is a member of NextEra Energy, Inc. corporate group and wholly owned by NextEra Energy Resources, LLC, a producer of renewable wind and solar energy.

Upper Canada has stated that it is making this application in order to qualify for participation in any upcoming Board transmitter designation process for new transmission investment in Ontario. The applicant has no existing transmission assets in Ontario although its intended business activity is to develop, construct, own and operate transmission facilities in the province.

As part of its licence application, Upper Canada requested a temporary exemption from the Board's *Affiliate relationship Code for Electricity Transmitters and Distributors* ("ARC") until such time as it becomes designated by the Board as transmission developer or owns or operates transmission facilities in Ontario. The request was subsequently amended for exemption from section 2.1.2 of the ARC only (which requires that at least on third of a transmitter's Board of Directors be independent from any affiliate).

On November 9, 2011 Upper Canada filed a letter with the Board requesting an amendment of its application such that the effective date of its transmission licence be the date upon which Upper Canada is designated as a developer of transmission assets in Ontario or the date upon which Upper Canada applies to amend Schedule 1 of its licence to specify the facilities to be owned and/or operated by Upper Canada, whichever is earlier.

FINDINGS

Licence Application

The Board assesses a licence application by reviewing the evidence filed by the applicant and parties who participated in the proceeding. Based on the evidence filed, I

have determined that it is in the public interest to grant an electricity transmission licence to Upper Canada for a period of five years.

The key areas reviewed by the Board in any licence application are the financial viability, technical capability and conduct of an applicant. In the case of electricity transmission licence applications, the Board's review is also guided by the Board's *Framework for Transmission Development Plans* (EB-2010-0059). The Board's policy seeks to encourage new transmission entrants to Ontario, thereby bringing additional resources for project development and supporting competition in the transmission sector to drive economic efficiency for the benefit of ratepayers. The Board stated in its Chatham-Kent Transmission Inc. licence decision (EB-2010-0351) that obtaining a transmission licence is intended to be a threshold qualification step, and is not intended to be unduly onerous.

I find that the applicant has provided sufficient evidence of its financial viability and technical capabilities to qualify for a transmission licence. Upper Canada provided the 2010 financial statements and annual report for its parent company NextEra Energy, Inc. as Upper Canada is a newly created entity and no financial results are available for it at this time. With respect to technical capabilities, Upper Canada, being a newly created entity with no technical expertise of its own, intends to rely on the technical expertise of its affiliates who were described as entities with extensive experience with electricity transmission, distribution and generation development. The information provided meets the threshold qualification requirements for the licensing process.

The issuance of a transmission licence will enable Upper Canada to participate in the designation process. The granting of this transmission licence does not endorse the applicant's technical and financial capabilities in relation to the development of a specific transmission project. Licensed transmitters who file plans to develop a transmission project under the Board's designation process will be required to provide a significantly more detailed demonstration of their technical and financial capabilities in relation to the development of a specific transmission project.

No concerns were raised regarding the conduct of the applicant, and I find that Upper Canada has demonstrated that it is likely to operate its business in conformity with relevant legislation and regulatory requirements.

Effective Date and Term of the Licence

The applicant made its request to amend its application regarding the effective date of its licence following a decision of the Board issued on November 2, 2011: EB-2011-0260. In the EB-2011-0260 decision the Board amended TransCanada Power Transmission (Ontario) L.P.'s transmission licence by changing the effective date of the licence to the date upon which the licensee is designated as a developer of transmission assets in Ontario pursuant to the Board's designation process or the date upon which the licensee applies to amend schedule 1 of the licence to specify the facilities to be owned and/or operated by it, whichever is earlier. In making its decision the Board considered that other entrant transmitters, either licensed or whose electricity transmission licence applications are currently before the Board, may choose to seek similar relief, stating:

> "A new entrant transmitter who has already been licensed, or whose application is before the Board, may choose to seek the same relief granted in this Decision and Order by way of application (or amendment to its application), referencing its licence or application number and this Decision and Order."[1]

Consistent with that decision, the effective date of the license will be the date upon which the applicant is designated as a developer of transmission assets in Ontario pursuant to the Board's designation process, or the date upon which it applies to amend schedule 1 of the licence to specify the facilities to be owned and/or operated by it, whichever is earlier. In light of the effective date of the licence I find that the applicant's request for exemption from section 2.1.2 of the ARC is no longer necessary.

A transmission licence is typically granted for a term of 20 years, recognizing the long term nature of transmission assets. However, the Board has found in the recent transmission licence decisions that a shorter term of licence is appropriate for entrant transmitters who presently have no facilities in Ontario. Consistent with those decisions, the term of the licence will be 5 years. The term of the licence may be amended and extended to the standard 20 year term in the event that Upper Canada develops or acquires transmission facilities in Ontario.

[1] Decision and Order in TransCanada Power Transmission (Ontario) L.P. Licence Amendment Application (EB-2011-0260), page 10.

IT IS THEREFORE ORDERED THAT:

1. The application by Upper Canada Transmission Inc. for an electricity transmission licence is granted.

2. The licence will become effective on the date upon which Upper Canada Transmission Inc. is designated as a developer of transmission assets in Ontario pursuant to a Board designation process, or the date upon which Upper Canada Transmission Inc. applies to amend schedule 1 of the licence to specify the facilities to be owned and/or operated by Upper Canada Transmission Inc., whichever is earlier.

DATED at Toronto November 28, 2011

ONTARIO ENERGY BOARD

Original signed by

Jennifer Lea
Counsel, Special Projects

Electricity Transmission Licence

ET-2011-0222

Upper Canada Transmission, Inc.

Original signed by

Jennifer Lea
Counsel, Special Projects
Ontario Energy Board

Date of Issuance: November 25, 2011

Effective Date: The date upon which Upper Canada Transmission, Inc. is designated as a developer of transmission assets in Ontario pursuant to a Board designation process or the date upon which Upper Canada Transmission, Inc. applies to amend schedule 1 of this Licence to specify the facilities to be owned and/or operated by Upper Canada Transmission, Inc., whichever is earlier.

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th. Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Board**" means the Ontario Energy Board;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Upper Canada Transmission, Inc.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**transmission services**" means services related to the transmission of electricity and the services the Board has required transmitters to carry out for which a charge or rate has been established in the Rate Order;

"**Transmission System Code**" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the obligations of a transmitter with respect to the services and terms of service to be offered to customers and provides minimum technical operating standards of transmission systems;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence to own and operate a transmission system consisting of the facilities described in Schedule 1 of this Licence, including all associated transmission equipment.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 2 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; and

b) the Transmission System Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Requirement to Enter into an Operating Agreement

6.1 The Licensee shall enter into an agreement ("Operating Agreement") with the IESO providing for the direction by the IESO of the operation of the Licensee's transmission system. Following a request made by the IESO, the Licensee and the IESO shall enter into an Operating Agreement

within a period of 90 business days, unless extended with leave of the Board. The Operating Agreement shall be filed with the Board within ten (10) business days of its completion.

6.2 Where there is a dispute that cannot be resolved between the parties with respect to any of the terms and conditions of the Operating Agreement, the IESO or the Licensee may apply to the Board to determine the matter.

7 Obligation to Provide Non-discriminatory Access

7.1 The Licensee shall, upon the request of a consumer, generator, distributor or retailer, provide such consumer, generator, distributor or retailer, as the case may be, with access to the Licensee's transmission system and shall convey electricity on behalf of such consumer, generator, distributor or retailer in accordance with the terms of this Licence, the Transmission System Code and the Market Rules.

8 Obligation to Connect

8.1 If a request is made for connection to the Licensee's transmission system or for a change in the capacity of an existing connection, the Licensee shall respond to the request within 30 business days.

8.2 The Licensee shall process connection requests in accordance with published connection procedures and participate with the customer in the IESO's Connection Assessment and approval process in accordance with the Market Rules, its Rate Order(s) and the Transmission System Code.

8.3 An offer of connection shall be consistent with the terms of this Licence, the Market Rules, the Rate Order, and the Transmission System Code.

8.4 The terms of such offer to connect shall be fair and reasonable.

8.5 The Licensee shall not refuse to make an offer to connect unless it is permitted to do so by the Act or any Codes, standards or rules to which the Licensee is obligated to comply with as a condition of this Licence.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its transmission system to the standards established in the Transmission System Code and Market Rules, and have regard to any other recognized industry operating or planning standards required by the Board.

10 Transmission Rates and Charges

10.1 The Licensee shall not charge for the connection of customers or the transmission of electricity except in accordance with the Licensee's Rate Order(s) as approved by the Board and the Transmission System Code

11 Separation of Business Activities

11.1 The Licensee shall keep financial records associated with transmitting electricity separate from its financial records associated with distributing electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

12 Expansion of Transmission System

12.1 The Licensee shall not construct, expand or reinforce an electricity transmission system or make an interconnection except in accordance with the Act and Regulations, the Transmission System Code and the Market Rules.

13 Provision of Information to the Board

13.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

13.2 Without limiting the generality of paragraph 13.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) business days past the date upon which such change occurs.

14 Restrictions on Provision of Information

14.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator, obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

14.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

14.3 Information regarding consumers, retailers, wholesalers or generators may be disclosed where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

14.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

14.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information is not be used for any other purpose except the purpose for which it was disclosed.

15 Term of Licence

15.1 This Licence shall take effect on the date upon which the Licensee is designated as a developer of transmission assets in Ontario pursuant to a Board designation process or the date upon which the Licensee applies to amend schedule 1 of this Licence to specify the facilities to be owned and/or operated by the Licensee, whichever is earlier. This Licence expires 5 years from the date it takes effect. The term of this Licence may be extended by the Board.

16 Transfer of Licence

16.1 In accordance with subsection 18(2) of the Act, this Licence is not transferable or assignable without leave of the Board.

17 Amendment of Licence

17.1 The Board may amend this Licence in accordance with section 74 of the Act or section 38 of the Electricity Act.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 SPECIFICATION OF TRANSMISSION FACILITIES

This Schedule specifies the facilities over which the Licensee is authorized to transmit electricity in accordance with paragraph 3 of this Licence.

1. Schedule 1 will be completed at such time as the Licensee applies, and the Board approves, an amendment to this Licence specifying the facilities over which the Licensee is authorized to transmit electricity

SCHEDULE 2 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the licensee has been exempted.

Appendix 3: Key Project Resource Resumes

Name	Project Responsibility
Eric Gleason	Board of Directors
Cindy Tindell	Board of Directors
Steven Zucchet	Board of Directors
Lino Luison	Board of Directors
Judith Moses	Aboriginal Advisory Board, Independent
Ed Chilton	Aboriginal Advisory Board, Independent
Senator Gerry Bedford	Aboriginal Advisory Board, Independent
Kath Hammond	Aboriginal Advisory Board, NextBridge
Brian Hay	Aboriginal Advisory Board, NextBridge
Teresa Homik	Aboriginal Advisory Board, NextBridge
Oliver Romaniuk	Operations Committee
Ryan Farquhar	Operations Committee
Annesley Wallace	Operations Committee
Robert van Beers	Project Director
John Schajatovic	Lead Engineering & Construction
Ed Devarona	Lead Operations & Maintenance
Brian Hay	Lead First Nation and Métis Affairs
Tania Persad	Lead Regulatory
Kara Green	Lead Land Acquisition
Dan O'Neill	Lead Environment & Permitting
Amber Pastoor	Lead Municipal and Community Relations
Rod Adams	Lead Project Controls and Procurement

Eric S. Gleason, Board of Directors

Biography

Eric S. Gleason is president of NextEra Energy Transmission, LLC, an indirect wholly owned subsidiary of NextEra Energy, Inc. (NYSE: NEE). NextEra Energy Transmission is the parent company of Lone Star Transmission, LLC and New Hampshire Transmission, LLC, NextEra Energy's regulated electric transmission utilities in Texas and New England, respectively. Eric joined the Company in February 2011. Prior to joining NextEra Energy, Eric served since 2008 as vice president, corporate development and quality at Allegheny Energy, Inc. In this role, his responsibilities encompassed key aspects of corporate strategy, finance, operations and commercial activities. As a member of Allegheny's Executive Council and head of the strategic planning function, he also provided oversight and support to their transmission expansion business. Prior to Allegheny Energy, he worked as an investment banker at JPMorgan Chase & Co. and The Goldman Sachs Group, Inc., where he advised leading North American and European energy utilities and financial investors. He began his career in the U.S. Army as a military intelligence officer. Eric received his bachelor of science from the University of Colorado in 1988, and his master of business administration in 1994 from Harvard Business School.

Professional Experience

NextEra Energy, Inc. - Juno Beach, FL **President of NextEra Energy Transmission, LLC** **Responsible for NextEra's transmission business across North America, excluding Florida**	• Oversaw the construction and operation of a Greenfield, 512 km 345kV transmission project in Texas for Lone Star Transmission, NextEra's rate-regulated transmission utility in Texas • Oversaw a transformational reliability upgrade program for the 345kV infrastructure of New Hampshire Transmission, NextEra's rate-regulated transmission utility in New England • Oversaw cost recovery proceedings for Lone Star Transmission and New Hampshire Transmission • Oversaw and helped to build one of the leading transmission development teams in the industry, with an active development pipeline across North America
Allegheny Energy, Inc. - Pennsylvania **Vice President, Corporate Development and Quality**	• Responsibilities encompassed key aspects of corporate strategy, finance, operations and commercial activities • As a member of Allegheny's Executive Council and head of the strategic planning function, provided oversight and support to their transmission expansion business • Oversaw the evaluation of the company's strategic options, and managed the sale of the company of FirstEnergy Corp.
JPMorgan Chase & Co. - New York and London **Executive Director, Investment Banking**	• Responsible for advising leading North American and European energy utilities and financial investors.
Goldman, Sachs & Co. - New York and London **Vice President, Investment Banking**	• Responsible for advising leading North American and European energy utilities and financial investors.

Education and Credentials

Master of Business Administration, Finance, Harvard Business School, Boston, MA

Bachelor of Science, Mechanical Engineering, University of Colorado, Boulder, CO

Cindy Tindell, Board of Directors

Biography

Cindy Tindell is vice president of transmission development for NextEra Energy Transmission, LLC, an indirect wholly owned subsidiary of NextEra Energy, Inc. (NYSE: NEE). NextEra Energy Transmission is the parent company of Lone Star Transmission, LLC, NextEra Energy's regulated electric utility in Texas, and New Hampshire Transmission, LLC, the entity that co-owns and operates certain substation assets at the Seabrook Nuclear Station. She joined the Company in September 2003.

Cindy leads corporate efforts to develop, construct, operate and acquire regulated and contracted power transmission and related assets in the U.S. and Canada. Prior to joining NextEra Energy Transmission, she served as the Regional Vice President for NextEra Energy Resources, responsible for overall profitability, operating performance, and strategic planning for two regions, including the "Midwest US, Canada and Spain", a $1 billion business consisting of 35 nuclear, wind, and solar power generation facilities. Cindy also led Florida Power & Light utility's development and construction planning for five natural gas fired plants totaling over $4 billion investment and the 75 MW solar thermal facility; the first ever to be integrated into an existing natural gas fired plant. She has extensive experience in project and acquisition finance, contract and regulatory negotiations, and project development. Cindy has served as an official at the U.S. State Department and is a member of the Council on Foreign Relations.

Cindy received a BS from Georgetown University, an MA from Columbia University and a MBA from the Harvard Business School.

Professional Experience

NextEra Energy/FPL ENERGY - Juno Beach, FL **Vice President, Transmission Development**	• Responsible for leading corporate efforts to develop, construct, operate and acquire regulated and contracted power transmission and related assets in the U.S. and Canada.
Vice President, Business Management	• Responsible for overall profitability, operating performance, and strategic planning for two regions in the U.S., Canada and Spain, including over $1 billion revenues, consisting of 35 nuclear, wind, and solar power generation facilities
Florida Power & Light – Juno Beach, FL **Senior Director, Development**	• Led the utility's development and construction planning for five natural gas plants totaling over $4 billion investment and 75 MW of solar thermal generation
Credit Suisse – New York **Vice President, Investment Banking**	• Led teams in proposing and executing corporate and project finance transactions in the Global Energy Group
GE Capital Corporation – Stamford, CT **Associate, Global Project and Structured Finance Group**	• Recommended, evaluated and structured potential investments in domestic and international infrastructure industries

Education and Credentials

BS, Georgetown University, Washington, DC

MA, Columbia University, New York, NY

MBA, Harvard Business School, Allston, Massachusetts

Steven Zucchet, Board of Directors

Biography

Steven Zucchet is a Senior Vice President at Borealis, a position he has held since November 2003. In his role as an officer of Borealis, Steven has been appointed as a director of several Borealis affiliates and companies in which Borealis invests. His focus at Borealis is in the energy sector, where he leads the pursuit of investment opportunities in the energy sector and is responsible for asset management. Steven is on the Board Directors of Oncor Electric Delivery Company LLC, Bruce Power and Midland Cogeneration Ventures.

Professional Experience

Borealis Infrastructure – Toronto **Senior Vice President**	• Transaction lead for pursuit of infrastructure assets in the transmission, distribution and generation sector in North America • Director on the Board of Oncor Electric, where he has served for the past 5 years, as well as, a member of the Nominating and Governance Committee and the Compensation Committee. • Director on the Board of Bruce A Power, where he has served for 7 years, as well as, a member of the Technical Oversight Committee that oversaw the $5 billion refurbishment of two nuclear reactors. • Project lead for Borealis on the previously proposed New York Regional Interconnect 1,200MW HDVC in NY State
Enwave Energy Corporation – Toronto **Chief Operating Officer**	• Responsible for all operations and capital projects for the both the steam and chilled water facilities and distribution systems. • Led the successful development and construction of the first-of-a-kind deep lake water cooling project used to provide cooling for Toronto's downtown.
Enwave Energy Corporation – Toronto **Director of Project Management and Marketing**	• Lead development and construction of steam and chilled water plant expansions • Lead marketing and sales initiatives of steam and chilled water

Education and Credentials

Master of Applied Science, Mechanical Engineering, Power Generation, University of Toronto, Toronto, Canada

Bachelor of Applied Science, Mechanical Engineering, University of Toronto, Toronto, Canada

Lino M. Luison, Board of Directors

Biography

Lino Luison has been with Enbridge since 1994. He has held a variety of senior management roles in both Enbridge Inc. and Enbridge Gas Distribution. Since 2008, Lino has held the position of Vice President Financial Partnerships.

Prior to his current role, Lino held the positions of Vice President Corporate Development for Enbridge Inc., and Vice President, Opportunity Development for Enbridge Gas Distribution. Previously, Lino was employed by Consumers Gas and Ontario Hydro.

Lino has testified on numerous occasions before the Ontario Energy Board (OEB) and the National Energy Board (NEB) and the New Brunswick Public Utilities Commission.

Professional Experience

Enbridge Inc. - Calgary, Alberta **Vice President Financial Partnerships**	• Responsible for creating innovative financial structures involving third-party financial partners, and optimizing certain of Enbridge's existing financial vehicles • Led the successful sale of Enbridge Electric • Responsible for establishing Enbridge's power transmission platform. In this capacity, acquired Tonbridge Power in 2011 and is currently overseeing the completion of the Montana-Alberta Tie-Line and pursuit of other transmission opportunities across North America.
Enbridge Inc. – Toronto, Ontario **Vice President, Corporate Development**	• Established and led Enbridge Energy Solutions, a retail-focused operating entity. • Responsible for Enbridge's unregulated storage business as well as Enbridge Electric.
Enbridge Gas Distribution **Vice President, Opportunity Development**	• Responsible for market development - specifically the identification and introduction of new products, services and technologies related to Enbridge's core gas distribution business. • Responsible for the company's Demand Side Management programs • Managed EGD's gas supply and gas storage functions
Enbridge Inc. and Enbridge Gas Distribution **Various roles in Business and Financial Analysis, Strategic Planning, Gas Supply, Marketing among others**	• Leading role in the $1 billion sale of Enbridge Services Inc. • Led and won the competition in New Brunswick that led to the successful creation of Enbridge Gas New Brunswick • Member of the founding team for ConsumersFirst, a retail energy services company that later became Enbridge Services Inc. • Member of the corporate development team created to acquire municipal electrical utilities in Ontario

Education and Credentials

Master of Arts degree in Economics, University of Western Ontario, London, Canada

Honours Bachelor of Arts degree in Economics , McMaster University, Hamilton, Canada

Previously held board positions: Canadian Manufacturers and Exporters (Ontario); Greater Toronto Marketing Alliance; Enbridge Gas New Brunswick Inc.; West Park Hospital Foundation

Judith Moses, Aboriginal Advisory Board

Biography

As Vice President of the Institute on Governance, a non-profit organization, Judith Moses is responsible for its practice in Ontario in the public and non-profit sectors and is active in its international activities in Iraq and Botswana.

Previously, Judith contributed to public service for thirty five years, specializing in large scale policy, institutional change and program reform at both federal and provincial levels. She has managed large organizations and billions of dollars of taxpayers' money.

Judith led task forces related to program review spending reductions and central agency coordination of federal activities across Canada. She has led major initiatives in labour market employment and training, aboriginal affairs, rural development and agriculture and international affairs. Judith has also had assignments in the United Kingdom and at the United Nations.

Judith led a review of central agencies in the Ontario Cabinet Office that resulted in reforms to Management Board, Ministry of Finance and Cabinet Office and the creation of the Ministry of Government Services.

In 2006, Judith started a consulting firm and a government relations firm. Clients included Accenture, Euler-Hermes, Genworth, etc.

In 2008 she ran for the Liberal Party of Canada in the riding of York-Simcoe and in 2009 for the nomination in St. Paul's.

Judith is a current Member and Past Chair of HIPPY Canada (aboriginal and immigrant mothers and pre-school children) and the Ontario Immigration Minister's Partnership Forum, an advisory Board of Directors on non-profit social innovation. She is a former board member of Carleton University's Board of Governors, Friends of the Canadian Museum of Civilization, Ottawa School of Dance and former Director of Outreach, St. John's York Mills.

She is past Program Co-Chair, Governor General's Study Conference and a 2012 recipient of the Governor General's Diamond Jubilee Award.

Professional Experience

Institute on Governance **Vice-President**	• Responsible for its practice in Ontario in the public and non-profit sectors and is active in its international activities in Iraq and Botswana
Judith Moses Consulting **President and CEO**	• Started Judith Moses consulting and a government relations firm • Clients included Accenture, Euler-Hermes, Genworth, etc

Education and Credentials

BA, University Of Guelph, 1972

Advanced Managers Development Program, Oxford Centre for Management Studies, 1975

Ed Chilton, Aboriginal Advisory Board

Biography

Principal of Edward W. Chilton Consultants, Ed Chilton has worked with First Nation communities in the area of infrastructure development for most of his professional career. For the last 15 years, he has been Project Coordinator for Five Nations Energy Inc. (FNEI) taking the project from the conceptual stage, through the development, construction and now the operations stages. FNEI was incorporated in 1997 and since then, now hold assets costing over $100 million. He most recently played a vital role in the development of FNEI's fiber optic telecommunications infrastructure and upgrades to the substations. Presently, FNEI is constructing an Office Building in Timmins to serve as its headquarters and Ed is the Project Advisor. Ed also serves as the Secretary-Treasurer on the FNEI Board and as an advisor to the FNEI Chief Executive Officer.

Ed worked as Project Coordinator for Moose Cree First Nation bringing the Lower Mattagami River Hydro Re-development Project to a level ready for development. The Project is now underway with the Moose Cree First Nation having the opportunity to become a potential 25% owner of the 440 MW, $2.6 billion project, with their partner, Ontario Power Generation. He serves on the Board of the Amisk-Kodim Corporation, a special projects vehicle of the Lower Mattagami Agreement ensuring that First Nation businesses participate in the opportunities the project presents. The Amisk-Kodim Corporation's mandate has been expanded to include the Detour Gold Corporation's development of the Detour Lake Gold Mine. Ed also serves on the Executive Committee of Moose Cree Constructors, who with their partners, constructed and commissioned the 180 km, 230 kV transmission line to service the Detour Gold Mine in Northeastern Ontario.

Ed is now interested in becoming involved in other First Nation specific energy projects. He was previously employed by the Mushkegowuk Council as Supervisor of Technical Services where he was responsible for the management of numerous multi-million dollar Capital Projects for the Mushkegowuk communities. In the role of a First Nation Project Developer, Ed brings to the table a unique blend of skills that he uses to develop the partnerships between First Nation governments, Canadian governments and the private sector that are necessary to develop a First Nation project.

In 2002, Ed was honoured with the Executive of the Year Award at the Nishnawbe Aski Nations Business Awards. Ed is also the Past President of the Kimesskanamenow Corporation which oversees the winter ice road servicing the coastal communities of Western James Bay.

Professional Experience

Five Nations Energy Inc. (FNEI) **Project Coordinator**	• Taking the project from the conceptual stage, through the development, construction and now the operations stages. FNEI was incorporated in 1997 and since then, now hold assets costing over $100 million. He most recently played a vital role in the development of FNEI's fiber optic telecommunications infrastructure and upgrades to the substations. Presently, FNEI is constructing an Office Building in Timmins to serve as its headquarters and Ed is the Project Advisor. Ed serves as the Secretary-Treasurer on the FNEI Board and as an advisor to the FNEI Chief Executive Officer.
Moose Cree First Nation **Project Coordinator for**	• Bringing the Lower Mattagami River Hydro Re-development Project to a level ready for development. The Project is now underway with the Moose Cree First Nation having the opportunity to become a potential 25% owner of the 440 MW, $2.6 billion project, with their partner, Ontario Power Generation
First Nation Project Developer	• Ed brings to the table a unique blend of skills that he uses to develop the partnerships between First Nation governments, Canadian governments and the private sector that are necessary to develop a First Nation project.
Mushkegowuk Council Supervisor of Technical Services	• Responsible for the management of numerous multi-million dollar Capital Projects for the Mushkegowuk communities

Senator Gerry Bedford, Aboriginal Advisory Board

Biography

Born near Timmins, Gerry Bedford was raised in the Sudbury area, attending St Charles College in Sudbury. Upon graduation, Gerry joined the Royal Canadian Air Force in 1959. After a two year stint in the RCAF, Gerry then enrolled in Brown's Business College. Diploma in hand, Gerry spent 18 months in long haul transport. Gerry then joined Kodak Canada in 1964, serving in number of stationary engineering capacities, rising to a First Class Stationary Engineer in 1971, For the next 25 years, Gerry worked in two Greater Toronto Area Kodak plants in a number of senior operating capacities, retiring in 1996. Gerry confirmed his Métis heritage when he joined the Métis Nation of Ontario (MNO) in 2001. He was elected as a Senator from the Credit River Métis Council (Region8) in 2003. Gerry sat on the Provincial Council of the MNO from 2005 to 2012, serving on the Finance, Economic development and Language Committees. Now retired from the Council, Gerry retains the role of Captain of the Hunt for Region 8 of the MNO.

Professional Experience

1964 to 1996	• Fourth through First Class Stationary Engineer with Kodak Canada

Education and Credentials

St. Charles College, Sudbury

Brown's Business College, Toronto

First Class Stationary Engineers Certificate

Kath Hammond, AAB NextBridge Representative

Biography

Kath Hammond is Vice President, Legal at Borealis Infrastructure. Her responsibilities include providing transactional legal support to investment teams on pursuits of assets in various infrastructure categories, including power generation, transmission and transportation, as well as providing legal support to asset management teams with respect to assets under management including Bruce Power. Prior to Borealis Infrastructure, Kath worked at Ontario Power Generation Inc. (OPG) holding both legal and business roles of increasing responsibility, including leadership of negotiations that resulted in the first ever OPG commercial partnership agreement with a First Nation for which she was recognized with an OPG "Power Within" award. Kath received her B.A. Economics degree from Huron College, University of Western Ontario in 1990 and her LL.B from the Faculty of Law, University of Toronto in 1993. Kath has been a Member of the Law Society of Upper Canada since 1995.

Professional Experience

Borealis Infrastructure Management Inc. – Toronto, Ontario **Vice President, Legal**	• Provide transactional legal support to investment teams on pursuits of assets in various infrastructure categories including power generation, transmission and transportation • Provide legal support to asset management teams with respect to assets under management including Bruce Power • Negotiate a wide range of agreements, including joint ventures, purchase and sale agreements, services agreements and funding agreements • Oversight and management of external counsel
Ontario Power Generation Inc. – Toronto, Ontario **Director Commercial Strategy** **Darlington Nuclear Refurbishment Project**	• Member of a 7 person leadership team accountable for the successful delivery of this 15 year, $6-$10 billion nuclear refurbishment project • Designed and led a competitive RFP process and dual track negotiations for the largest Engineer-Procure-Construct contract for the project
Hydroelectric Development **Director, Business Development/Project Manager**	• Accountable for delivery of 4 active hydroelectric projects valued between $25M and $1B at various stages of development from concept phase to construction and commissioning • Obtained business case approvals for projects through effective communication with finance, engineering, legal and other stakeholders including OPG Board of Directors and senior management • Approved project execution plans and provided ongoing oversight of cost, schedule, quality and risk aspects of projects • Led key negotiations with First Nation, regulators and contractors, including first ever commercial partnership agreement with a First Nation
Law Division **Assistant General Counsel-Commercial Transactions/Solicitor**	• Lead counsel on the sale by auction of the Mississagi Hydroelectric Generating Stations to Brascan, on the sale process for the Lakeview, Lennox, Thunder Bay and Atikokan Thermal Generating Stations, and on the Niagara Tunnel Project

Education and Credentials

LL.B. Faculty of Law, University of Toronto

B.A. Economics, Huron College, University of Western Ontario

D. Brian Hay, AAB NextBridge Representative and Lead First Nation and Métis Affairs

Biography

Brian Hay is the Director of Aboriginal Relations for NextEra Energy Canada ULC. Brian joined NextEra after a lengthy career in the electricity, oil and gas, mining, financial and consulting sectors. As the founding Director of First Nation and Métis Relations Department of the Ontario Power Authority, Brian managed the initial outreach to Ontario's First Nation and Métis communities for the province's Integrated Power System Plan. Earlier in his career, Brian managed the interface of Imperial Oil's Esso Resources with the First Nation and Métis of Alberta, Saskatchewan and the North West Territories, where he also worked with Inuit leaders. As a consultant with both a national communications agency and with his own company, he consulted projects with the Chiefs of Ontario, Elections Ontario Aboriginal Outreach, the Métis Nation of Ontario, the Métis Nation of the North West Territories, the North West Territories Native Housing Corporation, the Government of the North West Territories, the C.D. Howe Institute, the Canadian Fur Institute, the Mining Association of Canada and the Canadian Petroleum Association. A retired Major in the Canadian Army, Brian holds an Honors Degree in Political Science and Philosophy, and an MA in Behavioral Political Science.

Professional Experience	
NextEra Energy - Canada **Director, Aboriginal Relations**	• Responsible for the development of sustainable relations with Canadian First Nation and Métis peoples and communities • Extended and enhanced existing relations with selected First Nation and Métis communities and organizations in Ontario • Initiated implementation of Capacity Building Agreements • Supports development of Community Benefit Agreements • Supervises and directs consultation activities
National Public Relations **Manager, Aboriginal Relations**	• Responsible for the management of selected projects and for the development of new Aboriginal related new business • Helped win RFP and directed Aboriginal outreach for Elections Ontario • Secured contract for developing a strategic plan for the Chiefs of Ontario • Helped win and worked on a strategic plan for Aboriginal Outreach for an Ontario university, and advised clients on dealing with Aboriginal interests in mining and quarry operations
Ontario Power Authority **Director, First Nation and Métis Relations**	• Responsible for development and management of the OPA's outreach and engagement program to First Nation and Métis people, and communities for the FIT program • Developed the first FIT outreach program to Aboriginal peoples and successfully engaged First Nation communities and Métis people in the FIT launch • Helped 42 First Nation communities participate in making successful FIT applications

Education and Credentials

Master of Arts and Political Science, McMaster University, Hamilton, Ontario, Canada

Honors Bachelor of Arts (magna cum laude) and Political Science and Philosophy, McMaster University, Hamilton, Ontario

Corporate Finance Certificate I&II

Canadian Investment Dealers Association

Kepner Tregoe Apex Program

Kepner Tregoe Institute (IOL)

Teresa Homik, AAB NextBridge Representative

Biography

Teresa Homik is the Manager of Aboriginal Affairs (National Policies and Programs) at Enbridge Inc., where she is responsible for managing all National Policies and Programs within the Aboriginal Relations function, including: Enbridge Aboriginal and Native American Policy, and Major Aboriginal CSR programs (School Plus). Prior to joining Enbridge, Teresa practiced law with a focus on Treaty and Aboriginal Rights and land claims issues for First Nation, Government (INAC and the Indian Claims Commission), and Industry clients, for 17 years. Concurrently, for period of seven years, she served in multiple leadership roles within the Aboriginal Law Section of the Canadian Bar Association, both National and Alberta branch, and as Editor of the national newsletter of the Aboriginal Law Section of the Canadian Bar Association. Teresa has expertise in the legal and constitutional rights of First Nation and other Aboriginal peoples of Canada. She also has extensive knowledge of the history of First Nation and Métis peoples in Canada, and of the historical development of Canadian government policies regarding First Nation and other Aboriginals. Teresa was also a member of the Board of Directors of the Association of Women Lawyers (Calgary) for 10 years. Teresa received her Law Degree from the University of Manitoba and her Undergraduate Degree in Political Studies and French Literature.

Professional Experience

Enbridge Inc. - Calgary, Alberta **Manager, Aboriginal Affairs (National Policies & Programs)**	• Responsible for managing all National Policies and Programs within the Aboriginal Relations function, including: Enbridge Aboriginal and Native American Policy, Major Aboriginal CSR program (School Plus) • Responsible for strategic Aboriginal relationship building at the national level, National level Aboriginal issues management • Aboriginal Affairs due diligence support for renewable and alternate energy project acquisitions, including Gas Midstream and ongoing Aboriginal Affairs support for Enbridge-owned renewable energy projects during construction, particularly in Ontario.

Education and Credentials

National Policies and Programs management for Enbridge –5+ years

Law practice exclusively focused on Treaty and Aboriginal Rights and land claims issues for First Nation, Government (INAC and the Indian Claims Commission), and Industry clients - 17 years

Leadership roles within the Aboriginal Law Section of the Canadian Bar Association, both National and Alberta branch, and Editor of the national newsletter of the Aboriginal Law Section of the Canadian Bar Association- 7 years

Member of the Board of Directors of the Association of Women Lawyers (Calgary)- 10 years

Undergraduate Degree in Political Studies and French Literature, University of Manitoba, Winnipeg, Canada

Law Degree, University of Manitoba, Winnipeg, Canada

Oliver Romaniuk, Operations Committee

Biography

Oliver Romaniuk's academic background focused on power system analysis, economics and control. Since entering the power industry in 2002, he has participated in alternative energy system design and project management for smart metering, residential demand response and cogeneration pilot projects for a number of Ontario's largest distribution utilities. He returned to the University of Waterloo in September 2006 to pursue a Master's Degree in Electrical Engineering with Toronto Hydro Energy Services Inc. as the sponsoring corporation. After graduating Oliver has been with NextEra Energy in transmission development, focusing on competitive transmission procurement processes and supporting NextEra's Canadian wind generation group with transmission interconnection support. The team was recently awarded over 600MW of Ontario Feed-in-Tariff contracts. Oliver is a Registered Professional Engineer in the Province of Ontario.

Professional Experience

NextEra Energy/FPL ENERGY - Juno Beach, FL **Project Manager, Transmission Development**	• Responsible for responding to competitive transmission and generation procurement processes through regional power authorities • Analyst for transmission interconnections for wind energy facilities, interface between generation group and external system operators and incumbent transmission operators. • Participated in regulatory and technical working groups to drive policy objectives. As a developer, responsible for field work, community outreach, subject matter expert and external consultant coordination and management
Toronto Hydro Energy Services Ltd - Toronto, Ontario **Consultant, Generation Development**	• Focus on technical aspects of integrating small scale cogeneration in multi-unit residential buildings • Performed net energy balance and energy market forecast analysis to build business case for sales of cogeneration units • Managed software development of data acquisition tools, engine control systems and economic dispatch algorithms
OZZ Energy Solutions Inc. - Concord, Ontario **Energy Engineering Analyst**	• Project Manager for Hydro One and Toronto Hydro Residential Load Control Pilot Projects and participated in design of combined heat and emergency power systems. • Developed economic, performance and energy analysis algorithms for small scale cogeneration systems. • Participated in writing cogeneration feasibility studies for clients • Coordinating installation of monitoring equipment and collected consumption data for CBC's 'Code Green' reality television show. • Coordinated installation of monitoring system for Mattamy Homes' Green Initiative energy monitoring project • Acted as interim meter services technician during installation of multi-unit residential building smart metering systems for Wirebury Inc.

Education and Credentials

Master of Applied Science, Electrical Engineering, University of Waterloo, Waterloo, ON, Canada

Bachelor of Science, Electrical Engineering, University of Waterloo, Waterloo, ON, Canada

Ryan Farquhar, Operations Committee

Biography

Ryan Farquhar is Director of Power Transmission at Enbridge, responsible for developing Enbridge's power transmission business platform. Prior to joining Enbridge, Ryan was Vice-President & General Counsel of publicly-traded Tonbridge Power Inc. Ryan held a management role with respect to the Montana-Alberta Tie-Line (MATL) line, the first cross-border merchant electric transmission line in North America. The 330 km, 230 kV power transmission line will be in service in 2013. Tonbridge was acquired by Enbridge in late 2011.

Ryan has experience in private equity and venture capital investing, having been a Partner at one of Canada's leading independent fund managers. Ryan is a lawyer by training, having practiced corporate law at a leading national law firm, with a focus on transactions. Ryan received a Bachelor of Laws from The University of Western Ontario and Bachelor of Commerce from Queen's University.

Professional Experience

Enbridge Inc. – Toronto, Ontario **Director, Power Transmission**	• Key member of a team responsible for the growth of Enbridge's transmission platform. Responsible for all aspects of finding projects to invest in, including overseeing due diligence, developing partnerships, marketing the business unit and assisting with operation of projects in the portfolio. • Former member of the Montana-Alberta Tie-Line ("MATL") management team. • Co-led the sale of MATL to Enbridge Inc.
VenGrowth Private Equity Partners Inc. - Toronto **Partner**	• A leader of the Buyout Fund and Mezzannine Growth Fund. Responsible for all aspects of the Funds, including sourcing, evaluating and managing investments (including investment team oversight), and reporting to Fund investors. Acted as a member of the Investment Committee which approved all material Fund investment/business decisions involving portfolio companies. Responsible for developing strategy and execution for the Funds and the investee companies. Sourced and led the purchase of OnCorp Direct. This included successfully structuring and negotiating the financing and leading a successful search for a co-investor and President. Also led legal matters for the Funds • Director of Oncorp Direct, a leading service provider for online searches and registrations • Director of Numatech, a distributor and converter of corrugated plastic packaging.
Smith Lyons LLP (now Gowling Lafleur Henderson LLP) - Toronto **Associate**	▪ Actively involved in strategizing with and advising private and public corporate clients on various matters including mergers and acquisitions, and financings. Responsible for negotiations, drafting agreements and managing transactions.

Education and Credentials

Bachelor of Laws, The University of Western Ontario, London, ON

Bachelor of Commerce, Queens's University, Kingston, ON

Annesley Wallace, Operations Committee

Biography

Annesley Wallace is a Professional Engineer with operational and project management leadership experience, currently responsible for the assessment of infrastructure investment opportunities for a large pension plan. Annesley has extensive experience in multiple sectors including nuclear and thermal power, transmission & distribution, industrial and renewable energy. Annesley holds graduate degrees in mechanical and materials engineering from Queen's University and business administration from the Schulich School of Business, York University.

Professional Experience

Borealis Infrastructure **Assistant Vice-President, Transaction Team (2012-Present)**	• Analyzes infrastructure investment opportunities from technical and market perspectives to assess whether they align with Borealis' objectives and return expectations; • Manages due diligence work streams, including overseeing third party advisors throughout transaction processes; • Prepares investment memoranda for Borealis and OMERS internal investment committees and the OMERS Board of Directors; • Negotiates agreements with strategic partners for joint acquisition of investment entities; • Develops acquisition plans that include assessment of communications, human resources, governance, finance and health and safety issues for the transition of newly acquired entities to Borealis ownership.
SNC-Lavalin Inc. **Vice-President, Operations, Energy & Infrastructure (2011-2012)**	• Oversaw an organization of 300 employees in project management, engineering, procurement and construction management responsible for generating 200 million dollars of revenues annually for SNC-Lavalin's Energy & Infrastructure business; • Negotiated and executed projects under a wide range of contract models including fixed price, target price, and time and materials for engineering, procurement and construction; • Managed risk procedures for Energy & Infrastructure projects and implemented risk mitigation plans to reduce SNC-Lavalin's exposure to risk;
SNC-Lavalin Inc. **Director, Strategy & Special Projects, Global Power (2009-2011)**	• Developed the Global Power strategy for SNC-Lavalin's eight business units operating in nuclear, hydro, thermal and transmission and distribution to support a revenue forecast in excess of one billion dollars; • Implemented an account management system to support increased emphasis on developing long-term relationships with key clients in the power sector; • Evaluated domestic and international acquisitions for the Global Power sector and executed due diligence activities to prepare offers and negotiate deals; • Led the acquisition of a 1,400 person company in the nuclear industry, including preparing the bid, negotiating the agreements, acting as the point of contact for SNC-Lavalin with external parties and implementing a transition plan;

Education and Credentials

M.B.A., Schulich School of Business, York University, Specializations in Financial Management and Strategy

M.Sc. (Eng), Queen's University, Mechanical and Materials Engineering; received the R.S. McLaughlin Research Fellowship

B.Sc. (Eng), Queen's University, Mechanical specialization.

Robert van Beers, Project Director

Biography

Robert van Beers is the Senior Director of Power Transmission within Enbridge. Formerly founder and later CEO of publicly-traded Tonbridge Power Inc., Robert played a leading role in the financing and development of the Montana-Alberta Tie-Line (MATL), the first cross-border merchant electric transmission line in North America. The 330 km, 230 kV power transmission line will be in service in 2013. Tonbridge was acquired by Enbridge in September 2011. From his early role as an advisor to Trans-Elect in its establishment and later its acquisition of the transmission grid in Michigan from Consumers Energy through his role in shaping the *American Recovery and Reinvestment Act*'s Transmission Infrastructure Program through to his influence at the FERC on merchant transmission policy and the evolution of the independent business model, Robert has been instrumental in shaping and developing the North American transmission landscape for almost 20 years. Robert has extensive power sector experience in northern Ontario also, having been the lead advisor to all 11 municipal distribution utilities in the region in advance of the liberalization of the Ontario Power market (in the late 1990s), helping these companies establish unregulated affiliates, explore investment opportunities and forge partnerships with capital, energy service companies and major loads. Robert has a Master's Degree in Public Administration as well as an undergraduate Honours degree in Economics and Sociology.

Professional Experience

Enbridge Inc. – Toronto, Ontario **Sr. Director, Power Transmission Development**	• Leading the team responsible for all commercial aspects Enbridge's of transmission holdings as well major acquisitions, joint venture and development opportunities.
Tonbridge Power Inc. – Toronto, Ontario **Chief Executive Officer (previously COO)**	• Led the development of a 330 km merchant transmission line between Alberta and Montana, sold the public company to Enbridge Inc. in October 2011
CRA International **VP, National Energy & Environment Practice**	• Practice leader responsible for all client and practice matters in a leading global economics consultancy
PricewaterhouseCoopers Director, Mergers & Acquisitions, Energy & Utilities	• Responsible for the Canadian M&A strategy practice in energy and utilities

Education and Credentials

High Performance Leadership, U. of Chicago, Booth School of Business

Corporate Director's College, U. of T./Rotman, Institute of Corporate Directors (accredited corporate director)

Corporate Financial Strategy in Global Markets, INSEAD, France

Master of Public Administration, Queen's University, Kingston, Canada

Bachelor of Arts (Honours), Economics and Sociology, University of Guelph

John Schajatovic, Lead Engineering and Construction

Biography

John Schajatovic is a Project Manager for NextEra Energy Resources responsible for the early stage management within the Engineering & Construction Department. Since joining NextEra in September of 2010, John has been responsible for supporting the engineering, design, permitting and successful turnover to execution teams for multiple wind development projects and their associated transmission lines throughout the US and Ontario. Prior to joining NextEra, John has served in various project management roles responsible for all phases of infrastructure projects from inception to completion in both the private construction sector as well as with public development companies. John has a Bachelor of Science degree in Business Administration from Youngstown State University in Ohio.

Professional Experience

NextEra Energy/FPL ENERGY - Juno Beach, FL **Project Manager, Lead Professional - Construction**	• Responsible for the early stage management within the Engineering & Construction Department.
Palm Beach Grading, Inc. - Sarasota, Florida **Project Manager**	• Responsible for the coordination of geotechnical engineer and engineer of record to ensure completion of a quality product and timely turnover to the general contractor. Fiscal responsibility for maintaining production rates and monthly billings to the general contractor, and the coordination and reporting responsibilities to corporate office and general contractor • Managing $4 million contract as a subcontractor for a 14 km FDOT road widening project. • Built staff of 50 plus employees working day and night shifts.
Core Communities, LLC. - Port St. Lucie, Florida **Senior Project Manager**	• Managed development process within the scope, schedule, and budget for infrastructure projects in excess of $70 million, negotiated contracts with builders, commercial developers and civic users for multiple parcels, managed $8m public infrastructure roadway project successfully turned over to City for ownership and maintenance. Knowledge of Community Development District (CDD) financing, member of CDD Board of Supervisors. Job cost estimating, budgeting, cash flow reporting and monthly financial analysis. • Served as President of Master Home Owners Association and Master Commercial Association • Reduced assessments to residents for 2010 budget year ($2m annual budget) • Identified and captured unrecognized revenue from previous budget years • Implemented direct monthly billing process to residents to enhance Associations cash flow. • Integral part of management team executing on the master planning and development of the 8,200 acre master planned community of Tradition consisting of 3 DRI's (development of regional impact) including entitlements in excess of 19,000 residential units and 15 million square feet of various commercial uses

Education and Credentials

Bachelor of Science, Business Administration , Youngstown State University, Youngstown, Ohio

Eduardo (Ed) DeVarona, Operations and Maintenance

Biography

Ed DeVarona is director of operations at NextEra Energy Transmission, LLC, an indirect wholly owned subsidiary of NextEra Energy, Inc. (NYSE: NEE). NextEra Energy Transmission is the parent company of Lone Star Transmission, LLC, NextEra Energy's regulated electric utility in Texas, and New Hampshire Transmission, LLC, the entity that co-owns and operates certain substation assets at the Seabrook Nuclear Station. He joined the Company in July 2011. Prior to joining NextEra Energy Transmission, Eduardo held director level positions since July 2007 in Transmission Operations and Transmission & Substation Technology with NextEra Energy sister company Florida Power & Light. Ed led FPL's Transmission & Substation Technology group during the planning and implementation phases of Energy Management System and Control Center upgrade projects as well as FPL's implementation of the Energy Smart Florida Smart Grid initiative to revamp the FPL transmission grid and enable advanced analytics, reliability and efficiency improvements. During his tenure as Director of Transmission Operations, Ed's responsibilities encompassed key aspects of FPL's bulk electric system reliability plans and execution on FPL's transmission storm hardening efforts while leading FPL's statewide Transmission Field Operations organization. Ed also served as the NERC Reliability Coordinator agent for the Florida Reliability Coordinating Council (FRCC). During this assignment, Ed served FPL and the FRCC as representative on NERC Operating Reliability and Reliability Coordinator Subcommittees. Ed received his bachelor of science in electrical engineering from the University of Florida in 1994, and is a graduate of the NextEra Energy Leadership Development Program – Leadership for the Next Era.

Professional Experience

NextEra Energy Transmission - Juno Beach, FL **Director, Operations**	• Direct the safe, reliable and cost effective operations of NextEra Energy Transmission assets across North America to ensure Operational Excellence via comprehensive application of processes, procedures and standards for transmission operations • Developed and managed all activities to implement Lone Star Transmission company in ERCOT • Oversaw control centre operations and operational technology platform implementation • Managed staffing of company operations team and all transition to operations activities • Coordinated development, engineering and construction, and compliance activities • Successfully achieved NERC TOP certification
Florida Power & Light Co., (FPL) **Director, Transmission & Substation Technology**	• Responsible for the overall management, maintenance and capital improvement of FPL Energy Management Systems and infrastructure as well as technology strategy to implement smart grid systems and business applications to drive productivity and leverage information across Transmission & Substation business unit • Formed FPL Transmission & Substation Technology organization to focus on all transmission control centre applications and infrastructure systems • Responsible for NERC Critical Infrastructure Protection standards for FPL Transmission Operator and FRCC Reliability Coordinator entities • Ensured implementation of all FPL Energy Smart Florida applications for control centre operations and Transmission Performance & Diagnostic Center.
Director, Transmission Operations	• Responsible for the management and execution of processes for personnel safety, field condition assessments, maintenance of transmission equipment and assets, including rights of way and vegetation management • Responsible for organization's performance of event response and root cause analysis, repair, replacement, and construction of the over 10,720 km of transmission lines in the FPL system

Education and Credentials

Bachelor of Science, Electrical Engineering, Power Systems, University of Florida, Gainesville, FL

Graduate of NextEra Energy, Inc. "Leadership for the NextEra" development program

Tania Persad, Lead Regulatory

Biography

Tania Persad is the Senior Legal Counsel & Gas Distribution Compliance Officer with Enbridge Gas Distribution Inc. (EGD). The primary focus of Tania's legal practice has been on regulatory and administrative law matters, combined with corporate commercial and privacy law and implementing compliance systems for all aspects of the Gas Distribution businesses. Tania has represented EGD and its affiliated companies in several rate, facility, franchise, policy and rule-making proceedings before the Ontario Energy Board and the National Energy Board both as an applicant and an intervenor. In addition, Tania has advised and supported stakeholder relations and numerous commercial transactions, including gas delivery, supply, storage, transportation and other services, green energy developments, land negotiations and agreements, conservation demand and alternative energy technology projects and services. As the Compliance Officer, Tania is charged with oversight of policies, training programs and compliance reporting structures designed to ensure that Enbridge continues to operate all areas of its business to the highest legal, regulatory and ethical standards. Prior to joining Enbridge in 1999, Tania was counsel to the Alberta Energy and Utilities Board where she represented the Board in many regulatory proceedings. Tania began her legal career as an associate with Milner Fenerty (now Fraser Milner Casgrain) in Calgary in 1994. Tania received a Bachelor of Commerce from McGill University in 1991 and an LL.B. from the University of Calgary in 1994. She was called to the Alberta Bar in 1995 and the Ontario Bar in 1999.

Professional Experience

Enbridge Gas Distribution Inc. – Toronto, Ontario **Senior Legal Counsel & Gas Distribution Compliance Officer**	• Primary internal counsel for all EGD regulatory matters, and responsible for oversight of gas distribution policies, training programs and compliance reporting structures. • Developed and maintained in-house regulatory legal expertise and compliance function • Successful resolution of numerous regulatory applications and commercial transactions
Albert Energy & Utilities Board - Calgary, Alberta **Board Counsel**	• Represented the Board at numerous energy facility and utility proceedings and provided advice with respect to Board affairs. • In addition to Board proceedings, represented the Board before the Environmental Appeal Board regarding certain energy facilities • Presented Board's submissions to the Alberta Court of Appeal to successfully defend the Board's process and decisions in the gas over bitumen proceedings
Milner Fenerty – Calgary, Alberta **Associate, Litigation & Regulatory**	• Articling student and Associate in the litigation and regulatory groups practicing environmental, oil and gas, insurance and administrative law. • Co-authored Contaminated Property in Canada, Alberta Chapter (Carswell, 1997), and Considerations of Fairness in the Context of International Commercial Arbitration (Alberta Law Review, 1996)

Education and Credentials

Bachelor of Laws, University of Calgary

Bachelor of Commerce, McGill University

Called to the Alberta and Ontario Bars

Civil Law Summer Programs, Université de Sherbrooke and University of Oslo

Kara Green, Lead Land Acquisition

Biography

Kara Green is a Sr. Land & ROW Specialist with Enbridge Pipelines Inc. As a Senior Specialist Kara manages all land components related to a diverse set of projects. She is involved in all land aspects from route development and review to creation and execution of land acquisition plans. Prior to joining Enbridge Pipelines Inc., Kara served since 2008 as a Senior Right-of-Way Planner, at ATCO Electric ltd. In this role, her responsibilities encompassed analyzing data to identify potential and proposed facility locations, coordinated and conducted stakeholder, agency, First Nation and industry consultations. She managed numerous contracts, procurement activities and contractors covering a variety of scopes while focusing on meeting the ever changing project priorities as they arise and adapting to the changes or additions to job requirements. Prior to joining ATCO Electric ltd, she worked as an environmental consultant at Ridgeline Environmental Inc., where she Supervised and conducted all aspects of environmental site assessments including, DSA's, Phase I ESA, Phase II ESA and Phase III ESA on both upstream and downstream projects in Alberta, Saskatchewan and British Columbia. Kara received her B.Sc. Environmental Conservation Sciences, Majoring in Land Reclamation from University of Alberta, Diploma in Land Resource Management and Land Reclamation from Olds college and Deutsch Zertifikat Level B2 from Goethe Institute of Germany priorities as they arise and adapting to the changes or additions to job requirements.

Professional Experience

Enbridge Pipelines Inc. **Land & ROW Specialist,**	• As a Senior Specialist Kara manages all land components related to a diverse set of projects. She is involved in all land aspects from route development and review to creation and execution of land acquisition plans.
ATCO Electric Ltd. – Edmonton, AB **Senior Right-of-Way Planner**	• Analyzed data to identify potential and proposed facility locations based on such as economic, technical, environmental, industry and consultations • Coordinated and conducted stakeholder, agency, first nation and industry consultation • Managed numerous contracts, procurement activities and contractors • Arranged, completed and reviewed various environmental studies and assessments related to proposed facilities, decommissioning and abandonment of rural substations as well as commercial land/properties purchased for ATCO Assets group • Prepare federal and provincial applications including the Alberta Utilities Commission • Prepare evidence related to facility locations, environmental impacts and consultation and testify at AUC hearings • Responsible for the Right-of-Way planning project schedule, as well as inputs and deliverables to the overall project schedule • Accountable for all project costs associated with the right-of-way planning aspects
Ridgeline Environmental Inc. **Environmental Consultant**	• Supervised and conducted all aspects of environmental site assessments including, DSA's, Phase I ESA, Phase II ESA and Phase III ESA on both upstream and downstream projects in Alberta, Saskatchewan and British Columbia • Created and implemented scopes of wok, cost estimates, Emergency response plans, safety meetings, and problem solving on a daily basis when problems or concerns occurred, adjusting the scope of work accordingly • Trained junior staff on environmental assessments field work and reporting, conducted audits on pipelines, commercial buildings, and Indian Oil and Gas inspections, while continuously review of legislation and mandates to ensure compliance

Education and Credentials

B.Sc. Environmental Conservation Sciences, Majoring in Land Reclamation, University of Alberta (Edmonton, AB)

Diploma in Land Resource Management and Land Reclamation, Olds College (Olds, AB)

Dan O'Neill, Lead Environment and Permitting

Biography

Dan O'Neill is the Senior Environmental Analyst, Environment, Lands & ROW, Canadian Projects with Enbridge Inc. He is responsible for determining project environmental permitting requirements, schedules and budgeting management, project environmental applications and environmental compliance, and development of project environmental mitigation. Dan is the acting liaison with environmental regulators, and management of construction environmental monitoring and Inspection. Mr. O'Neill received his Bachelor of Science in Forestry and Environmental Management from the University of New Brunswick, and his Forest Technologist Diploma from Maritime Forest Ranger School.

Professional Experience

Enbridge Inc. – Calgary, Alberta **Senior Environmental Analyst, Environment, Lands & ROW, Canadian Projects**	• Responsible for Determining Project Environmental Permitting Requirements, Schedules and Budgeting Manage, Project Environmental Applications and Environmental Compliance, Development of Project Environmental Mitigation, Liaison with Environmental Regulators, and Management of Construction Environmental Monitoring and Inspection • Environmental Management for Enbridge MATL Powerline, Christina Lake Lateral Pipeline, Athabasca Tank Terminal, Sunday Creek Tank Terminal and Alberta Clipper Capacity Expansion • Right-of-way clearing management of numerous powerline and pipeline projects • 10 years of experience in Forestry, Oil and Gas and Electrical Utility Industries • Member of the College of Alberta Professional Foresters

Education and Credentials

Bachelor of Science in Forestry and Environmental Management, University of New Brunswick, Fredericton, Canada

Forest Technologist Diploma, Maritime Forest Ranger School, Fredericton, Canada

Amber Pastoor, Lead Municipal and Community Relations

Biography

In her current role at Enbridge Pipelines Amber Pastoor is responsible for developing and leading stakeholder engagement plans to guide and track projects and meet various regulatory and legal requirements. Amber has participated in the design and implementation of over 14 Enbridge public consultation programs. Amber joined Enbridge after gaining two years of experience with the University of Calgary as a director of external relations and marketing, where she helped launch an international branch of the U of Calgary's campus in Qatar. She holds a Master of Arts in journalism from the University of Western Ontario; a Bachelor of International Management from the University of Lethbridge; and is currently participating in the Cornell-Queen's Executive MBA program. She is also a certificated member of the International Association for Public Participation.

Professional Experience

Enbridge Pipelines **Senior Strategist, Stakeholder Relations**	• Demonstrate leadership in building in-house knowledge and the continuous improvement of processes for the Stakeholder Relations team; and achieve positive outcomes by encouraging, supporting, coaching, developing and mentoring others. • Function effectively in team situations both within and across departments and other organizations to achieve optimal results. • Develop and initiate opportunities to enhance the company's reputation and social license to operate, through effective engagement and communication with all (non-Aboriginal) stakeholders within the planned project consultation radii. Track and manage issues critical to the reputation and image of Enbridge and provide reactive communication strategies and advice in situations where Enbridge's reputation is at stake. • With a high level of independence, provide comprehensive senior stakeholder engagement support for major projects and associated regulatory applications, including proactive identification and management of project opportunities and risks. • Utilize business skills and knowledge of Enbridge operations to ensure consultation strategies are well integrated with other functional groups. • Identify the relevant stakeholders affected by or interested in the project and plan strategic engagement that considers varying levels of interest and influence.
Enbridge Pipelines **Senior Advisor, Stakeholder Relations**	• Lead development and implementation of stakeholder engagement plans to guide and track projects and meet regulatory requirements. • Identify project-related stakeholder risks and coordinate mitigation plans. • Plan and coordinate fulfillment of all legal/regulatory requirements for public consultation. • Maintain thorough records, to support hearing processes and potential legal challenges. • Develop and coordinate 'hand over' plans to guide transition of project from construction to operations, in regard to consultation and communications. • Contribute to development and tracking of comprehensive estimates for stakeholder relations project costs. Ensure established cost control practices are followed in working with contractors and consultants.

Education and Credentials

EMBA Student: Cornell Queen's Executive MBA program – Expected completion November 2013

Master of Arts-Journalism: University of Western Ontario - April 2001

Bachelor of International Management: University of Lethbridge - October 1997

R.B. "Rod" Adams, Lead Project Controls and Procurement

Biography

Rod Adams is the Director, Business Services of NextEra Energy Transmission, LLC, an indirect wholly owned subsidiary of NextEra Energy, Inc. (NYSE: NEE). He joined NextEra Energy in 1983 and NextEra Energy Transmission in April 2011. Within the NextEra Energy family of companies, Rod served in many diverse capacities for Florida Power & Light and NextEra Energy Resources. His roles included, Director, Property & Sales Tax, Business Manager, Power Generation and Manager, Property Accounting. Prior to joining NextEra Energy, Rod worked 10 years in power plant engineering and construction with Stone & Webster Engineering and EBASCO Services in various US locations. Rod received his Bachelor of science degree from Colorado State University in 1974 and he was certified as a Cost Engineer from the AACEI in 1986.

Professional Experience

NextEra Energy/FPL ENERGY - Juno Beach, FL **Director, Business Services**	• Responsible for the development of policy and strategy for NextEra Energy Transmission development and operating companies. Responsible for the generation and implementation of all Project Management (PMO) functions for our development sites • Oversee regulatory filings with state regulators and manage the development of software systems that support operations and regulatory • Include providing payment projections for accruals, interface with other business units for development of project management strategies that support the projects business needs, responding to legislative and regulatory proposals, and supporting the preparation for litigation and mediation involving construction/land activities • Established the PMO function for our Lone Star development project and have delivered all land parcels with a 99% on-time percentage • Supported our Lone Star rate case with all project management functions for schedules, filings, witness prep and data requests
NextEra Energy **Director, Property and Sales Tax**	• Responsible for the development of policy and strategy for FPL utility, NextEra Energy Resources and subsidiaries for all real and tangible property • Manage the preparation of the system appraisal of value for FPL and subsidiary property, including the analysis of financial and operating data, capital structure, cost of capital, net income, depreciation, exemptions, special classifications, and property tax laws • Perform negotiations for property tax values, develop supporting information, handle payment of taxes, and pursue appeals as appropriate • Providing payment projections for accruals, interface with other business units for development of tax strategies that support their business needs, responding to legislative and regulatory proposals involving property & sales taxes, and supporting the preparation for litigation and mediation as the corporate witness in each case involving property & sales taxes • Industry representative on the Council on State Taxation national property tax task force; Utility representative for the Florida Department of Revenue Property Tax Task Force • Participated on a team sponsored by Sen. Pruitt on regulation changes for large valuation disputes to hold harmless the state Department of Education funding for Counties • Special assignment to the CFO as Quality Deployment Leader for the Finance Bus. Unit

Education and Credentials

Bachelor of Science, Industrial Construction Management (civil engineering and finance), Colorado State University - Ft. Collins, Colorado

Appendix 4: Detailed Case Studies

NextBridge has selected 11 representative projects that demonstrate our capabilities across the following key areas relevant to the Project:

- Ontario project experience
- Transmission experience outside Ontario
- Major capital project experience
- Renewable energy experience
- Ontario regulatory experience
- Experience with acquisition of land use rights from private landowners and the Crown
- Experience with acquisition of necessary permits from government agencies
- Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project
- Community consultation
- Completion of the procedural aspects of Crown consultation with First Nation and Métis communities

For each project, we have provided a case study that opens with an overview of the project followed by a more fulsome description of the relevant capabilities.

Case Study 1: Ontario Feed-in-Tariff Wind Projects – NextEra

Overview	
Project Description	NextEra began to actively develop wind projects in Canada in 2006. Currently, NextEra owns and operates four wind energy facilities in Canada and was recently awarded an additional eight contracts under the Ontario provincial Feed-in-Tariff (FIT) program. These projects will provide over 600 MW of clean, renewable energy to the province. Six of the eight projects are transmission connected and include approximately 100 km of transmission infrastructure. Right-of-way acquisition for these facilities is ongoing and demonstrates further the commitment and willingness of NextEra's team to consult with stakeholders, complete environmental assessments, and secure the appropriate approvals and permits required. **Strengths:** • Commitment to First Nation and Métis consultation • Working closely with the Ministry of Environment to permit three projects simultaneously, a first for renewable energy projects in Ontario. • Established NextEra as a permanent member of the Ontario power industry with a total investment of over $1.5 billion
Demonstrated Capabilities	• Ontario Experience • Major Capital Project Experience • Renewable Energy Experience • Ontario Regulatory Experience • The acquisition of land use rights from private landowners • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation • Completion of the procedural aspects of Crown consultation with First Nation and Métis communities

Stakeholder Consultations: Multiple public meetings were held to present and discuss each wind farm project. In addition, NextEra sent out regular project updates through the mail to affected parties. For the transmission components, NextEra's land agents made repeated visits to each landowner to explain the project and address any questions or concerns.

NextEra also held specific events to inform stakeholders about the project, gather input and answer stakeholder questions. First, we held a tele-town hall meeting where affected parties were invited to participate in a tele-conference with subject matter experts from the wind project teams in real-time. Second, NextEra hosted a round-table with Municipal Councils to discuss the projects and answer questions. In addition, municipal councils were provided with regular presentations to explain the status and progress of the projects.

Aboriginal Experience: NextEra is currently engaging with 14 First Nation and three Métis communities and organizations in South Western Ontario as the company works to develop over 600 MW of

renewable energy from wind under the FIT program. NextEra staff is undertaking a well-defined engagement and consultation process attuned to the protocols and interests of each community. NextEra has retained recognized Aboriginal professionals to monitor its archeological and environmental assessment program. The company has also committed to a substantial 20 year post-secondary scholarship/bursary program for Aboriginal students.

Acquisition of land use rights: Land rights for a significant portion of the transmission corridor have been acquired. They consist of permanent easements and, in the case of temporary construction access, temporary easements or Municipal rights-of-way.

NextEra has had extensive discussions regarding the transmission line and the transmission easement with all of the landowners along the corridor, including adjacent landowners. Record of Consultation (ROC) reports were created to document land owner interactions. All affected landowners were offered standard form transmission easement option agreements.

NextEra made efforts to secure private easements along various portions of the route, including areas where there are existing Hydro One distribution facilities. All landowners adjacent to Hydro One distribution rights-of-way were offered an opportunity to enter into an option agreement, which was accepted by some landowners. Negotiations continue with unsigned adjacent landowners.

Due to the uncertainty of the possibility of co-locating the transmission with Hydro One distribution infrastructure, a two-pronged approach was taken to acquiring land rights by working to secure land on both sides of the road or property lines. This approach allowed NextEra to select the most expeditious route and provided for an alternative if Hydro One decided that co-location was not possible. After negotiations, Hydro One decided that co-location would not be possible and the decision was made to use an alternate rights-of-way. Currently, private land is being acquired, as well as negotiations with municipalities for the use of municipal rights-of-way.

Environmental Approvals: Each of the eight current wind farm projects required a Renewable Energy Approval (REA). This process establishes baseline environmental conditions, assesses the potential impacts of the project on the environment, and recommends specific mitigation to reduce or completely eliminate these impacts. The skills and experience required to coordinate and complete these projects are completely transferable to the regular environmental assessment process. The REA for the

Summerhaven site has been approved. Approvals for the Bornish, Adelaide and Bluewater projects have been submitted and are being reviewed. The REA for Goshen and Jericho will be submitted in early 2013. Of note is our work with the MOE to develop a permitting process to allow separate environmental approvals for three projects (Jericho, Adelaide and Bornish) even though they share a section of the transmission facilities (switchyard, lines, substation transformer).

In the table below, we provide additional information on six of the eight wind farm projects that have transmission facilities.

FIGURE 38: DATA RELATED TO LAND SERVICES WORK FOR ACQUIRING TRANSMISSION IN ONTARIO

Project	Total route distance in km	Total route distance in km that is signed	Total # of agreements that are signed	Total # of parcels along each route	Signed Arch Right of Entry	Signed Environmental Right of Entry	Signed Substation / Lay-down Areas	Signed Crop Compensation Agreements	Outstanding Crop Compensation Agreements
Adelaide	The 115 kV side of the interface transformer will be connected via a 115 kV transmission line, 11.5 km long, to a new "Bornish TS 115 kV Switching Station", owned by the proponent. Bornish TS will also be the common connection point for the Bornish and Adelaide Wind Energy Centres. Bornish TS will be connected via a 115 kV line, 11.4 km long, to a 500 kV/115 kV step up station called "Parkhill TS 500 kV/115 kV Substation", which will also be owned by the proponent. It will be adjacent to a new "Evergreen TS 500 kV Switching Station" that will loop in and out of the Bruce – Longwood 500 kV lines approximately 36.5 km North of Longwood TS. The Parkhill TS will be owned by Hydro One.								
	13.04	5.71	15	46	0	5	2	6	5
Bornish	The 115 kV Bornish collector substation will be adjacent to a new "Bornish TS 115 kV Switching Station", owned by the proponent. Bornish TS will also be the common connection point for the Jericho and Adelaide Wind Energy Centres. Bornish TS will be connected via a 115 kV line, 11.4 km long, to a 500 kV/115 kV step up station called "Parkhill TS 500 kV/115 kV Substation", which will also be owned by the proponent. It will be adjacent to a new "Evergreen TS 500 kV Switching Station" that will loop in and out of the Bruce – Longwood 500 kV lines approximately 36.5 km North of Longwood TS. The Parkhill TS will be owned by Hydro One.								
	12.78	12.78	26	78	0	23	3	10	11
Bluewater	The 115 kV Bluewater collector substation will be connected via a 115 kV line, 23 km long, to Hydro One's existing Seaforth Transmission Substation.								
	24.08	12.61	26	70	3	20	1	11	31
Goshen	The 115 kV Goshen collector substation will be connected via a 115 kV line, 22.3 km long, using a line tap, to Hydro One's existing L7S Seaforth – Centralia 115 kV line approximately 17 km from the Seaforth Transmission Substation.								
	23.44	23.44	48	64	2	16	4	22	5

Project	Total route distance in km	Total route distance in km that is signed	Total # of agreements that are signed	Total # of parcels along each route	Signed Arch Right of Entry	Signed Environmental Right of Entry	Signed Substation / Lay-down Areas	Signed Crop Compensation Agreements	Outstanding Crop Compensation Agreements
Jericho	The 115 kV Jericho collector substation will be connected via a 115 kV line, 14.5 km long, to a new "Bornish TS 115 kV Switching Station", owned by the proponent. Bornish TS will also be the common connection point for the Bornish and Adelaide Wind Energy Centres. Bornish TS will be connected via a 115 kV line, 11.4 km long, to a 500 kV/115 kV step up station called "Parkhill TS 500 kV/115 kV Substation", which will also be owned by the proponent. It will be adjacent to a new "Evergreen TS 500 kV Switching Station" that will loop in and out of the Bruce – Longwood 500 kV lines approximately 36.5 km North of Longwood TS. The Parkhill TS will be owned by Hydro One.								
	14.92	4.66	34	75	4	13	1	12	12
Summerhaven	The Summerhaven collector and transmission substation will be connected via a 230kV line, 8.7km long, to a new switching substation on the Hydro One Middle wood to Nanticoke 230kV line.								
	7.50	7.50	16	13	0	0	0	0	0
TOTALS	**95.75**	**66.70**	**165**	**346**	**9**	**77**	**11**	**61**	**64**

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FIGURE 39: ONTARIO FEED-IN-TARIFF WIND PROJECTS (CONESTOGO PROJECT)



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Case Study 2: Blythe Transmission - NextEra

Overview	
Project Description	Blythe Energy, LLC, a subsidiary of NextEra Energy Inc., developed a transmission line in the vicinity of its Blythe Energy 520 MW natural gas fired electric-generating Power Plant located in the City of Blythe in Riverside County, California. The Blythe Energy Gen-tie project was built for the sole purpose of improving the long-term transmission paths available for delivery of the Blythe Energy Plant electrical output to the southern California ISO-controlled electrical transmission system. Construction of the 108 km, 1,100 MW, 230kV line began in February 2009 and is valued at over $80 million of CapEx. The Blythe Energy Gen-tie project was completed six weeks ahead of schedule and 15 % under budget with a commercial operation date of June 11, 2010. The Blythe transmission line and the Blythe Plant were sold to LS Power in December, 2011. **Strengths:** • $80 million, 108 km, 230kV, • 16 months of construction February 2009 – June 2010 • Completed six weeks ahead of schedule and 15% under budget • NextEra worked through numerous private and government land acquisition processes
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of land use rights from private landowners and Government agencies • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation

Regulatory Permits and Environmental Approvals: NextEra and its subsidiary, Blythe Energy, LLC, worked with the Western Area Power Administration and Southern California Edison to assemble the necessary information and conduct the studies required to complete the permit applications for this project.

We prepared a Petition for Amendment to Certification for submission to the California Energy Commission (CEC), Bureau of Land Management (BLM) Right-of-Way grant applications, and other state and federal permit applications for a 230 kV transmission line totaling approximately 108 km in southern California. Other activities included modifications to two existing substations and an impact assessment for downstream upgrades resulting from an interconnection with the existing transmission system.

Key issues in project permitting included evaluating desert tortoise habitat, cultural resources (including WWII era military training artifacts), and visual resources. We prepared a Biological Assessment to expedite the review of the project by the U.S. Fish and Wildlife Service (USFWS). We obtained approvals from CEC (for CEQA review) and the BLM (for NEPA review). Field survey protocols were developed in cooperation with the USFWS and California Department of Fish and Game. Extensive biological surveys

and cultural surveys were conducted for the entire length of the transmission line and the planned substation locations. We prepared biological and cultural mitigation plans, construction storm water pollution prevention plans, erosion control plans, and visual mitigation plans for the project. We also participated in public hearings and workshops.

Aboriginal Experience: California maintains a database of tribal elders as well as official tribal contacts and requires project proponents to notify tribes and request information regarding cultural resources. Blythe Energy contacted tribes in 2008 regarding the project and received several letters, but none expressing concern regarding the project. Tribes and bands were invited to become involved in the programmatic agreement for treatment of cultural resources.

Blythe Energy invited local tribes to consider participation in Native American monitoring during construction. The Torres-Martinez Desert Cahuilla Indians agreed to participate by providing monitors to cover some 108 km of the Gen-Tie line. Blythe Energy staff worked with monitors to ensure health and safety for tribal members sent to the project during construction in 2009. These monitors worked directly with Blythe Energy staff and contractors daily in the field. Blythe Energy staff also worked closely with Tribal office staff to develop and improve contracting and invoicing skills.

The Blythe Energy project was a successful project for the Tribe—it built skills among monitors as well as in the tribal office. Most importantly, Native American monitors provided an every-day perspective during construction. Due to a change in business focus, NextEra sold its interest in the Blythe Energy Center in 2011.

FIGURE 40: BLYTHE PROJECT LOCATION



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Case Study 3: Texas Clean Energy Express - NextEra

Overview	
Project Description	The Texas Clean Energy Express is a 344 km, 345kV private generator tie-line constructed to transmit electric power from wind farm generation near Abilene, Texas to load centers in the South near San Antonio, Texas. It was completed without access to expropriation. The project was initiated in July 2008 and completed in October 2009, a total development and execution time of 15 months. The main components of the project include 344 km of new 345kV transmission line on concrete poles, two 345kV substations and additional 138kV lines and substations. This project demonstrates the ability to develop and construct transmission lines and substations in extremely short timeframes, while completing the appropriate processes for evaluation, land acquisition, material and equipment procurement, EPC contracts, geotechnical and ground based surveying, environmental and regulatory permitting, and pipeline mitigation. Existing vendor relationships allowed for significant expediting of material and equipment procurement in order to meet internal schedules. **Strengths:** • 344 km, 345kV line, two 345kV substations and six 138kV substations • From conception to commercial operation in 15 months, including design, permitting and construction to commercial operation: July 2008 – October 2009 • 270 landowners, 504 crossing agreements, all negotiated without access to the right of expropriation.
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of land use rights from private landowners • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Landowner consultation

Regulatory Permits and Acquisition of land use rights: Construction of the 138kV and 345kV transmission lines and substations took less than nine months to complete. All applicable interconnection agreements were negotiated and signed to accommodate the in-service date. All system planning and energization studies were conducted in parallel in order to comply with all applicable Electricity Reliability Council of Texas (ERCOT), American Electric Power and Lower Colorado River Authority requirements. As an additional note, the land acquisition was completed for this private gen-tie project without the ability to take advantage of Eminent Domain (expropriation).

In less than 15 months from project inception all stations and the 345kV and 138kV transmission lines were energized. These line terminations included interconnections with the Lower Colorado River Authority (LCRA) and American Electric Power (AEP).

This project involved 270 landowners and 504 total crossings of pipelines, transmission lines, distribution, railroads and roads. The total cleared area for right-of-way (ROW) access was 3,469 acres. The Texas Clean Energy Express went through an area in the South Texas hill country which had rock

outcroppings similar to the EWT Line. Where landowners allowed, roads could be cut into the hills in some locations. Where slopes were steep, bulldozers were used to haul poles to the structure locations, and assist other equipment when required, such as cranes and bucket trucks. Large drill rigs were used to drill the holes for the concrete and steel monopoles used on this line.

The Black Capped Vireo, a protected bird, nested in the lower portion of the hills. Trees were left in place in the valleys to protect the habitat, and adequate clearance was provided over the tops of the trees to meet NERC FAC-003 requirements for this 345 kV line. Alternative off-ROW access to structure locations had to be established.

FIGURE 41: TEXAS CLEAN ENERGY EXPRESS CONCRETE TRANSMISSION POLE



FIGURE 42: TEXAS CLEAN ENERGY EXPRESS 345KV SUBSTATION



NEXTBRIDGE INFRASTRUCTURE

Case Study 4: Lone Star Transmission – NextEra

Overview	
Project Description	NextEra Energy's regulated Texas transmission subsidiary is building approximately 512 km of double circuit 345 kV transmission lines and five (5) high voltage transmission substations which will interconnect Lone Star's transmission system with the Electric Reliability Council of Texas (ERCOT) grid through multiple 345 kV interconnections. Lone Star's system will also include series compensation and reactive resources for managing system flows and voltage profiles. The Lone Star system stretches from Scurry County in western Texas to South central Navarro County South of Dallas, Texas. The Lone Star system is part of ERCOT's Competitive Renewable Energy Zones (CREZ) project which was legislatively mandated by the Public Utility Commission of Texas to expand the utilization of renewable energy in the ERCOT system. The CREZ process was a competitive bid process by which the Texas PUC selected Lone Star as one of three new entrants in the Texas transmission market to develop, build and operate a portion of the overall build out. Lone Star, with the support of its NextEra affiliates, has managed all aspects of development including extensive work to establish final line routes. Phase I of the system is already operational, with the balance of the system on schedule for an early 2013 commissioning. Once completed, the system will bring wind power from the wind rich areas of West Texas to other areas of Texas. The transmission system is expected to transport enough energy to power over 2.5 million homes. Lone Star will build, own and operate this transmission line and associated facilities. The development of these facilities is expected to further strengthen the electric grid in the ERCOT and enhance the reliable transmission of electricity from all generation sources to the load centers in Texas. **Strengths:** • $800 million, 512 km, 345kV, five 345kV substations currently under budget and is 65% complete, trending to be on-time and under budget with commercial operation in early 2013 • Lone Star plans to construct, own and operate Competitive Renewable Energy Zone (CREZ) high-voltage electric transmission facilities within Texas
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of land use rights from private landowners • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation

Regulatory Permits: Lone Star Transmission, LLC became a public utility in the State of Texas in 2010. The Public Utility Commission (PUC) of Texas approved Lone Star's application to construct the Texas Competitive Renewable Energy Zone (CREZ) transmission project which was filed in Docket No. 38230 on May 24, 2010.

Acquisition of land use rights: Lone Star has acquired six tracts of land in fee – five substation tracts and one other piece of private property. Lone Star has acquired or has taken possession of 658 transmission line easements through either negotiations or Eminent Domain. Lone Star has acquired hundreds of temporary construction and access easements.

Stakeholder Consultations: The final route passes through three eco-regions and three watersheds in central and eastern Texas. The western terrain consists of prairie with scattered residential communities. The central area terrain consists of prairie and woody hills with more densely populated areas in the eastern section. The eastern area terrain transitions from woody hills to rolling hills mostly made up of agricultural land. Local outreach with all stakeholders (landowners, agencies, community leaders, etc.) along the project route resulted in multiple route segments that were combined into various routes that were then reviewed during Lone Star's CCN application. A final route was then approved.

The compact line design utilized monopole structures which only required 100 feet of right-of-way (ROW). Benefits of constructing the project with monopoles included less visual impact, ease of installation, less environmental impact due to the smaller footprint and less ROW.

Lone Star also contracted for an EPC project that consisted of five 345kV transmission substations - Navarro, Sam Switch, West Shackelford, Romney and Kopperl. All stations were completed months ahead of energization. We describe these EPC projects below.

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FIGURE 43: LONESTAR CONTRACTED EPC PROJECTS

Project	Details
Navarro switching substation	345 kV breaker and a half design with fifteen 5000A circuit breakers, disconnect switches and Station Service Voltage Transformers. (SSVT) This station interconnects eight existing Oncor and Centerpoint 345kV lines and will tie one additional line from West Shackelford in March 2013. This station is currently energized and carrying load.
Sam Switch switching substation	345 kV breaker and a half design with ten 5000A circuit breakers, disconnect switches and SSVT's. This station interconnects four existing Oncor 345kV lines and will tie one additional line from West Shackelford in March 2013. This station is currently energized and carrying load.
West Shackelford switching substation	345 kV breaker and a half design with thirteen circuit breakers and two 345kV 100 MVar shunt reactors. This station interconnects two existing Lone Star lines from Oncor's Scurry South Switching substation and two new Electric Transmission Texas (ETT) 345kV lines and will tie one additional line each to Navarro and to Sam Switch substations in March
Kopperl Substation	This substation consists of two series capacitor banks located on the West Shackelford to Sam Switch / Navarro 345 kV lines.
Romney Substation	This substation consists of two series capacitor banks located on the West Shackelford to Sam Switch / Navarro 345 kV lines. Also includes four – 345kV, 50MVar shunt reactors and circuit breakers.

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FIGURE 44: LONE STAR HELICOPTER WIRE STRINGING



NEXTBRIDGE INFRASTRUCTURE

FIGURE 45: LONE STAR 345KV MONOPOLES BESIDE NON-LONE STAR 345KV LATTICE TOWER



NEXTBRIDGE INFRASTRUCTURE

Case Study 5: Florida Power & Light - NextEra

Overview	
Project Description	Florida Power and Light (FPL) is a subsidiary of NextEra Energy, Inc.. FPL is the largest electric utility in Florida and one of the largest rate-regulated utilities in the United States. FPL serves approximately 4.6 million customer accounts in Florida and is a leading employer in the state with more than 10,000 employees. The company consistently outperforms national averages for service reliability while customer bills are 24% below the US national average in 2012. A clean energy leader, FPL has one of the lowest emissions profiles and one of the leading energy efficiency programs among utilities nationwide. FPL has a portfolio of completed and in-service transmission projects that together demonstrate NextEra's ability to successfully implement the EWT Line. For each of these projects, FPL provides expertise including siting and permitting; electrical, civil, and structural engineering; as well as project and construction management. Together, these projects lend credence to NextEra's ability to acquire land use rights, permits and approvals and consult with stakeholders when developing and constructing large and complex transmission lines. **Strengths:** • The largest electric utility in Florida and one of the largest rate-regulated utilities in the United States. • Serves approximately 4.6 million customers and consistently outperforms national averages for service reliability while keeping customer bills below the national average. • A clean energy leader, FPL has one of the lowest emissions profiles and one of the leading energy efficiency programs among utilities nationwide.
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of land use rights from private landowners • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation

Transmission Experience outside Ontario: NextEra's affiliate, Florida Power and Light (FPL), has an excellent record of transmission and substation reliability and robust designs, along with operations and maintenance programs based on condition assessment, diagnostics, and asset management that enable effective and efficient investment of resources and capital. From 2003 through 2012, the FPL average number of minutes that a customer is without service ("SAIDI") due to transmission and substation reliability concerns was consistently below 5.2 minutes per year. In 2011 this key reliability metric was 3.16 minutes. More directly in the bulk power area, FPL exhibited top-decile transmission reliability performance in a recent, well recognized benchmarking study (2011 SGS Transmission Reliability Benchmarking Study, by SGS Statistical Services), involving utilities from across the United States.

FPL has consistently utilized a philosophy of continuous improvement and manages its business through application of sound business practices, quality assurance and Six Sigma concepts to drive customer

satisfaction and reliability while reducing costs. Because of this philosophy, FPL is the lowest-cost service provider in Florida, and has excellent transmission service reliability. If provided more detail on the types of forced outages Hydro One has experienced on the existing Wawa-Marathon-Lakehead 230kV line, our highly skilled team may be able to develop appropriate countermeasures to address the outage causes, ensuring a more reliable EWT Line.

NextBridge has a wealth of transmission expertise at its disposal to ensure reliable transmission operations. Operating and maintaining a transmission system on the Florida peninsula presents a wide range of challenges ranging from hurricanes, tornados, and other high wind conditions, to salt spray contamination, avian interaction and lightning. FPL has embraced these challenges and has overcome them by superior transmission facility designs and maintenance practices. For example, every outage in the FPL transmission system is followed up by an Event Response Process in which FPL strives to find the root cause via diagnostic techniques to prevent the problem from recurring. Solutions to transmission O&M problems include new designs, new conditions assessment processes, and/or new products. FPL and equipment manufacturers work together to develop these solutions in order to continually improve the reliability of the transmission system. This background prepares us well to manage extreme geographic or climate conditions we might face in implementing in the EWT Line.

NextBridge will have access to FPL's Transmission & Substation Engineering & Technical Services department which consists of over 165 power system professionals including Professional Engineers, technicians and other staff with expertise in all aspects of transmission and substation equipment installation, maintenance and repair. The group prepares standard processes and procedures for maintenance activities as well as event response and diagnosis. The Transmission Performance & Diagnostic Center (TPDC), housed within the Technical Services department, serves as a hub for harnessing all of the institutional knowledge of the FPL TS Group in support of its FPL operating departments and other NextEra transmission affiliates across North America.

A notable example of FPL's technical strengths and use of innovative practices in challenging conditions is FPL's building of a 44km, 500kV transmission line in the Florida Everglades in 1996 – where construction roads could not be built. The area was under the jurisdiction of the US Army Corps of Engineers and South Florida Water Management District. Roadless construction was required and

foundations had to be installed in rock, above which rested several feet of muck and water. Special drill rigs on tracked pontoons were used to drill holes, and concrete was pumped to the hole from distant accessible sites. Helicopters were used to set the steel tubular H-frame structures on the foundations. Construction could not occur in Snail Kite nesting areas until the nesting season was over. Bird flight diverters had to be installed in the flight path of Wood Storks.

We provide below additional information on the FPL portfolio of projects.

FIGURE 46: FPL PROJECT PORTFOLIO HIGHLIGHTS

Project	Description	Acquisition of land use rights	Regulatory Permits	Environmental Approvals	Stakeholder Consultation
Bobwhite – Manatee 230kV Project (2014) **Cost: $48.8MM**	Construct 40 km of 230kV and a switching station		Required Licensing approval under the *State Transmission Line Siting Act* (TLSA)	Project traverses highly sensitive environmental areas in Sarasota and Manatee Counties	Conducted several outreach events and open houses to gain public acceptance
Riviera Beach Energy Center (2013) **Cost: $58.8MM**	Construct various 230 kV Line segments totaling 62 km, added new collector yard, constructed 230/138kV substation, and performed significant work at Ranch and Riviera Substations	Project occurred within exiting ROW within a mixture of urban and suburban settings. Project was immediately adjacent to city water supply catchment area		Project traverses multiple municipal jurisdictions and sensitive environmental habitats. Experienced some localized urban opposition	
Princeton – Turkey Point 230kV Project (2012) **Cost: $28.3MM**	Construct 18 km of 230 kV line, rebuild 17 km of existing 230 kV line, and construct 2 line terminals	Access challenges throughout Construction immediately adjacent to several energized lines		Project traverses environmentally sensitive areas including Biscayne National Park. Challenging permitting process with multi agency coordination	

Project	Description	Acquisition of land use rights	Regulatory Permits	Environmental Approvals	Stakeholder Consultation
Davis – Florida City 138kV Line Rebuild Project (2011) **Cost: $9.3MM**	Rebuild 17 km of 138 kV line	Rebuild and reconstruction of existing lines with limited access predominantly within residential areas Rear lot construction with inconsistent easement widths	Several permitting authorities; municipal, County, FAA, Federal and State Environmental		
Archcreek – Miami Shores 138kV Project (2009) **Cost: $11.7MM**	Construct 10 km of 230 kV line and 2 line terminals	Line constructed adjacent to road right-of-way mostly along heavily traveled city streets Employed customized insulators on pole lines to eliminate or reduce ROW acquisition requirements			Traverses densely populated areas in Miami-Dade County. Conducted numerous open houses with significant public opposition
Overtown – Venetian 138kV Cable Project (2009) **Cost $38.0MM**	Construct 5.3 km of 138 kV pipe cable line, in 9 5/8" Steel Pipe, cable Size/Type: 3,000 KCMIL Cu with Okonite Kraft Paper insulation	Access issues while working from barges		Project traverses extremely sensitive aquatic habitat within Biscayne Bay. Overcame challenging permitting process with effective coordination with Federal, State and Local agencies Required three (3) extremely long horizontal directional drills through an area with formidable geological conditions	

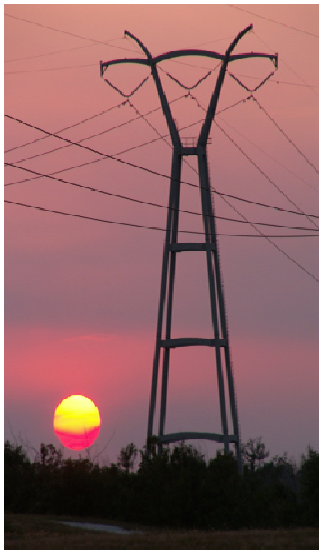
Project	Description	Acquisition of land use rights	Regulatory Permits	Environmental Approvals	Stakeholder Consultation
Osteen Loop 230kV Project (2009) **Cost $14.4MM**	Construct 37 km of 115 kV and 230kV lines and associated substation upgrades	Road ROW and roadless, cross country construction	Inability to obtain Federal Conservation Easement – Consent of Use resulted in a realignment of a portion of the route	Project traverses sensitive environmental habitats including crossing the St Johns River	
Bunnell – Pringle – Pellicer 230kV Project (2008) **Cost: $9.9MM**	Construct 26 km of 230 kV Line and associated substations			Siting & Permitting: Project traverses both roadside and cross country alignments with both environmental and access challenges	
Millcreek – Durbin – Tolomato 115kV Project (2006) **Cost: $2.8MM**	Construct 35 km of 115 kV line and construct substation	Building in railroad right-of-way (ROW) with lease requirements. Crossed two foreign utility 115 kV lines Design and constructed a portion of the line above the tree canopy on a State designated scenic roadway		Project traverses numerous sensitive environmental habitats requiring extensive Federal and State permitting	
Conservation – Oakland Park 230kV Project (2005) **Cost: $58.8MM**	Construct 32 km 230 kV Line	Extremely compressed ROW acquisition schedule Line constructed adjacent to road ROW mostly along heavily traveled city streets			Project traverses multiple municipal jurisdictions with localized urban opposition

Project	Description	Acquisition of land use rights	Regulatory Permits	Environmental Approvals	Stakeholder Consultation
Collier – Orange River #2 230kV Project (2005) **Cost: $28.4MM**	Construct 86 km of 230 kV line	Extremely compressed ROW acquisition schedule Roadless Construction for a significant portion of the project	Required Licensing approval under the *State Transmission Line Siting Act* (TLSA)		Project traverses highly sensitive environmental areas in Lee and Collier Counties. Conducted several outreach events and open houses to gain public acceptance

FIGURE 47: FPL 500KV HELICOPTER LINE INSPECTION



FIGURE 48: EXAMPLES OF FPL STRUCTURES AND MAINTENANCE



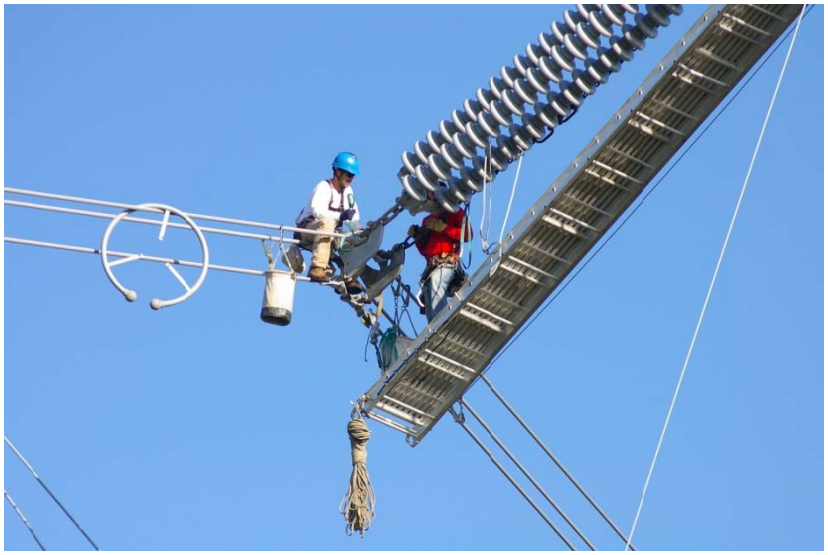


FIGURE 49: NEXTERA TRANSMISSION PERFORMANCE DIAGNOSTICS CENTRE



Case Study 6: Montana-Alberta Tie-Line (MATL) – Enbridge

Overview	
Project Description	The Montana-Alberta Tie-Line (MATL) is a 330 km 230 kV transmission line that will connect the Alberta system at Lethbridge, Alberta to the Northwestern Energy system in Great Falls, Montana. Enbridge acquired the MATL project in October 2011. Since that time, it has furthered the development and construction of MATL in a number of areas relevant to the development of the EWT Line. These areas include system design, procurement, consultation and land acquisition, as well as government permits and environmental approvals. This project is unique as it is a cross-border merchant line developed by a non-utility developer, requiring both Canadian and U.S. permitting. **Strengths:** • Demonstrates Enbridge capabilities in transmission • Extensive permitting required • Example of truly independent, merchant project (not rate-based) • Compression of timeline to enhance operations • Secured access to substantially all the land required to complete the project
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of land use rights from private landowners and the Crown • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation • Completion of the procedural aspects of Crown consultation with First Nation and Métis communities

Acquisition of land use rights from private landowners and the Crown: MATL was already partially built when Enbridge acquired the project. By adding a substation and moving some key components, Enbridge has re-designed the system on a compressed timeline to enhance its operations and better meet the needs of a key customer. Upon acquiring MATL, Enbridge re-initiated consultations with landowners in both Alberta and Montana. In addition, the Enbridge's in-house land experts have worked to secure access to substantially all the land needed to complete the project.

Environmental Approvals: From an environmental perspective, a number of key activities took place:

- A saturated soils contingency plan was created for the project to manage operations on sensitive native prairie and high value farm lands to mitigate the impact of construction activities during soft ground conditions.
- The plan includes clear indicators of when the saturated soils contingency would need to be implemented. It also includes an outline of what options are available when situations are not suitable.

- Restricted activity periods were agreed upon with the regulators to protect wildlife species such as Ferruginous Hawks, Grouse Leks, migratory birds, antelope and native prairie habitats.
- Environmental alignment sheets were created to outline the specific areas affected by the restricted activity periods and avoid construction activities in these areas during this time.
- Conservation of topsoil around pole structures has been maintained by ensuring a two-lift process when drilling structure foundations. Additionally sensitive saline sub-soils were encountered throughout the project area requiring development of specific handling procedures in these areas. Nearly all watercourse crossings utilized work-arounds (of existing water crossings) to minimize the impact on water and fish habitat. Stringing across watercourses will be entirely completed from the air to minimize impacts.
- Environmental orientations were completed for all project personnel. Management and supervisors went through a detailed review of the environmental protection plan and permits. Environmental inspectors are on site for all construction activities. Bird flight diverters and perch deterrents were placed around sensitive migratory bird habitats to: minimize the occurrence of bird strikes with the conductor wires; and to prevent predation advantages for raptors in sensitive areas (grouse leks, wetlands). Buffers of 100 metres and pole exclusion zones were placed on wetlands and watercourses to minimize the number of poles placed within the fringes of wetlands and watercourses to the extent.

Regulatory Permits: As an intertie, MATL is the gateway between two distinct systems: the Alberta system and the NorthWestern Energy system in Montana. These systems operate at different voltages and involve distinct procedures and protocols. To commence operations, MATL must secure clearance from a number of technical regulatory bodies, including the Alberta Electric System Operator and the Western Electric Coordination Council (WECC). Enbridge has shepherded the project through regulatory processes since its purchase, and has secured four approvals – namely WECC Path Rating (PRG), WECC Remedial Action Scheme (RAS), AC Mitigation for Montana and AC Mitigation for Alberta. MATL terminated its construction contractor before Enbridge acquired the project. The Enbridge Major Projects group managed the mid-construction selection and engagement of a new contractor that would

meet its requirements for safe and effective construction of the project. The tables below summarize the various permits that were obtained as part of the MATL project.

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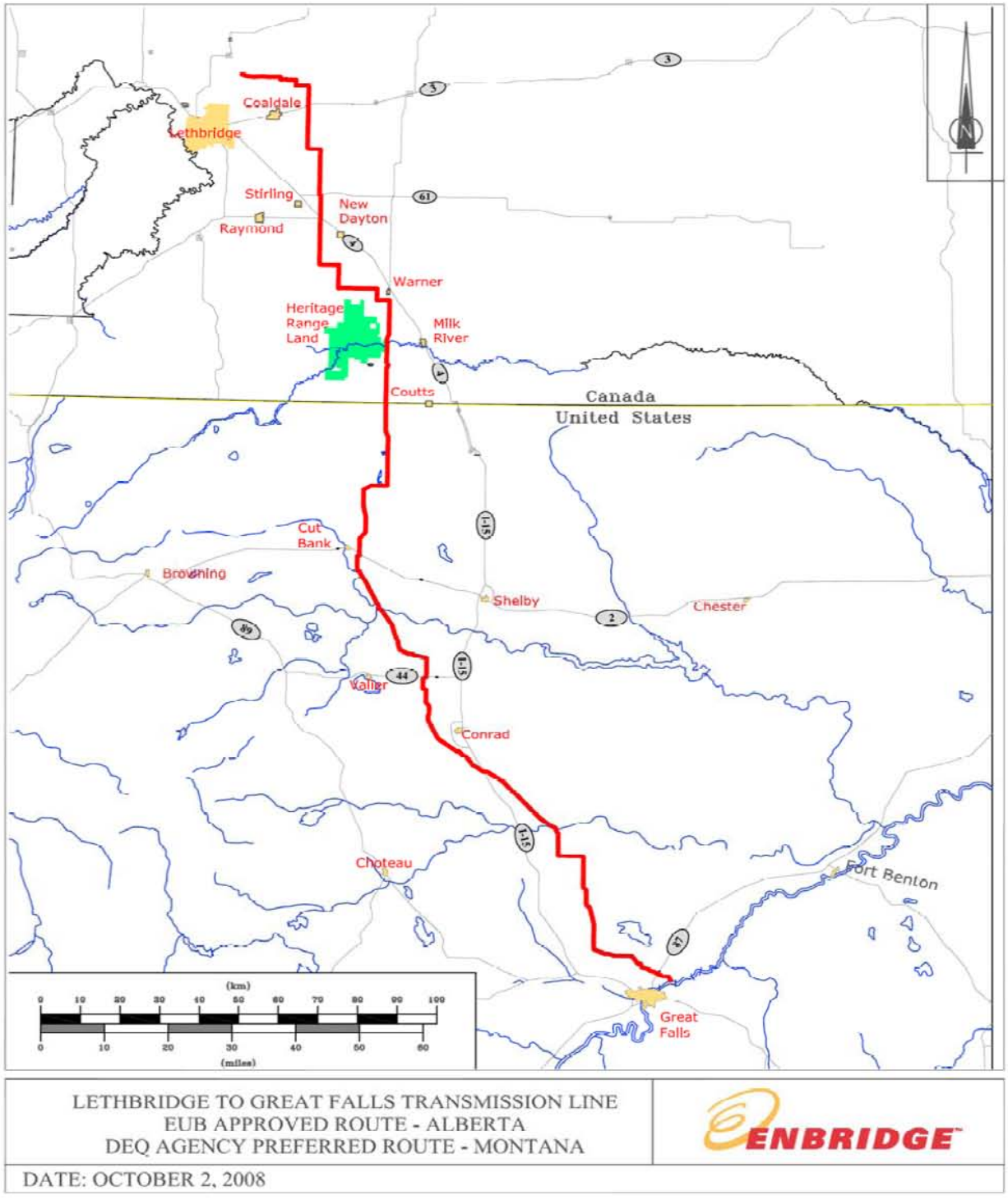
FIGURE 50: PERMITS FOR MATL PROJECT

Federal Permit Specifications	
Presidential Permit- DOE	Department of Energy
Section 404-USACE	US Army Corps of Engineers
Tariff Review and Approval-FERC	Federal Energy regulatory commission
Review Authority-DOD/USAF	Department of Defense / US Air Force
Consultation-DOD	Department of Defense
Utility Permit for Interstate Crossing-FHA	Federal Housing Authority
Biological Opinion/Biological Assessment-USFWS	US Fish and Wildlife Service
Rights of Way on Federal Land-BLM	Bureau of Lands Management
Compatibility Review-USDA	US Department of Agriculture
Montana Permit Specifications	
Certificate of Compliance-DEQ	Department of Environmental Quality
Section 401 Certification-DEQ	Department of Environmental Quality
Section 318 Authorization-DEQ	Department of Environmental Quality
Land Use License-DNRC	Department of Natural Resources Conservation
Pre-Construction Authorization-DNRC	Department of Natural Resources Conservation
Other Permits	
National Energy Board Approval EP-301, AO-M159-04-EP-301	National Energy Board
AUC Permit & License U2011-62-941L	AUC
AUC Permit & License U2011-61 120S	AUC
Transport Canada - Aeronautical Clearance 2010-486-941L	Transport Canada
Transport Canada - Aeronautical Clearance 2010-384-120S	Transport Canada
Navigable Waters Approval Middle Coulee	Transport Canada
Navigable Waters Approval Milk River	Transport Canada
Navigable Waters Approval Craddock Reservoir	Transport Canada
Navigable Waters Approval Etzikom Coulee	Transport Canada
Navigable Waters Approval Irrigation Canal Crossings	Transport Canada
Historical Resources Conservation Act Clearance 120S 120 S Substation	ACCS
Historical Resources Conservation Act Clearance 941L Transmission Line Clearance	ACCS
Environmental Field Reports Transmission Line	ASRD
Environmental Field Reports Substation	ASRD
DFO - COP Notifications DFO Transmission Line X-ing COP Notifications (S of 61)	DFO
AENV COP Notifications AENV Vehicle COP Notifications (S of 61)	AENV
Aeronautical Clearance Submission to raise approval height of Power line	Transport Canada
Nav Canada Submission to extend	NC
AEW Water Act Application Permission to remove pole from wetland	AEW
AEW Water Act Application Change hydrology at 120S	AEW

FIGURE 51: MATL MAP



NEXTBRIDGE INFRASTRUCTURE

Case Study 7: Alberta Clipper Pipeline Project (Clipper) - Enbridge

Overview	
Project Description	The Alberta Clipper (Clipper) is a 36-inch crude oil pipeline extending 1,600 km from Hardisty, Alberta to Superior, Wisconsin. Clipper crosses six provincial and state (AB, SK, MB, ND, MN, WI) boundaries and the U.S.-Canada international border. Enbridge undertook the $3.6 billion project between the years of 2008 and 2010 and successfully demonstrated its ability to develop and build large-scale linear infrastructure. In particular, the Clipper project illustrates Enbridge's ability to manage and integrate complex processes in the areas of consultation, permitting, land acquisition, procurement, and management of contractors, which are all critical to the successful development and build of the EWT Line. The Clipper project was also noted for its success in both training and employment of the Aboriginal people. **Strengths:** • Extensive land acquisition – strong relationships with landowners • Extensive permitting experience • Aboriginal participation
Demonstrated Capabilities	• Major Capital Project Experience • The acquisition of land use rights from private landowners and the Crown • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation • Completion of the procedural aspects of Crown consultation with First Nation and Métis communities

The project planned to conduct a horizontal directional drill (HDD) crossing of the South Saskatchewan River. This HDD was 1.2 km in length and took significant effort as crews dealt with 36-inch pipe. It was successfully completed and there was no need to open cut the river. Turbidity was constantly monitored and reported on and met Provincial regulatory criteria.

The project crossed the Pipestone Creek. Department of Fisheries and Oceans in Manitoba felt it was necessary to implement HADD compensation at this site due to the nature of the bank which was considered rare as they are vertical. A compensation plan was proposed and accepted. It is still being monitored under the Post Construction monitoring plan.

In Alberta, Club Root disease was a concern to local regulators. Enbridge planned to construct the Line 4 project from East to West in order to reduce the chance of spreading Club Root.

Aboriginal and Community Consultation: Enbridge consulted with various parties to secure the approval to build the Alberta Clipper Project, now Line 67 on the Enbridge Mainline system. Consultation included thousands of affected landowners, provincial and state officials in three provinces and three states and their respective federal officials in Quebec and Washington D.C. In Canada, consultation included 39 Aboriginal groups, 38 local governments, 26 Federal and Provincial

governmental representatives and 17 government ministries. For the United States portion of the 1600 km Clipper project, Enbridge worked with 14 county governments, dozens of municipal officials, two sovereign Tribal Reservations and their governments, as well as other tribal consultation on cultural and historical issues outside Reservations along the route. Also in the U.S. Enbridge consulted with the Governors, policy staff and regulatory leadership of three separate states and obtained a national interest determination from the U.S. Department of State – a key component in obtaining federal permits, approvals or clearances described further later in this case study.

During this project, Enbridge demonstrated its ability to be flexible in consultation and negotiation with affected Aboriginal/Native American or Tribal groups and governments using a variety of approaches and techniques, ultimately resulting in mutually beneficial outcomes. An example of successful consultation and relationship building was Enbridge's participation in two religious ceremonies (one in Canada and one on the Leech Lake Reservation in the U.S.) to respect the tradition of honoring the earth prior to the commencement of construction activities.

In Canada we were able to ameliorate and address issues and concerns raised by, and provide sustainable benefits to, Aboriginal communities. Enbridge negotiated agreements, provided training and ensured that contractors fulfilled commitments to maximize Aboriginal participation. Enbridge provided $1 million worth of training for 100 Aboriginal people. Enbridge also employed 645 Aboriginal people during construction, which accounted for 22% of our total construction workforce on the project and resulted in $24 million of wages paid to Aboriginal employees across Alberta, Saskatchewan and Manitoba (this was inclusive of both our own employees and our prime contractors' local work force). In 2008, Enbridge received the Aboriginal Relations-Best Practice Award of Distinction from INAC and the Aboriginal Workforce Participation Initiation for its achievements in this area.

In the United States, Enbridge worked with the U.S. federal government to support government-to-government consultations on issues related to protecting and mitigating the impacts to cultural, tribal and biological resources both inside the Reservations and also on traditional lands used by various tribal members. Enbridge negotiated for land rights across two sovereign tribal reservations, including several conditions related to community investments and training. Enbridge also hosted a Tribal Elders tour of construction.

Acquisition of land use rights: In addition to securing necessary permits and licenses or approvals for crown/government-owned land, Enbridge acquired land rights by way of fee owned, license or permanent easement agreements along approximately 1,600 km in both Canada and the United States. While the right-of-way (ROW) was generally along our existing route for the Enbridge system, such rights were required as Enbridge needed to expand the ROW and acquire temporary work space or working areas to facilitate completion of the project.

Environmental Approvals: The project traversed through two large archeological sites in Manitoba. One of these sites was very significant. It predated Aboriginal habitation and cost the project $2 million to complete the necessary Provincial regulatory obligations. As a result of the work completed, Enbridge created a publication about the site which was distributed to all public schools in Manitoba. It contributes to the current curriculum in the junior high school system in Manitoba.

The project team also initiated a research initiative to understand the behavior of a migratory bird (Sprague's Pipit) during pipeline construction (a short term disturbance). This was initiated to close an Environment Canada identified knowledge gap with respect to this species at the time (2009). The research covered the length of Line 4, Alberta Clipper and Southern Lights (1200 km) where the bird species was known to inhabit. It was approved by a panel of Provincial and Federal regulators and the team was composed of independent researchers from the University of Saskatchewan. Enbridge funded the initiative and recently presented the findings at the international ROW symposium in Arizona.

With the various challenges over the 1200 km length, (significant archeological site, migratory birds, species at risks, various land and soil types and summer vs. winter construction, etc.), there were no major non-compliance issues on this project raised by the regulators. Regulators (Provincial and Federal) would frequently come and inspect the sites to ensure measures in the EPP were being implemented accordingly.

Wetlands were also a concern in Saskatchewan. At one point in the project the regulator proposed to order Enbridge to horizontal direction drill (HDD) under all wetlands. With a group containing the resource specialist, construction manager, environmental manager, lead and inspectors, Enbridge was able to collaborate with the regulator to ensure that the current practice of open cutting would still present positive remedial results. Since that time, the Saskatchewan regulator has been pleased with

the Enbridge construction and Enbridge has maintained a good relationship with the regulator based on these positive results.

Regulatory Permits: Enbridge has more experience than any North American company in successfully dealing with multiple jurisdictions to assure coordinated and timely approvals from federal, provincial, state, Aboriginal/Tribal and local units of government.

In Canada, Enbridge secured a National Energy Board (NEB) approval and Governor in Council (GIC) approval in order to build Clipper. The table below demonstrates the full list of Canadian permits obtained. There was a potential for significant time delays with respect to Transport Canada and DFO permitting. As each agency had its own process, Enbridge had a very active Aboriginal engagement group to address concerns, and also negotiate with the regulators to have individual permits issued for each watercourse, rather than a blanket approval. This helped to get permits faster and organize work in a way that ensured the fulfillment of in-service objectives. Enbridge's environmental experts worked closely with the individual offices to address site specific concerns and work through difficulties, ultimately aiding in an efficient permitting process as well.

In the United States, Enbridge secured authorizations, clearances or approvals at the Federal level from the U.S. Department of State, the International Boundary Commission, U.S. Forest Service for special use to cross the Chippewa National Forest, U.S. Department of Interior Fish and Wildlife Service, Environmental Protection Agency, State Historic Preservation Office, U.S. Army Corps of Engineers, North Dakota Public Service Commission, Minnesota Public Utility Commission, Minnesota Department of Commerce, Leech Lake Reservation (Tribal), Fond du Lac Reservation / Bureau of Indian Affairs, Wisconsin Public Service Commission, and Wisconsin Department of Natural Resources. A number of county approvals, such as drainage, soil and water conservation permits, were obtained. Finally, rates and terms of services were approved and filed with the Federal Energy Regulatory Commission.

FIGURE 52: CANADIAN PERMITS FOR ALBERTA CLIPPER PROJECT

Agency	Permit	Report
FEDERAL		
National Energy Board	Certificate Condition	Post-Construction Monitoring
National Energy Board	ESA commitment	Noise Assessment
Fisheries and Oceans Canada	Authorization for Pipestone Creek	Monitoring Program Report
Fisheries and Oceans Canada	Authorization for Pipestone Creek	Habitat Compensation Monitoring
Fisheries and Oceans Canada	Authorization for Pipestone Creek	Fish Collection Permit Report
Canadian Wildlife Service	Scientific Permit to Take Migratory Birds	report
Praire Farm Rehabilitation Administration	Progress PFRA Right-of-Entry for Construction	as-built
Praire Farm Rehabilitation Administration	Mariposa PFRA Right-of-Entry for Construction	as-built
Praire Farm Rehabilitation Administration	Elbow PFRA Right-of-Entry for Construction	as-built
ALBERTA		
Alberta Sustainable Resource Development	PLA	Sand nut-grass Monitoring
Alberta Sustainable Resource Development	PLA	Native Grass Species Plug Monitoring
Alberta Sustainable Resource Development	Research and Collection Permit	Final Report and FWMIS Submission
Alberta Sustainable Resource Development	Fish Research License (10-2301-FR)	FWMIS data and report
SASKATCHEWAN		
Saskatchewan Tourism, Parks, Culture and Sport	Archaeological Resource Investigation Permit (09-093)	Elbow Construction Monitoring Final Report
Saskatchewan Ministry of Environment	Letter of Authorization under WHPA	Rare Plant Report
Saskatchewan Ministry of Environment	Fish and Wildlife Development Fund NE 34-24-3 W3M	Rare Plant Report
Saskatchewan Ministry of Environment	Fish and Wildlife Development Fund NW 35-24-3 W3M	Rare Plant Report
Saskatchewan Ministry of Environment	Scientific Research Special Permit	Northern leopard frog
Saskatchewan Ministry of Environment	Scientific Research Special Permit	Northern leopard frog

Agency	Permit	Report
Saskatchewan Ministry of Environment	Scientific Research Special Permit	Sprague's pipit setback study and 2009 Wildlife Survey Reports
Saskatchewan Ministry of Environment	Special Collection Permit - fish	Fish Salvage Report
Saskatchewan Ministry of Environment	Special Collection Permit - fish	Fish Salvage Report
Saskatchewan Ministry of Environment	Aquatic Habitat Protection Permit (EMPA2010-03)	Report
Saskatchewan Ministry of Environment	Aquatic Habitat Protection Permit (EMPA2010-04)	Report
Saskatchewan Ministry of Environment	Aquatic Habitat Protection Permit (EMPA2010-05)	Report
MANITOBA		
Manitoba Culture, Heritage, Tourism and Sport	DjMb-26 Construction Monitoring (A15-09)	Final Report
Manitoba Culture, Heritage, Tourism and Sport	DjMb-26 Monitoring (A04-10)	Final Report
Manitoba Culture, Heritage, Tourism and Sport	DkMi-5 Stage II Mitigation (A07-09)	Interim Report
Manitoba Culture, Heritage, Tourism and Sport	DkMi-5 Construction Monitoring (A57-09)	Report
Manitoba Culture, Heritage, Tourism and Sport	DkMi-5 Monitoring (A05-10)	Report
Manitoba Culture, Heritage, Tourism and Sport	DkMi-5 Site Delineation (A26-10)	Report
Manitoba Water Stewardship	Live Fish Handling Permit (04-09)	Fish Collection Permit Report
Manitoba Water Stewardship	Live Fish Handling Permit (03-10)	Fish Collection Permit Report
Manitoba Conservation	Data-Sharing Agreement	2009 Wildlife Survey Reports
Manitoba Conservation	Pesticide Use Permit - 2009198-R	Post Seasonal Pesticide Use Permit Report
Manitoba Conservation	Pesticide Use Permit - 2010095	Post Seasonal Pesticide Use Permit Report

.

FIGURE 53: ALBERTA CLIPPER MAP



NEXTBRIDGE INFRASTRUCTURE

Case Study 8: Bruce Power Project - Borealis

Overview	
Project Description	Bruce Power is Canada's first private nuclear generator. Its 2,300-acre site is on the shores of Lake Huron and houses the Bruce A and B generating stations, which each hold four CANDU reactors. Over the past decade, Bruce Power has refurbished all four units at its Bruce A station, returning 3,000 MW of low-cost, reliable electricity to Ontario consumers. Combined with its Bruce B units, Bruce Power generates 6,300 MW, providing power to over one in four hospitals, homes schools and businesses in Ontario. Ontario's Long-term Energy Plan relies on Bruce Power to provide a reliable source of clean, affordable electricity for the province's ratepayers for decades to come. Bruce Power employs approximately 4,000 people and in the last 10 years has been the single largest private investor in Ontario's electricity infrastructure with a total injection of $7 billion into the Bruce Power site. The site is leased from the Province of Ontario under a long-term arrangement where all of the assets remain publicly owned; while the company makes annual rent payments and funds the cost of waste management and eventual decommissioning of the facility. Over the past 11 years, Bruce Power's owners have been the largest private investor in Ontario's electricity infrastructure. **Strengths:** • Demonstrates significant investment and commitment in Ontario energy infrastructure • Demonstrates significant experience with Aboriginal communities
Demonstrated Capabilities	• Ontario Experience • Major Capital Project Experience • Ontario Regulatory Experience • The acquisition of necessary permits from government agencies • Obtaining environmental approvals similar to the environmental approvals that will be necessary for the Project • Community consultation • Completion of the procedural aspects of Crown consultation with First Nation and Métis communities

Major Capital Project: The Bruce A Units 1 and 2 Restart Project was launched on October 17, 2005, after a long-term power agreement was reached between Bruce Power and the Ontario Power Authority. The multi-billion dollar project to restore Units 1 and 2 for another 25 years of service has several components, including:

- Bulkhead installation
- Fuel channel and calandria tube replacement
- Steam generator replacement
- Feeder tube segment replacement
- Turbine generator overhaul
- Electrical system restoration
- Valves, maintenance and special projects
- Balance of plant

- Paperwork, commissioning and demobilization
- Return to operations and restart

Much of the work to restart Bruce A involved unchartered territory for the nuclear industry. The experience gained was significant and will serve Ontario well as other reactors in the province reach the end of their current life cycles. Ontario relies on nuclear energy to provide more than half of the province's electricity.

With Bruce A back on line, the Bruce Power site has eight operational units for the first time in 25 years. Capable of supplying one-quarter of Ontario's electricity, the site's current 6,300 MW output makes it the largest operating nuclear power facility in the world.

Aboriginal Relationships: Bruce Power has a strong relationship with the local Aboriginal communities, as it recognizes that its nuclear facility lies within the boundaries of the traditional territories of Aboriginal communities. During Bruce Power's 10 year history, it has combined with its Aboriginal partners for many successes, from both a community and business standpoint. Some, like the signing of historic land-use agreements, have taken time to develop, while other interactions have been more spontaneous and arise through a common desire to see the First Nation and Métis communities grow and prosper. Bruce Power's policy on Aboriginal relations promotes the hiring of qualified Aboriginal employees and developing students, strengthening the communities through sponsorship support, conducting environmental studies, and looking forward to even greater interaction going forward. In 2010, Bruce Power joined the Canadian Council for Aboriginal Business (CCAB). The CCAB is a national, member-based business organization that drives business opportunities and enables sustainable relationships. Being involved in CCAB events provides Bruce Power with nationwide networking opportunities to learn more about excellence in First Nation relations, history and education around First Nation law and treaties, key learnings from other companies.

Bruce Power's Aboriginal Relations Program focuses on the following key commitment areas: Education, Employment and Economic Development, Community Investment and Engagement and Environmental and Sustainability. These are the pillars that help guide Bruce Power's efforts and keep its focus on the things that will make a difference for its Aboriginal stakeholders. The following identifies only a few of the initiatives that Bruce Power has undertaken relative to each of these pillars:

- **Education:** In 2011 Bruce Power announced two scholarship programs aimed at local youth. The first was the Bruce Power 10th anniversary scholarship program designed to encourage and promote good writing skills. The second was in honour of the Chippewas of Nawash Unceded First Nation Chief Ralph Akiwenzie who passed away in 2011. This scholarship was designed to encourage and foster a love of science and technology among Aboriginal youth.
- **Employment and Economic Development:** In 2007, Bruce Power launched its Pathways to Employment initiative aimed at increasing the participation of Aboriginals in the Bruce Power workforce. Bruce Power and members of the company's employee-led Native Circle hosted a Job Fair at Chippewas of Nawash Unceded First Nation where members of the Native Circle spoke about their careers at Bruce Power to a group of about 70, mostly teenaged, job-seekers.
- **Community Investment and Engagement:** Bruce Power has sponsored the Community Aboriginal Recreation Activator Program, which aims to develop, mobilize and facilitate local sport and physical activity for youth. The company continued to promote healthy lifestyles through the Right to Play initiative, which launched in 2011 and will benefit local First Nation communities for years to come.
- **Environmental and Sustainability:** The Bruce Power site is home to a naturally diverse environment that contains more than 235 types of plants and more than 270 species of wildlife. The wildlife includes 150 bird species, 15 kinds of reptiles and amphibians, 15 types of mammals and 90 varieties of fish. Bruce Power sets even more aggressive internal goals than the regulators to maintain focus on reducing its environmental impact. In addition to complying with relevant legislation and regulations, Bruce Power is committed to: adopting the requirements of ISO 14001, reducing the environmental effects of its activities, products and services to a practical minimum through prevention of pollution, reduction of waste and effective use of resources, and continuing to promote a sense of environmental responsibility among both staff and contractors.

Additional activities of Bruce Power's Aboriginal Relations Program can be found at: http://www.brucepower.com/wp-content/uploads/2012/08/10473_Aboriginal_Report_FINAL.pdf.

FIGURE 54: BRUCE POWER FACILITY



NEXTBRIDGE INFRASTRUCTURE

Case Study 9: Greenwich Wind Energy Project - Enbridge

Overview	
Project Description	In 2010, Enbridge Inc. and Renewable Energy Systems Canada Inc. (RES Canada), an affiliate of RES Americas, entered into an agreement to construct and own a 99 MW wind energy project on the northern shore of Lake Superior, in Ontario. It is the first wind energy project to be sited entirely on Ontario crown land. In November 2011 the project became commercially operable and in May 2012 Enbridge acquired the RES interest and became the sole owner. The Greenwich Wind Energy Project produces enough clean wind energy to power 33,000 average Canadian homes. It comprises 43 Siemens SWT-2.3-101 MW wind turbines and was constructed by RES Canada under a fixed price, turnkey, engineering, procurement and construction agreement. Siemens provides operations and maintenance services for the wind turbines under a five-year, fixed-price agreement. The project delivers energy to the Ontario Power Authority under a Renewable Energy Supply (RES) III 20-year power purchase agreement. **Strengths:** • Demonstrates extensive Aboriginal consultation experience • Highlights Enbridge experience in operating a renewable energy facility • Demonstrates familiarity with Northern Ontario landscape
Demonstrated Capabilities	• Ontario Experience • Renewable Energy Experience • Completion of the procedural aspects of Crown consultation with First Nation and Métis communities

Aboriginal Relationships: In November of 2011, Enbridge and its partner Renewable Energy Systems Canada (RES) completed construction of the 99MW Greenwich Wind Energy Project, on Crown lands near Thunder Bay, Ontario, and began commercial operation. In May 2012, Enbridge acquired the remaining RES interest and is now the 100% owner of the project. Throughout the earlier regulatory process, two local First Nations, the Red Rock Indian Band and the Fort William First Nation, had been engaged, culminating in Agreements that provide sustainable benefits flowing from the project to each of the First Nation. The project hired community members during construction in 2011 on the Project, and First Nation members provided almost 7500 hours of labour to the project during that year. As well, in 2011 Greenwich Wind contracted with a First Nation owned company to provide road maintenance services to the project in 2011-2012. These services will be provided to the project on an ongoing basis by First Nation contractors. The Greenwich Limited Partnership had also concluded agreements with local Métis organizations in relation to the project. In 2011, the Project provided financial support to facilitate communication regarding the project between three local Métis Community Councils and their members, and to support Métis community development, as deemed appropriate by each of the Community Councils. In addition, Greenwich LP agreed to completely restrict the use of chemical

herbicide sprays in vegetation clearing activities during the operation of Project transmission line corridors, access roads, and turbine tower sites, in response to concerns expressed by the Métis Nation of Ontario.

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FIGURE 55: GREENWICH RENEWABLE ENERGY PROJECT



NEXTBRIDGE INFRASTRUCTURE

Case Study 10: New Hampshire Transmission - NextEra

Overview	
Project Description	The Seabrook 345kV Gas Insulated Switchgear (GIS) substation located at Seabrook, New Hampshire is a major bulk power transmission system facility and a critical node on the ISO-New England (ISONE) transmission grid. It is owned, operated and maintained by New Hampshire Transmission (NHT), a subsidiary of NextEra Energy Transmission. In 2007, an assessment of the substation equipment and design arrangement was undertaken to determine what system improvements could be achieved to improve the reliability of the Seabrook 345-kV Substation. Improvement recommendations were implemented from 2009 to 2011. All work had to be compliant with nuclear plant procedures and requirements. As well, NHT had to coordinate competing priorities, ISO-NE and nuclear schedules and design/engineering/procurement activities in a compressed schedule with suppliers. **Strengths:** • Technical capability: Association with a nuclear facility added significant complexity and tight tolerances on planning, design, approvals and construction schedules
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of necessary permits from government agencies

Transmission Experience Outside Ontario: Reliability concerns at the Seabrook Substation necessitated a significant transmission upgrade. Since nearly all major maintenance at the Seabrook Substation must be performed only during a scheduled refueling outage at the Seabrook Nuclear Power Plant, which lasts approximately 30 days every 18 months, a detailed plan was developed to facilitate an expeditious switchover during the outage. It was decided that the new station equipment would largely be put into place in and around the existing energized 345 kV equipment. Space restrictions required that a second story be built to house the new equipment. As the substation is associated with and partly behind the fence of a nuclear facility, all work was completed under nuclear plant procedures and security requirements. The complexity of this project was therefore significantly higher than that of a standard GIS substation. Permitting started in late 2008, and construction was initiated in early 2009 to allow for the first stage of cutover during the October 2009 Seabrook Plant refueling outage. Upgrades included: construction of an elevated equipment enclosure over an energized 345kV GIS switchyard in a compressed schedule and in a nuclear environment; addition of five new and removal of two existing 345kV GIS breakers and GIS bus; modification of the switchyard topology to meet ISO planning criteria while improving nuclear plant interconnection reliability; reconfiguration of the remote auxiliary

transformer and generator step-up transformer bus interconnections; and designing of new breaker control cabinets, breaker failure relay panel, bus differential panel, and new relay room annunciator.

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FIGURE 56: TWO STOREY SEABROOK 345KV GIS SUBSTATION



Case Study 11: Oncor Electric Delivery Company LLC - Borealis

Overview	
Project Description	Borealis manages OMERS investment in Oncor Electric Delivery Company (Oncor), which is a regulated electric transmission and distribution service provider that serves 10 million customers across Texas. Using cutting edge technology, more than 3,000 employees work to safely maintain reliable electric delivery service with the largest distribution and transmission system in Texas; made up of approximately 118,000 miles of lines and more than 3 million meters across the state. Oncor is leading the industry through a technology transformation. It is currently installing three million advanced meters that allow customers to better understand how they are using electricity to reduce consumption and manage costs. By the end of 2013, Oncor expects to complete the construction of more than 1,000 miles of transmission lines, alleviating grid congestion and delivering cleaner sources of energy including wind power from West Texas to the rest of the state. It is also developing communication tools for smart phones and tablets providing user-friendly information about power interruptions, including interactive maps, weather information and mobile-friendly solutions. **Strengths:** • Innovative technology upgrade initiatives, most notably the installation of over 3 million advanced meters to support a smart grid • Extensive transmission operations and maintenance experience
Demonstrated Capabilities	• Transmission Experience Outside Ontario • Major Capital Project Experience • The acquisition of necessary permits from government agencies • Community Consultation

Oncor's technology investments and grid expansion have a heavy focus in the transmission arena and have resulted in over $4.0B in capital expenditures in the last decade. The grid expansion component is highlighted by the recent addition of approximately 1,500 circuit miles of 5,000 amp 345 kV transmission lines being constructed to support the renewable generation resources in the western portions of Texas. Smart grid transmission investments include eleven (11) synchrophaser installations for grid wide area visibility, dynamically rated transmission conductors to maximize energy transfers across the 50,000 square mile Oncor grid, multiple static VAR compensators (SVC) for reactive power support, and microprocessor relay controlled circuit breakers.

Technology Upgrade Initiatives:

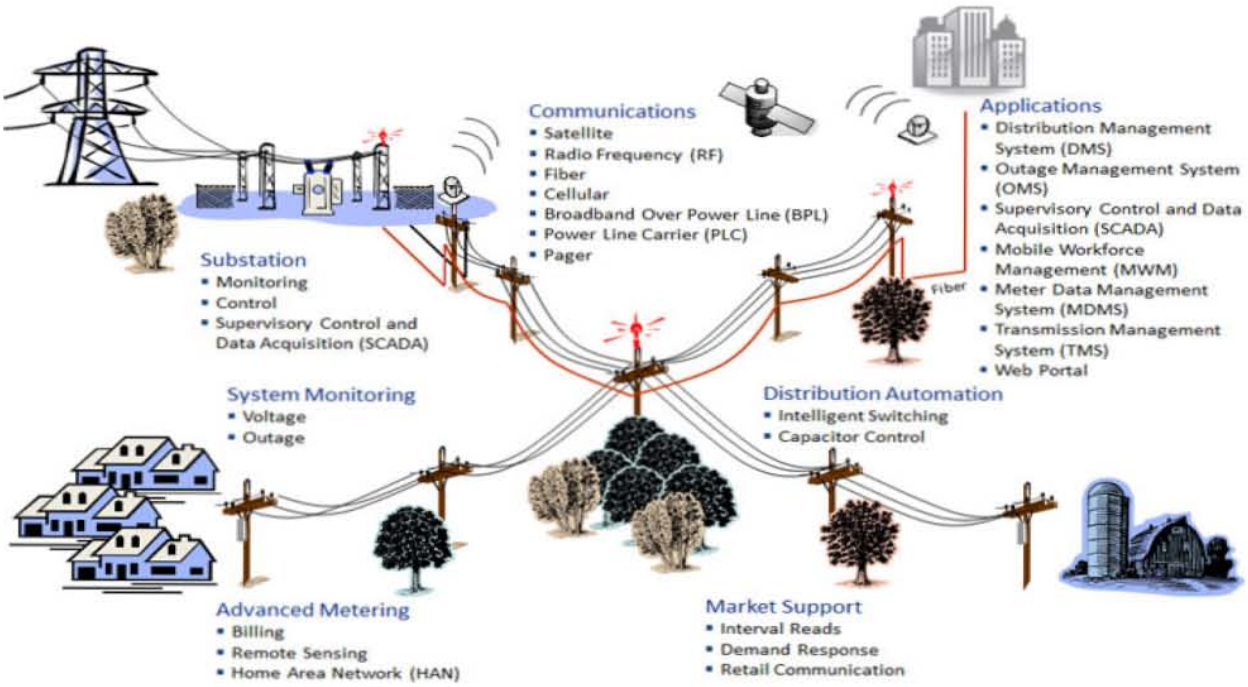
Oncor's technology upgrade initiatives include development of a modernized grid through the replacement of existing meters with advanced digital metering equipment and development of advanced digital communication, data management, real- time monitoring and outage detection capabilities. This modernized grid is expected to produce electricity service reliability improvements and

provide the potential for additional products and services from Retail Electric Providers (REP) that will enable businesses and consumers to better manage their electricity usage and costs. Oncor completed the full deployment of 3.2 million advanced meters in December of 2012. The advanced meters can be read remotely, rather than by a meter reader physically visiting the location of each meter. Advanced meters facilitate automated demand side management, which allows consumers to monitor the amount of electricity they are consuming and adjust their electricity consumption habits. As the new meters are integrated, Oncor reports 15-minute interval, billing-quality electricity consumption data to the Electric Reliability Council of Texas (ERCOT) for market settlement purposes. The data makes it possible for REPs to support new programs and pricing options.

What is an Advanced Metering System? Advanced meters are digital solid-state meters that will record electric consumption in 15 minute intervals. Consumers are able to receive real-time feedback through "in-home display" devices that receive usage information directly from the meter, and bring it into the home or workplace. Customers will be informed and empowered to alter their consumption patterns and take advantage of off-peak rates. Global experience suggests that such information is a key factor in changing overall consumption and creating new innovations and applications to reduce emissions and carbon footprint. In addition to recording data, each meter is also a communication device transmits the recorded data back to a centralized data depository. This new technology will eliminate the need to send a person to read and record data on a monthly basis. From March 2009 to December 2011, Oncor completed more than 3 million remote service orders, eliminating the need to dispatch personnel and vehicles. This capability eliminated the need to drive more than 15 million miles, saved over one million gallons of fuel and prevented over 12,000 tons of carbon dioxide from being released into the atmosphere.

Smart Grid Technology:

FIGURE 57: ONCOR SMART GRID TECHNOLOGY



Appendix 5: Approaches to Economic Participation

The following is a non-exhaustive list of approaches to economic participation that NextBridge has generated to date in the course of preparing its Application. This set of approaches illustrates NextBridge's readiness to enter into productive discussions with Aboriginal communities immediately upon designation, as further outlined in Chapter 3. NextBridge recognizes that in order for economic participation to be sustainable, it must meet the needs of many parties, including the participating Aboriginal community, NextBridge, and the ratepayer.

1. Preferred Equity/Limited Partnership Participation

A First Nation or Métis entity may purchase a preferred equity/limited partnership stake. A First Nation and Métis entity having to make initial investment may choose to use its own funds or access programs designed to assist in this regard, such as the Aboriginal Loan Guarantee Program, or utilize a combination of the two. Typical features of these types of investments include:

a. The participant buys a preferred equity stake having a lower relative risk profile, since the participant is entitled to a preferred dividend that must be paid in priority to any dividends payable to any common equity/limited partnership holders; and

b. Unlikely to have governance rights associated with it.

2. Common Equity/Limited Partnership Participation

A First Nation or Métis entity may purchase a common equity/limited partnership stake. A First Nation and Métis entity having to make initial investment may choose to use its own funds or access programs designed to assist in this regard, such as the Aboriginal Loan Guarantee Program, or utilize a combination of the two. Typical features of these types of investments include:

a. The participant buys an equity stake and shares the risks and returns of other common equity/limited partnership holders; and

b. It may or may not have governance rights associated with it.

3. Lump Sum Payment

a. In some cases it may be appropriate to make a onetime lump sum payment to a First Nation or Métis community as a community legacy of the project.

b. Any such payments may be regarded as a capital cost, and would therefore be subject to a prudence review.

4. First Nation and Métis Adder

a. Through the Ontario Feed-in-Tariff (FIT) Program, the Ontario Power Authority has advanced the concept that projects that benefit First Nation or Métis communities can receive a higher return than those that don't. In the FIT Program, it is expressed as a higher price per Megawatt-Hour that is passed through to ratepayers as part of the Global Adjustment. The adder ranges from 2-11% (assuming a price of 13 cents) depending on the level of Aboriginal participation.

b. It may be reasonable to propose that a similar concept be introduced to transmission projects in Ontario.

c. This "First Nation and Métis Adder" could be collected by the project entity and could flow through to either individual communities or to a broader group, on a regional basis.

It is recognized that this option is novel and would need to be proven to have an acceptable impact to ratepayers.

Appendix 6: NextBridge O&M Plan for the Project

The NextBridge strategy for operations & maintenance (O&M) of the EWT Line is to leverage industry best practices, standard processes and procedures in place at its partner companies to execute the most cost effective operations of its facilities in Ontario. NextBridge Transmission Operations will be located in the project area and staffed at an appropriate level that allows it to perform its primary function, which is to safely and reliably operate and maintain the NextBridge transmission facilities. The staffing level of NextBridge Transmission Operations also reflects the shared services support NextBridge will receive from its partner companies, as well as the relations for maintenance and specific tasks that will be subcontracted and provided by outside vendor services. NextBridge Transmission Operations will likely consist of one Area Operations Manager (AOM) supported by the required number of high voltage operations leads. The high voltage operations leads, through contractual arrangements with vendors, will be responsible for performing scheduled and unscheduled maintenance on NextBridge's facilities. The AOM will have a reporting relationship through the NextEra Energy Transmission (NEET) Operations organization and will have full support of Florida Power & Light's (FPL) Transmission & Substation (T&S) Operations groups including Technical Services which will also provide technical support, and condition assessment and reliability plan development of NextBridge's facilities. NextBridge will also have access to the FPL T&S Group's Transmission Performance & Diagnostic Center (TPDC), which serves as the hub for technical knowledge and field asset health information in support of its operations.

As referenced above, our Project OM&A costs will consist of NextBridge personnel as well as maintenance contracts with third party vendors with resources in the project area for transmission line maintenance, vegetation maintenance and right-of-way (ROW) maintenance activities. The costs provided in this application are based on experience with similar activities across other regions in which NextBridge affiliates operate transmission assets with appropriate assumptions and adjustments for performing these activities in the terrain and environment of the EWT Line. NextBridge has not tested the market for these services and as such final costs will be subject to confirmation during the development phase once NextBridge goes out to market for these services.

NextBridge Transmission Operations will be responsible for and will direct the overall operations effort, monitor and document compliance with applicable NERC Reliability Standards and the applicable IESO and regional reliability standards, protocols and operating guides. NextBridge Transmission Operations will utilize the FPL T&S Group to provide specific support to NextBridge as needed and will consist of the primary functions described below:

System Operations: The System Operations function will be responsible for managing the NextBridge transmission facilities on a 24/7 basis, monitoring reliability performance, scheduling outages in coordination with other utilities and IESO, and supporting construction and maintenance activities as required. In addition, the System Operations function will assist IESO operators by evaluating system conditions, reliability impacts, coordinating transmission element outages, providing data for updating operational models, and monitoring and implementing IESO emergency operations in compliance with NERC and IESO Standards.

Field Operations: The Field Operations function will be responsible for transmission facility maintenance and construction in a safe, timely and reliable manner. Field Operations includes the following key functions: reliable operation of NextBridge switching devices; periodic inspections; operational, functional and diagnostic testing; preventative and reactive maintenance of any applicable transmission and substation equipment; vegetation and transmission ROW management; and seasonal operational preparedness.

Field Operations will be supported by outside vendor services for major maintenance activities and management of equipment inventories to both support normal operations and meet emergencies. FPL T&S Group will provide SMEs through shared services and support development of equipment specifications, equipment recommendations, best practices and procedures related to installation and maintenance of assets, testing methods and technical support through experienced in-house engineers and analysts. NextBridge employees will perform field and office functions with assistance from both NEET and FPL shared resources.

Project Management of Operations and Maintenance Activities: NextBridge will leverage the well-established O&M practices and standard processes of its affiliates, NEET and FPL for its transmission

facilities. These practices include the management and execution of transmission O&M activities of the EWT Line.

NEET is responsible for support and management of its regulated utility entities Lone Star Transmission Operations in Texas and New Hampshire Transmission in New England. Through its internal staff and the use of its affiliate shared service resources in the FPL TS Group, NEET provides effective project management of its operating companies. With the Lone Star Transmission project in particular, NEET provided comprehensive project management and oversight from project inception through operations strategy development, construction and transition to operations phases. This support included dedicated project management of Lone Star Transmission's development of staffing plans, operating control centre construction and EMS implementation, construction and commissioning oversight and coordination with EPC contractors, and final equipment testing and energization to fully transition to operations. Throughout this process, NEET managed the establishment of shared support services with FPL T&S Group for ongoing O&M of the Lone Star Transmission facilities. Similarly, NEET and FPL T&S Group will support NextBridge with all project management activities for the ongoing operation and maintenance of the EWT Line. FPL T&S Group and NEET Operations personnel have extensive experience in establishing and managing O&M services internally as well as managing contracts with the appropriate vendors to provide maintenance of facilities, rights-of-way, vegetation management and technology systems.

Currently, FPL T&S Group manages all required activities for their regulated FPL facilities in Florida as well as provides project management and technical support services for Lone Star Transmission, New Hampshire Transmission, and NextEra Energy Resources (NEER) transmission type facilities in over 24 states and four Canadian provinces. The FPL system consists of over 10,700 km of transmission at voltages ranging from 69 kV to 500 kV throughout the state of Florida. The system also consists of over 600 substations and provides for interconnections with multiple utilities. Lone Star Transmission's system consists of 1,024 circuit km of 345 kV transmission lines interconnecting with multiple transmission service providers in Texas. The NEER system consists of approximately 1,552 circuit km of transmission facilities and gen-tie equipment throughout North America. FPL and NEET also provide project management for New Hampshire Transmission and Lone Star Transmission projects and

coordinate, along with NEET personnel, all operations and maintenance activities at the New Hampshire Transmission facilities.

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Appendix 7: Enbridge Neutral Footprint Program

As part of our ongoing efforts to find innovative ways to improve our business, we have pledged to stabilize our initial footprint through the following "Neutral Footprint" commitments:

- We will plant a tree for every tree we remove to build new facilities.
- We will conserve an acre of land for every acre of wilderness we permanently impact.
- We will generate a kilowatt of renewable energy for every kilowatt our operations consume.

Tree for a Tree

We will plant a tree for every merchantable tree we remove to construct or expand our facilities or rights-of-way. The trees counted and therefore replaced will be of adequate size to be considered "merchantable timber" as defined by the relevant local regulator.

We will replace trees from either forested or non-forested land (such as brush/scrub, prairie, grassland, alpine, rangeland, meadows, pasture or cultivated land). We will plant them in such a way that it takes into account the following priority considerations:

1. Plant trees to meet regulatory commitments and approval conditions.

2. Plant trees to maintain slope stability, control erosion and meet reclamation guidelines and aesthetic requirements.

3. Plant trees to meet the needs of local communities.

We will not always replace trees in the immediate area of impact, but will take into account land availability, local desire and consent. From the start of January 2009 through to the end of the second quarter of 2012, Enbridge had removed approximately 545,000 trees and had planted 375,000 tree seedlings. (Planting numbers lag removal numbers because in northern regions trees are removed during the winter season when the ground is frozen and seedlings are planted during the spring and summer.)

Acre for an Acre

We will help conserve an acre of natural habitat for every acre that it permanently impacts. The natural habitat NextBridge conserves could be forested land, wetlands or native prairie.

We will conserve the land while working with the Nature Conservancy of Canada (see below) and other organizations. As such, their guidelines and recommendations will determine how and where the land is conserved, and will ensure that it is of high ecological value.

The land conserved may not be in the same area or region as the land that is impacted, and may not be "like for like." Rather, we will make conservation decisions based on biological value and availability.

This commitment does not replace or negate regulatory obligations to reclaim land when it is decommissioning an asset.

For example, since the beginning of 2009 through to the end of the second quarter of 2012, approximately 1,700 acres (approximately 690 hectares) of natural habitat have been disturbed by Enbridge projects and Enbridge has contributed to conserving over 5,260 acres (approximately 2,100 hectares).

Nature Conservancy of Canada / The Conservation Fund – In early 2010, Enbridge invested $2.5 million in support of the Nature Conservancy of Canada's work to preserve and protect important and sensitive natural habitats across Canada. Through this investment, some of the best remaining wildlife habitat in Canada is being conserved. The investment is particularly significant at this time because, thanks to matching funds from sources including the Government of Canada's Natural Areas Conservation Program, Enbridge's contribution of $2.5 million will trigger a conservation impact of more than $10 million.

Similarly, in the United States in late 2011, Enbridge invested US$3 million in The Conservation Fund, which partners with community, government and corporate organizations to help them fulfill their conservation priorities.

Kilowatt for a Kilowatt

As part of our Neutral Footprint Initiative, we have has committed to generating a kilowatt hour of renewable energy for every kilowatt hour of additional power its operations consume. We will fulfill this commitment within five years of the additional power consumption.

Each year, we will compile the forecasted power consumption for operations. Any net increase in power consumption will be counterbalanced by the company's investments in economically viable renewable energy production. Enbridge has addressed growth in its electricity consumption on a five-year rolling basis consistent with the long-range planning horizon.

Alternative Key Stats presentation

From the start of January 2009 through to the end of the second quarter of 2012:

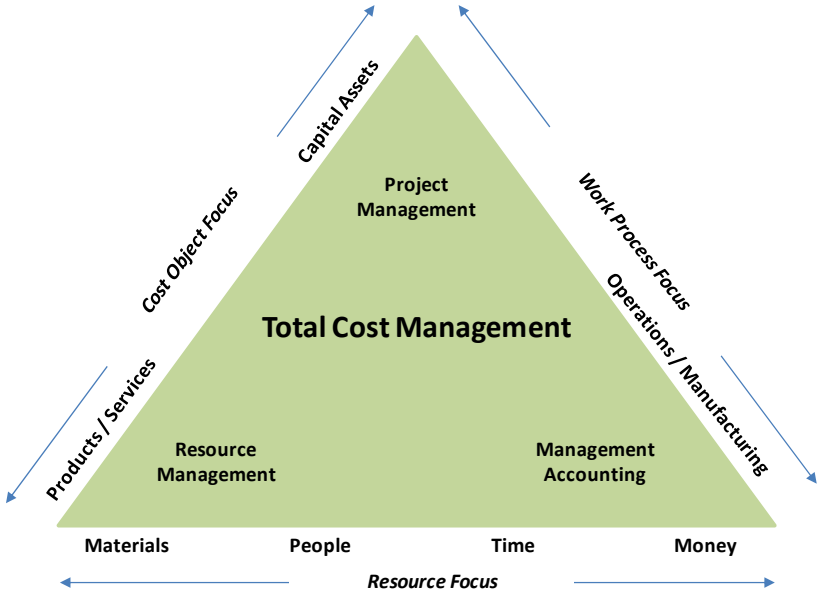
- 545,000 trees removed and 375,000 tree seedlings planted;
- Approximately 1,700 acres of natural habitat disturbed and 5,260 acres conserved (surplus will be applied to future projects); and
- By the end of 2011, we were forecasting that our power consumption will grow by 2,668 GWh by 2015, while power generated from our renewable energy assets (both existing and under construction) will be 3,080 GWh.

Appendix 8: Total Cost Management

Total Cost Management

Total Cost Management (TCM) is the effective application of professional and technical expertise to plan and control resources, costs, profitability and risk. Simply stated, TCM is a systematic approach to managing cost throughout the life cycle of any enterprise, program, facility, project, product or service. A key feature of the TCM Framework is that it highlights and differentiates the main cost management application areas: project control and strategic asset management.

Outlined here are some of the areas of focus that TCM covers. This is provided as a guide for the types of processes we utilize in executing on a NextEra Energy Transmission projects.

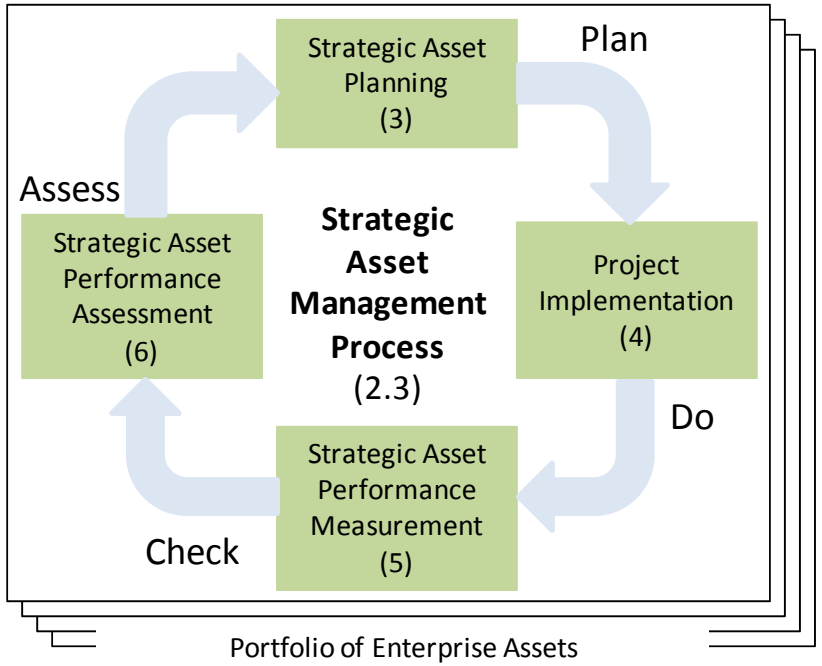


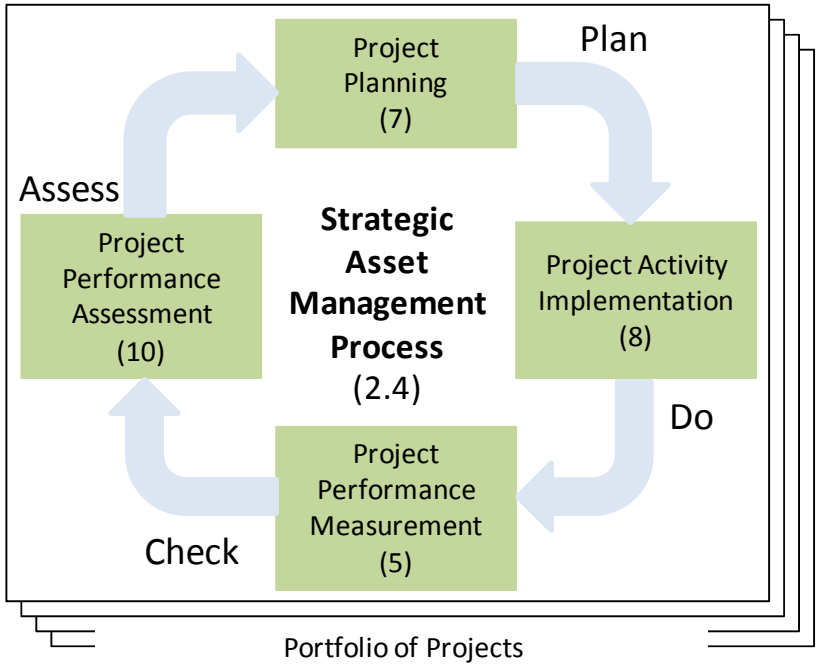
TCM's Place in the Cost Management Spectrum

Recently, project management models have been enhanced to better address pre-project processes, project portfolios, and consideration of overall business organization strategies. An example is the Project Management Institute's Organizational Project Management Maturity Model (OPM3). However, these models still do not cover production and operation management and costs to the extent addressed by TCM.

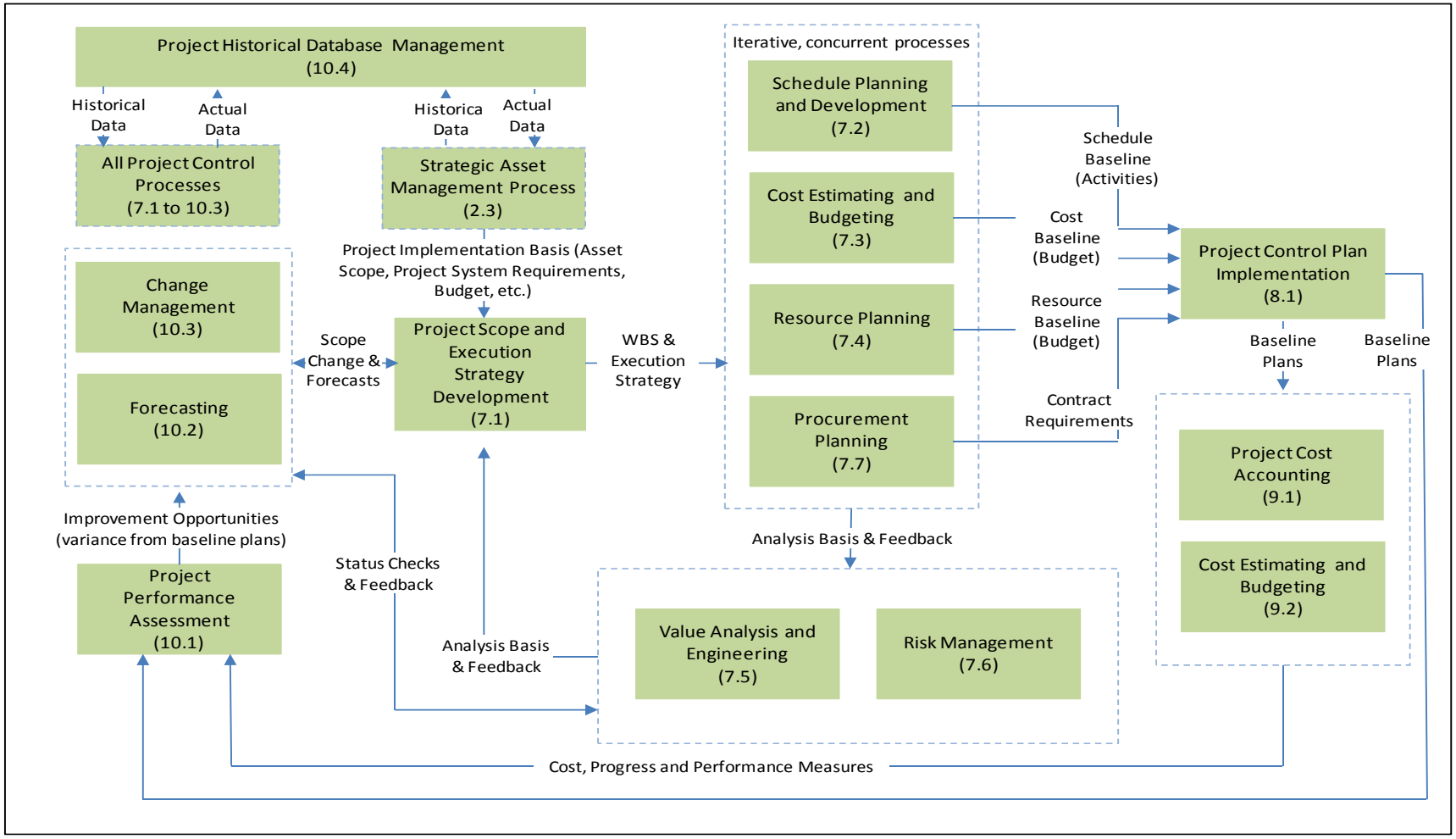
In summary, TCM is unique in that it integrates the best approaches from all the major fields that have cost management interests while emphasizing cost engineering's practices and major role in them all.

NEXTBRIDGE INFRASTRUCTURE





The two levels of the TCM processes shown above are referred to respectively as the Strategic Asset Management and Project Control processes. We focus here on Project Control processes (see process map below). Project Control is a process for controlling the investment of resources in an asset. In TCM, project control is the recursive process cycle that is nested within the "do" step of the strategic asset management process cycle. A project is a temporary endeavor an enterprise undertakes to create, modify, maintain, or retire a unique asset. Being a temporary and therefore unique endeavor, projects are by nature uncertain and that element of risk puts a premium on control and discipline.


Project Historical Database Management (10.4)
Historical Data
Actual Data
Historica Data
Actual Data
All Project Control Processes (7.1 to 10.3)
Strategic Asset Management Process (2.3)
Project Implementation Basis (Asset Scope, Project System Requirements, Budget, etc.)
Change Management (10.3)
Forecasting (10.2)
Scope Change & Forecasts
Project Scope and Execution Strategy Development (7.1)
WBS & Execution Strategy
Iterative, concurrent processes
Schedule Planning and Development (7.2)
Cost Estimating and Budgeting (7.3)
Resource Planning (7.4)
Procurement Planning (7.7)
Schedule Baseline (Activities)
Cost Baseline (Budget)
Resource Baseline (Budget)
Contract Requirements
Project Control Plan Implementation (8.1)
Baseline Plans
Baseline Plans
Project Cost Accounting (9.1)
Cost Estimating and Budgeting (9.2)
Improvement Opportunities (variance from baseline plans)
Project Performance Assessment (10.1)
Status Checks & Feedback
Analysis Basis & Feedback
Analysis Basis & Feedback
Value Analysis and Engineering (7.5)
Risk Management (7.6)
Cost, Progress and Performance Measures

Appendix 9: NextEra and Enbridge Safety Information

NextEra ZERO *Today!* - It's More than a Motto

NextEra Energy is working on many fronts to keep its more than 15,000 employees safe. NextEra Energy's ZERO *Today!* safety vision is intended to help the company achieve a zero-injury record across its operations. Under ZERO *Today!:* We promote an expectation of safe working practices, personal and peer-to-peer accountability for safety.

- We celebrate safe behavior and recognize those work groups and individual employees that have worked injury free.
- We continue to further refine our Safety Information Management System, which helps to drive a heightened level of safety responsibility among employees, supervisors and managers. Additionally, the system further prompts a higher level of analysis and loss prevention.
- The company has rolled out a comprehensive education program aimed at employees and management to ensure that "near misses" are appropriately reported and investigated, and that effective countermeasures are put into place. The act of identifying near misses serves as an early warning system for failures that can lead to injuries.
- Safety culture is an extremely important element of the success of a safety program. Therefore, the company recently administered a safety culture survey of our employees in field operations. The survey questions were carefully selected to assess our employees' perspectives on our safety culture and to help identify areas of opportunity.
- Many areas of the company have added additional safety training to their curricula, focusing on areas such as safety leadership, driver safety, and enhanced technical training.
- Our company-wide safety communications place a special emphasis on hazard recognition for field and office employees. The "What could go wrong?" theme further supports our ZERO *Today!* goal.
- Our incident investigation processes have been further strengthened to better identify and understand root causes, leading to more effective countermeasures. Additionally, we are training our employees on advanced incident investigation techniques.

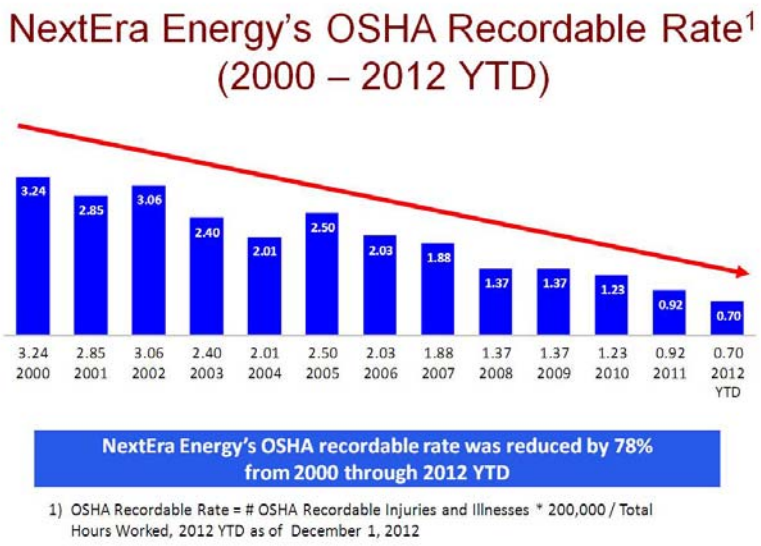
- ZERO *Today!* stresses that safety is everybody's job. All managers ask every employee to include at least one safety goal as part of their annual performance objectives.

NextEra Safety in Collective Bargaining Agreements and Supplier Contracts

NextEra Energy's safety focus permeates all 10 collective bargaining agreements with its family of companies. Specific provisions address safety equipment, hazardous working conditions, and joint company-union involvement in the development of safety standards. For example, the agreement between FPL and the International Brotherhood of Electrical Workers System Council U-4 has a detailed company-union program including Local Joint Safety Advisory Committees, Business Unit Joint Safety Committees and a Corporate Joint Safety Committee. It also includes a comprehensive program for serious incident investigations using a specially trained union-management team.

NextEra Energy is committed to maintaining a safe working environment, including using suppliers with a demonstrated commitment to safety. In general, suppliers who have a presence on company premises of 30 or more cumulative person-days within 12 months are required to comply with the requirements of NextEra Energy's Supplier Safe and Secure Workplace policy whereby suppliers are expected to demonstrate an Experience Modification Rate (EMR) for safety purposes that is equal to or better than average for their industry. An EMR is a ratio that indicates how a company's Workers' Compensation losses compare to those of other companies with similar classifications. NextEra Energy maintains specific guidelines for the implementation of these goals and invokes them as requirements within supplier contractual agreements.

FIGURE 58: NEXTERA SAFETY INFORMATION



Enbridge Major Projects – Contractor Safety Management System

Based on the performance requirements outlined in the HSMS, a unique and comprehensive Project Safety Management Plan is developed for construction of all major projects. This plan addresses safety requirements, responsibilities, and lines of communication during construction and commissioning. All Project field crews are trained and random internal audits are carried out to ensure that personnel comply with the health, environmental and safety plan. All field personnel are provided with a condensed field handbook describing the main features of this plan. In addition, both general and subcontractors are required to adhere to all local safety regulations, contractor safety manuals, their own company-specific safety manuals and Enbridge safety expectations.

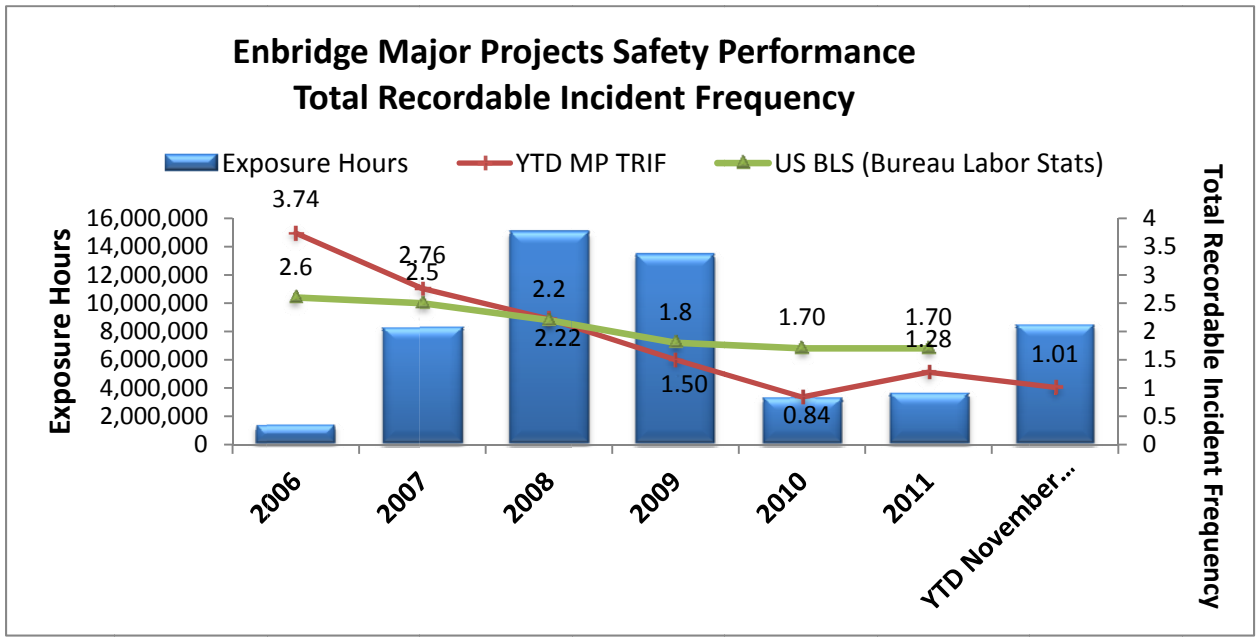
Enbridge places experienced Safety Coordinators & Inspectors on project teams who are on site during construction to ensure that all personnel follow safety procedures. Enbridge Major Projects utilizes both lagging and leading safety indicators to prequalify and measure in project safety performance of contractors. This approach is in alignment with Enbridge wide Safety Values and Principles which firmly put people, contractors and communities as the priority in accomplishing our work. Enbridge has developed a 3 year corporate strategy to be best in class in a number of areas, including safety

performance. Enbridge's belief is that a safe operation is a reliable, productive and sustainable operation.

The Total Recordable Incident Frequency (TRIF) is a measure of the number of contractor lost time, modified work, and medical aid personal injuries per 100 workers per year and is a measure of success of the HSMS. Since 2006, Major Projects has demonstrated continuous improvement of its TRIF year over year, as demonstrated by the figure below, and moves ever closer to the goal of zero incidents. The MP 2012 YTD TRIF sits at 1.0 & the three year rolling average TRIF is an industry leading 0.96 which accounts for over 8.5 million person hours worked in 2012 (YTD).

As part of the performance monitoring element of the Major Projects HSMS, Enbridge routinely benchmarks safety performance against industry peers. The figure below represents MP safety performance compared to the publicly available TRIF rates with major heavy pipeline and infrastructure companies. The United States Bureau of Labor Statistics (BLS) heavy construction average TRIF rate is also plotted.

FIGURE 59: ENBRIDGE SAFETY INFORMATION



Appendix 10: Supporting Calculations for Performance Based Rate-Making

FIGURE 60: SUPPORTING CALCULATIONS FOR PERFORMANCE BASED RATE-MAKING EXAMPLE IN SECTION 5

Assumptions ($ millions CAD)	Case 1	Case 2
Capital cost	$ 600	$ 540
ROE	9.0%	10.0%
Equity %	40%	40%
Cost of debt	4.00%	4.00%
Debt %	60%	60%
Tax rate	26.5%	26.5%
Project life (years)	40	40

Revenue Requirement ($ millions CAD)	Case 1	Case 2
Revenue requirement (RR)	63.8	60.8
(-) OM&A	5.0	5.0
EBITDA	58.8	55.8
(-) Depreciation	15.0	13.5
EBIT	43.8	42.3
(-) Interest	14.4	13.0
EBT	29.4	29.4
(-) Tax	7.8	7.8
Net income	21.6	21.6
Change in RR		(2.9)
% Change in RR		-4.6%

NEXTBRIDGE INFRASTRUCTURE

Appendix 11: PTerra Technology Assessment

The PTerra Technology Assessment is attached.

Pterra
Electric Power Consultants

Technical Report R114-12 Rev. 2

High Level Transmission Screening For Ontario Power Authority's East- West Tie Project



Submitted to

NextEra Energy

April, 2012

4 Automation Ln, Albany, NY 12205, tel: (518) 935-2579, www.pterra.com

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Notice

The information and conclusions connected with the evaluation study provided herein, are independently developed on the basis of NextEra Energy Resources, LLC ("NextEra") provided data, information, work scope, and requirements. Sound engineering methods and practice have been applied to NextEra's study to specifically identify practical concerns, best practices, and know-how relating to the NextEra's needs, and within the confidentiality provisions between Pterra, LLC ("Pterra") and NextEra.

This report includes data and information protected by the US Federal Energy Regulatory Commission as Critical Energy Infrastructure Information. Distribution of this report is restricted to those expressly identified by NextEra and Pterra.

Executive Summary

Pterra, LLC ("Pterra") was contracted by NextEra Energy ("NextEra") to conduct a high level transmission screening for Ontario Power Authority's ("OPA") East-West transmission line project (the "Project").

This high level technical assessment includes the OPA's reference case and the review of the following alternatives:

- Single circuit 345 kV
- Single circuit 500 kV
- HVDC (DC bipolar line with metallic return)

In order to evaluate the different transmission alternatives, Pterra developed the OPA reference case from the 2017 summer peak power flow model. The adjustments included: scaling load to model an expected increased in peak load of 950 MW in the Northwest region of Ontario system and re-dispatching generation to simulate a dry season loading condition. The revised dispatch is characterized by a high transfer level across the East-West tie (approximately 616 MW) in the west direction and limited availability of the hydroelectric generation in the Northwest region, to approximately 43% of its peak value of 780 MW.

Using the developed reference case, Pterra conducted analysis for steady state and P-V curves to determine if additional upgrades were needed for the different alternatives. Also, Pterra measured the transmission losses for each alternative and the total losses in the Northwest and Northeast regions. The results of the assessment are shown in Table 1-1.

Table 1-1 Summary of the Pre-Contingency Transmission Losses in the Proposed Transmission, and in the Northwest and Northeast Regions

N0.	Alternative	Alternative losses	Northwest	Northeast
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS)	23.3 MW	122 MW	290 MW
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	13.0 MW	93 MW	248 MW
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	12.5 MW	92 MW	258 MW
4	Case with a 500 MW HVDC from Wawa TS to Lake Head TS	21.7 MW	84 MW	276 MW

In summary, the findings are:

- The 500 kV alternative shows the lowest line losses (12.5 MW) while the new 230 kV double circuit line from the reference case showed the highest line losses (23.3 MW). The reference case showed the highest MW losses in both the Northwest and Northeast (122 MW and 290 MW, respectively). The lowest losses

for the Northwest region were observed in the HVDC option (84 MW); while for the Northeast region, the 345 alternative showed the least losses (248 MW).

- For the pre-contingency transfer levels (across the East-West tie) shown in Table 1-1, there were no N-1 post-contingency thermal criteria violations for any of the studied transmission alternatives. This was based on monitoring of the 230 kV and higher voltage system using the LTE rating for post-contingency conditions.
- P-V analysis showed that the reference case offers the highest voltage stability limit of 701 MW; followed by the HVDC alternative which provides a voltage limit of 686 MW. The limits for the 345 kV and 500 kV options are 601 MW and 637 MW, respectively. These results are summarized in Table 1-2.

Table 1-2 Summary of the P-V analysis of the Studied Options

N0.	Alternative	Voltage Limit	Limiting Contingency
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS)	701 MW	D/C Contingency: New Marathon to Lake Head circuits
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	601 MW	D/C Contingency: existing Wawa to Marathon circuits
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	637 MW	D/C Contingency: Existing Wawa to Marathon circuits
4	Case with a 500 MW HVDC from Wawa TS to Lake Head TS	686 MW	Loss of the HVDC line and converters (but retaining fixed capacitors)

Ballpark cost estimates for the reference case and the different alternatives were developed. In these estimates, the following are taken into account: length of new transmission, right of way (ROW) for each type of transmission addition, substation upgrades and transformer additions. Note that all the cost estimates assume lattice-type steel tower. Concrete towers at high voltage are used mostly in Canada; Pterra does not have cost information for this type of tower. These estimates are provided without benefit of site surveys or engineering assessment and are thus conceptual in nature to a level of detail that allows for comparison of relative costs between the alternatives. Table 1-3 provides a summary of the ballpark installation costs associated with each alternative and the comparison with estimated costs for the reference case.

Table 1-3 Summary of the Estimated Cost Associated with each Alternative

N0.	Alternative	Cost Estimate ($mil)	Incremental[1] Cost ($mil)
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS)	$ 274.0	-
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	$ 365.5	$ 91.5
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	$ 494.4	$ 220.5
4	Case with a 500 MW HVDC from Wawa TS to Lake Head TS	$ 519.1	$ 245.1

The Reference Case offers the lowest estimated cost to install. The key reason for this is that the Reference Case does not utilize step up transformers to a higher voltage or DC converters. The 345 kV alternative is about $91 million more costly than the Reference Case and is the lowest cost among the study alternatives. The 500 kV and the HVDC cost $220 million and $245 million more, respectively, than the Reference Case.

From a technical perspective, the HVDC option offers a key technical advantage over the Reference Case and the two other AC transmission alternatives. HVDC is a controllable resource that provides more flexibility for operation whereas the AC alternatives will require heavy reactive compensation that will present challenges to operators.

[1] Compared to Reference Case.

Section 1. Introduction

Pterra, LLC ("Pterra") was contracted by NextEra Energy ("NextEra") to conduct a high level transmission screening for Ontario Power Authority's ("OPA") East-West transmission line project (the "Project").

1.1. Objective

The objective of the evaluation is to provide a high level technical assessment of the various alternatives to the OPA's reference case. This includes the reference case and the review of the following alternatives:

- Single circuit 345 kV
- Single circuit 500 kV
- HVDC (DC bipolar line with metallic return)

1.2. Scope of Services

The tasks performed by Pterra for this study are:

- Obtained a power flow model of the future system when the Project will first operate. Developed the following additional models to represent:
    a. OPA reference case.
    b. Single circuit 345 kV.
    c. Single circuit 500 kV.
    d. HVDC (DC bipolar line with metallic Return).
- Conducted power flow analysis for steady sate and P-V curves to determine if additional upgrades were needed for the models represented in Task 1. Also, measured the transmission losses for each models.
- Developed conceptual cost estimates for each of the models, including any upgrades indicated in the analysis. Pterra notes that the cost estimates are very high level and do not have the benefit of survey and existing line and substation drawings.
- Reporting. Pterra prepared this brief report documenting the study assumptions and results.

Section 2. Study Data and Assumptions

The study data comprised of the following:

- 2017 summer peak power flow model of the IESO Ontario system.

2.1. Power Flow Model

The base case power flow used in this assessment is given in Table 2-1.

Table 2-1: Specifics of Power Flow Case

System Model	Description
Ontario	2017 summer peak model

In the study, single and double circuit outages are applied along the East-West tie. The study area included the northwest area and part of the northeast area of Ontario. Thermal overloads were monitored in the vicinity of the AC terminal for the Project for transmission elements rated 230 kV and above. With the system intact, the continuous or normal rating (RATEA) was applied. For first contingencies, the emergency rating (RATEB) was applied.

2.2. Analytical Method

The analytical approach uses AC power flow solutions to determine the thermal impact of the Project. Contingency analysis is performed to identify any thermal overloads. The voltage-constrained transfer limits of the different alternatives are evaluated using P-V analysis where the voltage-constrained transfer limit is determined as 95% of the pre-contingency power flow at the "nose" of the post-contingency voltage versus pre-contingency flow curve.

The "nose" is the point at which the slope of the curve becomes infinite (vertical) and reaches the point of voltage collapse. This operating point occurs when the reactive capability supporting the power transfers becomes exhausted. The region near the "nose of the curve" is generally referred to as the region of "voltage instability". Therefore, the voltage-constrained transfer limit is intended to ensure adequate post-contingency voltage and to avoid operating within this region of voltage instability.

The screening analysis addresses only thermal and voltage impacts and does not account for other constraining factors such as stability and short circuit impacts.

2.3. Load and Generation Re-Dispatch Assumptions

In order to evaluate the different transmission alternatives, Pterra developed the OPA reference case from the 2017 summer peak power flow model by:

- substantially adjusting load in the 2017 summer peak power flow model to model an expected increased peak load in the Northwest region of Ontario system and
- re-dispatching generation to simulate a dry season loading condition characterized by a high transfer level across the East-West tie in the west

direction and limited availability of the hydroelectric generation in the Northwest region.

The adjustments of load and generation were implemented as follows:

- A peak load of 950 MW was assumed for the Northwest region; this includes 215 MW of new load which was added in the Thunder Bay area in addition to 60 MW of new load which was distributed throughout the Read Lake, Crow River, and Musselwhite area.
- Since a new 115 kV connection between Valora Junction and Musselwhite substation is planned to be in service to address thermal criteria violations in the local area; this area was not monitored in the analysis. Appendix A shows the scaled loads in the Northwest region.
- The Northwest generation was set to 390 MW; this includes approximately 334 MW from existing hydroelectric facilities which represents approximately 43% of the peak output of 780 MW to resemble the scenario of a low hydro generation during a dry season. The rest of the generation was assumed available from the existing gas fired facilities in the area. The Atikokan and Thunder Bay facilities were assumed to be out of service and the output from wind turbine facilities was assumed to be zero. Appendix B shows the generation dispatch in the Northwest region.
- The output from the hydroelectric facilities owned by Great lake power (GLP) (which is part of the Northeast generation) within the area between Algoma TS and Wawa TS was set to 650 MW; approximately 70% of their peak output of 804 MW. The output from Lake Superior Power and Algoma Steel facilities was set to 142 MW. The total generation from the GLP is 702 MW. Appendix C shows the GLP generation re-dispatch.
- Generation re-dispatch in the rest of Northeast region east of Hanmer 500 kV was implemented to offset generation/load unbalance.
- Several capacitors were modeled in the OPA reference case as part of the OPA reference case (as modeled in the OPA Feasibility Study) and were included in the other alternative cases; a list of these capacitors and their sizes are provided in Appendix D.

2.4. Description of the East-West Tie

The East-West tie between Wawa TS 230 kV and Mackenzie TS 230 kV is shown in Figure 2-1; there are two intermediate substations at Marathon TS 230 kV and Lake Head TS 230 kV.

Currently, with the existing system topology, the present storm limit on the East-West tie under which double circuit contingencies are respected restricts transfers to approximately 175 MW. This limit severely affects the ability to supply the anticipated load in the Northwest region especially during a dry season where the output of the hydroelectric units would be restricted.

The OPA reference case modeled:

- A new 230 kV double circuit line between Wawa Ts and Lake Head TS with intermediate terminations into Marathon TS.

- An additional shunt capacitor bank with a nominal rating of 125 MVAR at Lake Head 230 kV.
- A +200/-100 MVAR SVC at Marathon TS 230 kV.

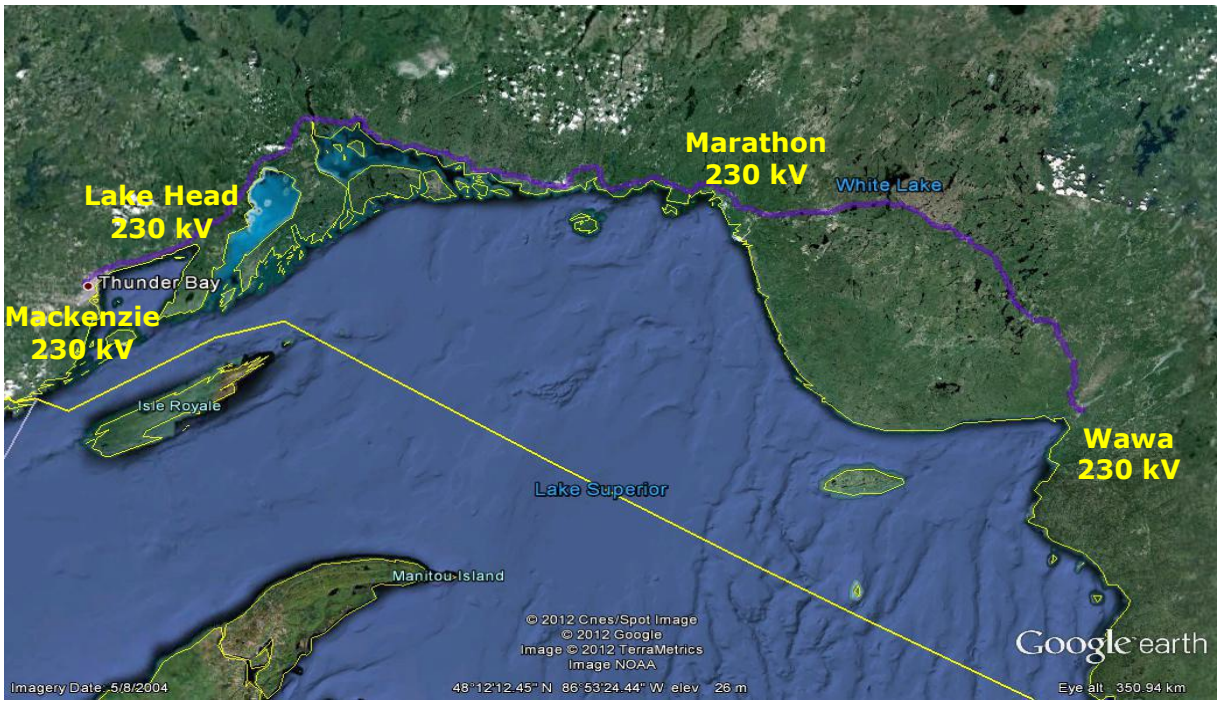

Figure 2-1: Site Map for the Terminals of the East-West Tie Between Wawa and Mackenzie

With the scaled load in the Northwest region equal to 950 MW, the generation re-dispatch in both Northwest and GLP regions as shown in Appendices B and C and the 230 kV new double circuit line between Wawa TS and Lake Head TS in service, the transfer across the East-West tie was 616 MW westwards.

Section 3. Transmission Evaluation

3.1. Thermal Contingency Analysis

Table 3-1 shows the transfer across the east-west tie in the study power flow cases, and how these flows are distributed between the proposed system additions and the existing 230 kV transmission.

Table 3-1: Summary of the Transfers Across the East–West Tie and distribution of power flows between proposed transmission additions and the existing 230 kV circuits.

N0.	Alternative	Transfer Level in MW Across the East-West Tie	Flow in MW Through Proposed Additions	Flow in MW Through Existing 230 kV Double Circuits
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS)	616 MW	308 MW	308 MW
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	574 MW	294 MW	280 MW
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	586 MW	319 MW	267 MW
4	Case with a 500 MW Bipole HVDC from Wawa TS to Lake Head TS	603 MW	500 MW	103 MW

N-1 contingency analysis, for contingencies along the path of the east-west tie, was conducted at the transfer levels shown in Table 3-1; the results showed no post-contingency thermal criteria violations for any of the studied transmission alternatives. Post-contingency flows in the 230 kV transmission system and above were within the LTE rating.

Table 3-2 shows a summary of the transmission losses for each alternative and the total losses in the Northwest and Northeast regions.

Table 3-2: Summary of the Pre-Contingency Transmission Losses in the Proposed Transmission, and in the Northwest and Northeast Regions

N0.	Alternative	Losses on Proposed Transmission	Northwest	Northeast
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into	23.3 MW	122 MW	290 MW
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	13.0 MW	93 MW	248 MW
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	12.5 MW	92 MW	258 MW
4	Case with a 500 MW Bipole HVDC from Wawa TS to Lake Head TS	21.7 MW	84 MW	276 MW

The 500 kV alternative shows the lowest line losses (12.5 MW) while the new 230 kV double circuit line from the reference case showed the highest line losses (23.3 MW). The reference case showed the highest MW losses in both the Northwest and Northeast (122 MW and 290 MW, respectively). The lowest losses for the Northwest region were observed in the HVDC option (84 MW); while for the Northeast region, the 345 alternative showed the least losses (248 MW).

3.2. P-V Analysis

With the loads modeled as constant MVA loads, the transfer across the East-West tie was increased in small increments until the "nose" of the P-V curve or thee voltage collapse point is reached. The interface voltage transfer limit is 95% of the interface flow at the "nose" of the P-V curve (allowing for 5% margin).

For this high level study the following assumptions were made:

1. No post-contingency adjustments were made to the phase shifters on the Manitoba and Minnesota interconnections.
2. No voltage analysis was conducted for the Sudbury West interface for any of the studied transmission alternatives.
3. For the Reference Case, the double circuit contingency that involves the outage of the new 230 kV lines from Marathon to Lake Head was studied.
4. For the 345 kV and 500 kV options, the double circuit contingency that involves the outage of the existing 230 kV circuits from Wawa TS to Marathon was studied.
5. For the HVDC option, the contingency that involves the outage of the HVDC line, including the converters, but retaining the capacitors, was studied.
6. No series compensation was studied at any level for either the 345 kV or the 500 kV options.
7. No sensitivity analysis that shows the impact of the level of shunt compensation at the terminals of either the 345 kV or the 500 kV alternatives on the voltage transfer limit across the East-West tie was conducted.

As shown in Table 3-3**Error! Not a valid bookmark self-reference.** the Reference Case showed the highest voltage stability limit of 701 MW while the 345 kV option showed the lowest limit of 601 MW; the 500 kV option provided a voltage limit of 637 MW while the HVDC alternative provided a voltage limit of 686 MW.

Table 3-3 Summary of the P-V analysis of the Studied Options

NO.	Power Flow Case	Voltage Limit	Limiting Contingency
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS)	701 MW	D/C Contingency: New Marathon to Lake Head circuits
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	601 MW	D/C Contingency: existing Wawa to Marathon circuits
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	637 MW	D/C Contingency: Existing Wawa to Marathon circuits
4	Case with a 500 MW HVDC from Wawa TS to Lake Head TS	686 MW	Loss of the HVDC converter

3.3. Cost Estimates of the Studied Options

Ballpark cost estimates for the reference case and the different alternatives were developed. In these estimates, the following are taken into account: length of new transmission, right of way (ROW) for each type of transmission addition, substation upgrades and transformer additions. Note that all the cost estimates assume lattice-type steel tower. Concrete towers at high voltage are used mostly in Canada; Pterra does not have cost information for this type of tower. These estimates are provided without benefit of site surveys or engineering assessment and are thus conceptual in nature to a level of detail that allows for comparison of relative costs between the alternatives.

Table 3-4 provides a summary of the ballpark costs associated with each alternative and a comparison with estimated costs for the reference case.

Table 3-4 Summary of the Estimated Cost Associated with each Alternative

NO.	Alternative	Cost Estimate ($mil)	Incremental[2] Cost ($mil)
1	Reference Case (with the new 230 kV Double circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS)	$ 274.0	-
2	Case with a 345 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	$ 365.5	$ 91.5
3	Case with a 500 kV circuit from Wawa TS to Lake Head TS with intermediate terminations into Marathon TS	$ 494.4	$ 220.5
4	Case with a 500 MW HVDC from Wawa TS to Lake Head TS	$ 519.1	$ 245.1

Details of the cost estimates are provided in Table 3-5 through Table 3-8.

[2] Compared to reference Case.

Table 3-5: Cost Estimate of the Reference Case with Double-Circuit 230 kV Line

Item	units	unit cost ($000)	No.of units	Cost ($million)
New single circuit steel-lattice tower, right-of-way and conductors - Wawa to Marathon	mi	$ 980	104.4	$ 102.3
New single circuit steel-lattice tower, right-of-way and conductors - Marathon to Lakehead	mi	$ 980	142.5	$ 139.7
230 kV Substation upgrade - Wawa	block	$ 3,750	1	$ 3.8
230 kV Substation upgrade - Marathon	block	$ 10,500	1	$ 10.5
230 kV Substation upgrade - Lakehead	block	$ 3,750	1	$ 3.8
Static Var Device - Marathon	MVAR	$ 70	200	$ 14.0
			Total	**$ 274.0**

Table 3-6 Cost Estimate of the 345 kV Single Circuit Line Wawa-Marathon, Marathon-Lake Head

Item	units	unit cost ($000)	No. of units	Cost ($million)
New single circuit steel-lattice tower, right-of-way and conductors - Wawa to Marathon	mi	$ 1,050	104.4	$ 109.6
New single circuit steel-lattice tower, right-of-way and conductors - Marathon to Lakehead	mi	$ 1,050	142.5	$ 149.7
230 kV Substation upgrade - Wawa	block	$ 750	1	$ 0.8
230 kV Substation upgrade - Marathon	block	$ 1,500	1	$ 1.5
230 kV Substation upgrade - Lakehead	block	$ 750	1	$ 0.8
New 345 kV Substation - Wawa	block	$ 17,500	1	$ 17.5
New 345 kV Substation - Marathon	block	$ 20,000	1	$ 20.0
New 345 kV Substation - Lakehead	block	$ 17,500	1	$ 17.5
345/230 kV autotransformer, 800 MVA	bank	$ 11,400	3	$ 34.2
Static Var Device - Marathon	MVAR	$ 70	200	$ 14.0
			Total	**$ 365.5**

Table 3-7 Cost Estimate of the 500 kV Single Circuit Line Wawa-Marathon, Marathon-Lake Head

Item	units	unit cost ($000)	No. of units	Cost ($million)
New single circuit steel-lattice tower, right-of-way and conductors - Wawa to Marathon	mi	$ 1,550	104.4	$ 161.8
New single circuit steel-lattice tower, right-of-way and conductors - Marathon to Lakehead	mi	$ 1,550	142.5	$ 220.9
230 kV Substation upgrade - Wawa	block	$ 750	1	$ 0.8
230 kV Substation upgrade - Marathon	block	$ 1,500	1	$ 1.5
230 kV Substation upgrade - Lakehead	block	$ 750	1	$ 0.8
New 500 kV Substation - Wawa	block	$ 19,000	1	$ 19.0
New 500 kV Substation - Marathon	block	$ 22,500	1	$ 22.5
New 500 kV Substation - Lakehead	block	$ 19,000	1	$ 19.0
500/230 kV autotransformer, 800 MVA	bank	$ 11,400	3	$ 34.2
Static Var Device - Marathon	MVAR	$ 70	200	$ 14.0
			Total	**$ 494.4**

Table 3-8 Cost Estimate of the HVDC Bipole Wawa-Lake Head

Item	units	unit cost ($000)	No. of units	Cost ($million)
New Bipole steel-lattice tower, right-of-way and conductors - Wawa to Lakehead	mi	$ 875	246.9	$ 216.1
230 kV Substation upgrade - Wawa	block	$ 750	1	$ 0.8
230 kV Substation upgrade - Marathon	block	$ 1,500	1	$ 1.5
230 kV Substation upgrade - Lakehead	block	$ 750	1	$ 0.8
New HVDC Converter Substation[3] - Wawa	block	$ 150,000	1	$ 150.0
New HVDC Converter Substation - Lakehead	block	$ 150,000	1	$ 150.0
			Total	**$ 519.1**

[3] The converter is assumed to use current source technology (thyristors), with a bipole configuration plus solid conductor return. The DC voltage is approximately +/- 50 kV.

Section 4. Conclusions

Pterra conducted a high level technical assessment of the various alternatives to the OPA's reference case. This included the reference case and the review of the following alternatives:

- Single circuit 345 kV
- Single circuit 500 kV
- HVDC (DC bipolar line with metallic return)

In order to evaluate the different transmission alternatives, Pterra developed the OPA reference case from the 2017 summer peak power flow model by substantially adjusting load and re-dispatching generation in the 2017 summer peak power flow model to model an expected increased peak load of 950 MW in the Northwest region and simulate a dry season loading condition which is characterized by a high transfer level across the East-West tie (approximately 600 MW) in the west direction and limited availability of the hydroelectric generation in the Northwest region, approximately 43% of its peak value of 780 MW.

Pterra conducted power flow analysis for steady state and P-V curves to determine if additional upgrades were needed for the different alternatives. Also, Pterra measured the transmission losses for each model. The 500 kV alternative shows the lowest line losses (12.5 MW) while the new 230 kV double circuit line from the reference case showed the highest line losses (23.3 MW). The reference case showed the highest MW losses in both the Northwest and Northeast (122 MW and 290 MW, respectively). The lowest losses for the Northwest region were observed in the HVDC option (84 MW); while for the Northeast region, the 345 alternative showed the least losses (248 MW).

The results of the assessment showed that:

- N-1 contingency analysis, for contingencies along the path of the east-west tie, was conducted; the results showed no post-contingency thermal criteria violations for any of the studied transmission alternatives; post-contingency flows in the 230 kV transmission system and above were within the LTE rating.
- The results of the P-V analysis showed that the reference case offers the highest voltage stability limit of 701 MW; while the 345 kV option showed the lowest limit of 601 MW; the 500 kV option provided a voltage limit of 637 MW while the HVDC alternative provided a voltage limit of 686 MW.

As for the cost estimates, the following table provides a summary of the cost associated with each alternative. These cost figures account for the right of way (ROW) requirement that is needed for each alternative (i.e., HVDC will require less of ROW versus for instance 500 kV option). Note that all the cost estimates assume lattice-type steel tower. Concrete towers at high voltage are used mostly in Canada; Pterra does not have cost information for this type of tower.

The Reference Case is offers the lowest estimated cost to install. The key reason for this is that the Reference Case does not utilize step up transformers to a higher voltage or DC converters. The 345 kV alternative is about $91 million more costly than the Reference Case and is the lowest cost among the study alternatives. The

500 kV and the HVDC cost $220 million and $245 million more, respectively, than the Reference Case.

Appendix A. Scaled Load in the Northwest Region

BUS#	BUS NAME	BASE KV	MW	MVAR	DIFF	MW	MVAR
	Thierry Mine	1	11.7	3	11.7	Connected to Crow River	
151647	MUSSELWHITE	13.8	40	5	40	0.0	0.0
151197	BARWICK_44KV	44	27.8	13.4552	10	17.8	8.7
151404	NWAM_RVR_TR	34.5	10	4.84	10	0	0.1
151406	LWR_NWAM_TR	34.5	10.1	4.8884	10	0.1	0.1
151407	UPR_NWAM_TR	34.5	10.1	4.8884	10	0.1	0.1
151450	LOWER-GEN1&2	4.16	10.1	4.8884	10	0.1	0.1
151452	UPPER-GEN1&2	13.8	10.1	4.8884	10	0.1	0.1
151467	HIGH_FLS_LD	25	10.5	5.082	10	0.5	0.3
151502	TROUT_LK_G	4.16	5.1	2.4684	5	0.1	0.1
151601	LAC_DES_ILT1	4.16	5.7	2.7588	5	0.7	0.3
151602	LAC_DES_T001	4.16	6.5	3.146	5	1.5	0.7
151603	LAC_DES_T002	4.16	6.5	3.146	5	1.5	0.7
151604	FT_FRANCS_L5	13.8	11.1	5	0.3	10.8	8.1
151605	AGIMAK_DS_B	24.9	6.4	3.0976	5	1.4	0.7
151606	FT_FRANC_L4A	13.8	18	8.712	5	13	2.7
151607	FT_FRANC_L4B	13.8	68	28	58.9	9.1	0
151608	FT_FRANCS_AB	6.6	11	4	1.7	9.3	13
151609	KENORA_MTSB2	12.5	9	4.356	5	4	1.9
151610	BEARDMORE_DS	24.9	5	2.42	5	0	0
151611	BIRCH_TS	24.9	55	26	2.3	52.7	16
151612	JELLICOE_#3	12.5	5.2	2.5168	5	0.2	0.1
151613	AINSWORTH	13.8	9.6	4.6464	5	4.6	2.2
151614	BURLEIGH_B	12.5	6.3	3.0492	5	1.3	0.6
151616	DOMTAR_DRYDN	13.2	11.1	5.3724	5	6.1	9.9
151617	BOWAT_KRAFT	13.8	5	2.42	5	0	0
151618	BOWAT_TB_L5B	4.16	11.2	5.4208	5	6.2	6.1
151619	BOWATR_TB_L8	4.16	6.2	3.0008	5	1.2	1.2
151620	BOWAT_TB_L10	4.16	5.7	2.7588	5	0.7	0.7
151621	BOWAT_TB_L11	4.16	5.7	2.7588	5	0.7	0.7
151622	BOWATR_TB_LT	13.8	13.4	6.4856	5	8.4	8.2
151623	NORAMPAC_CTS	6.9	5	2.42	5	0	0
151624	NORAMPAC_CTS	2.4	5	2.42	5	0	0
151625	DRYDEN_TS_Y	44	14.1	6.8244	5	9.1	0.1

BUS#	BUS NAME	BASE KV	MW	MVAR	DIFF	MW	MVAR
151631	ETON_B1B2	12.5	5.8	2.8072	5	0.8	0.4
151634	FT_FRANCS_TB	44	12.2	5.9048	5	7.2	3.5
151635	FT_FRANC_MS2	12.5	9.5	4.598	5	4.5	2.2
151636	FT_FRANC_MS1	12.5	9.5	4.598	5	4.5	2.2
151637	FT_WILLIAM	24.9	58.7	25.1	6.3	52.4	25.8
151639	MARATHN_PULP	13.8	5.2	2.5168	5	0.2	0.1
151640	WEYERHAU_KEN	13.8	12.8	6.1952	5	7.8	3.8
151642	KENORA_DS	12.5	8.5	4.114	5	3.5	1.7
151643	KENORA_MTSB1	12.5	16.9	8.1796	5	11.9	5.8
151644	TER_BAY_PULP	13.8	5.7	2.7588	5	0.7	0.3
151648	WILLIAM_M_L1	4.16	11.9	5.7596	5	6.9	3.4
151649	WILLIAM_M_L2	13.8	11.9	5.7596	4	6.9	3.4
151650	KENORA_MTSB3	12.5	2	0.968		0	2.3
151652	MANITOUWD_DS	12.5	5.4	2.6136	5	0.4	0.2
151653	MANITOUWADGE	44	8.7	4.2108	5	3.7	1.8
151655	MARATH_DS_25	24.9	6.9	3.3396	5	1.9	0.9
151658	MARGACH	24.9	7.9	3.8236	5	2.9	1.4
151659	MATTABI_CTS	4.16	5.5	2.662	5	0.5	0.2
151660	MINAKI_DS_B	24.9	5.3	2.5652	5	0.3	0.2
151661	INMET_WES_LK	2.4	5.1	2.4684	5	0.1	0
151664	MOOSE_LK_B2	44	6.3	3.0492	5	1.3	0.6
151665	MOOSE_LK_B3	44	6.3	3.0492	5	1.3	0.6
151668	MURILLO_DSB1	24.9	13.6	6.5824	5	8.6	4.2
151669	NESTOR_FLS_B	12.5	6.1	2.9524	5	1.1	0.5
151670	NIPIGNON_DS	4.16	6.4	3.0976	5	1.4	0.7
151671	XSTRADA_GECO	4.16	5.1	2.4684	5	0.1	0
151673	PERRAU_FLS_B	12.5	5.3	2.5652	5	0.3	0.2
151674	PIC_DS	24.9	6.7	3.2428	5	1.7	0.8
151675	PROV_PAP_S#1	4.16	5.2	2.5168	5	0.2	0.1
151677	KENORA_MSNL4	12.5	9	4.356	5	4	1.9
151678	KEEWATIN_DS	12.5	5	2.42	5	0	0
151682	RED_ROCK_DS	12.5	6.5	3.146	5	1.5	0.7
151685	SAM_LAKE_DS	24.9	13.2	6.3888	5	8.2	4
151686	SAPAWE_DS	12.5	5.3	2.5652	5	0.3	0.2
151687	SCHREIBER_DS	12.5	6.1	2.9524	5	1.1	0.5
151689	SHABAQUA_DS	12.5	6.2	3.0008	5	1.2	0.6
151691	LONGLAC_TSZ	44	9.9	4.7916	5	4.9	2.4
151692	SIOUX_NARROW	12.5	6.3	3.0492	5	1.3	0.6

BUS#	BUS NAME	BASE KV	MW	MVAR	DIFF	MW	MVAR
151693	ESKER	13.8	5	2.42	5	0	0
151694	DAVID_BELL	4.16	7.3	3.5332	5	2.3	1.1
151695	VALORA_DS	24.9	5.2	2.5168	5	0.2	0.1
151696	VERM_BAY_DS	12.5	5.2	2.5168	5	0.2	0.1
151697	WHITE_RIVER	24.9	5.7	2.7588	5	0.7	0.3
151698	GREENWITCHC1	34.5	5	2.42	5	0	0
151701	TCPL_VERML_X	4.16	5.1	2.4684	5	0.1	0.1
151702	CAT_LAKE_R1	24.9	5	2.42	5	0	0
151710	CLEARWATER	24.9	6.6	3.1944	5	1.6	0.8
151718	CROW_RIV_T13	27.6	0.75	0.35	0.35	0.4	0.2
151719	5.85	27.6	0.75	0.35	0.35	0.4	0.2
151728	AGUASABON_GS	13.8	6.3	1.59	5	1.3	0.6
151737	EAR_FALLS_TS	44	3.1	1.2	1.9	1.2	0.6
151750	STURGEON_FLS	6.6	7.1	3.4364	5	2.1	1
151752	WHITEDOG_GS	13.8	5.5	2.662	5	0.5	0.2
151758	PT_ARTHUR_#1	34.5	20	9	2.6	17.4	7.4
151759	RED_LAKE_TS	44	56	11.1	32	24	7.8
151769	SLATE_FALLS	24.9	5	2.42	5	0	0
Total			949.7		580.4	369.3	

Total Load in the Northwest Region in the 2017 Summer Model: 369.3 MW

Total Adjusted Northwest Load in the Created OPA Reference Case: 947.7 MW

Total Increase in the Northwest Load: 580.4 MW

Appendix B. Generation Re-Dispatch in the Northwest Region

BUS#	BUS NAME	BASE KV	Delta	PGEN-REF Case	PGEN	PGEN	PMAX	PMIN
151408	LWR_NWAM_G	4.16	0	2.8	2.8	2.8	2.8	0.3
151408	LWR_NWAM_G	4.16	0	2.8	2.8	2.8	2.8	0.3
151409	UPR_NWAM_G	4.16	0	2.2	2.2	2.2	2.2	0.2
151409	UPR_NWAM_G	4.16	0	2.2	2.2	2.2	2.2	0.2
151465	HIGH_FLS_GEN	4.16	0	3.2	3.2	3.2	3.2	0
151465	HIGH_FLS_GEN	4.16	0	3.2	3.2	3.2	3.2	0
151502	TROUT_LK_G	4.16	0	3.8	3.8	3.8	3.8	0
151616	DOMTAR_DRYDN	13.2	37	37	0	0	37.7	0
151617	BOWAT_KRAFT	13.8	34	34	0	0	34.2	0
151618	BOWAT_TB_L5B	4.16	7	17	10	10	17.1	0
151645	LAKEHEAD_T7	13.8	0	0	0	0	0	0
151646	LAKEHEAD_T8	13.8	0	0	0	0	0	0
151668	MURILLO_DSB1	24.9	0	0	0	0	5.3	0
151668	MURILLO_DSB1	24.9	0	0	0	0	5.3	0
151668	MURILLO_DSB1	24.9	5	5	0	0	5.3	0
151668	MURILLO_DSB1	24.9	-2.6	5	7.6	7.6	8.7	0
151700	AVEN_TBAY_G4	13.8	15	25	10	10	25.2	0
151708	MUSSELWHITE	4.16	1.3	1.3	0	0	1.3	0
151708	MUSSELWHITE	4.16	1.3	1.3	0	0	1.3	0
151720	ATIKOKAN_TGS	18	0	0	0	0	227	35
151722	THUN_BAY_GS2	18	-150	0	150	150	165	25
151723	THUN_BAY_GS3	18	-100	0	100	100	165	25
151731	CALM_LK_CGS	6.6	5	5	0	0	5	0
151731	CALM_LK_CGS	6.6	5	5	0	0	5	0
151735	CARIBOU_FLS	13.8	-6	14	20	20	25.7	0
151735	CARIBOU_FLS	13.8	-6	14	20	20	25.7	0
151735	CARIBOU_FLS	13.8	-7	13	20	20	25.7	0
151736	EAR_FALLS_GS	6.6	0	0	0	0	4.5	0
151736	EAR_FALLS_GS	6.6	0	0	0	0	4	0
151736	EAR_FALLS_GS	6.6	0.8	3.5	2.7	2.7	5.4	0
151736	EAR_FALLS_GS	6.6	0.5	3.5	3	3	5.4	0
151739	WESTCOAST_G2	13.8	1.4	49	47.6	47.6	49.4	0
151740	KENORA_CGS	2.4	0	10	10	10	10	0
151741	MAN_FLS_GS12	13.8	-3.2	10	13.2	13.2	14.4	0

BUS#	BUS NAME	BASE KV	Delta	PGEN-REF Case	PGEN	PGEN	PMAX	PMIN
151741	MAN_FLS_GS12	13.8	-3.9	9	12.9	12.9	14.4	0
151742	MAN_FLS_GS34	13.8	-4.1	9	13.1	13.1	14.4	0
151742	MAN_FLS_GS34	13.8	-6.9	5.7	12.6	12.6	14.4	0
151743	MAN_FLS_GS-5	13.8	-7.7	5.7	13.4	13.4	14.4	0
151744	NORMAN_CGS	6.6	2.1	13	10.9	10.9	13.2	0
151749	SILVER_FALLS	13.8	24	24	0	0	45	0
151750	STURGEON_FLS	6.6	4	4	0	0	4.1	0
151750	STURGEON_FLS	6.6	0	0	0	0	4.1	0
151752	WHITEDOG_GS	13.8	-9	11	20	20	21.6	0
151752	WHITEDOG_GS	13.8	11	11	0	0	21.6	0
151752	WHITEDOG_GS	13.8	-10	10	20	20	21.6	0
151753	VALERIE_FLS	4.16	3	3	0	0	4.1	0
151753	VALERIE_FLS	4.16	0	0	0	0	4.1	0
151763	LAC_SEUL_GS	13.8	1.1	12	10.9	10.9	12.2	0
151776	GREENWITCHG1	0.69	-10	0	10	10	25.3	0
151777	GREENWITCHG2	0.69	-5	0	5	5	23	0
151778	GREENWITCHG4	0.69	-5	0	5	5	25.3	0
151779	GREENWITCHG3	0.69	-5	0	5	5	25.3	0
Total			-182.9	390.2	573.1			

Total Generation in the Northwest Region in the 2017 Summer Model: 573.1 MW

Total Adjusted Northwest Generation in the Created OPA Reference Case: 390.2 MW

Total Reduction in Northwest Generation: 182.9 MW

Appendix C. Generation Re-Dispatch in the GLP Region

BUS#	BUS NAME	BASE KV	Delta	PGEN-REF Case	PGEN	PGEN	PMAX	PMIN
151450	LOWER-GEN1&2	4.16	-4.8	0	4.8	4.8	4.8	0
151450	LOWER-GEN1&2	4.16	-4.8	0	4.8	4.8	4.8	0
151451	LOWER-GEN3	0.6	-0.4	0	0.4	0.4	0.4	0
151452	UPPER-GEN1&2	13.8	-4.7	0	4.7	4.7	4.7	0
151452	UPPER-GEN1&2	13.8	-4.7	0	4.7	4.7	4.7	0
151453	UPPER-GEN3	0.6	-0.6	0	0.6	0.6	0.6	0
151600	UMBATTAFALLS	13.8	9	11	2	2	11.7	0
151600	UMBATTAFALLS	13.8	0	0	0	0	11.7	0
151644	TER_BAY_PULP	13.8	0	0	0	0	22.5	0
151644	TER_BAY_PULP	13.8	0	0	0	0	26.5	0
151728	AGUASABON_GS	13.8	10.5	10.5	0	0	20.2	0
151728	AGUASABON_GS	13.8	10.5	10.5	0	0	20.2	0
151729	ALEXANDER_GS	12	1.8	10	8.2	8.2	13.5	0
151729	ALEXANDER_GS	12	1	10	9	9	13.5	0
151729	ALEXANDER_GS	12	2.3	11	8.7	8.7	13.5	0
151729	ALEXANDER_GS	12	0	0	0	0	13.5	0
151729	ALEXANDER_GS	12	0	0	0	0	16.2	0
151730	WAWATAY_CGS	4.16	3	3	0	0	4.5	0
151730	WAWATAY_CGS	4.16	3	3	0	0	4.5	0
151730	WAWATAY_CGS	4.16	0	0	0	0	4.5	0
151732	CAMER_FLS_17	12	0	0	0	0	9.5	0
151732	CAMER_FLS_17	12	-0.2	20	20.2	20.2	20.7	0
151733	CAMER_FLS234	12	5	5	0	0	10.4	0
151733	CAMER_FLS234	12	0	0	0	0	12.3	0
151733	CAMER_FLS234	12	0	0	0	0	12.3	0
151734	CAMER_FLS_56	12	0.4	12	11.6	11.6	12.3	0
151734	CAMER_FLS_56	12	0	0	0	0	12.3	0
151745	PINE_PORT_G1	13.8	0	20	20	20	29.7	0
151746	PINE_PORT_G2	13.8	0	0	0	0	29.7	0
151747	PINE_PORT_G3	13.8	-7.2	22	29.2	29.2	34.7	0
151748	PINE_PORT_G4	13.8	-8	22	30	30	34.7	0
151751	TCP_NIPIGON	13.8	5.1	18	12.9	12.9	21.9	0
151751	TCP_NIPIGON	13.8	5.1	18	12.9	12.9	18.3	0
152625	DOM_ESPAN_G5	4.16	0	0	0	0	6.5	0

BUS#	BUS NAME	BASE KV	Delta	PGEN-REF Case	PGEN	PGEN	PMAX	PMIN
152743	AUBRY_FLS_G1	11	65	65	0	0	73	0
152744	AUBRY_FLS_G2	11	65	65	0	0	73	0
152770	RED_ROCK_GS	13.8	-11.7	0	11.7	11.7	20.8	0
152773	WELLS_GS-2	13.8	20	100	80	80	96.3	0
152775	WELLS_GS-1	13.8	20	100	80	80	96.3	0
152776	DOM_ESPANG89	13.8	-10	0	10	10	22.5	0
152811	MCPHAIL_G2	12	-1.6	0	1.6	1.6	5	0
152816	MISSIONFALLS	6.6	-4.5	0	4.5	4.5	13.9	0
152835	ALGOMA_STG34	11.5	12.5	12.5	0	0	20	0
152835	ALGOMA_STG34	11.5	12.5	12.5	0	0	20	0
151745	CLERGUE_G1	4.2	-3	13	16	16	16.4	0
152848	CLERGUE_G2	4.2	-1.8	13	14.8	14.8	17.3	0
152849	CLERGUE_G3	4.2	-3	13	16	16	16.4	0
152850	LAKESUPER_T1	13.8	3.7	40	36.3	36.3	47.1	0
152851	LAKESUPER_T2	13.8	8	40	32	32	47.1	0
152852	LAKESUPER_G1	13.8	2	22	20	20	25	0
152859	PRINCE_WF_1	0.575	-0.7	0	0.7	0.7	24	0
152860	PRINCE_WF_2	0.575	-0.7	0	0.7	0.7	24	0
152861	PRINCE_WF_3	0.575	-0.7	0	0.7	0.7	25.5	0
152862	PRINCE_WF_4	0.575	-0.7	0	0.7	0.7	25.5	0
152863	PRINCE_WF_5	0.575	-0.5	0	0.5	0.5	30	0
152864	PRINCE_WF_6	0.575	0	0	0	0	30	0
152865	PRINCE_WF_7	0.575	0	0	0	0	30	0
Total			191.1	702	510.9			

Total GLP Generation in the 2017 Summer model: 510.9 MW

Total Adjusted GLP generation in the Created OPA Reference Case: 702 MW

Total Increase in GLP Generation: 191.1 MW

Appendix D. List of Added Capacitors to the OPA Reference Case

BUS#	BUS NAME	BASKV	MVAR
151229	FT_FRANC_F2B	118.05	43.7 MVAR
151054	LAKEHEAD_TS	220	125 MVAR
151205	LAKEHEAD_TS	118.05	82.95 MVAR
151759	RED_LAKE_TS	44	16.5 MVAR
151708	MUSSELWHITE	4.16	31.2 MVAR
151323	SELCO_J	118.05	8.8 MVAR
151201	BIRCH_TS	118.05	67 MVAR
152117	THRDLINEP22G	220	22.9 MVAR
152118	THRDLINEP21G	220	23 MVAR

Appendix 12: IESO Feasibility Study

The IESO Feasibility Study is attached.

CONFIDENTIAL **REP-3**

Feasibility Study

Power to Ontario.
On Demand.

An assessment of the westward transfer capability of the East-West Tie following its reinforcement with a ± 300kV HVdc Link between Wawa TS & Lakehead TS

1.0

Upper Canada Transmission Inc.

A study to review the performance of an HVdc Link to reinforce the existing East-West

CAA ID No 2012-479 *FINAL VERSION* *17th December 2012*

FEASIBILITY STUDY FOR UPPER CANADA TRANSMISSION INC. 1
STUDY REPORT 1
1. *Introduction* 1
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3. *Conductor Size proposed for the HVdc Link* 4
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5. *Assumed Layouts for the Terminal Stations* 4
5.1 At Wawa TS 5
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FEASIBILITY STUDY FOR UPPER CANADA TRANSMISSION INC.

STUDY REPORT

1. Introduction

This report examines the ability of a ± 300kV HVdc Link between Wawa TS and Lakehead TS, when operated in parallel with the existing East-West Tie, to achieve the targeted transfer of 650MW westwards, while respecting all NERC, NPCC & IESO reliability standards.

2. Conclusions

The conclusions are as follows:

- The analysis showed that with the proposed HVdc link operating at a voltage of ± 300kV and with the HVdc converters rated at around 750MVA, it would be possible to achieve the targeted transfer of 650MW westwards.

  [Although the analysis was performed with the rating of the HVdc converters increased to 800MVA, this was found to provide 'excess' margin, beyond the 5% margin required by the IESO's criteria. During the design phase, once all the parameters for the HVdc Link have been finalised, it is expected that further analysis would be performed to optimise the rating of the converters.]

- Under normal system conditions, with all transmission elements in-service and with the HVdc Link carrying approximately half the East-West Tie transfer of 650MW, the combined transmission losses for the north-west zone would be reduced by approximately 5MW from those recorded with the proposed *`ac Reference Case`* reinforcement of the East-West Tie.

- Under post-contingency conditions with either the Wawa x Marathon section or the Marathon x Lakehead section of the existing East-West Tie out-of-service, the combined losses for the north-west zone would be reduced by approximately 30MW, compared to those obtained for the *`ac Reference Case`* reinforcement.

- Following a contingency involving either the Wawa x Marathon section or the Marathon x Lakehead section of the existing East-West Tie, facilities would need to be available to automatically increase the transfer on the HVdc Link to minimise the transfers via the Interconnections with Manitoba & Minnesota.

- An SVC with a minimum rating of +250/-100MVAr would be required at Marathon TS to achieve an adequate voltage stability limit to support the East-West Tie transfer following the loss of the entire HVdc Link. This would represent an increase of 50MVAr over the 200MVAr rating proposed for the 230kV *'ac Reference Case'.*

- A 230kV-connected shunt capacitor rated at 125MVAr (at 250kV) would also be required at Lakehead TS. This would be the same requirement that was identified in the original Feasibility Study report.

- Since the most critical contingency would involve the loss of the HVdc converters at Wawa TS, it has been concluded that there is no compelling argument for requiring HVdc breakers to be included in the design of the HVdc link to reinforce the existing East-West Tie.

Requirements:

- A control system for the HVdc Link to allow automatic adjustment of the transfer level following a contingency involving either the Wawa x Marathon or the Marathon x Lakehead sections of the existing East-West Tie to minimise the effect that contingencies involving the existing East-West Tie would have on the transfers across the Interconnections with Manitoba & Minnesota.

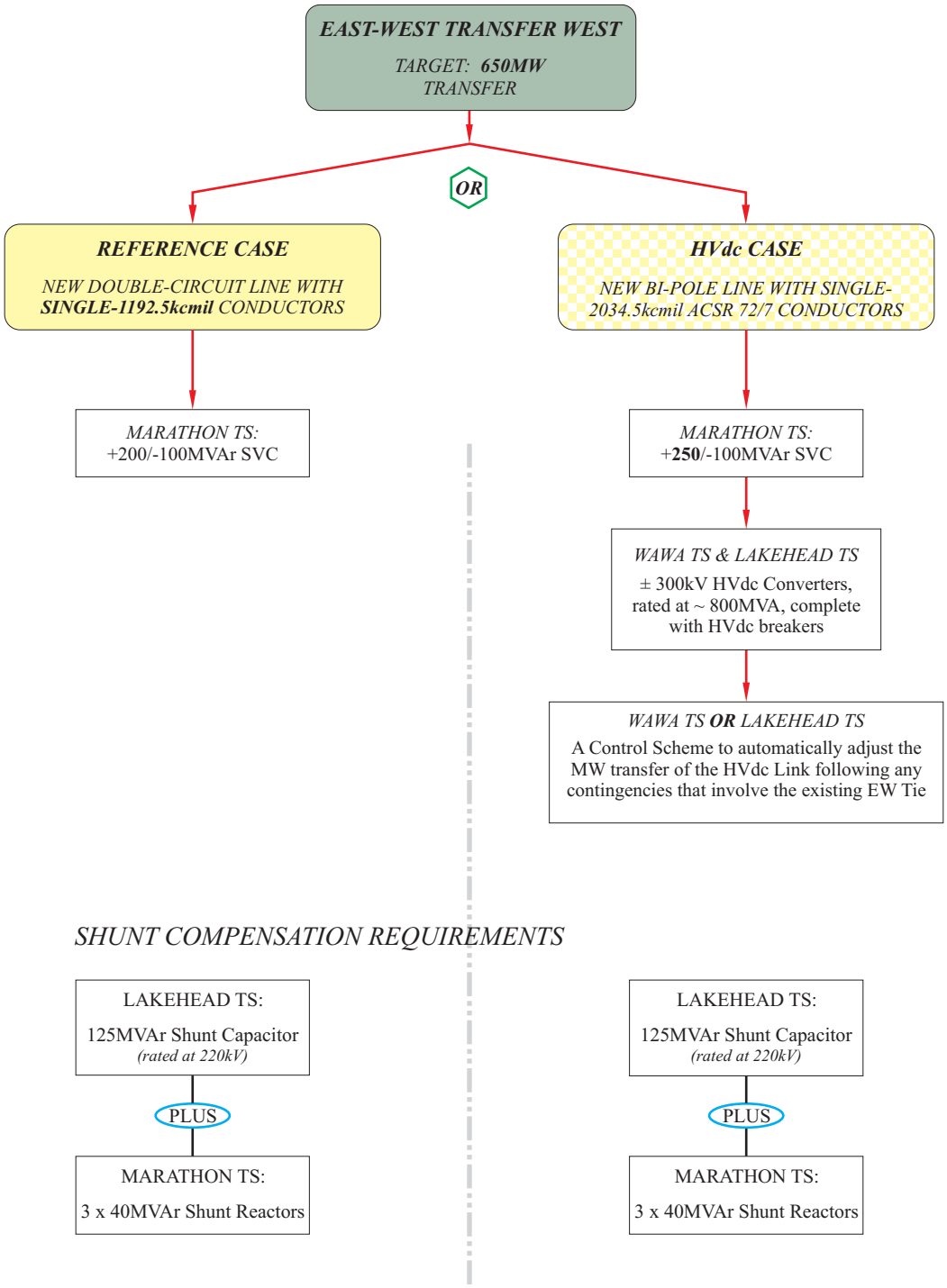
- A reactor/capacitor switching scheme. The requirement for this scheme was identified in the original Feasibility Study report and it is to include facilities to initiate cross-tripping of the 115kV circuit B6M following contingencies involving the 230kV double-circuit line between Lakehead TS & Mackenzie TS.

  The principal justification for this scheme was a need to initiate switching of the shunt capacitor banks following a possible separation of the system between Lakehead TS & Mackenzie TS. Under conditions when high transfers are being made westwards, the separation of this interface would unload the system through to Lakehead and result in higher than acceptable voltages.

  It is recommended that the scope of this scheme be expanded to include automatic switching of the shunt reactors at Wawa TS and Marathon TS following a contingency involving the proposed HVdc Link to increase the reactive power available to support voltages at the critical Wawa 230kV busbar.

- Since NW Ontario is prone to high levels of geo-magnetically induced currents (GICs) and past experience has shown that they can cause adverse effects in devices that combine power electronics and transformers like HVdc and SVC installations, it is recommended that the components of the HVdc Link satisfy the same GIC withstand capability standards as those of Hydro One.

The principal requirements for the HVdc option have been summarised in **Figure 1**. For comparison, the requirements for the *ac Reference Case* have also been included in this Figure



SUMMARY OF THE REINFORCEMENT OPTIONS

FIGURE 1

SVC Static VAr Compensator

3. Conductor Size proposed for the HVdc Link

Upper Canada Transmission Inc. is proposing to equip the HVdc Link with Mockingbird conductors with the following parameters. It is also understood that *Upper Canada Transmission Inc.* is proposing to equip the neutral connection of the HVdc Link with the same size conductor, which would improve the performance of the HVdc Link in a monopole mode. Since possible monopole operation of the HVdc Link is considered to be outside the scope of this study, this mode of operation has not been assessed:

Conductors Size proposed for the HVdc Link			
Rating required for a post-contingency transfer of ~ 665MW at Wawa TS [at 600kV]			~ 1110A
Mockingbird 2034.5kcmil ACSR 72/7 stranding			
Ratings at an ambient temperature of 30°C & a wind speed of 0-4km/hr	Continuous rating at 93°C		2040A
	Long-term emergency rating at 127°C		2660A
Conductor resistance at 50°C	0.03206Ω/km	2 x 400km loop impedance	25.65Ω

The ratings provided above show that, following a double-circuit contingency involving the Wawa-to-Marathon section of the existing East-West Tie, when the entire East-West Tie transfer would be carried by the HVdc Link, the Mockingbird conductors would be more than adequate to accommodate the expected peak post-contingency transfer.

4. Modelling of the HVdc Converters & the Marathon SVC

Diagram A-1 of Appendix A shows the capability curve for the Voltage Source Converters (VSCs) that it is proposed to install at Wawa TS & Lakehead TS and it also provides a summary of the parameters used to represent the HVdc Link in the analysis.

The parameters that were used in the dynamic model *VSCDCT* to represent the VSCs in the transient stability studies have been summarised in **Table A-1** of Appendix A.

Similarly, the parameters used in the dynamic model *CHSVCT* to represent the Static VAr Compensator (SVC) at Marathon TS in the transient stability studies have been summarised in **Diagram A-2**.

With the addition of the HVdc Link, the reference voltage for the two SVCs at Lakehead TS was changed to be that of the 115kV busbar. This was done to avoid possible conflict between the HVdc converter and the two SVCs at Lakehead TS should they all be attempting to control the voltage of the 230kV busbar at Lakehead TS.

5. Assumed Layouts for the Terminal Stations

Diagram 1 shows the detailed arrangement of the HVdc converters together with the associated step-up transformers and the switching arrangements assumed at each of the terminal stations of the HVdc Link.

Upper Canada Transmission Inc. has informed the IESO that the respective terminals at Wawa TS & Lakehead TS for the HVdc connection are to be equipped with HVdc breakers so that any contingencies involving the 400km line could be isolated without removing either of the converters from service.

It is expected that the facilities for each terminal of the HVdc Link will be located within a proponent-owned compound, in close proximity to the existing Hydro One switchyards at Wawa TS and Lakehead TS.

Expansion of the existing station layouts at Wawa TS and Lakehead TS will be required to accommodate the connections between the facilities in the proponent-owned compounds and the existing Hydro One switchyards. Additional changes will also be required at Lakehead TS for the incorporation of the new 230kV-connected shunt capacitor bank.

At Marathon TS, changes will also be required to accommodate the new SVC.

It has been assumed that while this work is being done, other changes, as detailed below, would be completed at each of the existing stations to limit the effects of breaker-failure conditions that could adversely affect the transfer capability of the reinforced East-West Tie.

5.1 At Wawa TS

Diagram 2 shows the addition of one 230kV breaker in the existing ring busbar together with two new 230kV diameters, each equipped with two 230kV breakers.

It also shows the transposition of the existing terminations of circuits W21M & W23K. This is considered to be necessary to avoid the simultaneous loss of the two 'eastward' circuits, P25W & W23K, due to a failure of breaker L23L25.

The new diameter, to which circuit W23K is shown to be connected, together with the additional breaker in the existing ring busbar will eliminate the present use of shared terminations for the two 230/115kV auto-transformers while also reducing the severity of the remaining breaker-failure conditions. With the two auto-transformers separately terminated, normally-cleared double-circuit contingencies involving circuits P25W & P26W or W21M & W22M will no longer result in the simultaneous loss of one of the 230/115kV auto-transformers at Wawa TS together with the reactive compensation connected to its tertiary winding.

The second two-breaker diameter provides the termination point for the connection to the proponent-owned terminal station of the proposed HVdc Link.

Additional Facilities required:

- Five new 230kV breakers
- Two new 230kV diameters
- The interchange of the 230kV circuits W21M & W23K
- The termination of the single 230kV connection to the UCTI-owned switchyard for the HVdc Link

5.2 At Marathon TS

With the existing layout at Marathon TS, the two 230/115kV auto-transformers are each shown to share its terminal position with that of a 230kV circuit.

Diagram 3 shows the addition of two 230kV breakers in the existing ring-busbar to allow the terminations of circuits W21M & M23L to be separated from those of the two 230/115kV auto-transformers. It also shows the addition of a new two-breaker diameter for the connection of the new SVC at Marathon TS.

These additional facilities will avoid the simultaneous loss of one of the 230/115kV auto-transformers at Marathon TS together with the isolation of one of the 230kV circuits in response to a double-circuit contingency involving either circuits W21M & W22M or circuits M23l & M24L.

Additional Facilities required:

- Four new 230kV breakers
- One new 230kV diameter
- One 230kV-connected SVC - nominal rating: +250/-100MVAr

5.3 At Lakehead TS

Diagram 4 shows the addition of one new 230kV breaker in the existing ring-busbar to accommodate the 230kV-connected shunt capacitor bank that will be required at Lakehead TS for the higher East-West Tie transfers. A new, dedicated two-breaker diameter has also been shown for the connection to the proponent-owned terminal station of the proposed HVdc Link.

Additional Facilities required:

- Three new 230kV breakers
- One new 230kV diameter
- One 230kV-connected shunt capacitor bank - nominal rating: 125MVAr
- The termination of the single 230kV connection to the UCTI-owned switchyard for the HVdc Link

Following the implementation of the proposed enhancements at Wawa TS, Marathon TS & Lakehead TS, double-circuit contingencies involving either of the existing lines between Wawa TS & Marathon TS and Marathon TS & Lakehead TS would no longer result in the simultaneous loss of any of the auto-transformers at any of the three terminal stations. Although breaker-failure conditions would still result in the loss of a single 230kV circuit and an auto-transformer, or an eastward circuit with a westward circuit, none of these conditions would be more limiting than the corresponding double-circuit contingencies.

6. Failure Modes that were assessed for the Proposed HVdc Link

Diagram 5 shows the three principal failure modes of the HVdc Link that were assessed:

- Loss of the Wawa converter: the Lakehead converter would remain in-service.
- Loss of the Lakehead converter: the Wawa converter would remain in-service.
- Loss of the HVdc line: both the Wawa & Lakehead converters would remain in-service.

Although it would not be considered a viable condition due to the inclusion of the HVdc breakers in the design of the HVdc Link, additional studies were performed to examine the effect of the loss of the *entire* HVdc Link, including both converters.

7. Reference Cases from the East-West Tie Feasibility Study of 18th August 2011

Diagrams 6, 7 & 8 *(reproduced from Diagrams 5, 7 & 10 of the original East-West Tie Study Report)* show the pre- and post-contingency study results for an initial East-West Tie transfer of 652MW.

The relevant details from each of these studies are summarised in the following **Table**:

TABLE 1	*Study Results for the 'Reference Case'*					*Feasibility Study Report - 18th August 2011*
	East-West Tie Transfer	*Westward Flow into Lakehead/Alexander*		*Imports*		*∑ NW Transmission Losses*
Diagram 6	652MW	L: 529MW	∑ 552MW	Manitoba:	3.4MW	92MW
Pre-contingency		A: 23MW		Minnesota:	2.2MW	
Diagram 7	668MW	L: 515MW	∑ 536MW	Manitoba:	18.0MW	123MW
Post-contingency Wawa x Marathon	*Δ +16MW*	A: 21MW	*Δ -16MW*	Minnesota:	2.5MW	*Δ +31MW*
Diagram 8	673MW	L: 487MW	∑ 543MW	Manitoba:	14.6MW	124MW
Post-contingency Marathon x Lakehead	*Δ +21MW*	A: 56MW	*Δ -9MW*	Minnesota:	2.4MW	*Δ +32MW*

8. Reference Case for the UCTI Study

The Reference Case for this study, for which the results are summarised in **Diagram 9**, was produced by adjusting the transfers on the HVdc Link to achieve similar transfers on the existing 230kV double-circuit line between Wawa TS & Marathon TS (circuits W21M & W22M) as those shown in **Diagram 6**.

The principal transfers from each of the 'Reference Cases' are summarised in the following **Table**:

TABLE 2	*Comparison of the 'Reference Cases'*					
	East-West Tie Transfer	*Westward Flow into Lakehead/Alexander*		*Imports*		*∑ NW Transmission Losses*
Reference Case:	*New 230kV double-circuit line between Wawa TS & Lakehead TS, via Marathon TS*					
Diagram 6	**652MW**	Lakehead: 529MW	∑ **552MW**	Manitoba:	3.4MW	92MW
Pre-contingency		Alexander: 23MW		Minnesota	2.2MW	
UCTI Reference Case:	*New HVdc Link between Wawa TS & Lakehead TS.*		*Operating at ± 300kV*			
Diagram 9	**647MW** *Δ -5MW*	Lakehead ac: 234MW Lakehead dc: 300MW	∑ **551MW**	Manitoba:	3.6MW	87MW
Pre-contingency	*ac: 333MW* *dc: 314MW*	Alexander: 17MW		Minnesota	2.3MW	*Δ -5MW*

The results show that with the HVdc Link carrying 314MW of the total East-West Tie transfer of 647MW, there would be a net reduction in the transmission losses within the north-west zone of approximately 5MW from those recorded for the *ac Reference Case*.

9. Contingency Studies

Since the revised layouts proposed for Wawa TS, Marathon TS & Lakehead TS would reduce the effect of breaker-failure conditions to the loss of just a single circuit and an auto-transformer, or to the simultaneous loss of an eastward 230kV circuit with a westward circuit, the analysis for this study has therefore been limited to the following contingency conditions. These would represent the more onerous contingencies for that section of the East-West Tie between Wawa TS & Lakehead TS:

1. A double-circuit contingency involving the existing line between Wawa TS & Marathon TS:
   Loss of circuits W21M & W22M
2. A double-circuit contingency involving the existing line between Marathon TS & Lakehead TS:
   Loss of circuits M23L & M24L
3. The loss of the entire HVdc Link between Wawa TS and Lakehead TS, including the two converters:

   *With the inclusion of HVdc breakers at each terminal station as shown in **Diagram 1**, this would not be a credible contingency. It has been included as a reference for the following two contingency conditions.*
4. The loss of the HVdc converter at Wawa TS
   The companion HVdc converter at Lakehead TS was assumed to remain in-service
5. The loss of the HVdc converter at Lakehead TS
   The companion HVdc converter at Wawa TS was assumed to remain in-service

For each of the double-circuit contingencies, the post-contingency transfer on the HVdc Link was increased to achieve post-contingency transfers of approximately 0MW across the Manitoba & Minnesota Interconnections.

9.1 Summary of the Study Results: Load Flow Analysis

TABLE 3	***Summary of Study Results - 230kV ac Contingencies***						
Study Reference		*Transfer on HVdc Link at Wawa TS*	*Transfer across East-West Tie*	*Flow on 115kV cct T1M*	*Transfers across the Interconnections*		*∑ NW Transmission Losses*
Diagram	*Reinforcement Case*				*Manitoba*	*Minnesota*	
Contingency Condition: Wawa x Marathon double-circuit							
Diagram 7	Ref Case: 230kV ac	-	669MW	56MW	18MW	3MW	123MW
Diagram 10	HVdc: ± 300kV	663MW	663MW	11MW	-3MW	-2MW	92MW
						Change in Losses:	*Δ -31MW*
Contingency Condition: Marathon x Lakehead double-circuit							
Diagram 8	Ref Case: 230kV ac	-	673MW	97MW	15MW	2MW	124MW
Diagram 12	HVdc: ± 300kV	607MW	659MW	27MW	-9MW	2MW	87MW
						Change in Losses:	*Δ -37MW*

i. For a double-circuit contingency involving the Wawa x Marathon section of the existing East-West Tie

For this contingency, which would leave Marathon TS radially connected to Lakehead TS, the +250/-100MVAr SVC at Marathon TS was shown to have sufficient absorption capability to maintain acceptable post-contingency voltages without requiring the two tertiary-connected shunt capacitor banks to be automatically tripped.

Following this contingency, the post-contingency transfer on the HVdc Link was immediately increased to 620MW. This resulted in a combined post-contingency transfer of just 5MW across the Manitoba & Minnesota Interconnections.

The results also show that with the HVdc Link carrying all of the post-contingency transfer across the East-West Tie, the losses would be reduced by approximately 31MW from those recorded for the *ac Reference Case*.

ii. For a double-circuit contingency involving the Marathon x Lakehead section of the East-West Tie

Similarly, automatic tripping of the two tertiary-connected shunt capacitor banks at Marathon TS was not found to be necessary for this contingency.

Following this contingency, due to the presence of the parallel 115kV path between Marathon TS & Lakehead TS, via Alexander TS, it was possible to maintain the combined transfer across the Manitoba & Minnesota Interconnections at 7MW by increasing the post-contingency transfer on the HVdc Link to only 570MW.

With a portion of the post-contingency East-West Tie Transfer being carried via this parallel 115kV connection, the reduction in the transmission losses for the north-west zone, when compared to those obtained for the *ac Reference Case*, totalled 37MW.

TABLE 4 **Summary of Study Results - HVdc Contingencies**

Diagram No.	*SVC & Converter Reactive Outputs*				*East-West Tie Transfer*	*Flow on 115kV cct T1M*	*Transfers across the Interconnections*		*∑ NW Transmission Losses*
	Marathon SVC	*Lakehead SVCs*	*Wawa Converter*	*Lakehead Converter*			*Manitoba*	*Minnesota*	
Contingency Condition 1: Loss of the entire HVdc Link, including both converters									
Diag. 14	250MVAr *SVC limit*	34MVAr	0MVAr	0MVAr	651MW	89MW	54MW	3MW	141MW
Contingency Condition 2: Loss of the HVdc Link - with the converters at both Wawa & Lakehead remaining in-service									
Diag. 16	222MVAr	19MVAr	20MVAr	-16MVAr	654MW	89MW	53MW	3MW	144MW
Contingency Condition 3: Loss of the Wawa HVdc Converter									
Diag. 18	249MVAr	19MVAr	0MVAr	-19MVAr	651MW	89MW	54MW	3MW	143MW
Contingency Condition 4A: Loss of the Lakehead HVdc Converter – with a new 125MVAr capacitor at Lakehead									
Diag. 20	223MVAr	35MVAr	18MVAr	0MVAr	653MW	89MW	52MW	3MW	142MW
Contingency Condition 4B: Loss of the Lakehead HVdc Converter – with no new 230kV capacitor at Lakehead TS									
Diag. 22	248MVAr	120MVAr *SVC Limit*	16MVAr	0MVAr	651MW	90MW	54MW	4MW	142MW

For the four conditions that examined the loss of all, or part, of the HVdc connection between Wawa TS & Lakehead TS, the results shown above reveal that the post-contingency flows on the EW-Tie; on the 115kV path associated with circuit T1M; and on the Interconnections with Manitoba & Minnesota would remain essentially the same for each condition.

The results also confirm the need for the rating of the SVC at Marathon TS to be increased to *250MVAr* since its post-contingency output (even before margin is applied for voltage stability) is shown to be well in excess of the 200MVAr rating that had been assumed for the *ac Reference Case*.

For each of the conditions examined, the Table also shows the combined reactive output of the SVCs at Lakehead as well as the reactive outputs of the HVdc converters at Wawa TS & Lakehead TS.

The final two entries in the Table above are for the same contingency condition (the loss of the Lakehead HVdc converter) but with, and without, a new 125MVAr shunt capacitor installed at Lakehead TS. These show that omitting the proposed 125MVAr capacitor bank would not only increase the post-contingency output of each of the SVCs at Lakehead TS to 60MVAr (representing a combined increase of 85MVAr), but would also increase the output of the SVC at Marathon TS to 248MVAr (representing an increase of 25MVAr).

Since the SVCs at Lakehead TS would already be at their maximum output, and the output of the SVC at Marathon TS would be just 2MVAr below its rated maximum, there would be very little reactive support remaining available to provide the required 5% margin.

It should also be noted that for any outage involving one of the HVdc converters, the associated 33MVAr capacitive filters at that terminal would also be automatically removed from service.

9.2 Summary of the Study Results: PV-Analysis

9.2.1 ac Contingencies involving the existing East-West Tie circuits

i. Wawa x Marathon Double-circuit Contingency

With the post-contingency transfer on the HVdc Link adjusted to 620MW (monitored at the Lakehead terminal) so as to maintain approximately zero transfers across the Manitoba & Minnesota Interconnections, the corresponding transfer at Wawa TS increased to approximately *663MW,* to account for the HVdc transmission losses.

The initial PV-analysis terminated at an East-West Tie transfer of 681MW, when the transfer through the HVdc converters exceeded their assumed rating of 731MVA. After allowing for the required 5% margin, this would have provided a Voltage Stability Limit of only *646MW* which would have been insufficient to support the post-contingency transfer of *663MW* that is shown in **Diagram 10**.

With the rating of the HVdc converters increased to a *nominal* value of 800MVA, the transfer level at which the PV-analysis terminated was improved but, once again, the PV-analysis was found to terminate when the transfer on the HVdc Link exceeded the new 800MVA rating of the converters.

The results of this PV-analysis are summarised in **Diagram 11** and they show that, when the enhanced rating of the converters had been reached and the analysis terminated, reactive support would still remain available at each of the monitored sources.

Diagram 11 shows the transfer at which the PV-analysis terminated *(773MW)* and the corresponding Voltage Stability Limit *(734MW)* after allowing for a margin of 5% as required by the Ontario Resource & Transmission Assessment Criteria (ORTAC).

An additional line has been added to this Diagram to show the *minimum* Voltage Stability Limit *(698MW)* that would be necessary to provide the required margin of 5% on the post-contingency East-West Tie transfer of *662.8MW* (from **Diagram 10**).

ii. Marathon x Lakehead Double-circuit Contingency

The rating of the converters was similarly increased to 800MVA for the PV-analysis for this contingency condition.

The results have been summarised in **Diagram 13**. This shows that although the PV-analysis terminated when the transfer through the Wawa converter exceeded its increased rating of 800MVA, the corresponding East-West transfer was higher at *814MW* due to a portion of this transfer being carried via the parallel 115kV connection between Marathon TS & Lakehead TS, via Alexander TS.

The corresponding Voltage Stability Limit would be *773MW* which would be well in excess of the *minimum* value required *(694MW)* to provide the required margin of 5% on the post-contingency East-West Tie transfer of *659.4MW* (from **Diagram 12**).

The results for the contingency involving the existing East-West Tie are summarised in the following **Table**:

TABLE 5	***Summary of Study Results – Voltage Stability Limits for Contingencies on the existing EW Tie***			
Diagram No.	*Contingency*	*Post-contingency transfer through HVdc Link*	*East-West Tie Transfer*	
			Post-contingency	*PV-analysis terminated*	*Voltage Stability Limit*
Diag. 11	W21M + W22M double-circuit	620MW	663MW	773MW	734MW *Δ: 71MW*
Diag. 13	M23L + M24L double-circuit	570MW	659MW	814MW	773MW *Δ: 114MW*

9.2.2 dc Contingencies involving the HVdc Link

The following Table summarises the results of the PV-analysis for different contingencies involving the HVdc Link.

TABLE 6	***Summary of Study Results – Voltage Stability Limits for Contingencies Involving the HVdc Link***					
Diagram No.	*Contingency*		*Status of the HVdc Converters*	*East-West Tie Transfer*		
				Post-contingency	*PV-analysis terminated*	*Voltage Stability Limit*
Diag. 15	Loss of the entire HVdc Link		Both converters out-of-service	***651MW***	686MW	***652MW*** *Δ: 1MW*
Diag. 17	Loss of the HVdc line		Both converters in-service	654MW	785MW	745MW *Δ: 91MW*
Diag. 19	Loss of the Wawa converter		Lakehead converter in-service	651MW	690MW	655MW *Δ: 4MW*
Diag. 21	Loss of the Lakehead converter	With a 125MVAr cap at Lakehead TS	Wawa converter in-service	653MW	740MW	703MW *Δ: 50MW*
Diag. 23		With no cap bank at Lakehead TS		***651MW***	676MW	***642MW*** ***Δ: -9MW***

The results above show that without a new 125MVAr capacitor bank at Lakehead TS (**Diagram 23**), it would not be possible to provide the 5% margin required for voltage stability following a contingency involving the *Lakehead* HVdc converter.

With a 125MVAr shunt capacitor bank installed at Lakehead TS, the results show that the loss of the *Wawa* HVdc converter, either independently (**Diagram 19**) or with the entire HVdc Link if no HVdc breakers are installed (**Diagram 15**), would then represent the most severe contingency condition. With both a 125MVAr capacitor bank at Lakehead & a +250/-100MVAr SVC at Marathon TS, it would therefore be possible to just meet the requirement for a 5% margin.

Although the proposed facilities would provide the required margin and satisfy criteria, further margin could be provided by placing the tertiary-connected reactors & capacitors at Wawa TS in-service pre-contingency (effectively neutralising their reactive output) and then automatically tripping the two reactors immediately post-contingency.

For contingencies involving the loss of the HVdc converter at Lakehead TS, the results show that with the 125MVAr capacitor installed at Lakehead TS (**Diagram 21**), the two tertiary-connected SVCs would then be able to provide additional reactive support. This would result in an increased voltage stability limit that would provide additional margin beyond the minimum of 5% required under the criteria.

It should be noted, however, that to achieve the additional margins indicated in Table 6, the HVdc converters were assumed to be rated at 800MVA.

Since the results summarised in Table 5 show that an increase to 800MVA in the rating of the HVdc converters would provide 'excess' margin, beyond the minimum margin of 5% required under the IESO's criteria, a lower rating (possibly around 750MVA) should therefore be sufficient for the converters.

It is expected that the optimal rating for the converters would be determined during the design phase, once all the other parameters for the HVdc Link have been finalised.

9.3 HVdc Breakers

Diagram 5 showed the three possible failure modes of the HVdc Link that could occur if HVdc breakers were to be installed at each terminal. Since the existing NERC, NPCC & ORTAC planning criteria all require the 'simultaneous permanent loss of both poles of a direct current bi-polar facility' to be respected, this means that the loss of the entire converter facility at either terminal of the HVdc Link must be considered.

With HVdc breakers installed, the loss of the entire converter facility at one of the terminals would still leave the converter facility at the remote terminal available to provide reactive support. However, the analysis has shown that this would have a negligible effect at the faulted terminal and provide no material increase in the transfer capability of the East-West Tie.

For contingencies that involve the actual HVdc line, the installation of HVdc breakers has been shown to result in an increase of almost 100MW in the East-West Tie transfer capability by allowing the converters at both terminals to remain in-service post-contingency. However, since the East-West transfer limit would need to respect the most-severe contingency, which would involve the loss of the converters at Wawa TS, then it is not apparent how the increased transfer capability would be beneficial.

It has therefore been concluded that there is no compelling argument for requiring HVdc breakers to be included in the design of the HVdc link to reinforce the existing East-West Tie.

9.4. Conclusions from the Contingency Analysis

The following Table summarises the conclusions from the Contingency Analysis.

TABLE 7	***Conclusions from the Contingency Analysis***	*East-West Tie Transfer Limit*
ac Contingencies		
Wawa-to-Marathon double-circuit	HVdc converter rating increased to 800MVA	734MW
Marathon-to-Lakehead double-circuit		773MW
• *The most-limiting ac Contingency: the Wawa-to-Marathon section of the existing EW-Tie*		
HVdc Contingencies		
Loss of the entire HVdc Link – no HVdc Breakers		***652MW***
Loss of the actual HVdc line – both HVdc converters remain in-service		745MW
Loss of the Wawa HVdc converters – the Lakehead HVdc converters remain in-service		***655MW***
Loss of the Lakehead HVdc converters – the Wawa HVdc converters remain in-service		703MW
• *The most-limiting dc contingency: either the loss of the Wawa converter OR the entire HVdc Link.*		

These results show that the proposed HVdc Link for reinforcing the existing East-West Tie, together with a 125MVAr shunt capacitor at Lakehead TS and a +250/-100MVAr SVC at Marathon TS, would satisfy the requirement to increase the transfer capability of the East-West Tie to 650MW.

10. Transient Stability Analysis

Transient Stability studies were performed for each of the contingency conditions listed in Table 6.

In the model used for this analysis, the transfer across the East-West Tie was increased to 715MW through the addition of negative load to provide the 10% margin on the most critical transfer, as required by ORTAC.

The times assumed for the transient stability analysis were as follows:

Fault applied:	0.100 sec	
Fault cleared at local terminal:	0.183 sec	Δ + 83ms
Fault cleared at remote terminal:	0.241 sec	Δ + 58ms

Table 8 shows that the maximum deviation recorded in the rotor angular swing (141°) was recorded at Pine Portage GS for a double-circuit contingency at the Marathon terminals of circuits W21M & W22M.

The detailed response for this particular contingency is shown **Diagram 24**.

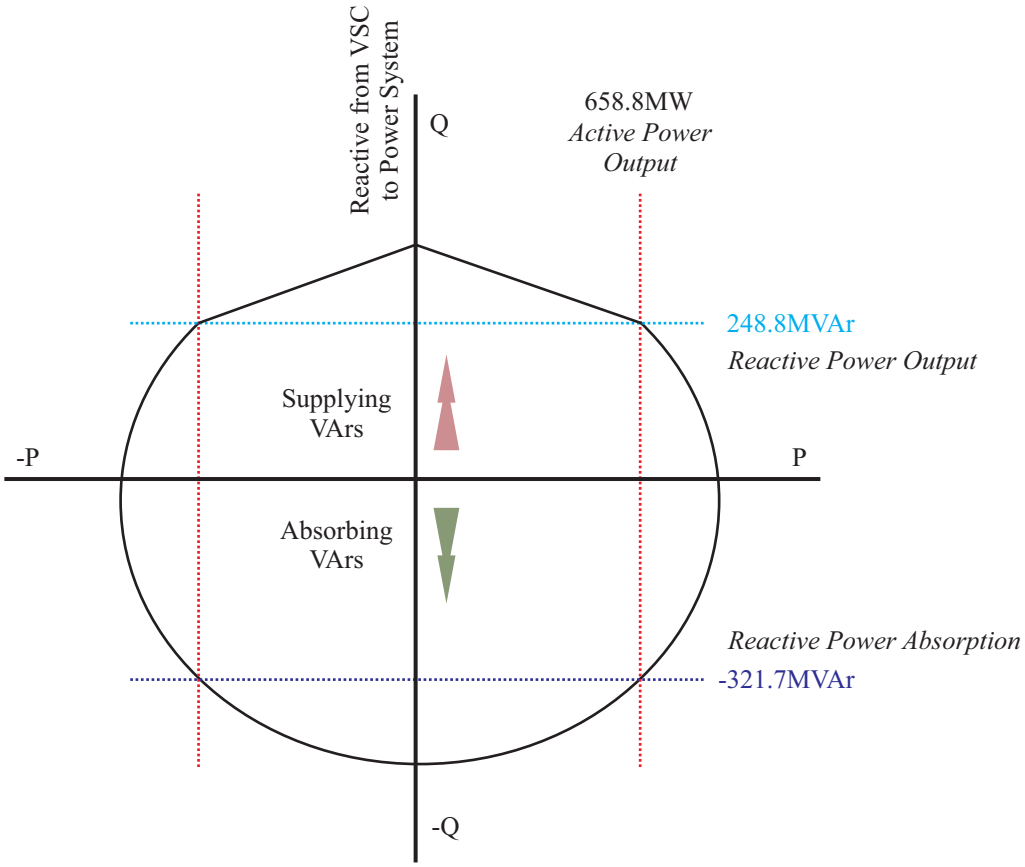
For this contingency and all the others that were studied, the transient stability and post-contingency damping requirements stipulated in ORTAC were satisfied.

It was therefore concluded that transient stability would not be the limiting phenomena of the proposal to reinforce the East-West Tie to achieve an enhanced westward transfer capability of 650MW, through the addition of an HVdc Link between Wawa TS and Lakehead TS.

TABLE 8	***Summary of Study Results - Transient Stability Analysis***			
Contingency	*Rotor Angle Variation*		*Transient Performance*	
	Maximum Value	*Generator Location*	*Stable*	*Acceptable Damping*
W21M & W22M fault at Marathon TS	141˚	Pine Portage GS	Yes	Yes
P21G & P22G fault at the centre of the line	129˚	Lake Superior Power	Yes	Yes
W21M & W22M fault at Wawa TS	126˚	Pine Portage GS	Yes	Yes
P25W & P26W fault at Mississagi TS	120˚	Hogg GS	Yes	Yes
A23P & A24P fault at Mississagi TS	92˚	Andrews GS	Yes	Yes
Loss of two Manitoba HVdc circuits - Henday to Dorsey: 2 x 889 MW	81˚	Ear Falls GS	Yes	Yes
M23L & M24L fault at Marathon TS	75˚	Hogg GS	Yes	Yes
M23L & M24L fault at Lakehead TS	75˚	Hogg GS	Yes	Yes
A21L & A22L fault at Lakehead TS	59˚	Silver Falls GS	Yes	Yes
Loss of VSC HVdc Bi-pole at Wawa TS Converter at Lakehead operates as STATCOM	29˚	Silver Falls GS	Yes	Yes
Loss of the VSC HVdc line - Wawa & Lakehead Converters operate as STATCOMs	28˚	Silver Falls GS	Yes	Yes

APPENDIX A

Converter Rating: 731MVA



HVdc Link Operating at ± 300kV	
HVdc Line Resistance (Entire loop)	25.65Ω
ac Bus Voltage	191.5kV
Converter 'A' Loss	1.8MW
Converter 'B' Loss factor	3.8kW/dc A
Filter Rating/terminal	33MVAr
Converter Rating/terminal	731MVA
Active Power Output of each Converter	658.8MW
Reactive Power Capability of each Converter	+248.8MVAr -321.7MVAr
ac Current Rating	2204.0A

Capability Curves & Parameters for the HVdc Converters & HVdc Line

DIAGRAM A-1

17th December 2012

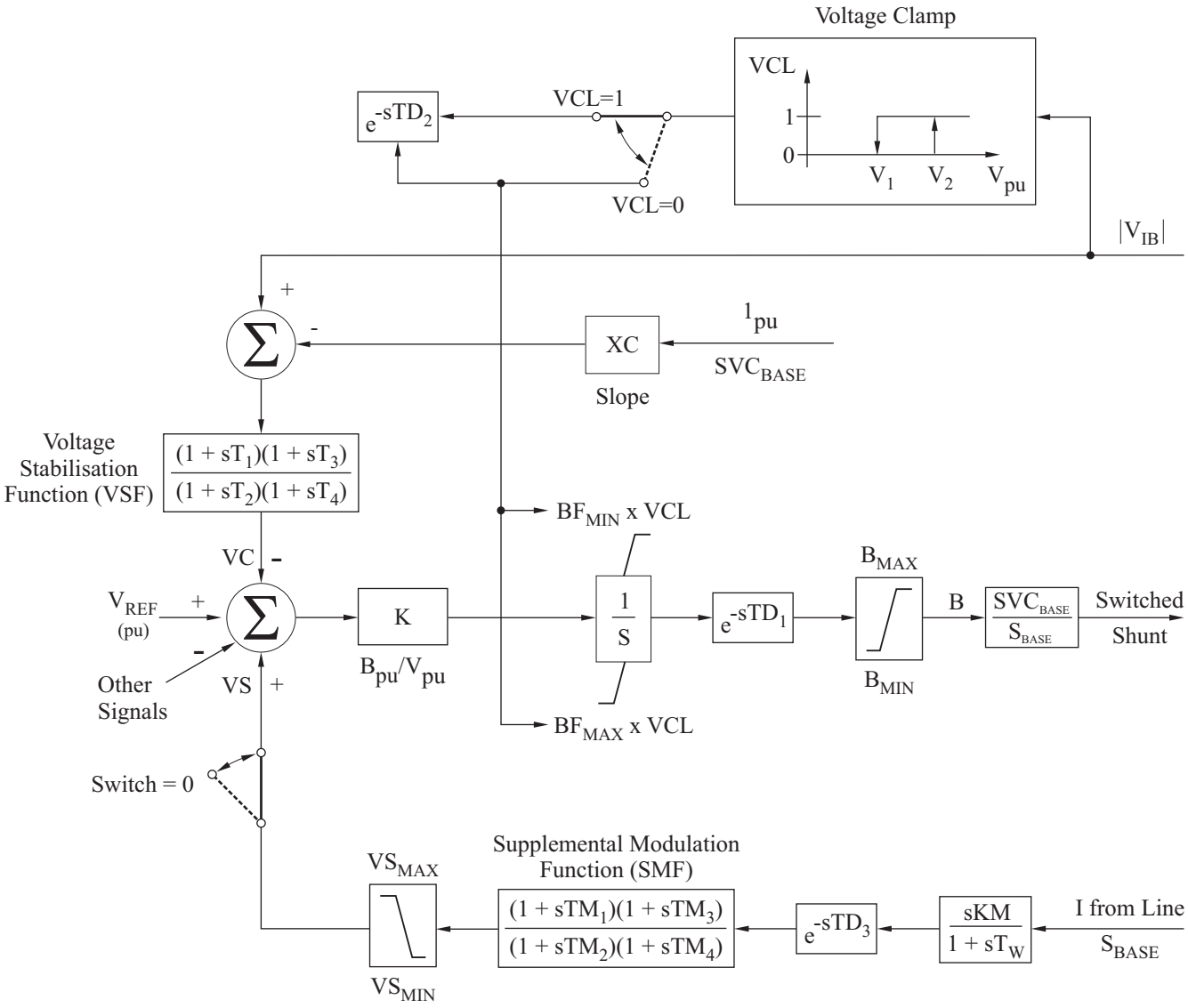
Appendix A: **Parameters used in the PTI VSC-based HVdc Dynamic Model Type: VSCDCT**

INTEGER CONSTANTS		*For ± 300kV HVdc Option*
For VSC No. 1		*Description*
Block_Flag_1: 1	0	Blocked Converter
XFBus_Ctrl_Side_1	0	System bus number for voltage or reactive power control. When 0, controlled bus number is assigned from corresponding power flow input data
For VSC No. 2		*Description*
Block_Flag_2: 1	0	Blocked Converter
XFBus_Ctrl_Side_2	0	System bus number for voltage or reactive power control. When 0, controlled bus number is assigned from corresponding power flow input data

CONSTANTS		*For ± 300kV HVdc Option*
For VSC No. 1		*Description*
Tpo_1	0.1sec	Time constant of active power order controller
AC_VC_Limits_1	0	Reactive power limit for ac voltage control, pu on converter MVA rating. When 0, it is not used and Qmax/Qmin pair is used instead
AC_Vctrl_kp_1	0.4	ac Voltage control proportional gain: converter MVA rating/BASEKV
Tac_1 > 0.0	0.7sec	Time constant for ac voltage PI integral.
Tacm_1	0.01sec	Time constant of the ac voltage transducer
Iacmax_1	1.2	Current Limit, pu on converter MVA rating
Droop_1	0	ac Voltage control droop: converter MVA rating/BASEKV1).
VCMX_1	1.3	Maximum VSC Bridge Internal Voltage
XREACT_1 > 0.0	0.174	pu reactance of the ac series reactor on converter MVA rating.
QMAX_1	248.8	Maximum system reactive limits in MVAr.
QMIN_1	-321.7	Minimum system reactive limits in MVAr.
AC_VC_KT_1	1.2	Feedback Adjustment Parameter - from the reactive power limiter to the ac voltage controller
AC_VC_KTP_1	1	Feedback Adjustment Parameter - from the current order limiter to the ac voltage controller

Appendix A** (Continued)**: **Parameters used in the PTI VSC-based HVdc Dynamic Model Type: VSCDCT**

CONSTANTS		*For ± 300kV HVdc Option*
For VSC No. 2		*Description*
Tpo_2	0.1sec	Time constant of active power order controller
AC_VC_Limits_2	0	Reactive power limit for ac voltage control, pu on converter MVA rating. When 0, it is not used & Qmax/Qmin pair is used instead
AC_Vctrl_kp_2	0.4	ac Voltage control proportional gain: converter MVA rating/BASEKV
Tac_2 > 0.0	0.7sec	Time constant for ac voltage PI integral. When 0, VSC#2 is ignored.
Tacm_2	0.01sec	Time constant of the ac voltage transducer
Iacmax_2	1.2	Current Limit, pu on converter MVA rating
Droop_2	0.1	ac Voltage control droop: converter MVA rating/BASEKV
VCMX_2	1.09	Maximum VSC Bridge Internal Voltage
XREACT_2 > 0.0	0.174	pu reactance of the ac series reactor on converter MVA rating.
QMAX_2	248.8	Maximum system reactive limits in MVAr.
QMIN_2	-321.7	Minimum system reactive limits in MVAr.
AC_VC_KT_2	1.2	Feedback Adjustment Parameter - from the reactive power limiter to the ac voltage controller
AC_VC_KTP_2	1	Feedback Adjustment Parameter - from the current order limiter to the ac voltage controller
Tpo_DCL	0.05sec	Time constant of the power order controller (For dc Line).
Tpo_lim	0.05sec	Time constant of the power order limit controller (For dc Line).



SVC set to control the voltage of the 230kV busbar at Marathon TS

BF_{MAX}	999	T_1	0
BF_{MIN}	-999	T_2	0.005
B_{MAX}	0	T_3	0
B_{MIN}	0	T_4	0
VS_{MAX}	0.1	T_W	1
VS_{MIN}	-0.1	TD_1	0.004
K	30	TD_2	0.01
KM	1	TD_3	1
V_1	0.5	TM_1	0.4
V_2	0.58	TM_2	0.07
XC	-0.0167	TM_3	0.00
		TM_4	0.03

SVC_{BASE} = Σ Capacitors - Σ Reactors

IF BF_{MAX} = 0.0, BF_{MAX} = Σ Capacitors/SVC_{BASE}

IF BF_{MIN} = 0.0, BF_{MIN} = Σ Reactors/SVC_{BASE}

IF B_{MAX} = 0.0, B_{MAX} = Σ Capacitors/SVC_{BASE}

IF B_{MIN} = 0.0, B_{MIN} = Σ Reactors/SVC_{BASE}

IF IB = 0, $|V_{IB}| = |V_{IBUS}|$

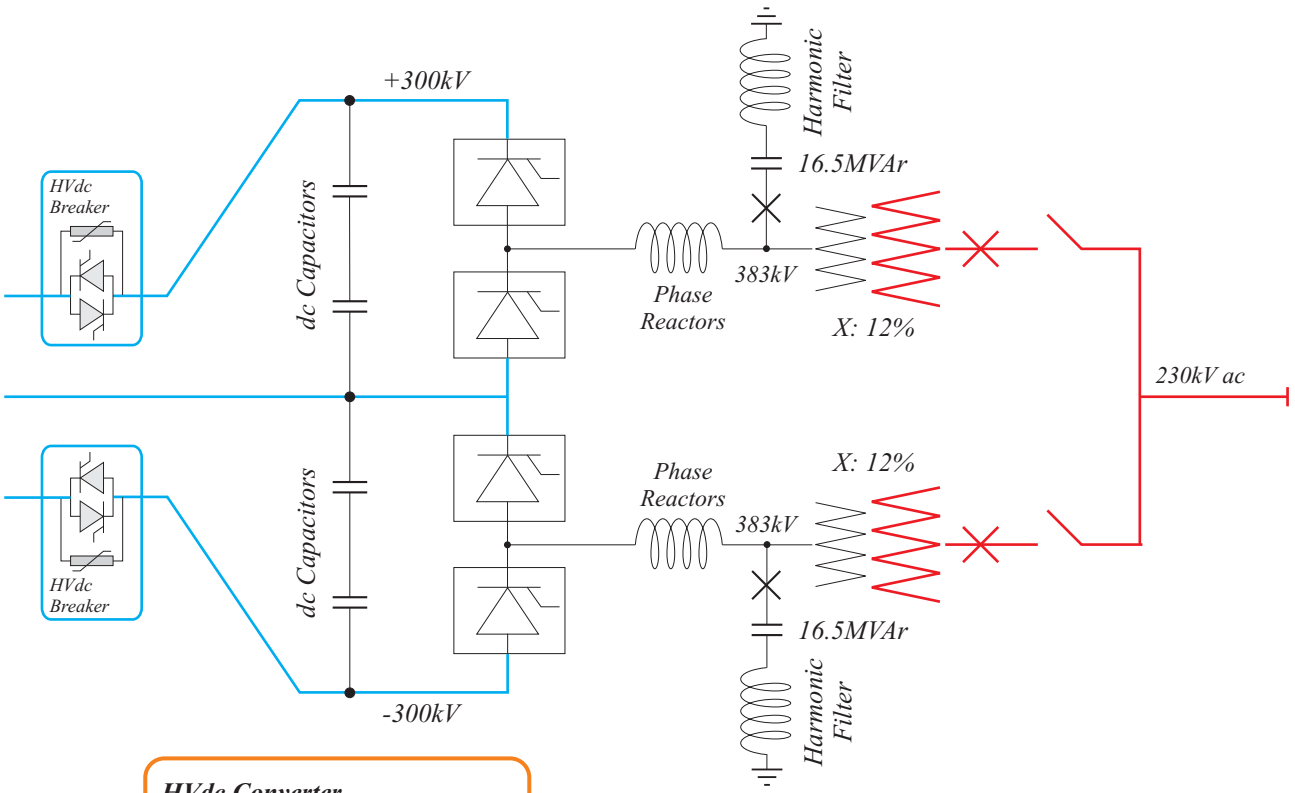
PTI CHSVCT Model Used to Represent the Marathon SVC

DIAGRAM A-2

18th November 2012

DIAGRAMS

The terminal arrangements for the HVdc Link at Wawa TS & Lakehead TS are to be identical



Wawa to Lakehead HVdc Connection *~400km*

Conductor: Mockingbird 2034.5kcmil 72/7 ACSR

Wawa x Lakehead dc path resistance
(at a conductor temperature of 50°C): 25.65 Ω

HVdc Converter

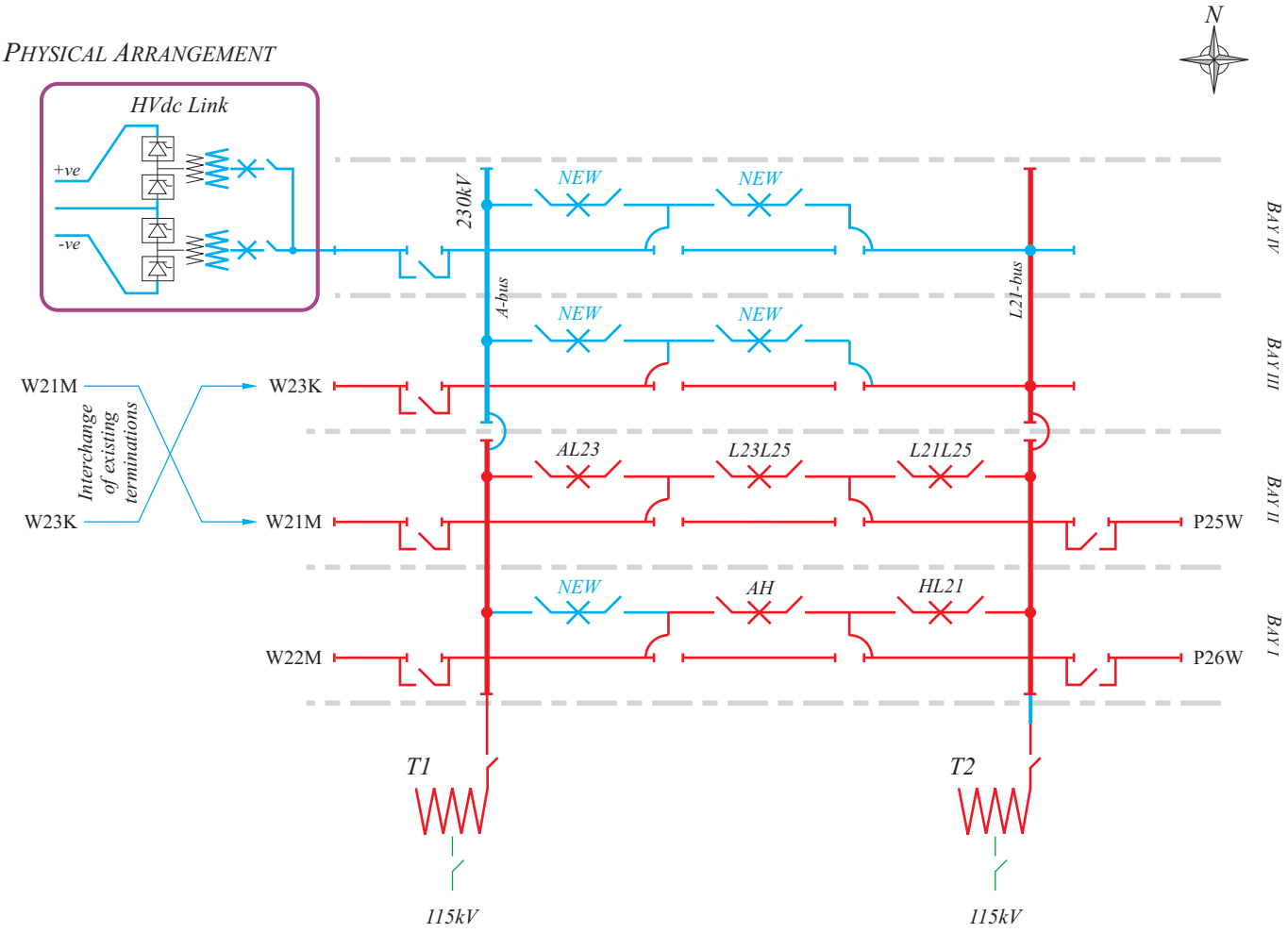
Rating: 731MVA

Reactive Range: +248.8MVAr
-321.7MVAr

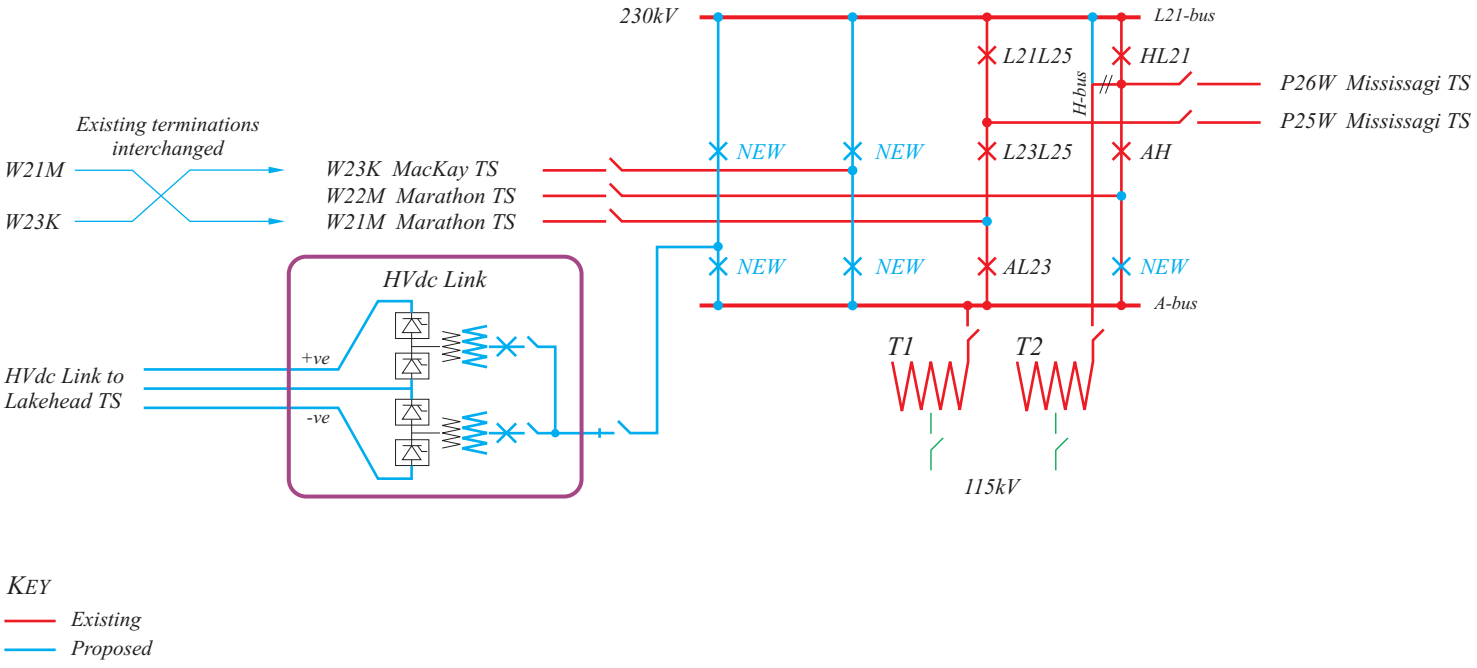
Proposed Arrangement of the Terminations at Wawa TS & Lakehead TS for the HVdc Reinforcement of the East-West Tie

DIAGRAM 1
7th November 2012

PHYSICAL ARRANGEMENT



SINGLE-LINE DIAGRAM



KEY

Existing

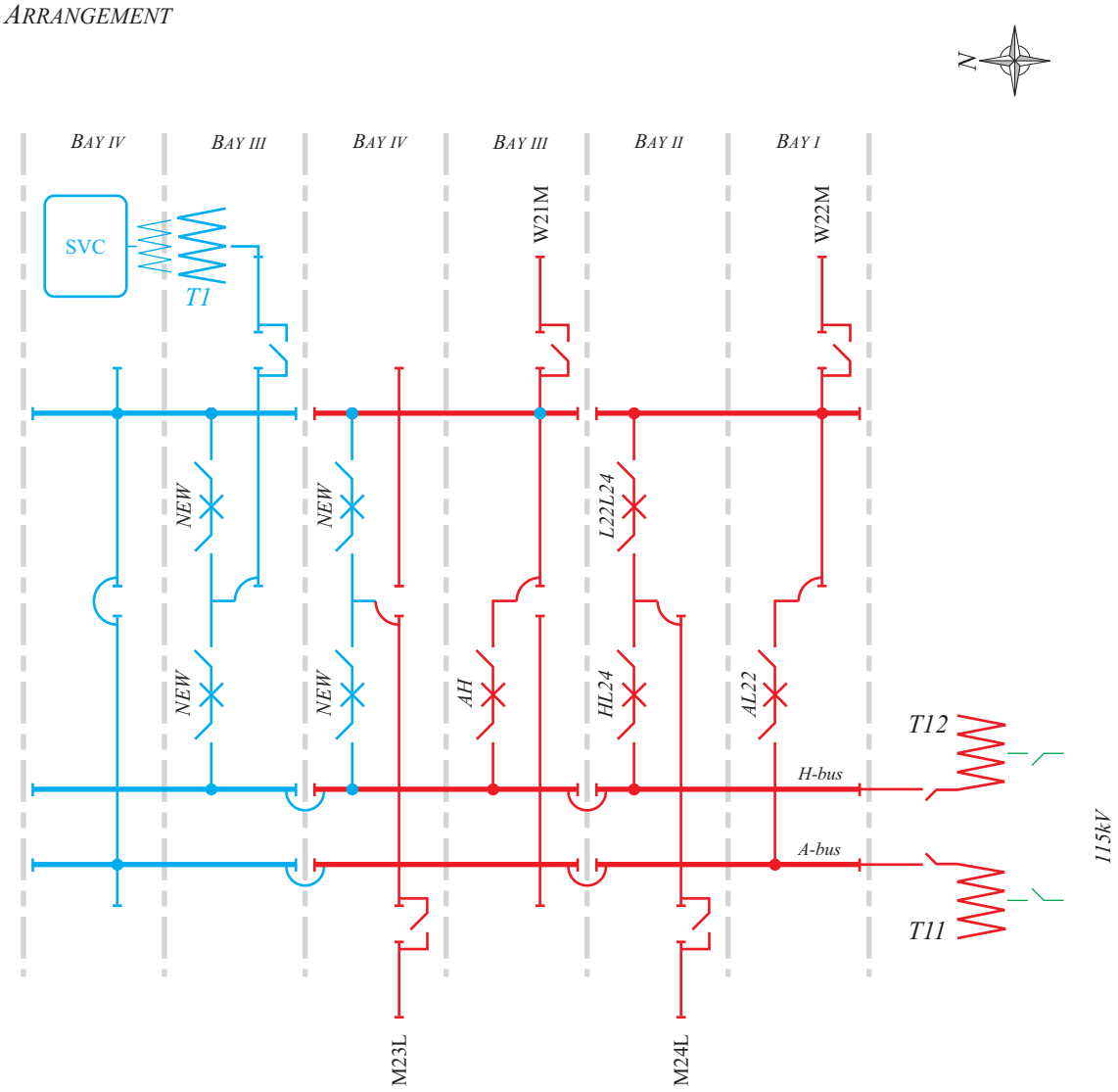
Proposed

WAWA TS: Termination of the new HVdc Link

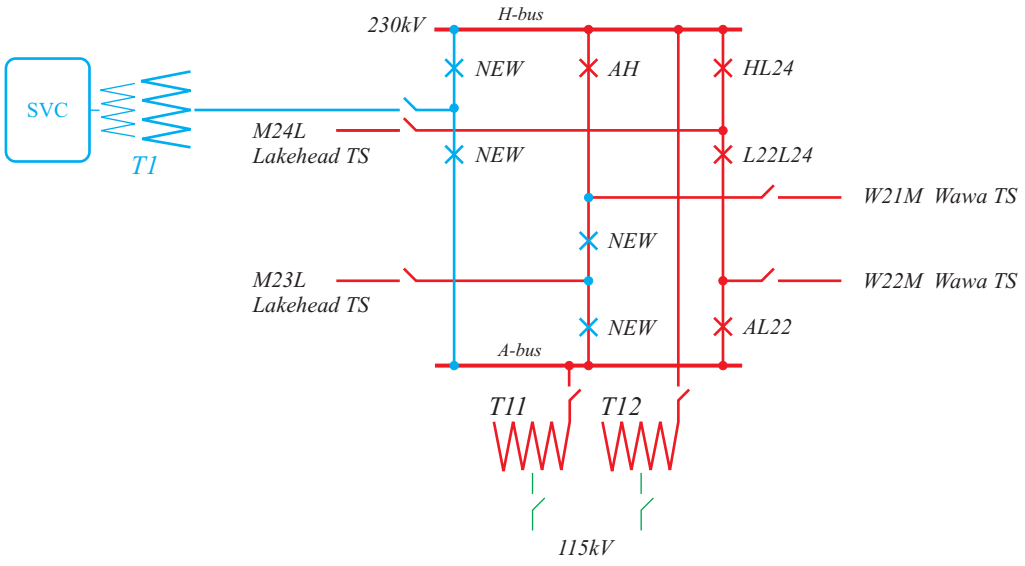
DIAGRAM 2

7th November 2012

PHYSICAL ARRANGEMENT



SINGLE-LINE DIAGRAM



KEY

Existing

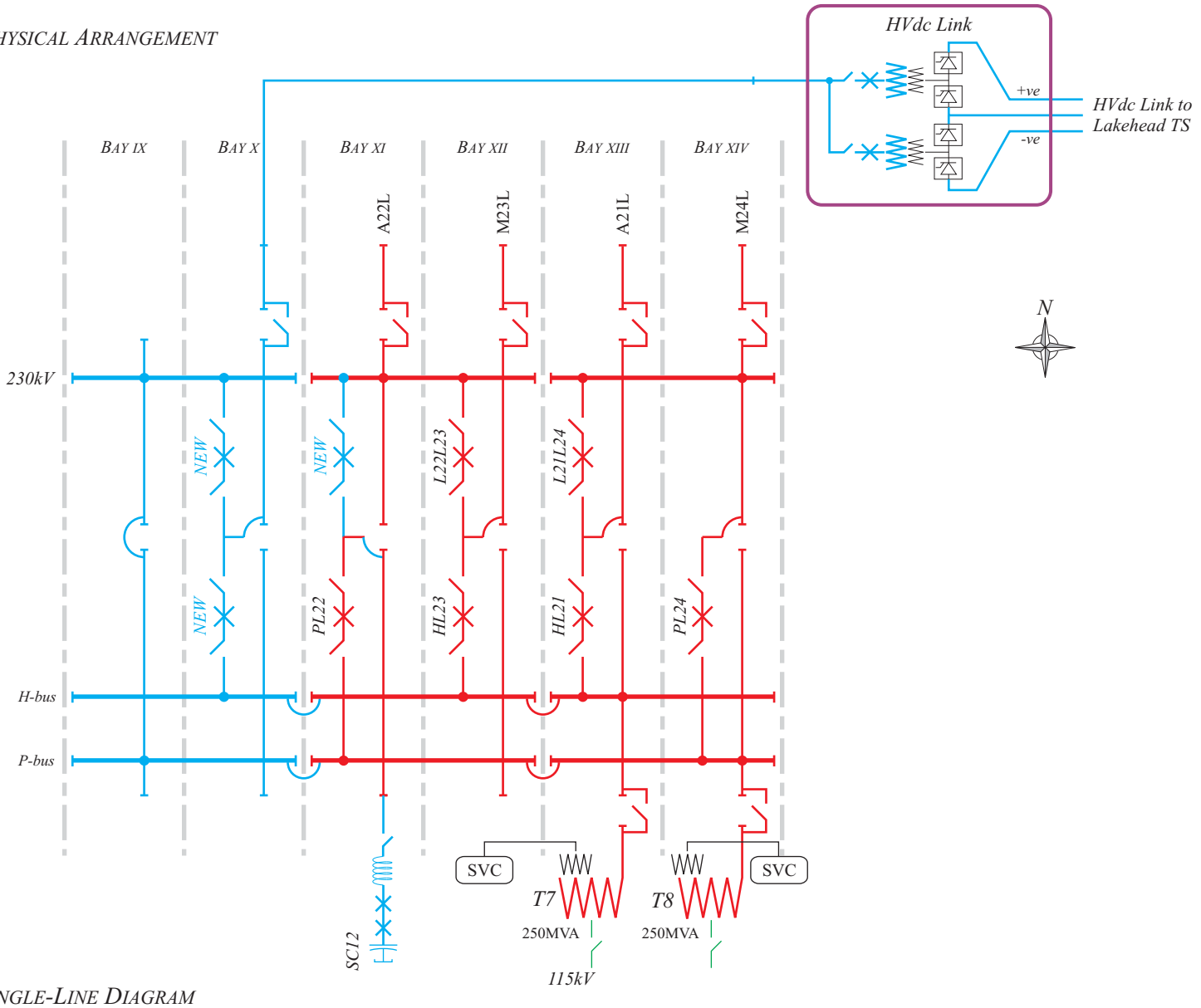
Proposed

MARATHON TS: With a new SVC installed

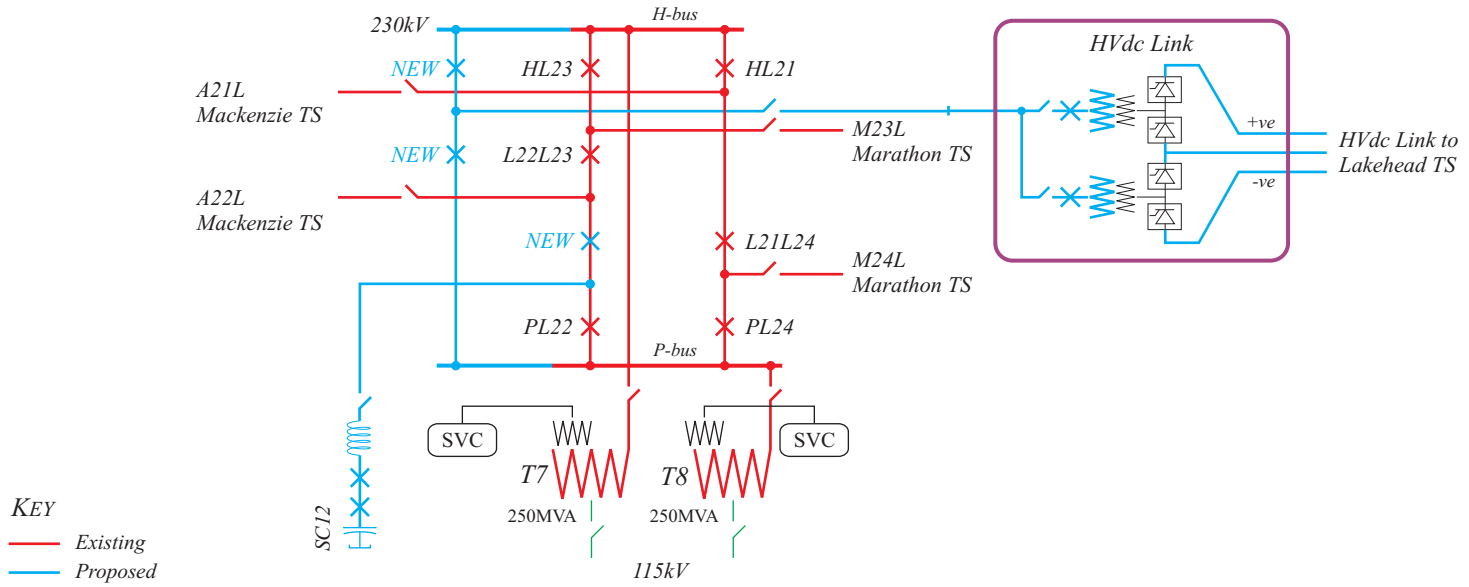
DIAGRAM 3

12th July 2012

PHYSICAL ARRANGEMENT



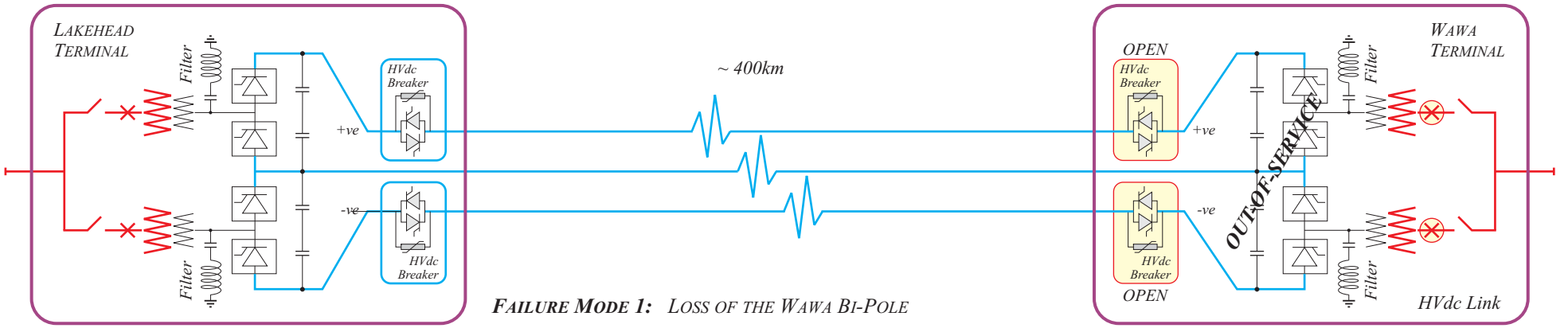
SINGLE-LINE DIAGRAM



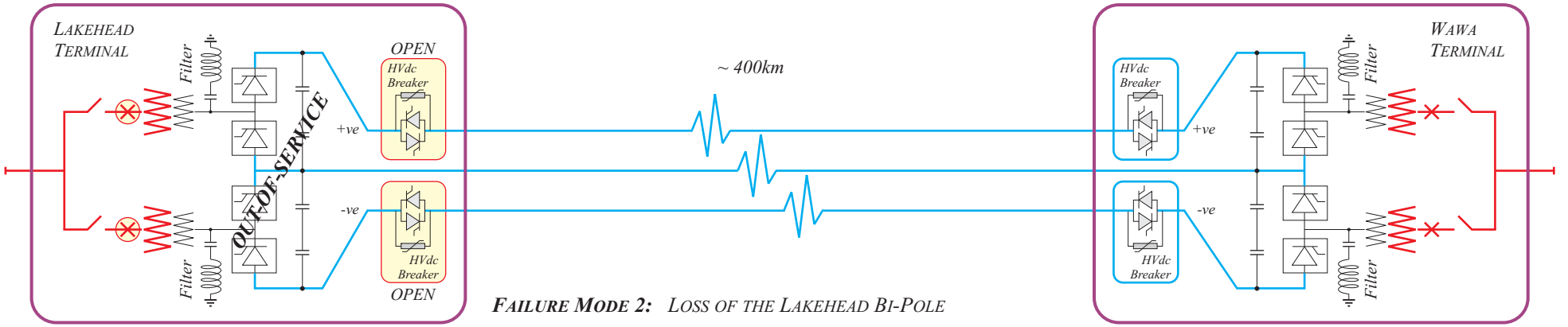
LAKEHEAD TS: Termination of the new HVdc Link

DIAGRAM 4

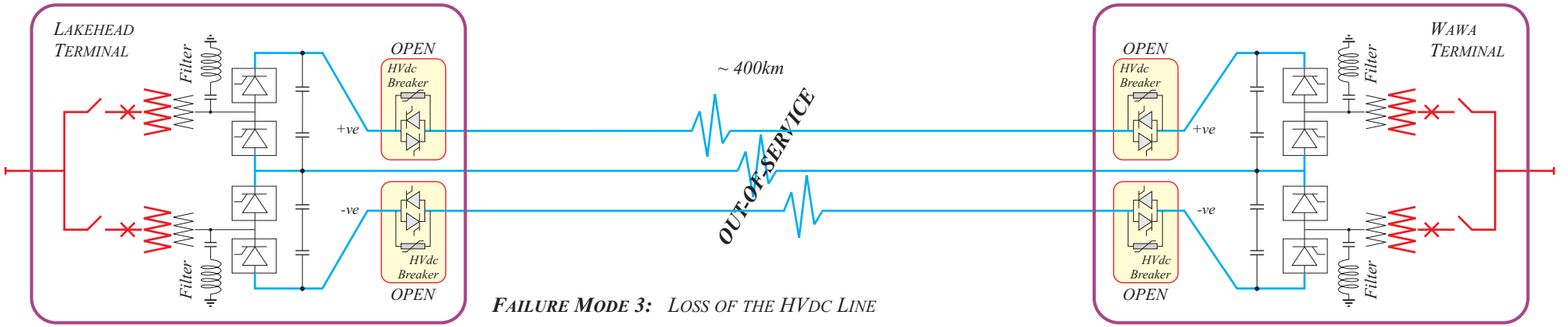
7th November 2012



FAILURE MODE 1: *LOSS OF THE WAWA BI-POLE*
LAKEHEAD BI-POLE REMAINS IN-SERVICE



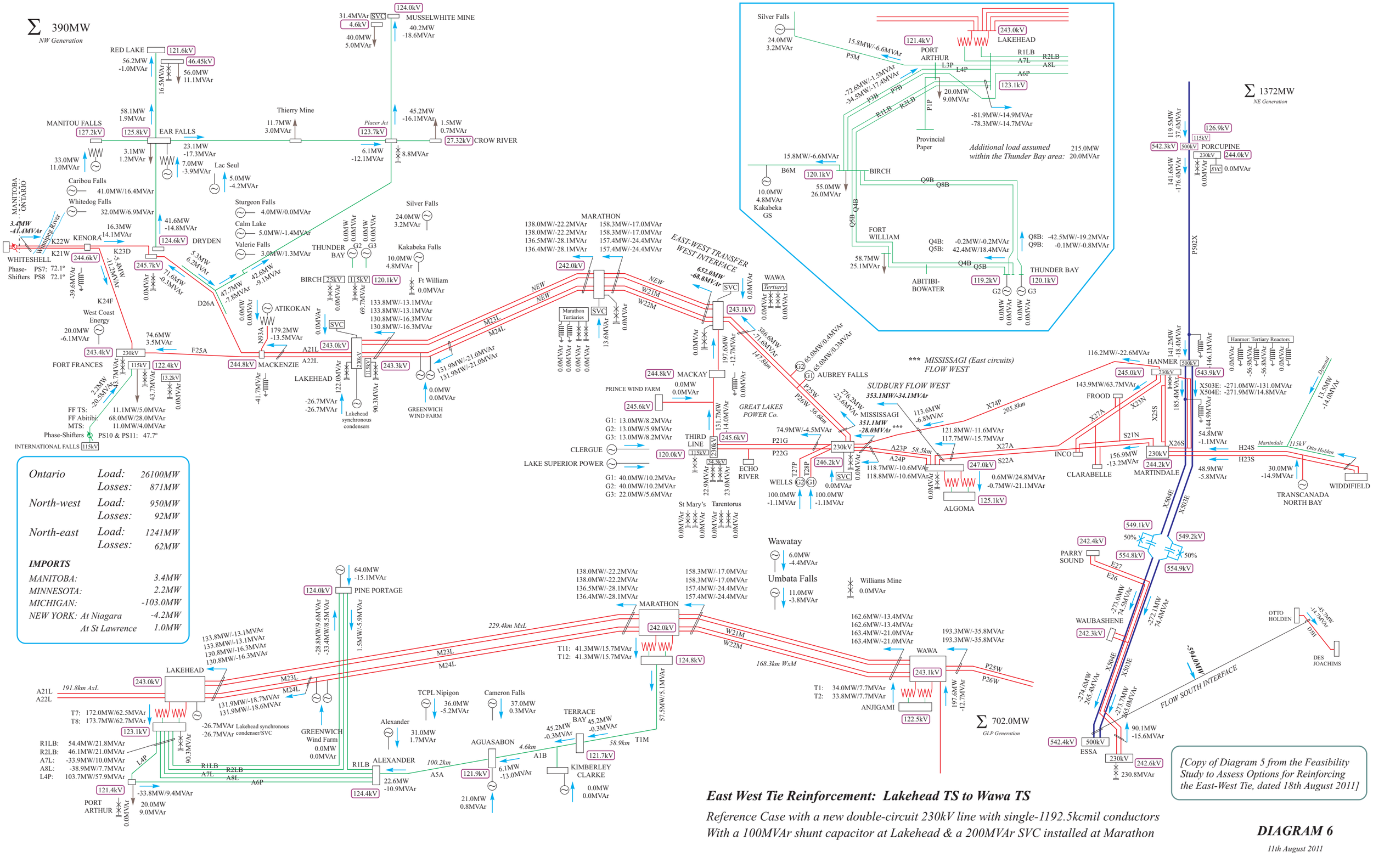
FAILURE MODE 2: *LOSS OF THE LAKEHEAD BI-POLE*
WAWA BI-POLE REMAINS IN-SERVICE



FAILURE MODE 3: *LOSS OF THE HVDC LINE*
BOTH CONVERTERS REMAIN IN-SERVICE

DIAGRAM 5

7th November 2012



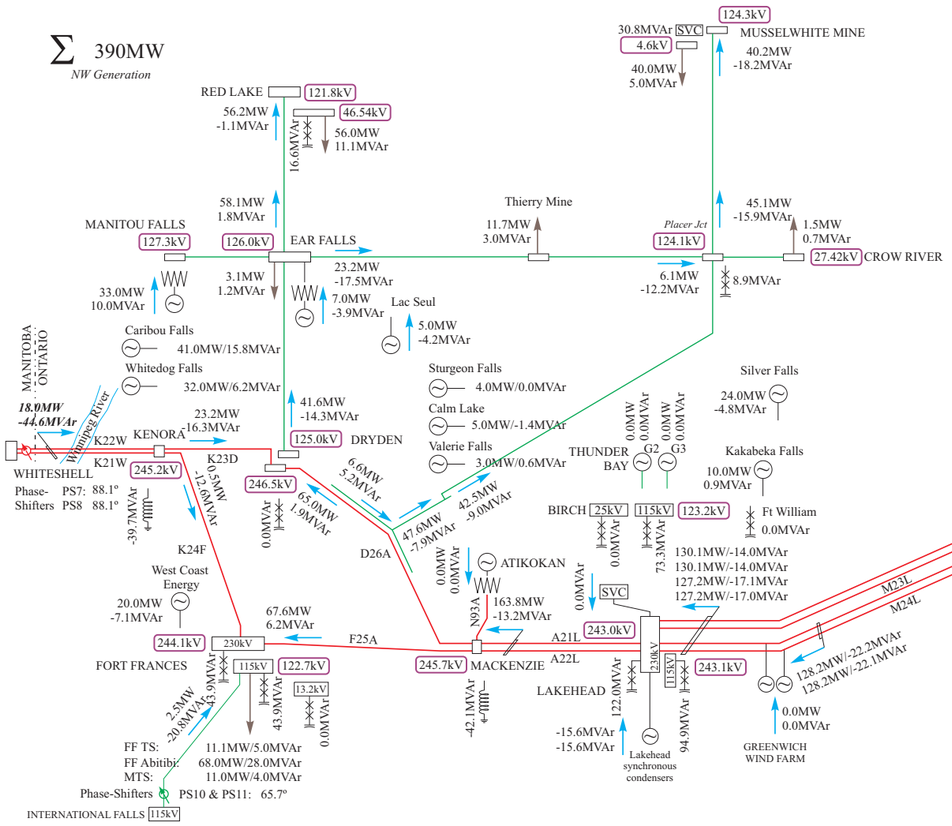
[Copy of Diagram 5 from the Feasibility Study to Assess Options for Reinforcing the East-West Tie, dated 18th August 2011]

East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

DIAGRAM 6

11th August 2011



Ontario	*Load:*	*26100MW*
	Losses:	*907MW*
North-west	*Load:*	*950MW*
	Losses:	*123MW*
North-east	*Load:*	*1241MW*
	Losses:	*66MW*

IMPORTS

MANITOBA:	*18.0MW*
MINNESOTA:	*2.5MW*
MICHIGAN:	*-80.4MW*
NEW YORK: At Niagara	*-2.1MW*
At St Lawrence	*-0.6MW*

[Copy of Diagram 7 from the Feasibility Study to Assess Options for Reinforcing the East-West Tie, dated 18th August 2011]

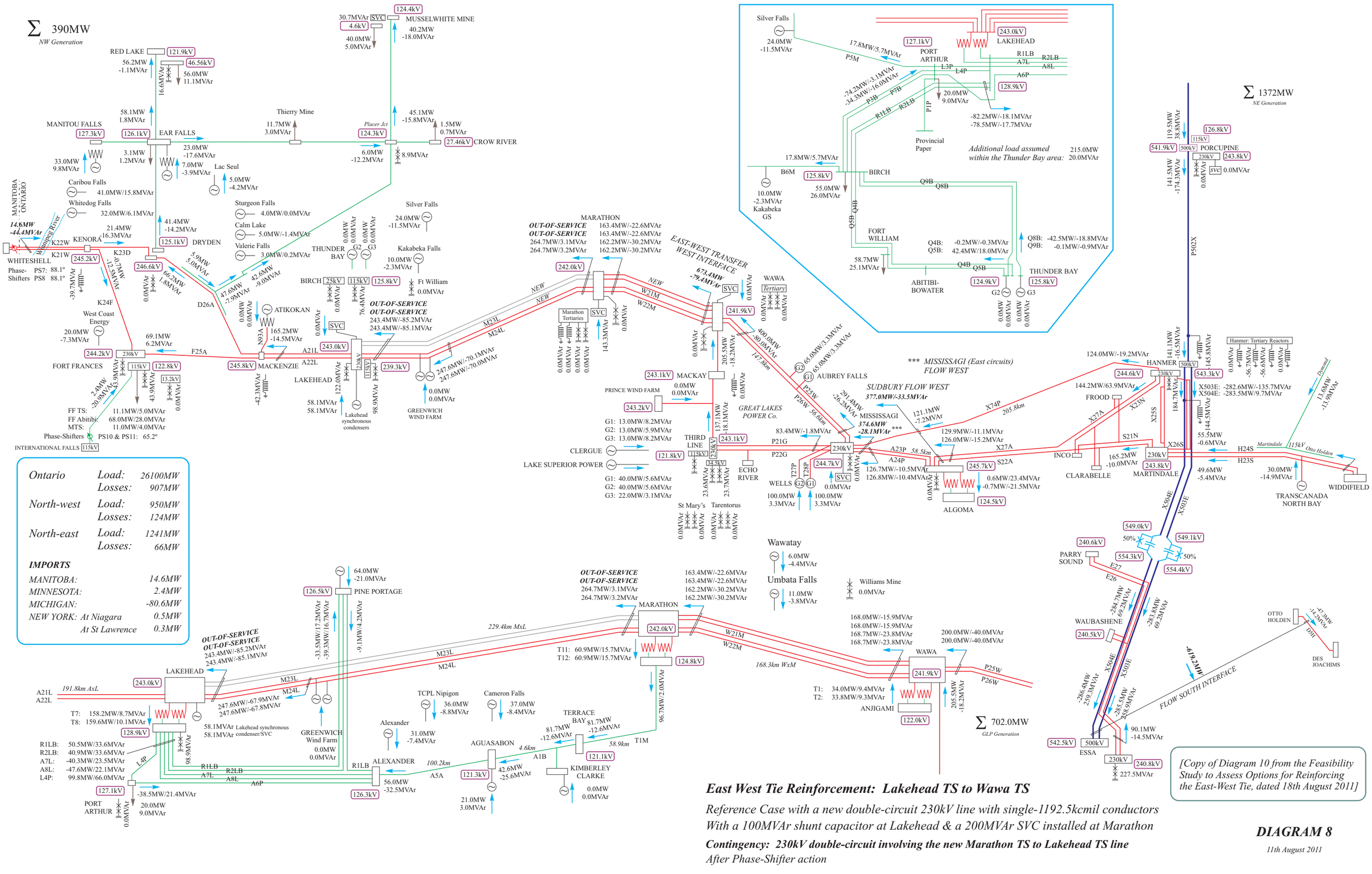
East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

Contingency: 230kV double-circuit involving the new Wawa TS to Marathon TS line
After Phase-Shifter action

DIAGRAM 7

11th August 2011



Ontario	*Load:*	*26100MW*
	Losses:	*907MW*
North-west	*Load:*	*950MW*
	Losses:	*124MW*
North-east	*Load:*	*1241MW*
	Losses:	*66MW*

IMPORTS

MANITOBA:	*14.6MW*
MINNESOTA:	*2.4MW*
MICHIGAN:	*-80.6MW*
NEW YORK: At Niagara	*0.5MW*
At St Lawrence	*0.3MW*

East West Tie Reinforcement: Lakehead TS to Wawa TS

Reference Case with a new double-circuit 230kV line with single-1192.5kcmil conductors
With a 100MVAr shunt capacitor at Lakehead & a 200MVAr SVC installed at Marathon

Contingency: 230kV double-circuit involving the new Marathon TS to Lakehead TS line
After Phase-Shifter action

[Copy of Diagram 10 from the Feasibility Study to Assess Options for Reinforcing the East-West Tie, dated 18th August 2011]

DIAGRAM 8

11th August 2011

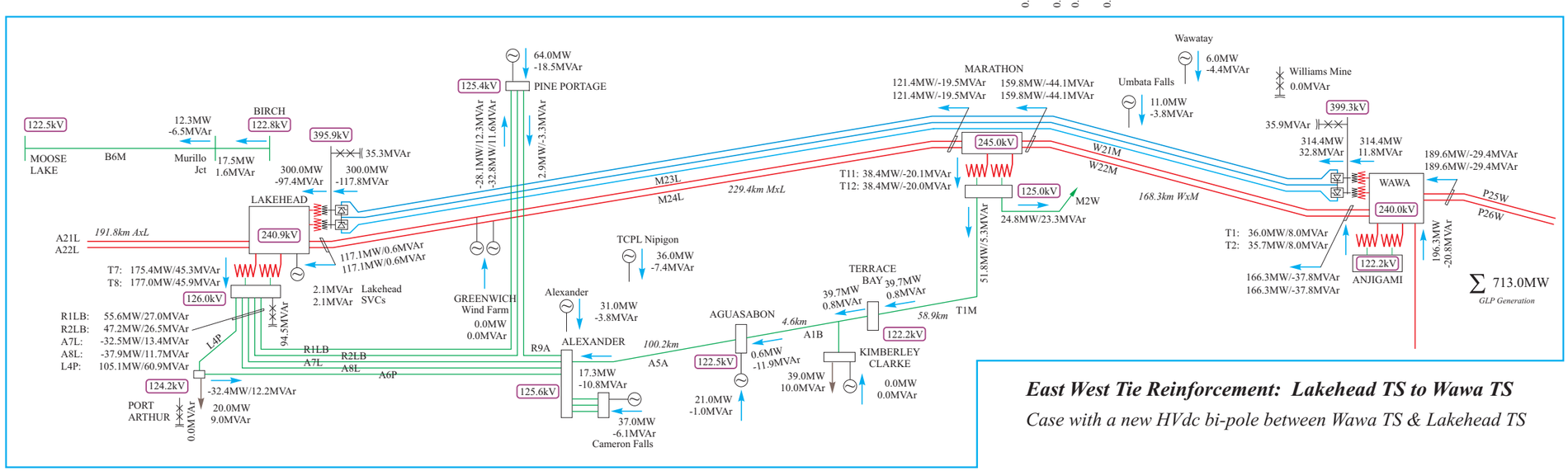
Ontario	*Load:*	*26020MW*
	Losses:	*813MW*
North-west	*Load:*	*950MW*
	Losses:	*87MW*
North-east	*Load:*	*1241MW*
	Losses:	*60MW*

IMPORTS

MANITOBA:		*3.6MW*
MINNESOTA:		*2.3MW*
MICHIGAN:		*-98.6MW*
NEW YORK:	*At Niagara*	*-5.2MW*
	At St Lawrence	*-1.6MW*

Σ 390MW
NW Generation

RED LAKE 121.5kV
56.2MW -1.0MVAr
46.42kV
56.0MW 11.1MVAr
16.5MVAr
58.1MW 2.0MVAr
MANITOU FALLS 127.1kV
125.8kV EAR FALLS
33.0MW 11.3MVAr
3.1MW 1.2MVAr
23.1MW -17.3MVAr
7.0MW -3.9MVAr
Lac Seul
5.0MW -4.2MVAr
Caribou Falls
41.0MW/18.2MVAr
Whitedog Falls
32.0MW/9.3MVAr
MANITOBA ONTARIO
3.6MW -43.2MVAr
Winnipeg River
41.6MW -14.9MVAr
16.8MW 11.2MVAr
K22W KENORA
K21W
245.1kV
WHITESHELL
Phase- PS7: 70.4°
Shifters PS8 70.4°
-39.0MVAr
-4.0MW -8.9MVAr
K23D
245.6kV
0.0MVAr
71.2MW -2.2MVAr
124.5kV DRYDEN
5.0MW 6.2MVAr
47.7MW -7.8MVAr
42.7MW -9.1MVAr
Valora
D26A
K24F
West Coast Energy
20.0MW -5.6MVAr
74.4MW 1.4MVAr
243.2kV
230kV
F25A
FORT FRANCES
115kV
122.3kV
13.2kV
2.3MW -20.1MVAr
6.0MVAr
43.6MVAr
0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 46.0°
INTERNATIONAL FALLS 115kV
Sturgeon Falls
4.0MW/0.0MVAr
Calm Lake
5.0MW/-1.4MVAr
Valerie Falls
3.0MW/1.4MVAr
Silver Falls
24.0MW -4.0MVAr
Kakabeka Falls
10.0MW -0.6MVAr
Ft William
0.0MVAr
THUNDER BAY G2 G3
0.0MW 0.0MVAr
BIRCH 25kV 115kV 122.8kV
72.8MVAr
0.0MVAr
ATIKOKAN
N93A
177.2MW -20.1MVAr
-41.6MVAr
SVC 35.3MVAr
300.0MW
A21L
240.9kV
230kV
LAKEHEAD
119.9MVAr
2.1MVAr 2.1MVAr
Lakehead SVCs
94.5MVAr
244.0kV MACKENZIE
A22L
126.0kV
242.5kV
GREENWICH WIND FARM
0.0MW 0.0MVAr
117.1MW/0.6MVAr
117.1MW/0.6MVAr
124.0kV
-1.5MVAr SVC
4.6kV
40.0MW 5.0MVAr
33.0MVAr
MUSSELWHITE MINE
40.2MW -18.7MVAr
Thierry Mine
11.7MW 3.0MVAr
Placer Jct
123.6kV
45.2MW -16.2MVAr
1.5MW 0.7MVAr
27.3kV CROW RIVER
6.1MW -12.0MVAr
8.8MVAr
NEW M23L M24L
MARATHON
121.4MW/-19.5MVAr 159.8MW/-44.1MVAr
121.4MW/-19.5MVAr 159.8MW/-44.1MVAr
245.0kV
Marathon Tertiaries
37.4MVAr 37.4MVAr
SVC 9.2MVAr
EAST-WEST TRANSFER
WEST INTERFACE
647.0MW
-63.8MVAr
NEW W21M W22M
35.9MVAr
SVC
Wawa Tertiaries
WAWA
240.0kV
379.2MW -58.8MVAr
147.8km
65.0MW/3.5MVAr
65.0MW/3.5MVAr
G2 G1 AUBREY FALLS
P25W P26W 30.6km
240.5kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
242.7kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
CLERGUE
LAKE SUPERIOR POWER
121.8kV
G1: 40.0MW/5.7MVAr
G2: 40.0MW/5.7MVAr
G3: 22.0MW/3.1MVAr
THIRD LINE 115kV 230kV
242.8kV
124.1MW -5.0MVAr
23.6MVAr 23.7MVAr
34.5kV
St Mary's Tarentorus
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
ECHO RIVER
P21G P22G
66.2MW/5.2MVAr
230kV
244.9kV SVC 0.0MVAr
WELLS G2 G1
100.0MW 2.8MVAr
100.0MW 2.7MVAr
T27P T28P
GREAT LAKES POWER Co.
268.2MW -19.1MVAr
MISSISSAGI
334.3MW
-14.0MVAr ***
108.2MW -2.6MVAr
A23P 58.5km A24P
113.0MW/-5.7MVAr
113.1MW/-5.7MVAr
246.1kV
0.0MVAr
0.6MW/24.0MVAr
-0.7MW/-21.3MVAr
124.7kV
ALGOMA
116.1MW/-7.7MVAr
111.9MW/-11.7MVAr
X27A
S22A
**** MISSISSAGI (East circuits) FLOW WEST*
SUDBURY FLOW WEST
336.2MW/-22.0MVAr
X74P 205.8km
INCO
CLARABELLE
S21N
151.1MW -10.9MVAr
230kV 244.1kV
MARTINDALE
48.3MW -5.4MVAr
X26S
H24S H23S
Martindale 115kV Otto Holden
30.0MW -14.9MVAr
TRANSCANADA NORTH BAY
WIDDIFIELD
Dymond
13.5MW -13.9MVAr
X25S X23N X27A
FROOD
143.7MW/63.8MVAr
110.5MW/-20.4MVAr
244.9kV
HANMER 230kV 500kV
543.9kV
X503E: -262.9MW/-133.3MVAr
X504E: -263.7MW/12.4MVAr
185.2MVAr
144.8MVAr
54.2MW -0.7MVAr
Hanmer: Tertiary Reactors
0.0MVAr -56.8MVAr -56.8MVAr 0.0MVAr
141.3MW -18.2MVAr
146.1MVAr
P502X
119.5MW 37.6MVAr
126.9kV 115kV
542.2kV 500kV PORCUPINE
230kV 243.9kV
SVC 0.0MVAr
141.7MW -176.2MVAr
0.0MVAr
Σ 1383MW
NE Generation
Silver Falls
24.0MW -4.0MVAr
17.5MW/1.6MVAr
P5M
124.2kV
PORT ARTHUR
L3P L4P
240.9kV
LAKEHEAD
R1LB A7L R2LB A8L A6P
126.0kV
-72.9MW/-4.3MVAr
-34.9MW/-18.1MVAr
P3B P7B R1LB R2LB P1P
20.0MW 9.0MVAr
-82.5MW/-17.8MVAr
-78.8MW/-17.4MVAr
Provincial Paper
5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
17.5MW/1.6MVAr
B6M
122.8kV
10.0MW -0.6MVAr Kakabeka GS
55.0MW 26.0MVAr
BIRCH
Q9B Q8B
Q5B Q4B
FORT WILLIAM
58.7MW 25.1MVAr
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
Q4B Q5B
121.9kV
G2 G3
THUNDER BAY
122.8kV
0.0MW 0.0MVAr 0.0MW 0.0MVAr



East West Tie Reinforcement: Lakehead TS to Wawa TS

Case with a new HVdc bi-pole between Wawa TS & Lakehead TS

DIAGRAM 9

1st November 2012

Ontario	*Load:*	*26020MW*
	Losses:	*822MW*
North-west	*Load:*	*950MW*
	Losses:	*92MW*
North-east	*Load:*	*1241MW*
	Losses:	*63MW*

IMPORTS

MANITOBA:	*-3.2MW*
MINNESOTA:	*-2.1MW*
MICHIGAN:	*-88.3MW*
NEW YORK: At Niagara	*1.8MW*
At St Lawrence	*1.3MW*

Σ 390MW
NW Generation

RED LAKE 121.4kV
56.2MW -0.9MVAr
46.38kV 56.0MW 11.1MVAr
16.5MVAr
MANITOU FALLS 127.1kV
125.7kV EAR FALLS
58.1MW 2.0MVAr
3.1MW 1.2MVAr
33.0MW 11.6MVAr
23.1MW -17.2MVAr
7.0MW -3.9MVAr
Lac Seul 5.0MW -4.2MVAr
Thierry Mine 11.7MW 3.0MVAr
Placer Jct 123.4kV
6.0MW -11.9MVAr
8.8MVAr
123.9kV MUSSELWHITE MINE
-1.4MVAr SVC 4.6kV
40.0MW 5.0MVAr
33.0MVAr
40.2MW -18.8MVAr
45.2MW -16.3MVAr
1.5MW 0.7MVAr
27.26kV CROW RIVER
Caribou Falls 41.0MW/18.5MVAr
Whitedog Falls 32.0MW/9.6MVAr
MANITOBA ONTARIO
-3.2MW -41.8MVAr
Winnipeg River
12.5MW 10.1MVAr
41.5MW -15.2MVAr
124.3kV DRYDEN
Sturgeon Falls 4.0MW/0.0MVAr
Calm Lake 5.0MW/-1.4MVAr
Valerie Falls 3.0MW/1.6MVAr
Valora
Silver Falls 24.0MW -4.0MVAr
Kakabeka Falls 10.0MW -0.6MVAr
KENORA
K22W
K21W
K23D
WHITESHELL
Phase- PS7: 70.4°
Shifters PS8 70.4°
244.9kV
-38.9MVAr
-6.7MW -8.5MVAr
245.2kV
0.0MVAr -5.2MW -3.5MVAr
4.1MW 6.6MVAr
47.8MW -7.8MVAr
42.7MW -9.1MVAr
D26A
K24F
West Coast Energy 20.0MW -5.2MVAr
80.6MW -0.5MVAr
242.9kV 230kV
F25A
FORT FRANCES
115kV 122.2kV 13.2kV
-2.1MW -18.7MVAr 0.0MVAr
43.5MVAr 0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 46.0°
INTERNATIONAL FALLS 115kV
243.5kV MACKENZIE
-41.4MVAr
0.0MVAr
ATIKOKAN
N93A
188.2MW -21.5MVAr
BIRCH 25kV 115kV 122.8kV
0.0MVAr 72.8MVAr
Ft William 0.0MVAr
THUNDER BAY G2 G3
0.0MW 0.0MVAr
0.0MW 0.0MVAr
SVC 34.8MVAr 620.0MW
A21L 240.9kV
A22L
LAKEHEAD 230kV 115kV
119.9MW -4.1MVAr
-4.1MVAr
Lakehead SVCs
94.5MVAr
126.0kV
243.6kV GREENWICH WIND FARM
0.0MW 0.0MVAr
-18.2MW/35.5MVAr
-18.2MW/35.5MVAr

MARATHON
-18.1MW/-11.4MVAr *OUT-OF-SERVICE*
-18.1MW/-11.4MVAr *OUT-OF-SERVICE*
245.0kV SVC
Marathon Tertiaries
0.0MVAr 37.4MVAR 0.0MVAr 37.4MVAr
-67.0MVAr 0.0MVAr
EAST-WEST TRANSFER
WEST INTERFACE
662.8MW -73.6MVAr
NEW W21M W22M
37.1MVAr SVC 0.0MVAr
Wawa Tertiaries 0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
240.0kV
WAWA
0.0MVAr
NEW M22L M24L
389.2MW -65.8MVAr
147.8km
201.9MW -23.6MVAr
G2 65.0MW/4.2MVAr
G1 65.0MW/4.2MVAr
AUBREY FALLS
240.3kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
242.4kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
129.2MW -5.5MVAr
THIRD LINE 115kV 230kV
242.5kV
121.7kV
34.5kV
23.5MVAr 23.7MVAr
CLERGUE
LAKE SUPERIOR POWER
G1: 40.0MW/6.0MVAr
G2: 40.0MW/5.9MVAr
G3: 22.0MW/3.3MVAr
St Mary's 0.0MVAr 0.0MVAr
Tarentorus 0.0MVAr 0.0MVAr
ECHO RIVER
72.4MW/1.8MVAr
P21G P22G
230kV
244.5kV SVC 0.0MVAr
T27P T28P
WELLS G2 G1
100.0MW 3.9MVAr
100.0MW 3.8MVAr
A23P 58.5km A24P
118.9MW/-7.2MVAr
119.0MW/-7.2MVAr
245.7kV S22A
0.6MW/23.5MVAr
-0.7MW/-21.4MVAr
0.0MVAr
124.5kV
ALGOMA
GREAT LAKES POWER Co.
279.4MW -20.4MVAr
P25W P26W 56.0km
SUDBURY FLOW WEST
353.8MW/-25.8MVAr
MISSISSAGI
351.7MW
-18.6MVAr ***
113.8MW -4.2MVAr
122.0MW/-8.8MVAr
118.0MW/-12.8MVAr
X27A
205.8km
X74P
**** MISSISSAGI (East circuits) FLOW WEST*

Silver Falls 24.0MW -4.0MVAr
18.1MW/1.7MVAr P5M
124.3kV PORT ARTHUR
240.9kV LAKEHEAD
R1LB A7L L3P L4P R2LB A8L A6P
126.0kV
-71.8MW/-5.2MVAr
-35.5MW/-17.8MVAr
P3B P7B R1LB R2LB P1P
20.0MW 9.0MVAr
-83.1MW/-17.5MVAr
-79.4MW/-17.2MVAr
Provincial Paper 5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
18.1MW/1.7MVAr
B6M 122.8kV BIRCH
10.0MW -0.6MVAr Kakabeka GS
55.0MW 26.0MVAr
Q9B Q8B Q5B Q4B
FORT WILLIAM
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
58.7MW 25.1MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
121.9kV
Q4B Q5B
THUNDER BAY 122.8kV
G2 G3
0.0MW 0.0MVAr 0.0MW 0.0MVAr

Σ 1383MW
NE Generation

119.5MW 38.6MVAr
126.8kV
115kV
541.9kV 500kV PORCUPINE
141.6MW -174.6MVAr
230kV 243.8kV
0.0MVAr SVC 0.0MVAr
P502X
116.3MW/-19.5MVAr
141.2MW -16.8MVAr
HANMER 500kV 543.4kV
-145.9MVAr
Hanmer: Tertiary Reactors
0.0MVAr -56.7MVAr -56.6MVAr 0.0MVAr
X503E: -271.2MW/-134.3MVAr
X504E: -272.1MW/11.1MVAr
244.7kV 230kV
143.9MW/63.9MVAr
FROOD
X23N X25S X27A
184.8MVAr
144.6MVAr
54.8MW -0.3MVAr
S21N
X26S
157.2MW -10.1MVAr
INCO
230kV 243.9kV
MARTINDALE
CLARABELLE
49.0MW -5.1MVAr
H24S H23S
Martindale 115kV *Otto Holden*
30.0MW -14.9MVAr
WIDDIFIELD
TRANSCANADA NORTH BAY
15.5MW -15.9MVAr
Dymond

X504E X503E
548.9kV 50% 549.0kV 50%
554.3kV 554.4kV
242.3kV PARRY SOUND
E27 E26
-273.3MW 70.7MVAr
-272.4MW 70.7MVAr
WAUBASHENE 242.3kV
X504E X503E
-274.8MW 261.5MVAr
-273.9MW 261.1MVAr
OTTO HOLDEN
-45.8MW -15.8MVAr
D5H
DES JOACHIMS
-594.5MW
FLOW SOUTH INTERFACE
542.2kV 500kV ESSA
90.1MW -15.6MVAr
230kV 242.5kV
230.6MVAr

MOOSE LAKE 122.3kV
B6M
12.9MW -6.4MVAr
Murillo Jct 18.1MW 1.7MVAr
BIRCH 122.8kV
393.3kV 34.8MVAr
619.8MW -165.0MVAr
620.0MW -138.4MVAr
LAKEHEAD 240.9kV
A21L A22L *191.8km AxL*
T7: 194.1MW/45.3MVAr
T8: 196.0MW/45.8MVAr
126.0kV
-4.1MVAr -4.1MVAr Lakehead SVCs
R1LB: 61.4MW/24.3MVAr
R2LB: 53.9MW/23.8MVAr
A7L: -24.0MW/9.1MVAr
A8L: -27.9MW/7.8MVAr
L4P: 111.0MW/57.7MVAr
94.5MVAr
R1LB R2LB L4P A7L A8L A6P
124.3kV PORT ARTHUR
-25.3MW/8.1MVAr
20.0MW 9.0MVAr
0.0MVAr
64.0MW -18.5MVAr
125.4kV PINE PORTAGE
-22.5MW/11.0MVAr -26.3MW/10.4MVAr
15.0MW/-5.9MVAr
GREENWICH Wind Farm 0.0MW 0.0MVAr
M23L M24L *229.4km MxL*
TCPL Nipigon 36.0MW -7.3MVAr
Alexander 31.0MW -3.6MVAr
R9A ALEXANDER *100.2km* A5A
-22.5MW -1.8MVAr
125.5kV
37.0MW -6.0MVAr Cameron Falls
AGUASABON 121.7kV
4.6km A1B
-39.2MW -5.5MVAr
21.0MW 1.8MVAr
TERRACE BAY 121.4kV
-0.1MW 7.4MVAr
39.0MW 10.0MVAr
KIMBERLEY CLARKE
0.0MW 0.0MVAr
T1M 11.2MW/9.1MVAr *58.9km*
Wawatay 6.0MW -4.4MVAr
Umbata Falls 11.0MW -0.8MVAr
Williams Mine 0.0MVAr
405.9kV
37.1MVAr
662.6MW -103.4MVAr
662.8MW -73.6MVAr
194.6MW/-32.9MVAr
194.6MW/-32.9MVAr
W21M W22M *168.3km WxM*
M2W 122.8kV
24.8MW/20.7MVAr
T11: 18.1MW/15.3MVAr
T12: 18.1MW/15.3MVAr
T1: 36.0MW/8.0MVAr
T2: 35.7MW/8.0MVAr
OUT-OF-SERVICE *OUT-OF-SERVICE*
WAWA 240.0kV
P25W P26W
201.9MW -23.6MVAr
122.2kV ANJIGAMI
Σ 713.0MW
GLP Generation

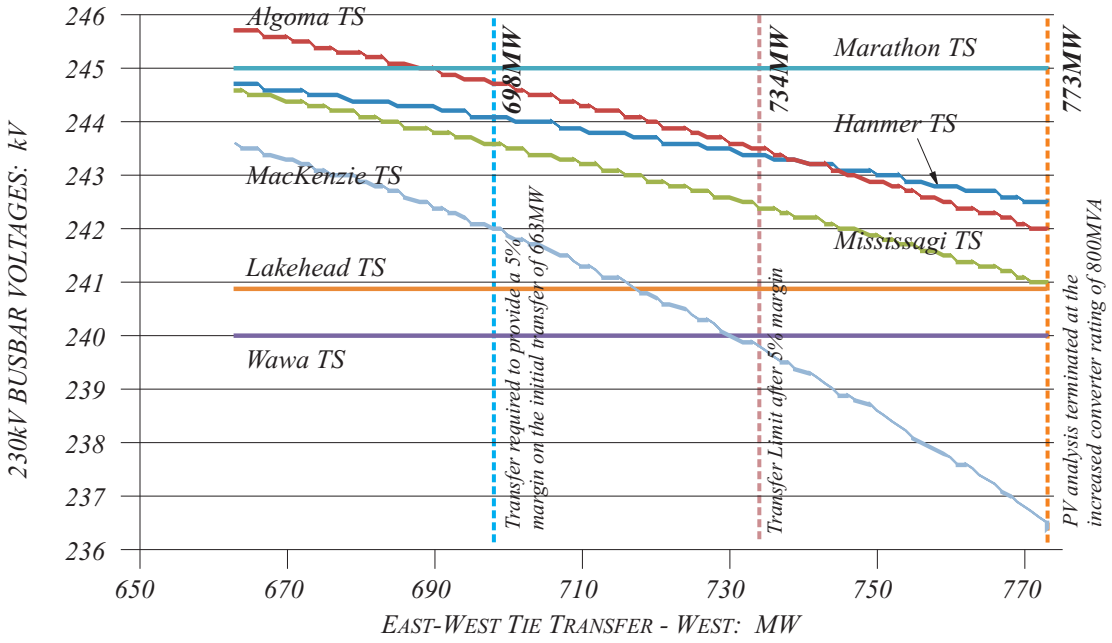
East West Tie Reinforcement: Lakehead TS to Wawa TS

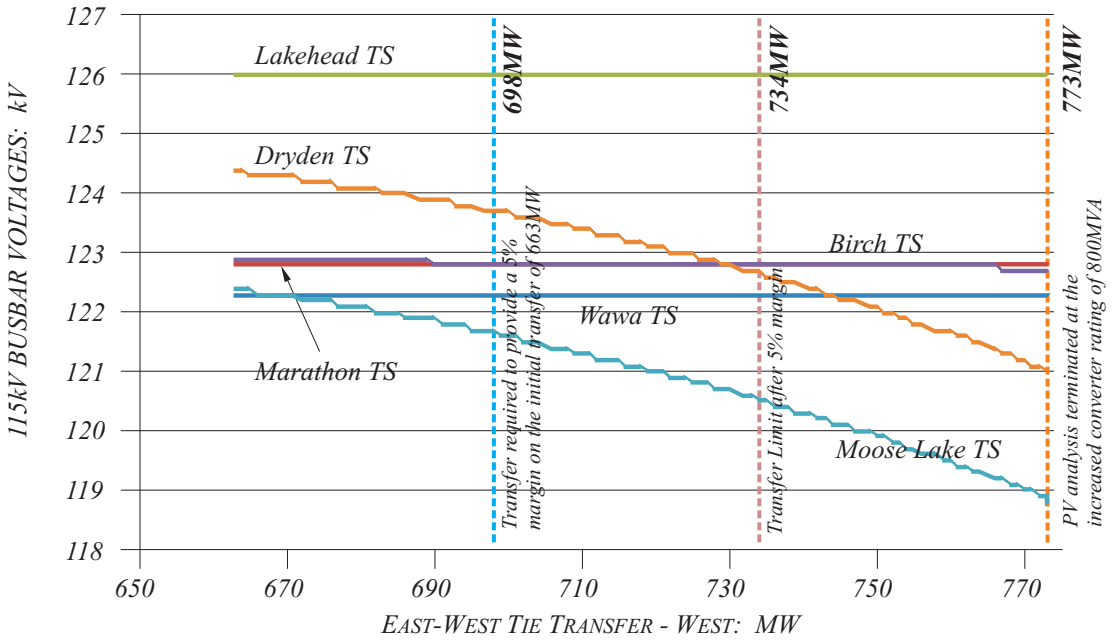
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS

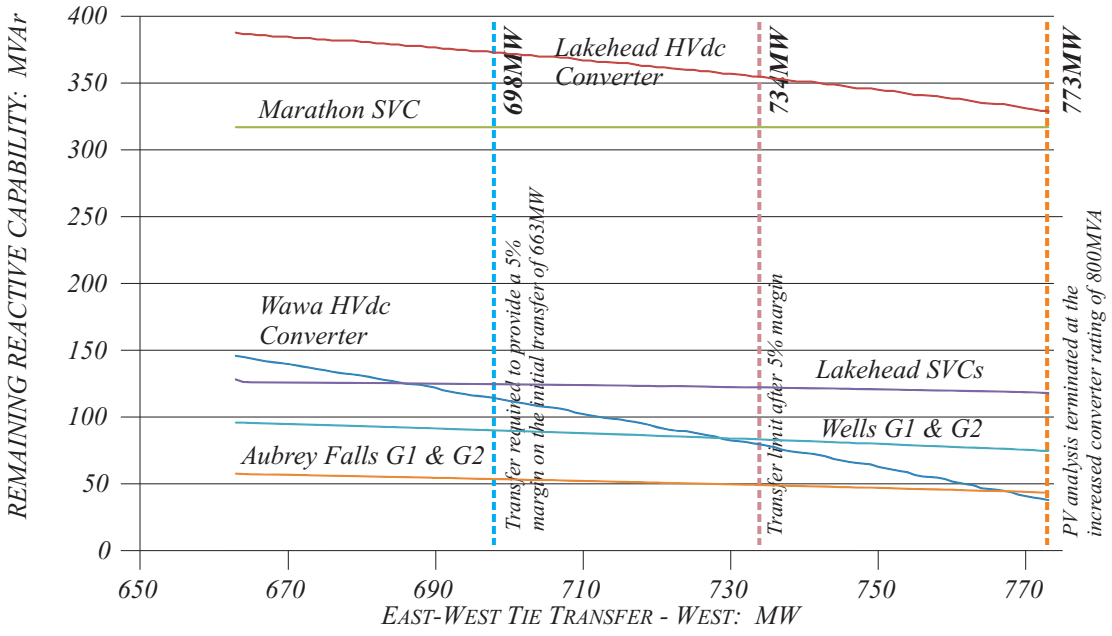
Contingency: *Double-circuit contingency between Wawa & Marathon - W21M & W22M*
HVdc transfer adjusted to 620MW at the Lakehead terminal

DIAGRAM 10

9th November 2012







East-West Tie Reinforcement:

Case with a new HVdc Link between Wawa TS & Lakehead TS
With a +250/-100MVAr SVC at Marathon TS
Contingency: Double-circuit contingency between Wawa Ts & Marathon TS
HVdc post-contingency transfer increased to 620MW

PV-analysis

Post-Contingency

DIAGRAM 11

9th November 2012

Ontario	*Load:*	*26020MW*
	Losses:	*816MW*
North-west	*Load:*	*950MW*
	Losses:	*87MW*
North-east	*Load:*	*1241MW*
	Losses:	*62MW*

IMPORTS

MANITOBA:	*-9.0MW*
MINNESOTA:	*2.2MW*
MICHIGAN:	*-89.3MW*
NEW YORK: At Niagara	*-0.3MW*
At St Lawrence	*0.0MW*

Σ 390MW
NW Generation

RED LAKE 121.9kV
56.2MW -1.1MVAr
46.59kV 56.0MW 11.1MVAr
16.6MVAr
58.1MW 1.8MVAr
MANITOU FALLS 127.4kV
126.1kV EAR FALLS
33.0MW 9.5MVAr
3.1MW 1.2MVAr
23.0MW -17.3MVAr
7.0MW -3.9MVAr
Lac Seul 5.0MW -4.2MVAr
Caribou Falls 41.0MW/18.4MVAr
Whitedog Falls 32.0MW/9.5MVAr
MANITOBA ONTARIO
-9.0MW -39.9MVAr
Winnipeg River
11.3MW -7.0MVAr
41.4MW -13.8MVAr
125.3kV DRYDEN
KENORA K22W K21W K23D
244.5kV
WHITESHELL
Phase-Shifters PS7: 54.4° PS8 54.4°
-38.9MVAr
-8.2MVAr -10.0MVAr
244.2kV
0.0MVAr -1.8MVAr
76.8MW
4.0MW 8.1MVAr
47.8MW -8.0MVAr
42.7MW -9.2MVAr
Valora
D26A
K24F
West Coast Energy 20.0MW -4.7MVAr
80.2MW -0.5MVAr
242.6kV 230kV
FORT FRANCES
115kV 122.1kV 13.2kV
2.2MW -19.7MVAr 0.0MVAr
43.4MVAr 0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 28.3°
INTERNATIONAL FALLS 115kV
F25A
243.3kV MACKENZIE
-41.5MVAr
A21L A22L
240.9kV
189.2MW -20.7MVAr
N93A
ATIKOKAN
0.0MVAr 0.0MVAr
0.0MVAr 0.0MVAr
BIRCH 25kV 115kV 122.8kV
0.0MVAr 72.8MVAr
Ft William 0.0MVAr
THUNDER BAY G2 G3
0.0MW 0.0MVAr
0.0MW 0.0MVAr
Kakabeka Falls 10.0MW -0.6MVAr
Silver Falls 24.0MW -4.0MVAr
Sturgeon Falls 4.0MW/0.0MVAr
Calm Lake 5.0MW/-1.4MVAr
Valerie Falls 3.0MW/1.5MVAr
Thierry Mine 11.7MW 3.0MVAr
Placer Jct 124.0kV
6.0MW -11.9MVAr
45.2MW -16.0MVAr
1.5MW 0.7MVAr
27.39kV CROW RIVER
8.8MVAr
124.2kV
-2.0MVAr SVC 33.0MVAr
4.6kV
40.0MW 5.0MVAr
MUSSELWHITE MINE
40.3MW -18.3MVAr
SVC 35.5MVAr 570.0MW
230kV 115kV
119.9MW -1.8MVAr
-1.8MVAr Lakehead SVCs
94.5MVAr
126.0kV
GREENWICH WIND FARM
OUT-OF-SERVICE
OUT-OF-SERVICE
LAKEHEAD
A21L
A22L
NEW
M23L
M24L
MARATHON
OUT-OF-SERVICE 25.8MW/-2.6MVAr
OUT-OF-SERVICE 25.8MW/-2.6MVAr
245.0kV SVC
Marathon Tertiaries
0.0MVAr 37.4MVAr
0.0MVAr 37.4MVAr
-42.3MVAr 0.0MVAr
EAST-WEST TRANSFER
WEST INTERFACE
659.4MW -71.2MVAr
NEW
W21M
W22M
36.2MVAr SVC 0.0MVAr
Wawa Tertiaries
0.0MVAr 0.0MVAr
0.0MVAr 0.0MVAr
0.0MVAr 0.0MVAr
240.0kV
WAWA
0.0MVAr
387.0MW -64.2MVAr
147.8km
200.7MW -23.0MVAr
G2 65.0MW/4.1MVAr
G1 65.0MW/4.1MVAr
AUBREY FALLS
240.4kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
242.5kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
128.1MW -5.4MVAr
THIRD LINE 115kV 230kV
242.6kV
121.7kV
34.5kV
23.6MVAr 23.7MVAr
CLERGUE
LAKE SUPERIOR POWER
G1: 40.0MW/5.9MVAr
G2: 40.0MW/5.9MVAr
G3: 22.0MW/3.2MVAr
ECHO RIVER
St Mary's Tarentorus
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
GREAT LAKES POWER Co.
71.0MW/2.6MVAr
P21G P22G
230kV
244.6kV SVC 0.0MVAr
T27P T28P G2 G1
WELLS
100.0MW 3.6MVAr
100.0MW 3.6MVAr
P25W P26W 56.0km
276.8MW -20.1MVAr
*** MISSISSAGI (East circuits) FLOW WEST
SUDBURY FLOW WEST
349.8MW/-24.9MVAr
MISSISSAGI
347.8MW -17.5MVAr ***
112.5MW -3.8MVAr
120.7MW/-8.5MVAr
116.6MW/-12.6MVAr
A23P 58.5km
A24P
117.6MW/-6.9MVAr
117.7MW/-6.8MVAr
X74P 205.8km
X27A
S21N
S22A
245.8kV
0.0MVAr
0.6MW/23.6MVAr
-0.7MW/-21.4MVAr
124.5kV
ALGOMA
Silver Falls 24.0MW -4.0MVAr
18.5MW/1.5MVAr P5M
124.3kV PORT ARTHUR
240.9kV LAKEHEAD
R1LB A7L L3P L4P A6P R2LB A8L
126.0kV
-72.4MW/-4.8MVAr
-35.4MW/-17.9MVAr
P3B P7B R1LB R2LB
20.0MW 9.0MVAr
-83.0MW/-17.6MVAr
-79.3MW/-17.3MVAr
P1P
Provincial Paper 5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
18.5MW/1.5MVAr
B6M
122.8kV BIRCH
Q9B Q8B
10.0MW -0.6MVAr Kakabeka GS
55.0MW 26.0MVAr
Q5B Q4B
FORT WILLIAM
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
58.7MW 25.1MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
Q4B Q5B
121.9kV
122.8kV THUNDER BAY
G2 G3
0.0MW 0.0MVAr
0.0MW 0.0MVAr
0.0MW 0.0MVAr

Σ 1383MW
NE Generation

119.5MW 38.4MVAr
126.8kV
542.0kV 500kV PORCUPINE 243.9kV
115kV
230kV SVC 0.0MVAr
141.6MW -175.0MVAr
0.0MVAr
P502X
141.2MW -17.1MVAr
145.9MVAr
543.5kV
115.0MW/-19.7MVAr
HANMER 500kV
244.7kV 230kV
143.9MW/63.8MVAr
FROOD
X23N X27A X25S
184.9MVAr
144.6MVAr
54.7MW -0.4MVAr
S21N
X26S
INCO
155.8MW -10.3MVAr
230kV
243.9kV MARTINDALE
CLARABELLE
48.8MW -5.2MVAr
H24S Martindale 115kV Otto Holden
H23S
30.0MW -14.9MVAr
WIDDIFIELD
TRANSCANADA NORTH BAY
Hanmer: Tertiary Reactors
0.0MVAr -56.7MVAr -56.7MVAr 0.0MVAr
X503E: -269.4MW/-134.1MVAr
X504E: -270.3MW/11.4MVAr
Dymond
15.5MW -15.9MVAr
X504E X503E
548.9kV 549.0kV
50% 50%
554.4kV 554.5kV
242.3kV PARRY SOUND
E27 E26
-271.4MW 71.0MVAr
-270.5MW 71.0MVAr
WAUBASHENE
242.3kV
X504E X503E
-272.9MW 262.1MVAr
-272.0MW 261.6MVAr
-590.4MW
FLOW SOUTH INTERFACE
OTTO HOLDEN
-45.5MW -15.5MVAr
D5H
DES JOACHIMS
90.1MW -15.6MVAr
542.3kV 500kV ESSA 230kV 242.5kV
230.7MVAr

122.4kV
MOOSE LAKE
B6M
13.3MW -6.6MVAr
Murillo Jct
18.5MW 1.5MVAr
BIRCH 122.8kV
397.3kV
569.8MW -92.8MVAr
570.0MW -78.7MVAr
35.5MVAr
LAKEHEAD
240.9kV
A21L A22L
191.8km AxL
T7: 187.0MW/45.3MVAr
T8: 188.8MW/45.8MVAr
126.0kV
94.5MVAr
R1LB: 59.2MW/25.3MVAr
R2LB: 51.4MW/24.8MVAr
A7L: -27.4MW/10.7MVAr
A8L: -31.9MW/9.3MVAr
L4P: 108.8MW/58.9MVAr
L4P R1LB A7L R2LB A8L A6P
124.3kV
-28.2MW/9.7MVAr
PORT ARTHUR
0.0MVAr
20.0MW 9.0MVAr
64.0MW -18.5MVAr
125.4kV PINE PORTAGE
-24.7MW/11.5MVAr
-28.8MW/10.9MVAr
0.2MW/-4.9MVAr
OUT-OF-SERVICE
OUT-OF-SERVICE
GREENWICH Wind Farm
-1.8MVAr Lakehead SVCs
-1.8MVAr
TCPL Nipigon 36.0MW -7.3MVAr
Alexander 31.0MW -3.7MVAr
R9A ALEXANDER 100.2km A5A
125.6kV
-6.7MW -5.2MVAr
37.0MW -6.0MVAr
Cameron Falls
AGUASABON 4.6km A1B
121.8kV
-23.7MW -9.8MVAr
21.0MW 1.3MVAr
TERRACE BAY 15.4MW 3.0MVAr
15.4MW 3.0MVAr
58.9km T1M
121.5kV
KIMBERLEY CLARKE
39.0MW 10.0MVAr
0.0MW 0.0MVAr
MARATHON
OUT-OF-SERVICE 25.8MW/-2.6MVAr
OUT-OF-SERVICE 25.8MW/-2.6MVAr
245.0kV
T11: 25.8MW/13.7MVAr
T12: 25.8MW/13.7MVAr
123.0kV M2W
24.8MW/20.9MVAr
26.7MW/5.1MVAr
M23L M24L 229.4km MxL
W21M W22M 168.3km WxM
Wawatay 6.0MW -4.4MVAr
Umbata Falls 11.0MW -1.1MVAr
Williams Mine 0.0MVAr
401.3kV
36.2MVAr
607.0MW -21.1MVAr
607.2MW -1.8MVAr
193.5MW/-32.1MVAr
193.5MW/-32.1MVAr
WAWA
240.0kV
P25W P26W
T1: 36.0MW/8.0MVAr
T2: 35.7MW/8.0MVAr
26.1MW/-34.7MVAr
26.1MW/-34.7MVAr
200.7MW -23.0MVAr
122.2kV ANJIGAMI
Σ 713.0MW
GLP Generation

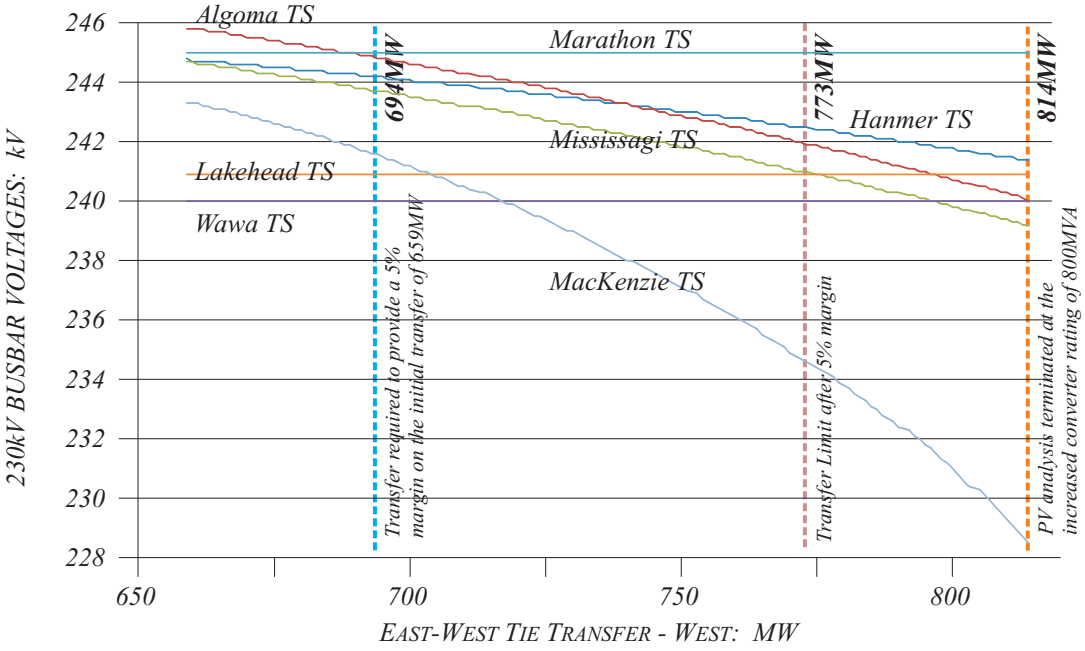
East West Tie Reinforcement: Lakehead TS to Wawa TS

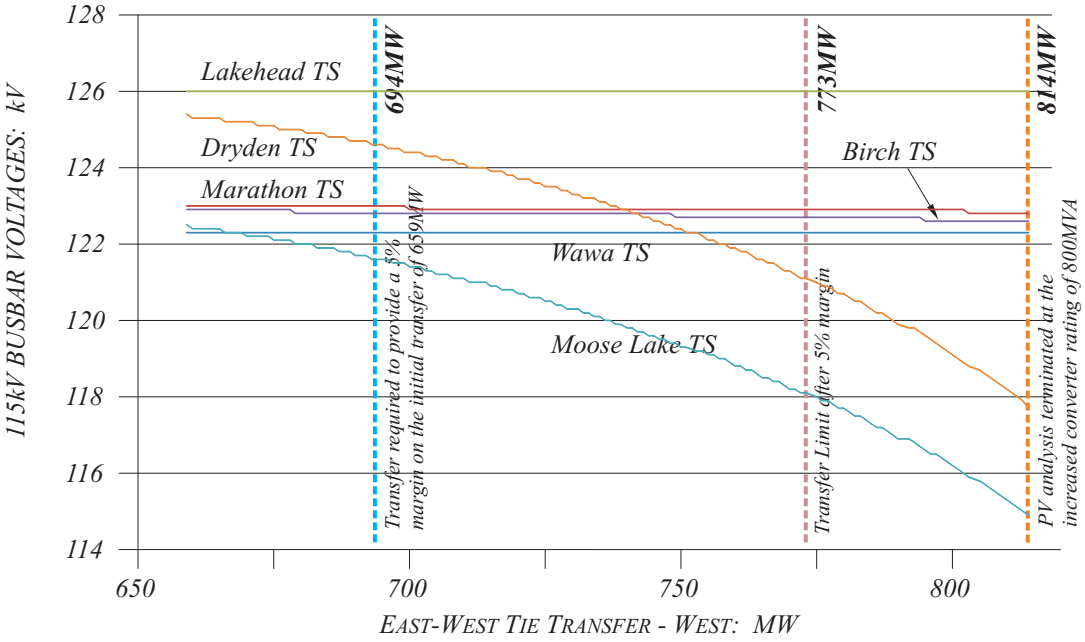
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS

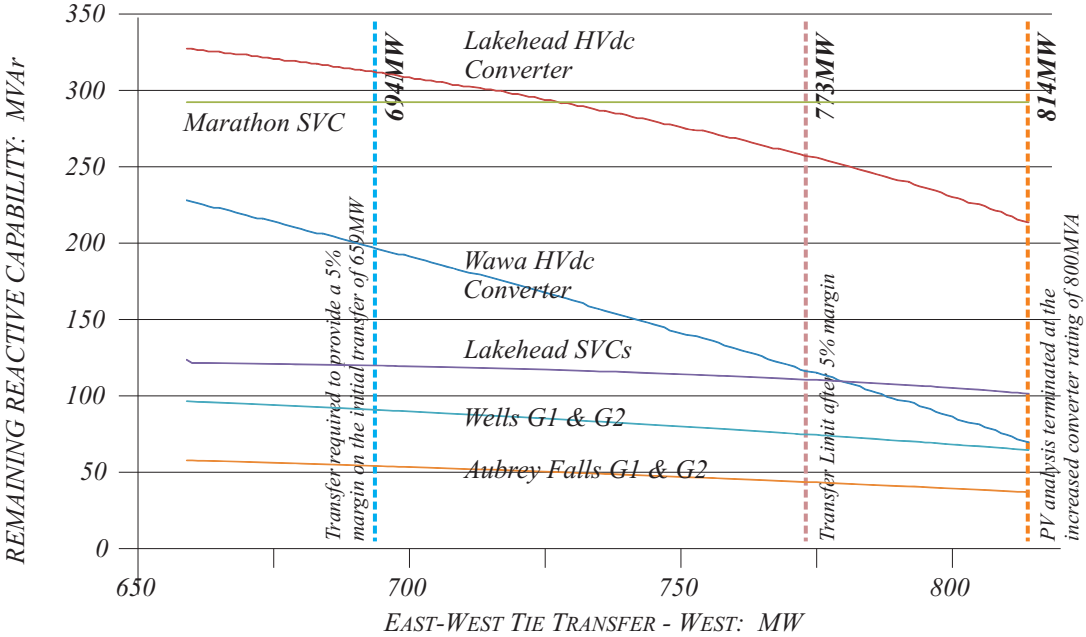
Contingency: *Double-circuit contingency between Marathon & Lakehead - M23L & M24L*
HVdc transfer adjusted to 570MW at the Lakehead terminal

DIAGRAM 12

8th November 2012







East-West Tie Reinforcement:

Case with a new HVdc Link between Wawa TS & Lakehead TS
With a +250/-100MVAr SVC at Marathon TS
Contingency: Double-circuit contingency between Marathon TS & Lakehead TS
HVdc post-contingency transfer increased to 570MW

PV-analysis

Post-Contingency

DIAGRAM 13

10th December 2012

Ontario	*Load:*	*26020MW*
	Losses:	*868MW*
North-west	*Load:*	*950MW*
	Losses:	*141MW*
North-east	*Load:*	*1241MW*
	Losses:	*61MW*

IMPORTS

MANITOBA:	*53.8MW*
MINNESOTA:	*2.8MW*
MICHIGAN:	*-99.0MW*
NEW YORK: At Niagara	*-1.1MW*
At St Lawrence	*-0.3MW*

Σ 390MW
NW Generation

RED LAKE 121.8kV
56.2MW -1.1MVAr
46.54kV 56.0MW 11.1MVAr
16.6MVAr
58.1MW 1.8MVAr
MANITOU FALLS 127.3kV
126.0kV EAR FALLS
33.0MW 10.0MVAr
3.1MW 1.2MVAr
23.6MW -17.6MVAr
7.0MW -3.9MVAr
Lac Seul 5.0MW -4.2MVAr
Caribou Falls 41.0MW/17.3MVAr
Whitedog Falls 32.0MW/8.1MVAr
MANITOBA ONTARIO
53.8MW -50.4MVAr
Winnipeg River
42.0MW -14.3MVAr
40.3MW 15.8MVAr
K22W KENORA
K21W
246.0kV WHITESHELL
Phase- PS7: 86.4°
Shifters PS8 86.4°
-39.2MVAr
246.6kV
14.6MW -12.7MVAr
K23D
246.6kV
0.0MVAr
49.9MW -3.6MVAr
125.0kV DRYDEN
10.3MW 4.2MVAr
47.2MW -7.9MVAr
42.2MW -8.9MVAr
Valora
D26A
K24F
West Coast Energy 20.0MW -7.1MVAr
51.4MW 7.7MVAr
244.2kV 230kV F25A
FORT FRANCES
115kV 122.7kV 13.2kV
2.8MW -20.6MVAr 6.0MVAr
43.9MVAr 0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 68.8°
INTERNATIONAL FALLS 115kV
Thierry Mine 11.7MW 3.0MVAr
Placer Jct 124.0kV
45.1MW -16.0MVAr
1.5MW 0.7MVAr
27.4kV CROW RIVER
6.4MW -12.5MVAr
8.8MVAr
124.2kV
-2.0MVAr SVC 4.6kV
40.0MW 5.0MVAr
33.0MVAr
MUSSELWHITE MINE
40.2MW -18.3MVAr
Sturgeon Falls 4.0MW/0.0MVAr
Calm Lake 5.0MW/-1.4MVAr
Valerie Falls 3.0MW/0.8MVAr
Silver Falls 24.0MW -4.0MVAr
THUNDER BAY G2 G3
0.0MW 0.0MVAr
0.0MW 0.0MVAr
0.0MW 0.0MVAr
Kakabeka Falls 10.0MW -0.7MVAr
BIRCH 25kV 115kV 122.8kV
0.0MVAr
72.8MVAr
Ft William 0.0MW
ATIKOKAN
130.8MW -15.5MVAr
N93A
0.0MVAr
SVC
0.0MW
OUT-OF-SERVICE
A21L
A22L
240.2kV
230kV
LAKEHEAD
119.2MVAr
16.9MVAr 16.9MVAr Lakehead SVCs
94.5MVAr
-41.9MVAr
245.1kV MACKENZIE
126.0kV
238.6kV GREENWICH WIND FARM
0.0MW 0.0MVAr
225.4MW/-58.7MVAr
225.4MW/-58.6MVAr

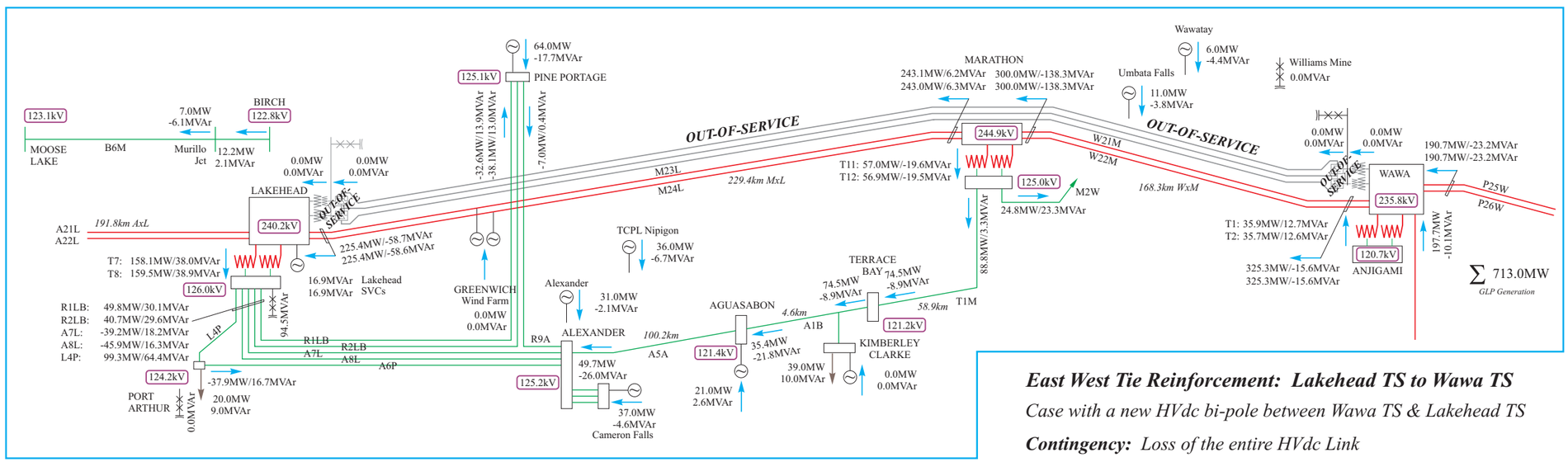
EAST-WEST TRANSFER WEST INTERFACE
650.6MW -31.2MVAr
NEW OUT-OF-SERVICE M23L M24L
NEW OUT-OF-SERVICE W21M W22M
MARATHON
243.1MW/6.2MVAr 300.0MW/-138.3MVAr
243.0MW/6.3MVAr 300.0MW/-138.3MVAr
244.9kV
Marathon Tertiaries
0.0MVAr 37.4MVAr 0.0MVAr 37.4MVAr
SVC 250.0MVAr 0.0MVAr
OUT-OF-SERVICE
WAWA
0.0MVAr
235.8kV
Wawa Tertiaries
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
381.4MW -46.4MVAr
147.8km
197.7MW -10.1MVAr
238.1kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
241.1kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
125.5MW 0.6MVAr
THIRD LINE 115kV 230kV
241.4kV
23.3MVAr 23.5MVAr
34.5kV
CLERGUE 121.2kV
LAKE SUPERIOR POWER
G1: 40.0MW/7.3MVAr
G2: 40.0MW/7.3MVAr
G3: 22.0MW/4.0MVAr
St Mary's 0.0MVAr 0.0MVAr
Tarentorus 0.0MVAr 0.0MVAr
ECHO RIVER
GREAT LAKES POWER Co.
65.0MW/7.3MVAr
G2 G1 AUBREY FALLS
P25W P26W 30.6km
68.0MW/0.5MVAr
P21G P22G
230kV
WELLS G2 G1
100.0MW 6.4MVAr
100.0MW 6.3MVAr
243.7kV SVC 0.0MVAr
114.5MW/-3.6MVAr
114.6MW/-3.6MVAr
245.2kV
0.6MW/22.9MVAr
-0.7MW/-21.6MVAr
124.2kV ALGOMA

**** MISSISSAGI (East circuits) FLOW WEST*
SUDBURY FLOW WEST
340.7MW/-17.1MVAr
270.8MW -8.9MVAr
MISSISSAGI
338.7MW -8.3MVAr ***
109.6MW -1.1MVAr
X74P 205.8km
117.6MW/-6.0MVAr
113.5MW/-10.0MVAr
X27A
A23P 58.5km
A24P
INCO
CLARABELLE
S21N
152.7MW -8.6MVAr
230kV 243.8kV MARTINDALE
48.5MW -4.9MVAr
X26S
H24S
H23S
Martindale 115kV Otto Holden
30.0MW -14.9MVAr
TRANSCANADA NORTH BAY
WIDDIFIELD
13.5MW -13.8MVAr
Dymond

Silver Falls 24.0MW -4.0MVAr
12.2MW/2.1MVAr
P5M
124.2kV PORT ARTHUR
L3P L4P
240.2kV LAKEHEAD
R1LB A7L R2LB A8L A6P
126.0kV
-72.5MW/-3.5MVAr
-33.1MW/-18.4MVAr
P3B P7B R1LB R2LB P1P
20.0MW 9.0MVAr
-80.8MW/-18.0MVAr
-77.2MW/-17.7MVAr
Provincial Paper 5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
12.2MW/2.1MVAr
B6M 122.8kV
10.0MW -0.7MVAr Kakabeka GS
55.0MW 26.0MVAr
BIRCH
Q9B Q8B
Q5B Q4B
FORT WILLIAM
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
58.7MW 25.1MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
Q5B
121.9kV
THUNDER BAY 122.8kV
G2 G3
0.0MW 0.0MVAr 0.0MW 0.0MVAr

Σ 1405MW
NE Generation

119.5MW 38.6MVAr
126.8kV 115kV
541.9kV 500kV PORCUPINE
230kV 243.8kV
141.6MW -174.7MVAr
SVC 0.0MVAr 0.0MVAr
P502X
141.2MW -16.9MVAr
Hanmer: Tertiary Reactors
0.0MVAr -56.7MVAr -56.6MVAr 0.0MVAr
145.9MVAr
112.0MW/-18.0MVAr
244.6kV HANMER 500kV 543.4kV
230kV
X503E: -265.0MW/-135.8MVAr
X504E: -265.9MW/9.7MVAr
143.8MW/63.9MVAr
FROOD
184.8MVAr 144.6MVAr
X27A X23N X25S
54.3MW -0.1MVAr
X504E X503E
549.0kV 50% 549.0kV 50%
554.3kV 554.3kV
242.3kV PARRY SOUND
E27 E26
-266.0MW 69.2MVAr
-266.1MW 69.2MVAr
WAUBASHENE 242.3kV
-268.4MW 260.7MVAr
-267.6MW 260.2MVAr
542.3kV 500kV ESSA
230kV 230.7MVAr
242.5kV
90.1MW -15.6MVAr
-580.8MW
FLOW SOUTH INTERFACE
OTTO HOLDEN
-15.4MW -15.5MVAr
DSH
DES JOACHIMS



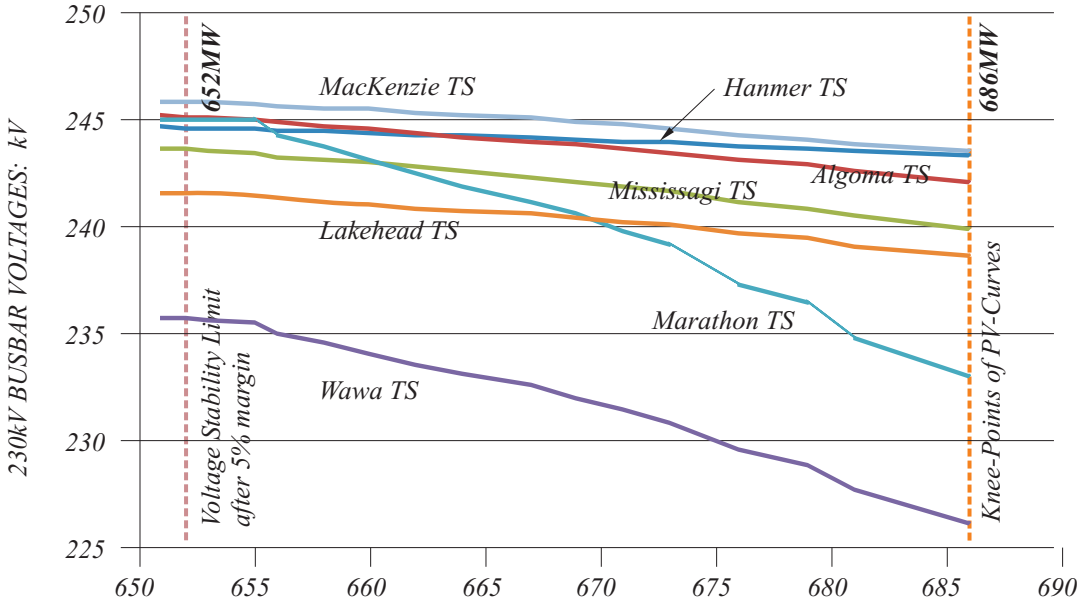
East West Tie Reinforcement: Lakehead TS to Wawa TS

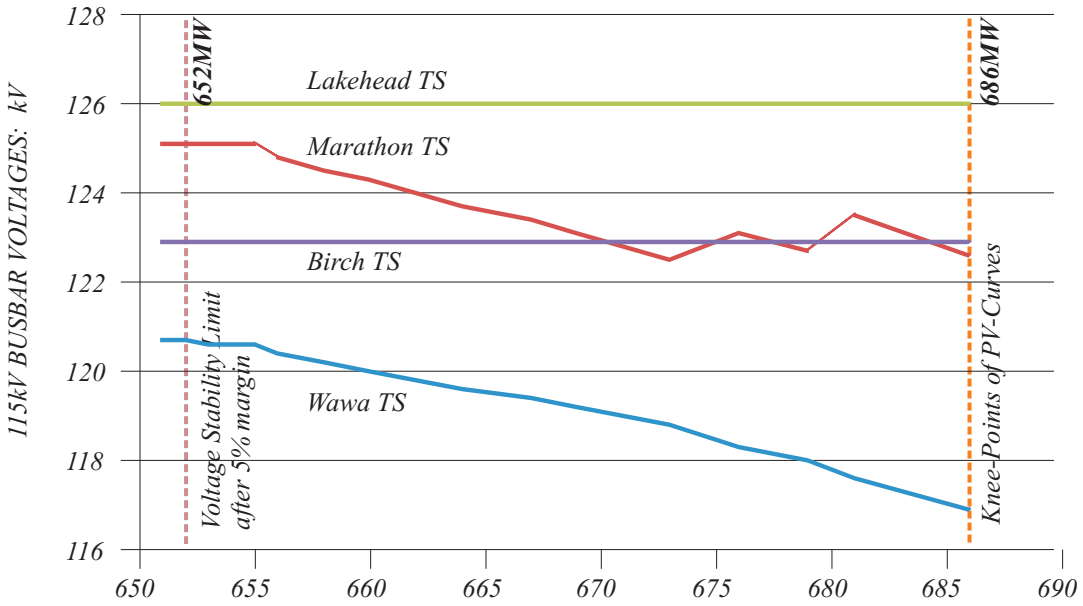
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS

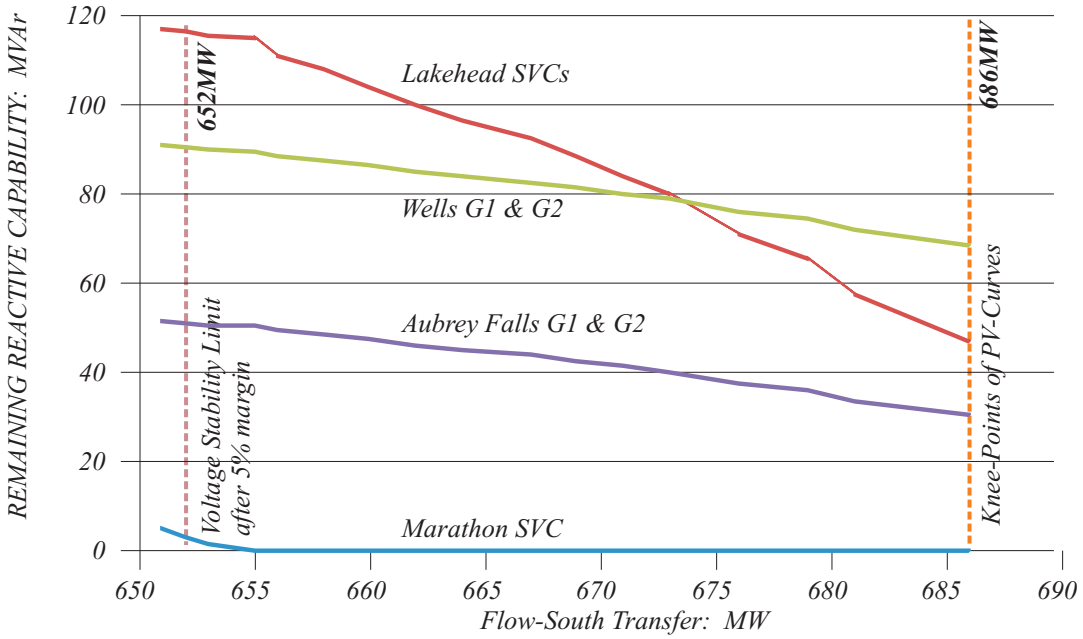
Contingency: *Loss of the entire HVdc Link*

DIAGRAM 14

1st November 2012







East-West Tie Reinforcement:
Case with a new HVdc Link between Wawa TS & Lakehead TS
With a +250/-100MVAr SVC at Marathon TS
Contingency: Loss of the Entire HVdc Link

PV-analysis

Post-Contingency

DIAGRAM 15

2nd November 2012

Ontario	*Load:*	*26020MW*
	Losses:	*872MW*
North-west	*Load:*	*950MW*
	Losses:	*144MW*
North-east	*Load:*	*1241MW*
	Losses:	*61MW*

IMPORTS

MANITOBA:		*53.4MW*
MINNESOTA:		*2.5MW*
MICHIGAN:		*-95.1MW*
NEW YORK:	*At Niagara*	*-0.7MW*
	At St Lawrence	*-0.2MW*

Σ 390MW
NW Generation

RED LAKE 121.9kV
56.2MW -1.1MVAr
46.56kV
56.0MW 11.1MVAr
16.6MVAr
58.1MW 1.8MVAr
MANITOU FALLS 127.3kV
126.1kV EAR FALLS
23.6MW -17.7MVAr
3.1MW 1.2MVAr
7.0MW -3.9MVAr
Lac Seul
5.0MW -4.2MVAr
33.0MW 9.8MVAr
Caribou Falls
41.0MW/17.2MVAr
Whitedog Falls
32.0MW/8.0MVAr
42.0MW -14.2MVAr
125.1kV DRYDEN
MANITOBA ONTARIO
53.4MW -51.0MVAr
Winnipeg River
K22W KENORA
40.1MW 16.2MVAr
K21W
246.1kV
WHITESHELL
Phase- PS7: 86.4°
Shifters PS8 86.4°
-39.3MVAr
14.6MW -12.9MVAr
246.9kV
K23D
0.0MVAr
50.1MW 4.1MVAr
10.2MW 4.1MVAr
47.2MW -7.9MVAr
42.2MW -8.9MVAr
Valora
D26A
K24F
West Coast Energy
20.0MW -7.4MVAr
51.7MW 8.3MVAr
244.4kV 230kV
F25A
FORT FRANCES
115kV 122.8kV 13.2kV
2.5MW -20.7MVAr
6.0MVAr
43.9MVAr
0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 68.8°
INTERNATIONAL FALLS 115kV
Thierry Mine
11.7MW 3.0MVAr
Placer Jct 124.1kV
45.1MW -15.9MVAr
1.5MW 0.7MVAr
27.42kV CROW RIVER
6.4MW -12.5MVAr
8.8MVAr
124.3kV
-2.2MVAr SVC
4.6kV
40.0MW 5.0MVAr
33.0MVAr
MUSSELWHITE MINE
40.2MW -18.2MVAr
Sturgeon Falls
4.0MW/0.0MVAr
Calm Lake
5.0MW/-1.4MVAr
Valerie Falls
3.0MW/0.6MVAr
Silver Falls
24.0MW -4.0MVAr
THUNDER BAY G2 G3
0.0MW 0.0MVAr
Kakabeka Falls
10.0MW -0.7MVAr
BIRCH 25kV 115kV 122.8kV
Ft William
0.0MW
0.0MW 0.0MVAr
ATIKOKAN
N93A
131.4MW -14.0MVAr
-42.0MVAr
0.0MVAr SVC 36.5MVAr -3.6MW
A21L
A22L
240.9kV
245.5kV MACKENZIE
LAKEHEAD 230kV 115kV
119.9MVAr
9.5MVAr 9.5MVAr Lakehead SVCs
94.5MVAr
126.0kV
239.1kV GREENWICH WIND FARM
0.0MW 0.0MVAr
227.4MW/-61.1MVAr
227.3MW/-61.0MVAr
OUT-OF-SERVICE
NEW M23L M24L
EAST-WEST TRANSFER WEST INTERFACE
654.4MW -68.2MVAr
NEW W21M W22M
MARATHON
245.3MW/5.5MVAr 302.5MW/-125.0MVAr
245.2MW/5.6MVAr 302.5MW/-125.0MVAr
245.0kV
Marathon Tertiaries
0.0MVAr 37.4MVAr 0.0MVAr 37.4MVAr
SVC 222.1MVAr 0.0MVAr
36.5MVAr
Wawa Tertiaries
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
WAWA
240.0kV
0.0MVAr
198.9MW -22.1MVAr
363.9MW -52.1MVAr
147.8km
65.0MW/3.8MVAr
G2 G1 AUBREY FALLS
240.4kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
242.6kV
126.5MW -5.2MVAr
242.7kV
THIRD LINE 115kV 230kV
23.6MVAr 34.5kV 23.7MVAr
CLERGUE
LAKE SUPERIOR POWER
121.7kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
G1: 40.0MW/5.8MVAr
G2: 40.0MW/5.8MVAr
G3: 22.0MW/3.2MVAr
ECHO RIVER
St Mary's Tarentorus
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
GREAT LAKES POWER Co.
P21G P22G
WELLS G2 G1
100.0MW 3.3MVAr
100.0MW 3.2MVAr
T27P T28P
69.1MW/3.6MVAr
230kV
244.8kV SVC 0.0MVAr
0.0MVAr
*** MISSISSAGI (East circuits) FLOW WEST ***
SUDBURY FLOW WEST
344.4MW/-23.7MVAr
273.4MW -19.7MVAr
MISSISSAGI
342.5MW -16.1MVAr ***
110.8MW -3.3MVAr
118.9MW/-8.2MVAr
114.7MW/-12.2MVAr
X74P 205.8km
A23P 58.5km
A24P
115.8MW/-6.4MVAr
115.9MW/-6.4MVAr
245.9kV
0.6MW/23.8MVAr
-0.7MW/-21.4MVAr
124.6kV
ALGOMA
Silver Falls
24.0MW -4.0MVAr
12.2MW/1.9MVAr
P5M
124.2kV
PORT ARTHUR
L3P L4P
240.9kV
LAKEHEAD
R1LB A7L R2LB A8L A6P
126.0kV
-72.6MW/-3.5MVAr
-33.1MW/-18.4MVAr
P3B P7B R1LB R2LB
20.0MW 9.0MVAr
P1P
-80.8MW/-18.0MVAr
-77.2MW/-17.6MVAr
Provincial Paper
5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
12.2MW/1.9MVAr
B6M
122.8kV
55.0MW 26.0MVAr
10.0MW -0.7MVAr Kakabeka GS
BIRCH
Q9B Q8B
Q5B Q4B
FORT WILLIAM
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
58.7MW 25.1MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
Q4B Q5B
121.9kV
THUNDER BAY
122.8kV
G2 G3
0.0MW 0.0MVAr 0.0MW 0.0MVAr

Σ 1383MW
NE Generation

119.5MW 38.1MVAr
126.8kV
115kV
542.1kV 500kV PORCUPINE
230kV 243.9kV
141.6MW -175.5MVAr
SVC 0.0MVAr
0.0MVAr
P502X
141.2MW -17.6MVAr
146.0MVAr
Hanmer: Tertiary Reactors
0.0MVAr -56.8MVAr -56.7MVAr 0.0MVAr
113.2MW/-20.0MVAr
HANMER 500kV
244.8kV 230kV 543.7kV
X503E: -266.8MW/-133.8MVAr
X504E: -267.7MW/11.8MVAr
185.1MVAr
144.7MVAr
143.8MW/63.8MVAr
FROOD
X27A X23N X25S
S21N
153.9MW -10.5MVAr
54.5MW -0.5MVAr
48.6MW -5.3MVAr
230kV 244.0kV
MARTINDALE
X26S H24S H23S
Martindale 115kV Otto Holden
30.0MW -14.9MVAr
TRANSCANADA NORTH BAY
WIDDIFIELD
Dymond
13.5MW -13.9MVAr
INCO
CLARABELLE
X504E X503E
549.0kV 50% 549.1kV 50%
554.5kV 554.6kV
242.4kV
PARRY SOUND
E27 E26
-268.7MW 71.5MVAr
-267.9MW 71.4MVAr
WAUBASHENE
242.3kV
-270.3MW 262.8MVAr
-269.4MW 262.3MVAr
542.3kV 500kV
ESSA
230kV 242.6kV
230.7MVAr
90.1MW -15.6MVAr
OTTO HOLDEN
-45.1MW -15.2MVAr
DSH
DES JOACHIMS
-584.8MW
FLOW SOUTH INTERFACE

123.2kV
MOOSE LAKE
B6M
7.0MW -6.3MVAr
Murillo Jct
12.2MW 1.9MVAr
BIRCH 122.8kV
402.5kV
36.5MVAr
-3.6MW 20.2MVAr
-3.6MW -16.3MVAr
LAKEHEAD
240.9kV
A21L 191.8km AxL A22L
T7: 157.9MW/45.5MVAr
T8: 159.3MW/46.3MVAr
126.0kV
R1LB: 49.7MW/30.1MVAr
R2LB: 40.6MW/29.7MVAr
A7L: -39.3MW/18.3MVAr
A8L: -46.0MW/16.3MVAr
L4P: 99.2MW/64.4MVAr
94.5MVAr
L4P R1LB R2LB A7L A8L A6P
124.2kV
PORT ARTHUR
-38.0MW/16.7MVAr
0.0MVAr
20.0MW 9.0MVAr
227.4MW/-61.1MVAr
227.3MW/-61.0MVAr
9.5MVAr 9.5MVAr Lakehead SVCs
64.0MW -17.7MVAr
125.1kV PINE PORTAGE
-32.7MW/13.9MVAr
-38.1MW/13.1MVAr
-7.1MW/0.4MVAr
GREENWICH Wind Farm
0.0MW 0.0MVAr
TCPL Nipigon
36.0MW -6.7MVAr
Alexander
31.0MW -2.0MVAr
ALEXANDER
R9A
100.2km
A5A
50.1MW -26.2MVAr
125.2kV
37.0MW -4.5MVAr
Cameron Falls
AGUASABON
4.6km
A1B
121.4kV
35.9MW -21.9MVAr
21.0MW 2.7MVAr
TERRACE BAY
75.0MW -9.0MVAr
75.0MW -9.0MVAr
58.9km
121.2kV
KIMBERLEY CLARKE
39.0MW 10.0MVAr
0.0MW 0.0MVAr
T1M
89.4MW/3.4MVAr
MARATHON
245.3MW/5.5MVAr 302.5MW/-125.0MVAr
245.2MW/5.6MVAr 302.5MW/-125.0MVAr
OUT-OF-SERVICE
M23L M24L
229.4km MxL
245.0kV
T11: 57.2MW/-19.6MVAr
T12: 57.2MW/-19.4MVAr
125.1kV
M2W
24.8MW/23.3MVAr
W21M W22M
168.3km WxM
Wawatay
6.0MW -4.4MVAr
Umbata Falls
11.0MW -3.8MVAr
Williams Mine
0.0MVAr
403.0kV
36.5MVAr
0.0MW -19.6MVAr
0.0MW -55.6MVAr
OUT-OF-SERVICE
WAWA
240.0kV
T1: 36.0MW/8.0MVAr
T2: 35.7MW/8.0MVAr
327.2MW/-6.3MVAr
327.2MW/-6.3MVAr
122.2kV
ANJIGAMI
191.9MW/-31.1MVAr
192.0MW/-31.0MVAr
P25W P26W
198.9MW -22.1MVAr
Σ 713.0MW
GLP Generation

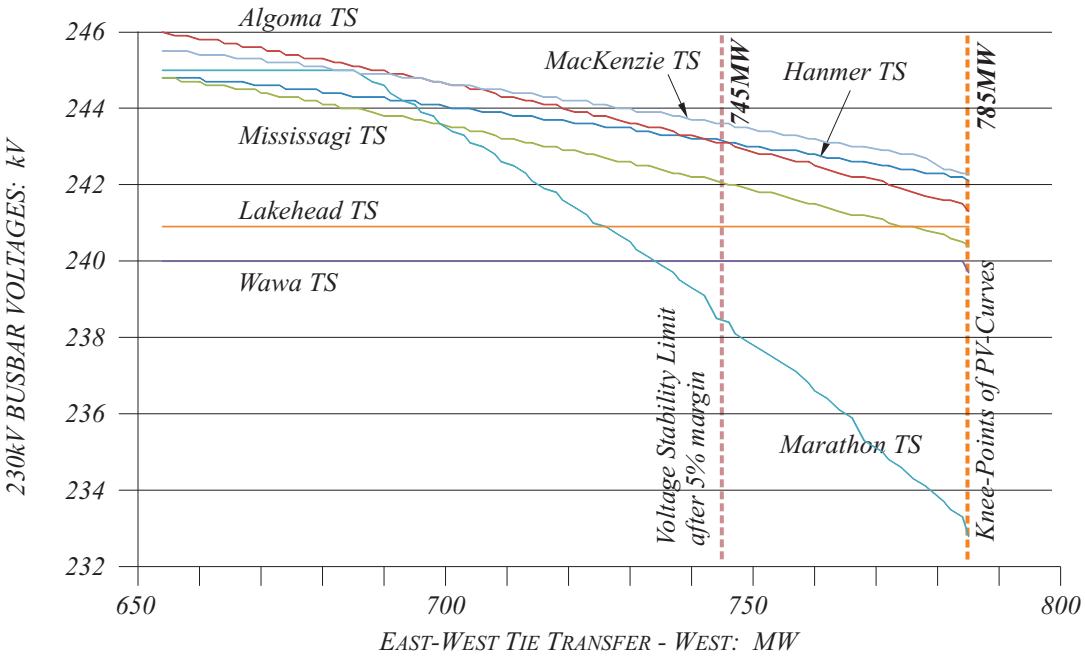
East West Tie Reinforcement: Lakehead TS to Wawa TS

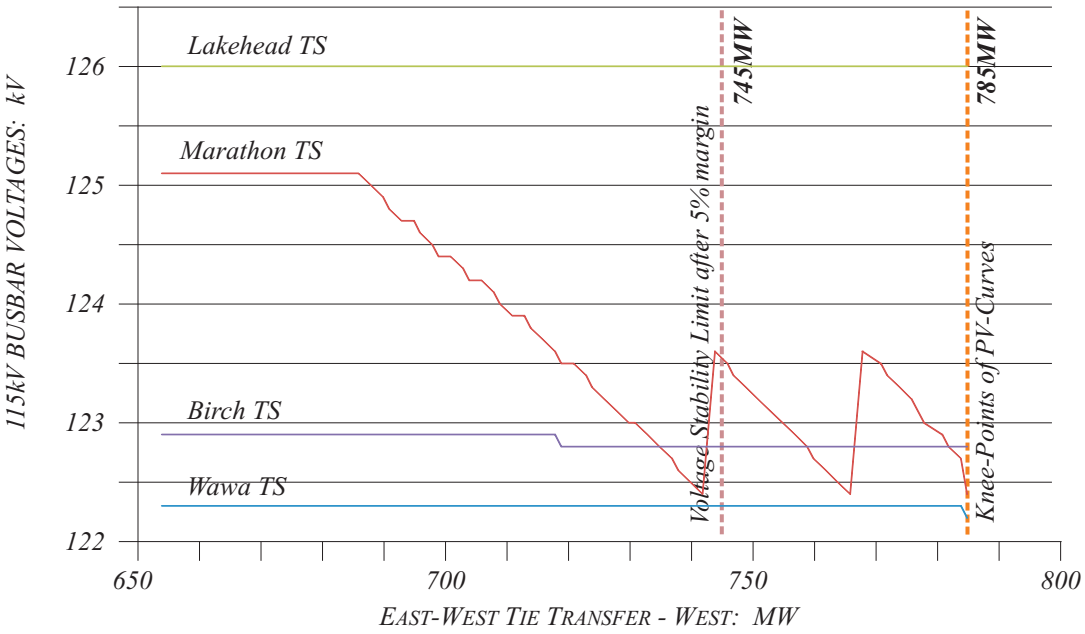
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS

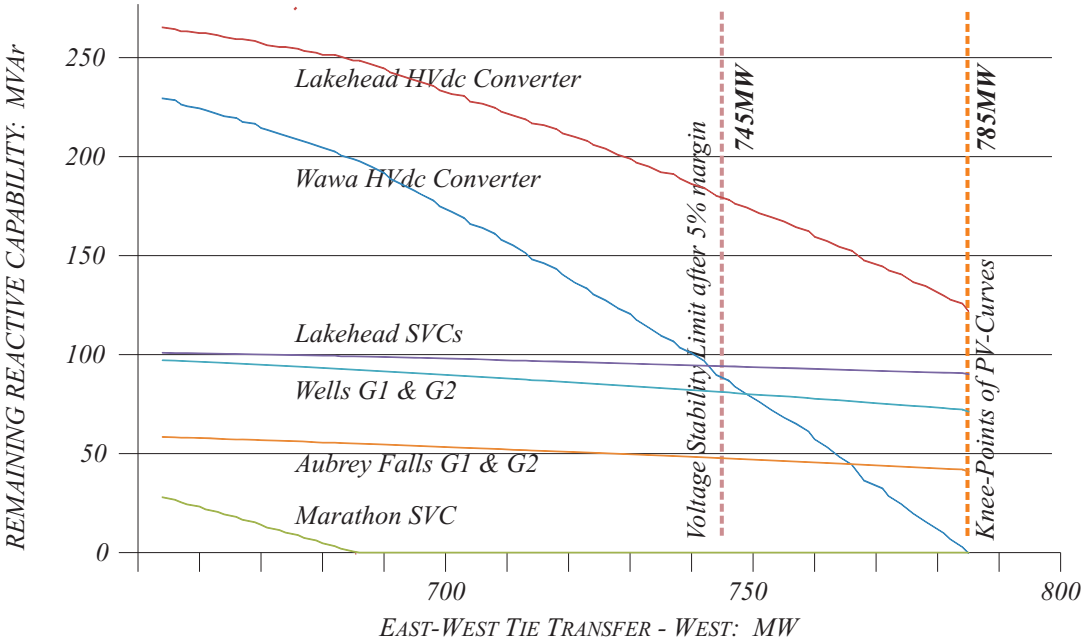
Contingency: *Loss of the HVdc line - the Wawa & Lakehead converters both remain in-service*

DIAGRAM 16

21st November 2012







East-West Tie Reinforcement:

Case with a new HVdc Link between Wawa TS & Lakehead TS
With a +250/-100MVAr SVC at Marathon TS
Contingency: Loss of the HVdc Line - Both Converters remain in-service

PV-analysis

Post-Contingency

DIAGRAM 17

11th December 2012

Ontario	*Load:*	*26020MW*
	Losses:	*870MW*
North-west	*Load:*	*950MW*
	Losses:	*143MW*
North-east	*Load:*	*1241MW*
	Losses:	*61MW*

IMPORTS

MANITOBA:	*54.2MW*
MINNESOTA:	*3.4MW*
MICHIGAN:	*-97.5MW*
NEW YORK: At Niagara	*-1.4MW*
At St Lawrence	*-0.4MW*

Σ 390MW
NW Generation

RED LAKE 121.9kV
56.2MW -1.1MVAr
46.56kV 56.0MW 11.1MVAr
16.6MVAr
58.1MW 1.8MVAr
MANITOU FALLS 127.3kV 126.1kV EAR FALLS
3.1MW 1.2MVAr
33.0MW 9.8MVAr
23.6MW -17.7MVAr
7.0MW -3.9MVAr
Lac Seul 5.0MW -4.2MVAr
Thierry Mine 11.7MW 3.0MVAr
Placer Jct 124.1kV
6.4MW -12.6MVAr
124.3kV MUSSELWHITE MINE
-2.2MVAr SVC 4.6kV
40.0MW 5.0MVAr
33.0MVAr
40.2MW -18.2MVAr
45.1MW -15.9MVAr
1.5MW 0.7MVAr
27.42kV CROW RIVER
8.9MVAr
Caribou Falls 41.0MW/17.2MVAr
Whitedog Falls 32.0MW/8.0MVAr
MANITOBA ONTARIO
54.2MW
-51.0MVAr
Winnipeg River
KENORA
K22W K21W K23D K24F
WHITESHELL
Phase- PS7: 86.4°
Shifters PS8 86.4°
246.1kV
-39.3MVAr
14.7MW -12.9MVAr
40.7MW 16.3MVAr
42.0MW -14.2MVAr
125.2kV DRYDEN
246.9kV
0.0MVAr
49.6MW -2.2MVAr
10.4MW 4.1MVAr
47.2MW -7.9MVAr
42.2MW -8.9MVAr
Sturgeon Falls 4.0MW/0.0MVAr
Calm Lake 5.0MW/-1.4MVAr
Valerie Falls 3.0MW/0.6MVAr
Valora
Silver Falls 24.0MW -4.0MVAr
Kakabeka Falls 10.0MW -0.8MVAr
THUNDER BAY G2 G3
0.0MW 0.0MVAr
0.0MW 0.0MVAr
BIRCH 25kV 115kV 122.8kV
72.8MVAr
Ft William 0.0MVAr
D26A
0.0MVAr 0.0MVAr
ATIKOKAN
N93A
129.8MW -13.8MVAr
West Coast Energy 20.0MW -7.4MVAr
50.7MW 8.6MVAr
244.4kV 230kV
F25A
245.5kV MACKENZIE
A21L A22L
-42.1MVAr
SVC 36.4MVAr -1.8MW
240.9kV
LAKEHEAD 230kV 115kV
119.9MW
9.4MVAr 9.4MVAr
Lakehead SVCs
94.5MVAr
126.0kV
239.2kV GREENWICH WIND FARM
0.0MW 0.0MVAr
225.8MW/-60.0MVAr
225.8MW/-59.8MVAr
FORT FRANCES 115kV 122.8kV 13.2kV
3.4MW -21.0MVAr 0.0MVAr
43.9MVAr 0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 68.7°
INTERNATIONAL FALLS 115kV

MARATHON
243.4MW/4.9MVAr 300.3MW/-138.8MVAr
243.4MW/5.0MVAr 300.3MW/-138.8MVAr
245.0kV
Marathon Tertiaries SVC
0.0MVAr 37.4MVAr 0.0MVAr 37.4MVAr
248.6MVAr
0.0MVAr
NEW M22L M24L
EAST-WEST TRANSFER WEST INTERFACE
651.4MW
-31.4MVAr
OUT-OF-SERVICE
NEW W21M W22M
WAWA
0.0MVAr
SVC 0.0MVAr
Wawa Tertiaries 0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
235.8kV
198.0MW -10.2MVAr
381.8MW -46.8MVAr
147.8km
G2 65.0MW/7.3MVAr
G1 65.0MW/7.3MVAr
AUBREY FALLS
P25W P26W 56.0km
238.1kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
241.1kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
125.7MW 0.6MVAr
THIRD LINE 115kV 230kV
121.1kV
241.3kV
CLERGUE
LAKE SUPERIOR POWER
G1: 40.0MW/7.3MVAr
G2: 40.0MW/7.3MVAr
G3: 22.0MW/4.0MVAr
34.5kV
23.3MVAr 23.5MVAr
St Mary's Tarentorus
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
ECHO RIVER
GREAT LAKES POWER Co.
68.2MW/0.4MVAr
P21G P22G
230kV
243.7kV
SVC 0.0MVAr
T27P T28P G2 G1
WELLS
100.0MW 6.5MVAr
100.0MW 6.4MVAr
A23P 58.5km A24P
114.8MW/-3.7MVAr
114.9MW/-3.7MVAr
245.1kV
0.0MVAr
0.6MW/22.9MVAr
-0.7MW/-21.6MVAr
124.2kV
ALGOMA
**** MISSISSAGI (East circuits) FLOW WEST*
SUDBURY FLOW WEST
341.6MW/-17.3MVAr
-271.4MW -8.9MVAr
MISSISSAGI
339.6MW
-8.6MVAr ***
109.9MW -1.2MVAr
117.9MW/-6.1MVAr
113.8MW/-10.0MVAr
X27A
X74P 205.8km
S21N
S22A

Silver Falls 24.0MW -4.0MVAr
12.0MW/1.9MVAr P5M
124.2kV PORT ARTHUR
240.9kV LAKEHEAD
R1LB A7L R2LB A8L A6P
126.0kV
-72.5MW/-3.5MVAr -33.1MW/-18.4MVAr P3B P7B R1LB R2LB
L3P L4P
20.0MW 9.0MVAr
-80.7MW/-18.0MVAr -77.1MW/-17.6MVAr
P1P
Provincial Paper 5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
12.0MW/1.9MVAr
B6M
122.8kV
10.0MW -0.8MVAr Kakabeka GS
55.0MW 26.0MVAr
BIRCH
Q9B Q8B Q5B Q4B
FORT WILLIAM
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
58.7MW 25.1MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
121.9kV
THUNDER BAY 122.8kV
G2 G3
0.0MW 0.0MVAr 0.0MW 0.0MVAr

Σ 1383MW
NE Generation

119.5MW 38.7MVAr
126.8kV
115kV
541.9kV 500kV PORCUPINE
141.6MW -174.6MVAr
230kV 243.8kV
0.0MVAr SVC 0.0MW
P502X
141.2MW -16.8MVAr
145.8MVAr
543.4kV
Hanmer: Tertiary Reactors
0.0MVAr -56.7MVAr -56.7MVAr 0.0MVAr
112.2MW/-18.0MVAr
HANMER 500kV
244.6kV 230kV
143.8MW/63.9MVAr
FROOD
X23N X27A X25S
184.8MVAr
144.6MVAr
X503E: -265.4MW/-135.9MVAr
X504E: -266.3MW/9.6MVAr
54.3MW -0.1MVAr
153.0MW -8.5MVAr
INCO
CLARABELLE
S21N
X26S
230kV 243.8kV
MARTINDALE
48.6MW -4.8MVAr
H24S Martindale 115kV Otto Holden
H23S
30.0MW -14.9MVAr
WIDDIFIELD
TRANSCANADA NORTH BAY
13.5MW -13.8MVAr
Dymond
X504E X503E
548.9kV 50% 549.0kV 50%
554.2kV 554.3kV
242.3kV PARRY SOUND
E27 E26
-267.3MW 69.2MVAr
-266.5MW 69.1MVAr
WAUBASHENE
242.3kV
X504E X503E
-268.8MW 200.5MVAr
-268.0MW 200.1MVAr
-581.7MW
FLOW SOUTH INTERFACE
OTTO HOLDEN
-14.9MW -15.5MVAr
D5H
DES JOACHIMS
542.2kV 500kV ESSA
90.1MW -15.6MVAr
230kV 242.5kV
230.7MVAr

64.0MW -17.7MVAr
125.1kV PINE PORTAGE
-32.6MW/13.9MVAr -38.0MW/13.0MVAr
-6.9MW/0.4MVAr
123.2kV MOOSE LAKE
B6M
6.8MW -6.2MVAr
Murillo Jct
12.0MW 1.9MVAr
BIRCH 122.8kV
402.3kV
36.4MVAr
-1.8MW 17.8MVAr
-1.8MW -18.7MVAr
LAKEHEAD
240.9kV
A21L A22L
191.8km AxL
225.8MW/-60.0MVAr
225.8MW/-59.8MVAr
T7: 158.0MW/45.5MVAr
T8: 159.5MW/46.3MVAr
9.4MVAr 9.4MVAr Lakehead SVCs
126.0kV
94.5MVAr
R1LB: 49.8MW/30.0MVAr
R2LB: 40.6MW/29.6MVAr
A7L: -39.2MW/18.2MVAr
A8L: -45.8MW/16.2MVAr
L4P: 99.2MW/64.3MVAr
L4P R1LB A7L R2LB A8L A6P
124.2kV
-37.9MW/16.7MVAr
PORT ARTHUR
0.0MVAr
20.0MW 9.0MVAr
GREENWICH Wind Farm 0.0MW 0.0MVAr
R9A
125.2kV
Alexander 31.0MW -2.1MVAr
ALEXANDER
49.6MW -25.9MVAr
37.0MW -4.6MVAr Cameron Falls
TCPL Nipigon 36.0MW -6.7MVAr
100.2km
A5A
AGUASABON
4.6km
A1B
121.4kV
35.4MW -21.7MVAr
21.0MW 2.6MVAr
TERRACE BAY
74.5MW -8.8MVAr
74.5MW -8.8MVAr
58.9km
T1M
121.2kV
KIMBERLEY CLARKE
39.0MW 10.0MVAr
0.0MW 0.0MVAr
MARATHON
243.4MW/4.9MVAr 300.3MW/-138.8MVAr
243.4MW/5.0MVAr 300.3MW/-138.8MVAr
245.0kV
T11: 56.9MW/-19.6MVAr
T12: 56.9MW/-19.5MVAr
125.1kV
M2W
24.8MW/23.3MVAr
88.8MW/3.4MVAr
M23L M24L
229.4km MxL
W21M W22M
168.3km WxM
Wawatay 6.0MW -4.4MVAr
Umbata Falls 11.0MW -3.8MVAr
Williams Mine 0.0MVAr
392.6kV
0.0MVAr 0.0MW 0.0MVAr 0.0MW 0.0MVAr
OUT-OF-SERVICE
WAWA
235.8kV
190.9MW/-23.4MVAr
190.9MW/-23.4MVAr
P25W P26W
198.0MW -10.2MVAr
T1: 35.9MW/12.7MVAr
T2: 35.7MW/12.7MVAr
325.7MW/-15.7MVAr
325.7MW/-15.7MVAr
120.7kV
ANJIGAMI
Σ 713.0MW
GLP Generation

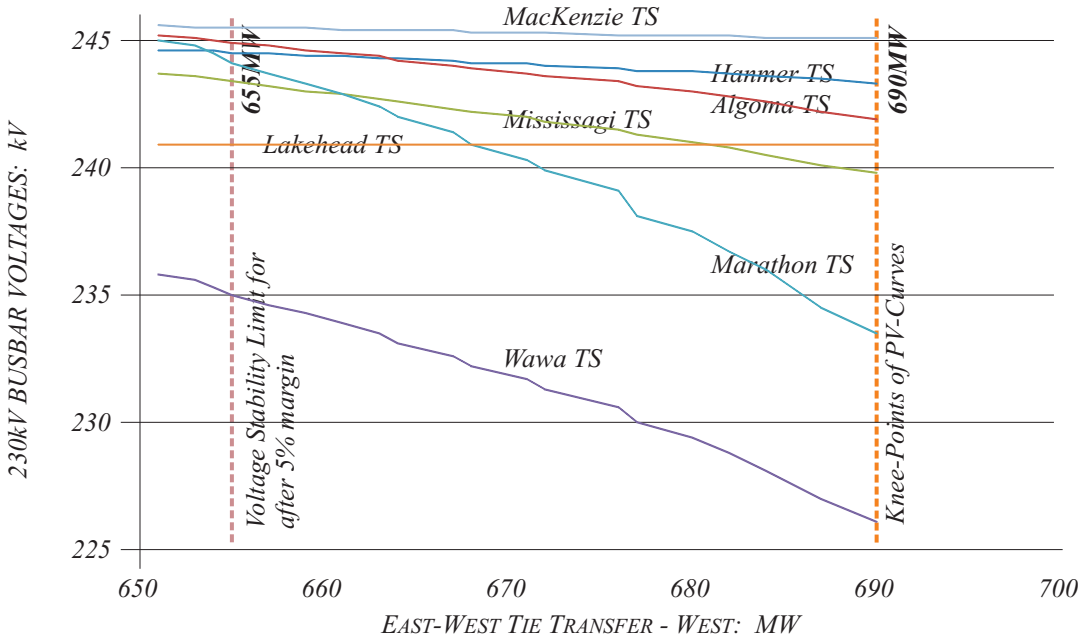
East West Tie Reinforcement: Lakehead TS to Wawa TS

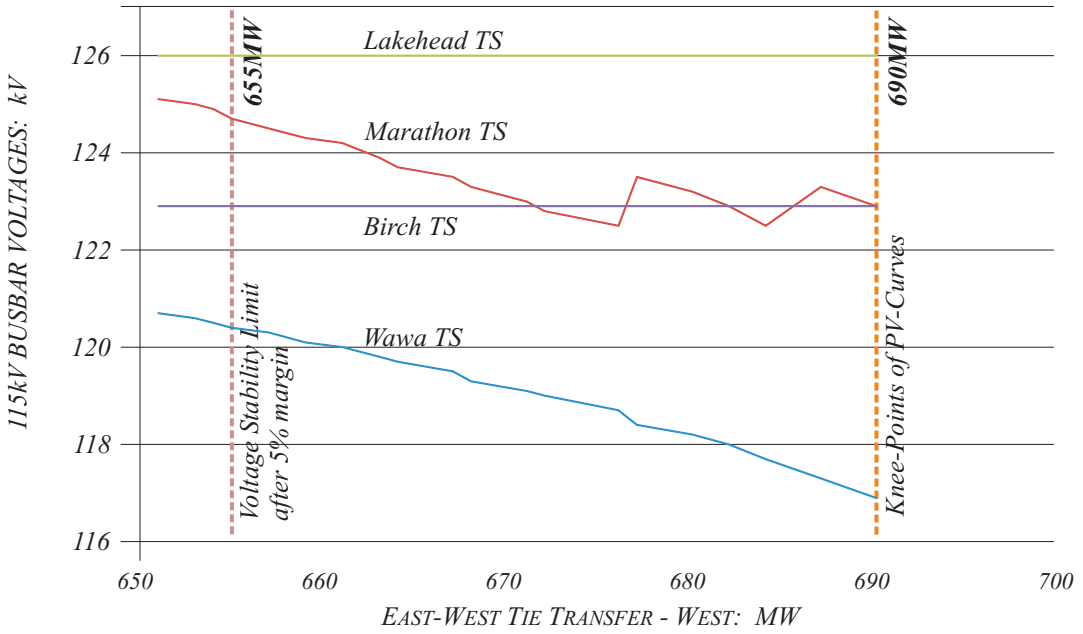
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS

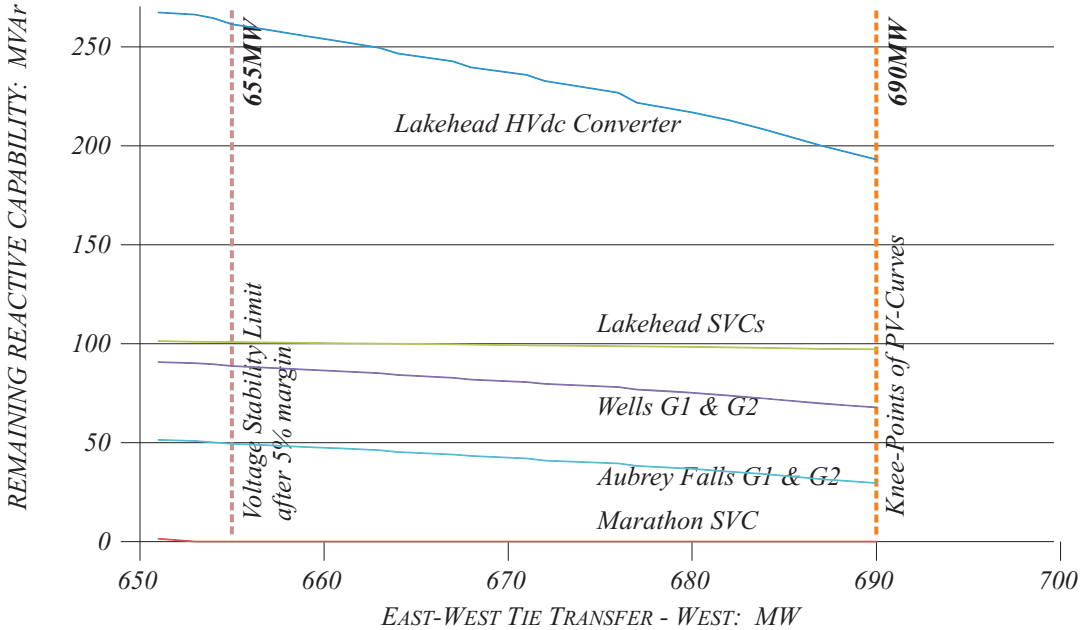
Contingency: *Loss of the Wawa HVdc Converters & Filters*

DIAGRAM 18

7th December 2012







East-West Tie Reinforcement:
Case with a new HVdc Link between Wawa TS & Lakehead TS
With a +250/-100MVAr SVC at Marathon TS
Contingency: Loss of the Wawa HVdc Converter

PV-analysis

Post-Contingency

DIAGRAM 19

7th December 2012

Ontario	*Load:*	*26020MW*
	Losses:	*869MW*
North-west	*Load:*	*950MW*
	Losses:	*142MW*
North-east	*Load:*	*1241MW*
	Losses:	*61MW*

IMPORTS

MANITOBA:	*51.8MW*
MINNESOTA:	*2.7MW*
MICHIGAN:	*-96.4MW*
NEW YORK: At Niagara	*-1.1MW*
At St Lawrence	*-0.2MW*

Σ 390MW
NW Generation

RED LAKE 121.8kV
56.2MW -1.1MVAr
46.53kV 56.0MW 11.1MVAr
16.6MVAr
58.1MW 1.8MVAr
MANITOU FALLS 127.3kV 126.0kV EAR FALLS
3.1MW 1.2MVAr
23.6MW -17.6MVAr
33.0MW 10.0MVAr
7.0MW -3.9MVAr
Lac Seul 5.0MW -4.2MVAr
Caribou Falls 41.0MW/17.4MVAr
Whitedog Falls 32.0MW/8.2MVAr
MANITOBA ONTARIO
51.8MW -50.2MVAr
Winnipeg River
39.4MW 15.7MVAr
42.0MW -14.4MVAr
K22W KENORA K21W
125.0kV DRYDEN
245.9kV WHITESHELL
Phase-Shifters PS7: 86.4° PS8 86.4°
-39.2MVAr
13.9MW -12.5MVAr
246.6kV
0.0MVAr 50.7MW 3.3MVAr
10.1MW 4.2MVAr
47.2MW -7.9MVAr
42.2MW -8.9MVAr
Valora
D26A
K24F
West Coast Energy 20.0MW -7.1MVAr
244.2kV 230kV 115kV 122.7kV 13.2kV
FORT FRANCES
2.7MW -20.5MVAr 0.0MVAr 43.9MVAr 0.0MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 68.5°
INTERNATIONAL FALLS 115kV
52.3MW 7.4MVAr
F25A
245.1kV MACKENZIE
-41.9MVAr
293A
132.4MW -15.8MVAr
ATIKOKAN
A21L
A22L
240.2kV
LAKEHEAD
119.2MVAr
17.4MVAr 17.4MVAr Lakehead SVCs
94.5MVAr
OUT OF SERVICE
0.0MW 0.0MVAr
238.6kV
GREENWICH WIND FARM
0.0MW 0.0MVAr
126.0kV
226.3MW/-59.1MVAr
226.3MW/-58.9MVAr
124.2kV
-2.1MVAr SVC 4.6kV
40.0MW 5.0MVAr
33.0MVAr
MUSSELWHITE MINE
40.2MW -18.3MVAr
45.1MW -16.0MVAr
1.5MW 0.7MVAr
27.4kV CROW RIVER
8.8MVAr
Thierry Mine 11.7MW 3.0MVAr
Placer Jct 124.0kV
6.4MW -12.5MVAr
Sturgeon Falls 4.0MW/0.0MVAr
Calm Lake 5.0MW/-1.4MVAr
Valerie Falls 3.0MW/0.8MVAr
Silver Falls 24.0MW -4.0MVAr
Kakabeka Falls 10.0MW -0.7MVAr
THUNDER BAY G2 G3
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
BIRCH 25kV 115kV 122.8kV
0.0MVAr 72.8MVAr
Ft William 0.0MVAr
SVC 0.0MVAr
MARATHON
244.1MW/6.7MVAr 301.2MW/-124.0MVAr
244.0MW/6.8MVAr 301.2MW/-124.0MVAr
NEW W21M W22M M22L M24L
245.0kV Marathon Tertiaries SVC
0.0MVAr 37.4MVAr 0.0MVAr 37.4MVAr
222.5MVAr 0.0MVAr
EAST-WEST TRANSFER WEST INTERFACE
653.2MW -67.4MVAr
36.5MVAr SVC 0.0MVAr
Wawa Tertiaries 0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
240.0kV WAWA
0.0MVAr 198.4MW -21.9MVAr
383.0MW -61.6MVAr
147.8km
G2 65.0MW/3.8MVAr
G1 65.0MW/3.8MVAr
AUBREY FALLS
240.4kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
242.6kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
THIRD LINE 115kV 230kV
126.1MW -5.2MVAr
242.7kV
121.8kV
CLERGUE
LAKE SUPERIOR POWER
G1: 40.0MW/5.8MVAr
G2: 40.0MW/5.8MVAr
G3: 22.0MW/3.2MVAr
115kV 34.5kV
23.6MVAr 23.7MVAr
ECHO RIVER
St Mary's Tarentorus
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
GREAT LAKES POWER Co.
68.6MW/3.9MVAr
P21G P22G
230kV
244.8kV SVC 0.0MVAr
WELLS G2 G1
100.0MW 3.2MVAr
100.0MW 3.1MVAr
T27P T28P
P25W P26W 56.4km
272.4MW -19.0MVAr
*** MISSISSAGI (East circuits) FLOW WEST
SUDBURY FLOW WEST
343.0MW/-23.4MVAr
MISSISSAGI
341.1MW -15.7MVAr ***
110.4MW -3.2MVAr
A23P 58.5km A24P
115.3MW/-6.3MVAr
115.4MW/-6.2MVAr
118.4MW/-8.1MVAr
114.2MW/-12.1MVAr
X27A
S21N
245.9kV
0.0MVAr
S22A
0.6MW/23.8MVAr
-0.7MW/-21.4MVAr
124.6kV
ALGOMA
Silver Falls 24.0MW -4.0MVAr
12.4MW/2.0MVAr P5M
124.2kV PORT ARTHUR
-72.6MW/-3.5MVAr -33.2MW/-18.4MVAr
P3B P7B R1LB R2LB
L3P L4P
240.2kV LAKEHEAD
R1LB A7L R2LB A8L A6P
126.0kV
20.0MW 9.0MVAr
-80.8MW/-18.0MVAr -77.3MW/-17.7MVAr
P1P
Provincial Paper 5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
12.4MW/2.0MVAr
B6M
122.8kV BIRCH
55.0MW 26.0MVAr
10.0MW -0.7MVAr Kakabeka GS
Q9B Q8B Q5B Q4B
FORT WILLIAM
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.2MVAr
Q8B: -42.5MW/-19.0MVAr
Q9B: -0.1MW/-0.8MVAr
58.7MW 25.1MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
121.9kV
G2 G3
0.0MW 0.0MVAr 0.0MW 0.0MVAr
122.8kV THUNDER BAY

Σ 1383MW
NE Generation

119.5MW 38.0MVAr
126.8kV
542.1kV 500kV PORCUPINE 243.9kV
115kV 230kV SVC 0.0MVAr
141.6MW -175.6MVAr
0.0MVAr
P502X
141.2MW -17.7MVAr
146.0MVAr
543.7kV HANMER 500kV
Hanmer: Tertiary Reactors
0.0MVAr -56.8MVAr -56.7MVAr 0.0MVAr
112.7MW/-20.0MVAr
244.8kV 230kV
143.8MW/63.8MVAr
FROOD
X24N X25S X27A
185.1MVAr
144.7MVAr
X503E: -266.1MW/-133.7MVAr
X504E: -267.0MW/11.9MVAr
X74P 205.8km
54.4MW -0.6MVAr
H24S H23S
Martindale 115kV Otto Holden
153.4MW -10.6MVAr
INCO
CLARABELLE
244.0kV MARTINDALE
48.6MW -5.3MVAr
30.0MW -14.9MVAr
WIDDIFIELD
TRANSCANADA NORTH BAY
13.5MW -13.9MVAr
Dymond
X504E X503E
549.1kV 50% 50% 549.1kV
554.5kV 554.6kV
242.4kV PARRY SOUND
E27 E26
-268.0MW 71.6MVAr
-267.2MW 71.5MVAr
WAUBASHENE
242.3kV
X504E X503E
-269.6MW 262.6MVAr
-268.7MW 262.5MVAr
542.4kV 500kV ESSA 230kV 242.6kV
230.7MVAr
90.1MW -15.6MVAr
OTTO HOLDEN
-45.0MW -15.5MVAr
D5H
DES JOACHIMS
-583.3MW
FLOW SOUTH INTERFACE

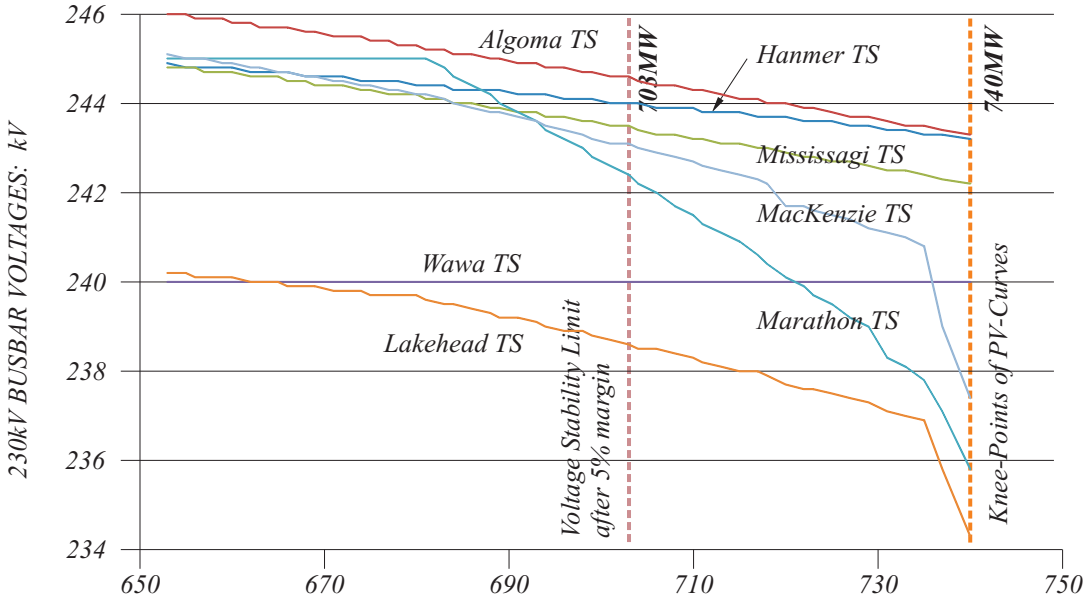
123.1kV MOOSE LAKE B6M
7.2MW -6.1MVAr
Murillo Jct
12.4MW 2.0MVAr
BIRCH 122.8kV
400.1kV 0.0MVAr
0.0MW 0.0MVAr 0.0MW 0.0MVAr
LAKEHEAD
OUT OF SERVICE
A21L A22L 191.8km AxL
240.2kV
226.3MW/-59.1MVAr
226.3MW/-58.9MVAr
T7: 158.0MW/37.6MVAr
T8: 159.5MW/38.5MVAr
17.4MVAr 17.4MVAr Lakehead SVCs
126.0kV
94.5MVAr
R1LB: 49.8MW/30.1MVAr
R2LB: 40.7MW/29.6MVAr
A7L: -39.3MW/18.3MVAr
A8L: -45.9MW/16.3MVAr
L4P: 99.3MW/64.4MVAr
L4P R1LB A7L R2LB A8L A6P
124.2kV
-38.0MW/16.7MVAr
PORT ARTHUR
0.0MVAr 20.0MW 9.0MVAr
125.1kV PINE PORTAGE
64.0MW -17.7MVAr
-32.6MW/13.9MVAr -38.1MW/13.0MVAr
-7.0MW/0.4MVAr
GREENWICH Wind Farm 0.0MW 0.0MVAr
TCPL Nipigon 36.0MW -6.7MVAr
Alexander 31.0MW -2.0MVAr
R9A ALEXANDER A5A 100.2km
50.0MW -26.1MVAr
125.2kV
37.0MW -4.5MVAr Cameron Falls
AGUASABON 121.4kV
4.6km A1B
35.7MW -21.8MVAr
21.0MW 2.6MVAr
TERRACE BAY 74.8MW -8.9MVAr
74.8MW -8.9MVAr
58.9km T1M
121.2kV KIMBERLEY CLARKE
39.0MW 10.0MVAr
0.0MW 0.0MVAr
89.2MW/3.4MVAr
MARATHON
244.1MW/6.7MVAr 301.2MW/-124.0MVAr
244.0MW/6.8MVAr 301.2MW/-124.0MVAr
245.0kV
T11: 57.1MW/-19.6MVAr
T12: 57.1MW/-19.4MVAr
125.1kV M2W
24.8MW/23.3MVAr
M23L M24L 229.4km MxL
W21M W22M 168.3km WxM
Wawatay 6.0MW -4.4MVAr
Umbata Falls 11.0MW -3.8MVAr
Williams Mine 0.0MVAr
402.9kV
36.5MVAr
1.8MW -17.8MVAr
1.8MW -53.8MVAr
191.5MW/-30.8MVAr
191.5MW/-30.8MVAr
WAWA 240.0kV
P25W P26W
T1: 36.0MW/8.0MVAr
T2: 35.7MW/8.0MVAr
325.7MW/-6.8MVAr
325.7MW/-6.8MVAr
198.4MW -21.9MVAr
122.2kV ANJIGAMI
Σ 713.0MW
GLP Generation

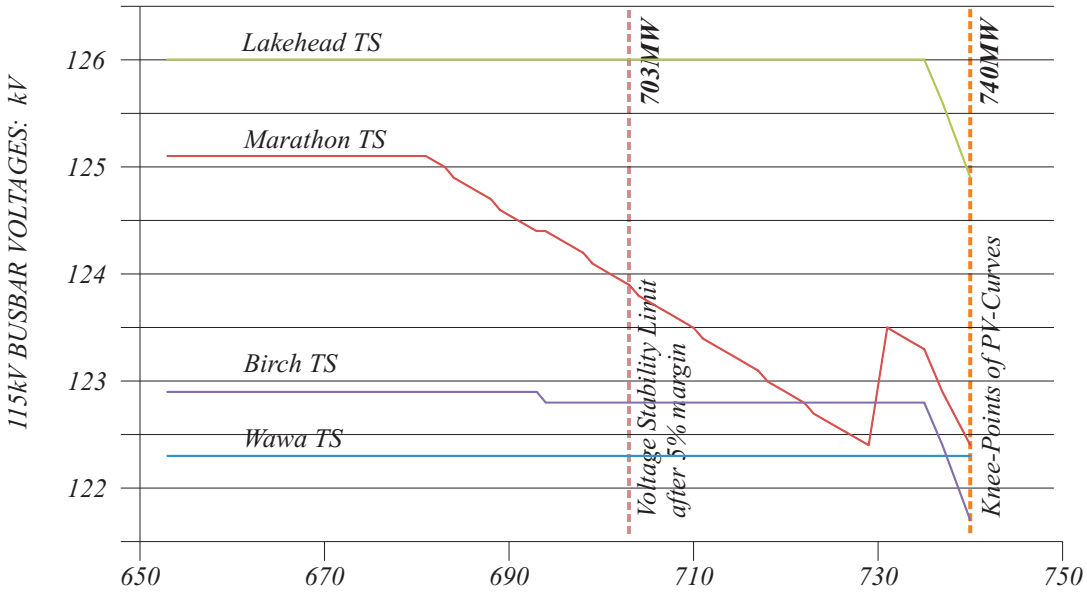
East West Tie Reinforcement: Lakehead TS to Wawa TS

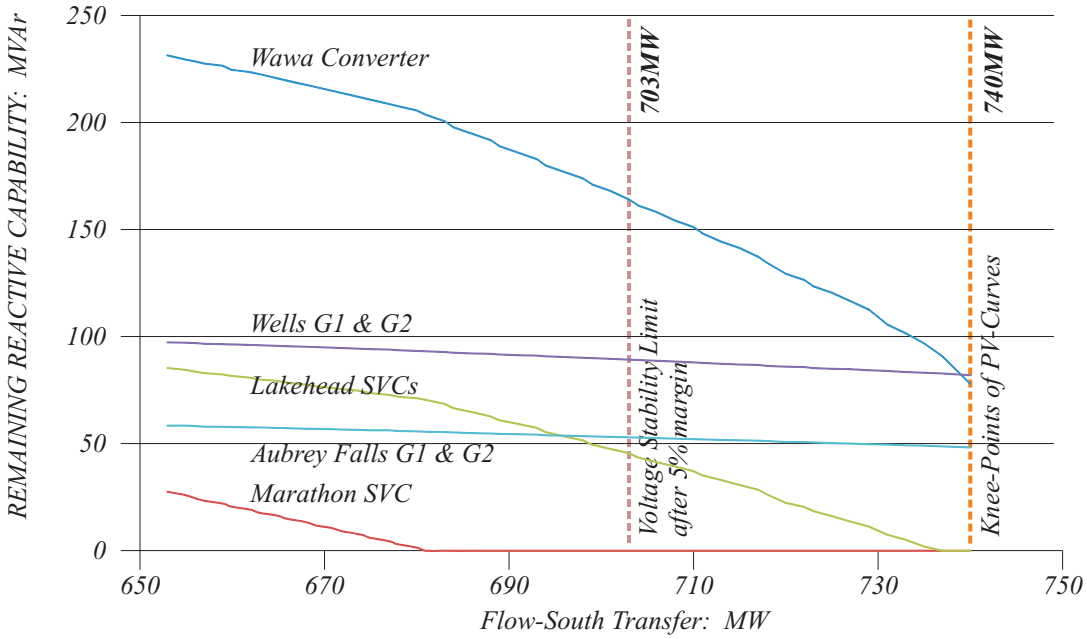
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS
With a 125MVAr shunt capacitor bank at Lakehead TS
Contingency: *Loss of the Lakehead HVdc Converters & Filters*

DIAGRAM 20

6th December 2012







East-West Tie Reinforcement:

Case with a new HVdc Link between Wawa TS & Lakehead TS
With a +250/-100MVAr SVC at Marathon TS & a 125MVAr Capacitor at Lakehead
Contingency: Loss of the Lakehead HVdc Converter & Filters

PV-analysis

Post-Contingency

DIAGRAM 21

4th December 2012

Ontario	*Load:*	*26020MW*
	Losses:	*869MW*
North-west	*Load:*	*950MW*
	Losses:	*142MW*
North-east	*Load:*	*1241MW*
	Losses:	*61MW*

IMPORTS

MANITOBA:	*53.6MW*
MINNESOTA:	*3.8MW*
MICHIGAN:	*-97.7MW*
NEW YORK: At Niagara	*-1.8MW*
At St Lawrence	*-0.7MW*

Σ 390MW
NW Generation

RED LAKE 121.2kV
56.1MW -0.9MVAr
46.3kV 56.0MW 11.1MVAr
16.4MVAr
58.0MW 2.1MVAr
MANITOU FALLS 126.9kV
125.5kV EAR FALLS
3.1MW 1.2MVAr
33.0MW 12.4MVAr
23.8MW -17.3MVAr
7.0MW -3.9MVAr
Lac Seul 5.0MW -4.2MVAr
Thierry Mine 11.7MW 3.0MVAr
Placer Jct 123.0kV
6.5MW -12.4MVAr
123.7kV -1.0MVAr SVC 4.6kV
MUSSELWHITE MINE 40.1MW -19.2MVAr
40.0MW 5.0MVAr
33.0MVAr
45.1MW -16.5MVAr
1.5MW 0.7MVAr
27.17kV CROW RIVER
8.7MVAr
Caribou Falls 41.0MW/18.6MVAr
Whitedog Falls 32.0MW/9.7MVAr
MANITOBA ONTARIO
53.6MW -45.6MVAr
Winnipeg River
KENORA
K22W K21W
WHITESHELL
Phase-Shifters PS7: 86.4° PS8 86.4°
244.7kV
40.4MW 12.0MVAr
42.3MW -15.6MVAr
124.0kV DRYDEN
-38.9MVAr
14.2MW -10.0MVAr
K23D
244.5kV
49.9MW -1.2MVAr
10.3MW 5.0MVAr
47.2MW -7.8MVAr
Sturgeon Falls 4.0MW/0.0MVAr
Calm Lake 5.0MW/-1.4MVAr
Valerie Falls 3.0MW/2.0MVAr
Valora 42.1MW -9.0MVAr
D26A
THUNDER BAY G2 G3
0.0MW 0.0MVAr
0.0MW 0.0MVAr
Silver Falls 24.0MW -1.3MVAr
Kakabeka Falls 10.0MW 0.8MVAr
BIRCH 25kV 115kV 121.8kV
71.6MVAr
Ft William 0.0MVAr
ATIKOKAN
129.8MW -28.3MVAr
N93A
West Coast Energy 20.0MW -4.3MVAr
50.9MW 1.1MVAr
242.3kV 230kV
F25A
FORT FRANCES
115kV 122.0kV
13.2kV
3.8MW -18.4MVAr
43.4MVAr
FF TS: 11.1MW/5.0MVAr
FF Abitibi: 68.0MW/28.0MVAr
MTS: 11.0MW/4.0MVAr
Phase-Shifters PS10 & PS11: 68.5°
INTERNATIONAL FALLS 115kV
241.4kV MACKENZIE
A21L A22L
-40.9MVAr
SVC 0.0MVAr
0.0MW OUT OF SERVICE
234.2kV
LAKEHEAD
60.0MVAr 60.0MVAr
Lakehead SVCs
124.9kV
92.9MVAr
233.7kV
GREENWICH WIND FARM
0.0MW 0.0MVAr
224.6MW/-47.6MVAr
224.6MW/-47.5MVAr

NEW M21L M24L

MARATHON
242.5MW/19.7MVAr 300.3MW/-123.4MVAr
242.5MW/19.8MVAr 300.3MW/-123.4MVAr
245.0kV
Marathon Tertiaries
SVC 0.0MVAr
0.0MVAr 37.4MVAr 0.0MVAr 37.4MVAr
247.7MVAr
NEW W21M W22M
WAWA
240.0kV
Wawa Tertiaries
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
EAST-WEST TRANSFER WEST INTERFACE
651.0MW -66.2MVAr
36.5MVAr SVC 0.0MVAr
381.8MW -60.6MVAr
147.8km
197.7MW -21.5MVAr
G2 65.0MW/3.7MVAr
G1 65.0MW/3.7MVAr
AUBREY FALLS
240.5kV MACKAY
0.0MW 0.0MVAr
PRINCE WIND FARM
242.6kV
G1: 13.0MW/8.2MVAr
G2: 13.0MW/5.9MVAr
G3: 13.0MW/8.2MVAr
CLERGUE
LAKE SUPERIOR POWER
G1: 40.0MW/5.8MVAr
G2: 40.0MW/5.8MVAr
G3: 22.0MW/3.2MVAr
THIRD LINE 115kV 230kV 34.5kV
23.6MVAr 23.7MVAr
121.8kV
125.4MW -5.1MVAr
242.8kV
ECHO RIVER
St Mary's Tarentorus
0.0MVAr 0.0MVAr 0.0MVAr 0.0MVAr
GREAT LAKES POWER Co.
67.7MW/4.4MVAr
P21G P22G
230kV
244.8kV
SVC 0.0MVAr
WELLS G2 G1
100.0MW 3.0MVAr
100.0MW 3.0MVAr
T27P T28P
SUDBURY FLOW WEST
340.6MW/-23.0MVAr
271.0MW -19.4MVAr
P25W P26W 56.0km
MISSISSAGI
338.7MW -15.1MVAr ***
109.6MW -3.0MVAr
A23P 58.5km A24P
114.5MW/-6.1MVAr
114.6MW/-6.0MVAr
246.0kV
0.0MVAr
S22A
0.6MW/23.9MVAr
-0.7MW/-21.4MVAr
124.6kV
ALGOMA
**** MISSISSAGI (East circuits) FLOW WEST*

Silver Falls 24.0MW -1.3MVAr
12.6MW/1.2MVAr P5M
123.2kV PORT ARTHUR
234.2kV LAKEHEAD
R1LB A7L L3P L4P R2LB A8L A6P
124.9kV
-72.7MW/-3.9MVAr -33.3MW/-19.0MVAr
P3B P7B R1LB R2LB P1P
20.0MW 9.0MVAr
-80.8MW/-18.0MVAr -77.3MW/-17.7MVAr
Provincial Paper 5.2MW 2.0MVAr
Additional load assumed within the Thunder Bay area: 215.0MW 20.0MVAr
12.6MW/1.2MVAr
B6M 121.8kV BIRCH
10.0MW 0.8MVAr Kakabeka GS
55.0MW 26.0MVAr
Q9B Q8B Q5B Q4B
FORT WILLIAM
58.7MW 25.1MVAr
Q4B: -0.2MW/-0.2MVAr
Q5B: 42.4MW/18.3MVAr
Q8B: -42.5MW/-19.1MVAr
Q9B: -0.1MW/-0.8MVAr
ABITIBI-BOWATER
88.0MW 20.0MVAr
120.9kV
THUNDER BAY 121.7kV
G2 G3
0.0MW 0.0MVAr 0.0MW 0.0MVAr

Σ 1383MW
NE Generation

119.5MW 37.8MVAr
126.8kV
542.1kV 500kV PORCUPINE 243.9kV
115kV 230kV
141.7MW -175.8MVAr
0.0MVAr SVC 0.0MVAr
P502X
141.3MW -17.9MVAr
146.0MVAr
543.8kV
HANMER 500kV
Hanmer: Tertiary Reactors
0.0MVAr -56.8MVAr -56.7MVAr 0.0MVAr
112.0MW/-20.2MVAr
244.9kV 230kV
143.8MW/63.8MVAr
FROOD
X24N X27A X25S
185.1MVAr
X74P 205.8km
X504E X503E
549.1kV 50% 549.2kV 50%
554.6kV 554.7kV
PARRY SOUND
242.4kV
E27 E26
-266.9MW 71.7MVAr
-266.0MW 71.7MVAr
WAUBASHENE
242.3kV
-268.4MW 263.2MVAr
-267.6MW 52.7MVAr
90.1MW -15.6MVAr
542.4kV 500kV ESSA 230kV 242.6kV
230.8MVAr
X503E X504E
-580.8MW FLOW SOUTH INTERFACE
OTTO HOLDEN
-14.8MW -15.3MVAr
D5H
DES JOACHIMS
Dunnville 13.5MW -13.9MVAr
Martindale 115kV *Otto Holden*
H24S H23S
30.0MW -14.9MVAr
TRANSCANADA NORTH BAY
WIDDIFIELD
X503E: -265.0MW/-133.6MVAr
X504E: -265.8MW/12.1MVAr
S21N X26S
54.3MW -0.6MVAr
144.8MVAr
INCO
152.6MW -10.7MVAr
230kV 244.1kV MARTINDALE
CLARABELLE
48.5MW -5.3MVAr

Σ 713.0MW
GLP Generation

121.6kV
MOOSE LAKE
B6M
7.5MW -5.4MVAr
Murillo Jct
12.6MW 1.2MVAr
BIRCH 121.8kV
390.2kV
0.0MVAr
0.0MW 0.0MVAr
0.0MW 0.0MVAr
LAKEHEAD
OUT OF SERVICE
A21L A22L
191.8km AxL
234.2kV
224.6MW/-47.6MVAr
224.6MW/-47.5MVAr
T7: 157.6MW/-6.5MVAr
T8: 159.1MW/-5.3MVAr
60.0MVAr 60.0MVAr Lakehead SVCs
124.9kV
92.9MVAr
R1LB: 49.7MW/29.1MVAr
R2LB: 40.6MW/28.5MVAr
A7L: -39.6MW/16.8MVAr
A8L: -46.1MW/14.7MVAr
L4P: 99.1MW/63.1MVAr
L4P R1LB A7L R2LB A8L A6P
123.2kV
-38.3MW/15.5MVAr
PORT ARTHUR
0.0MVAr
20.0MW 9.0MVAr
64.0MW -16.5MVAr
124.6kV PINE PORTAGE
-32.8MW/12.8MVAr -38.2MW/11.8MVAr
7.3MW/-0.7MVAr
GREENWICH Wind Farm 0.0MW 0.0MVAr
TCPL Nipigon 36.0MW -5.9MVAr
Alexander 31.0MW -0.1MVAr
R9A ALEXANDER
100.2km A5A
124.8kV
50.9MW -25.8MVAr
37.0MW -2.0MVAr
Cameron Falls
AGUASABON
4.6km A1B
121.3kV
36.8MW -21.8MVAr
21.0MW 3.2MVAr
TERRACE BAY
75.9MW -8.8MVAr
75.9MW -8.8MVAr
58.9km
121.1kV
KIMBERLEY CLARKE
39.0MW 10.0MVAr
0.0MW 0.0MVAr
T1M
90.3MW/3.8MVAr
MARATHON
242.5MW/19.7MVAr 300.3MW/-123.4MVAr
242.5MW/19.8MVAr 300.3MW/-123.4MVAr
245.0kV
T11: 57.7MW/-19.3MVAr
T12: 57.7MW/-19.2MVAr
M23L M24L
229.4km MxL
125.0kV M2W
24.8MW/23.3MVAr
Wawatay 6.0MW -4.4MVAr
Umbata Falls 11.0MW -3.8MVAr
Williams Mine 0.0MVAr
402.7kV
36.5MVAr
1.8MW -15.8MVAr
1.8MW -52.0MVAr
190.9MW/-30.3MVAr
190.9MW/-30.3MVAr
W21M W22M
168.3km WxM
WAWA
240.0kV
P25W P26W
T1: 36.0MW/8.0MVAr
T2: 35.7MW/8.0MVAr
324.6MW/-7.1MVAr
324.6MW/-7.1MVAr
122.2kV
ANJIGAMI
197.7MW -21.5MVAr

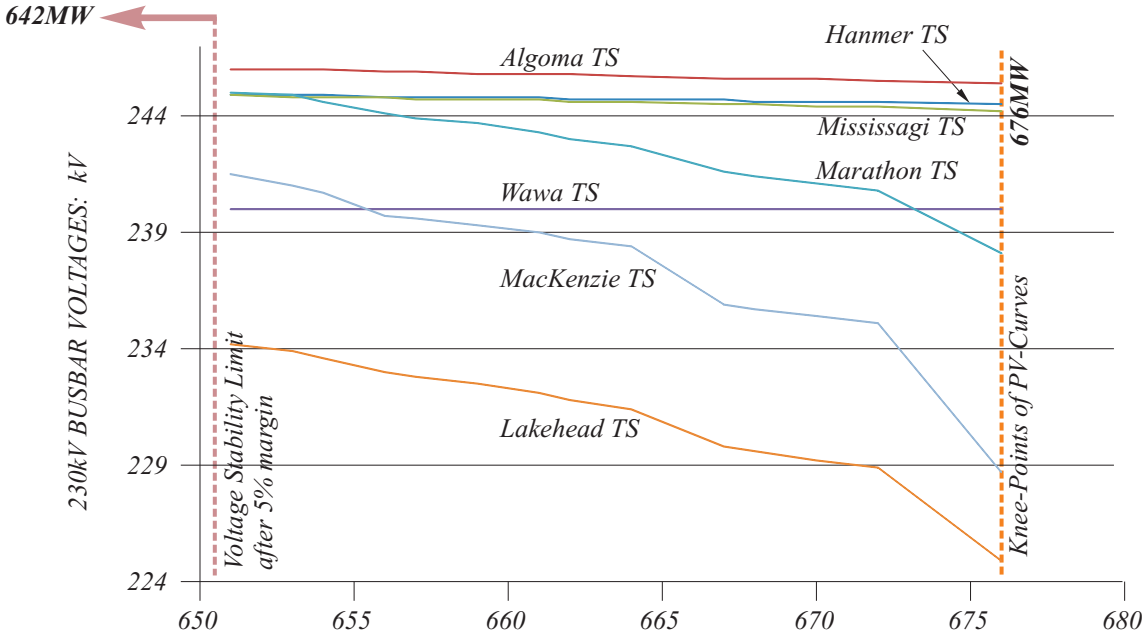
East West Tie Reinforcement: Lakehead TS to Wawa TS

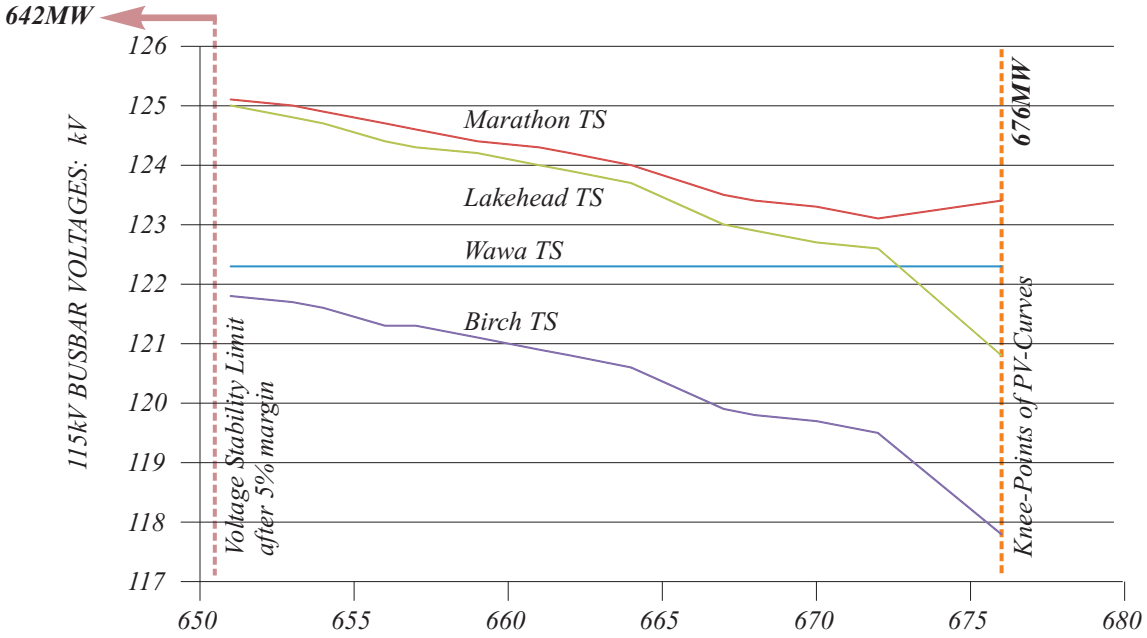
Case with a new HVdc bi-pole between Wawa TS & Lakehead TS
With no 230kV capacitor bank at Lakehead TS

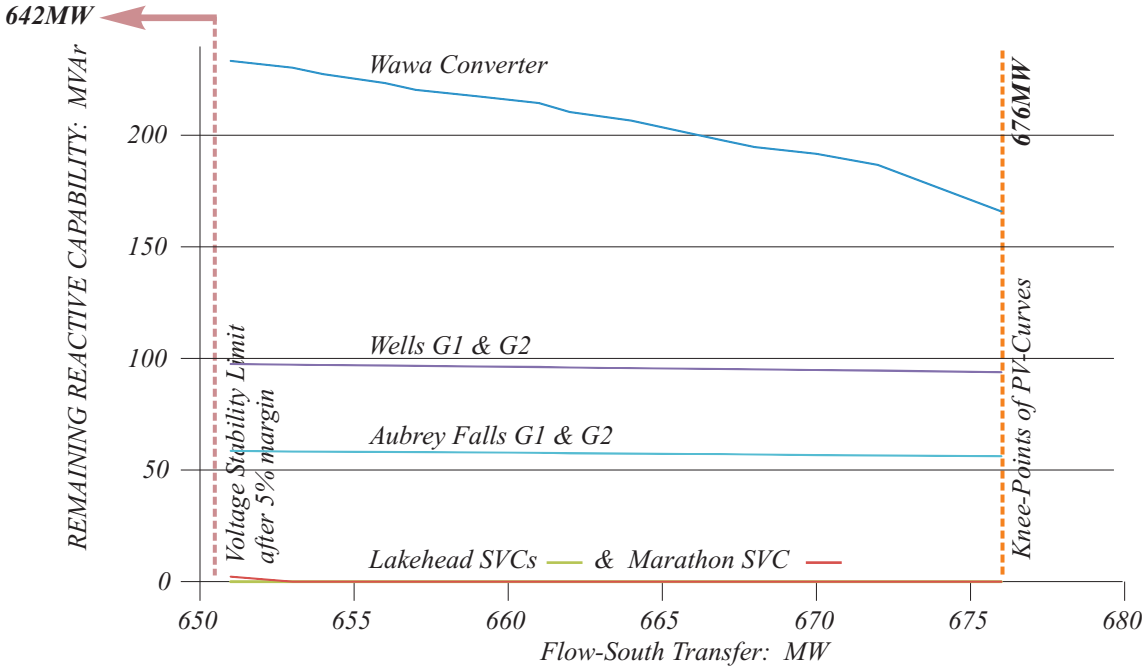
Contingency: *Loss of the Lakehead HVdc Converters & Filters*

DIAGRAM 22

6th December 2012







East-West Tie Reinforcement:

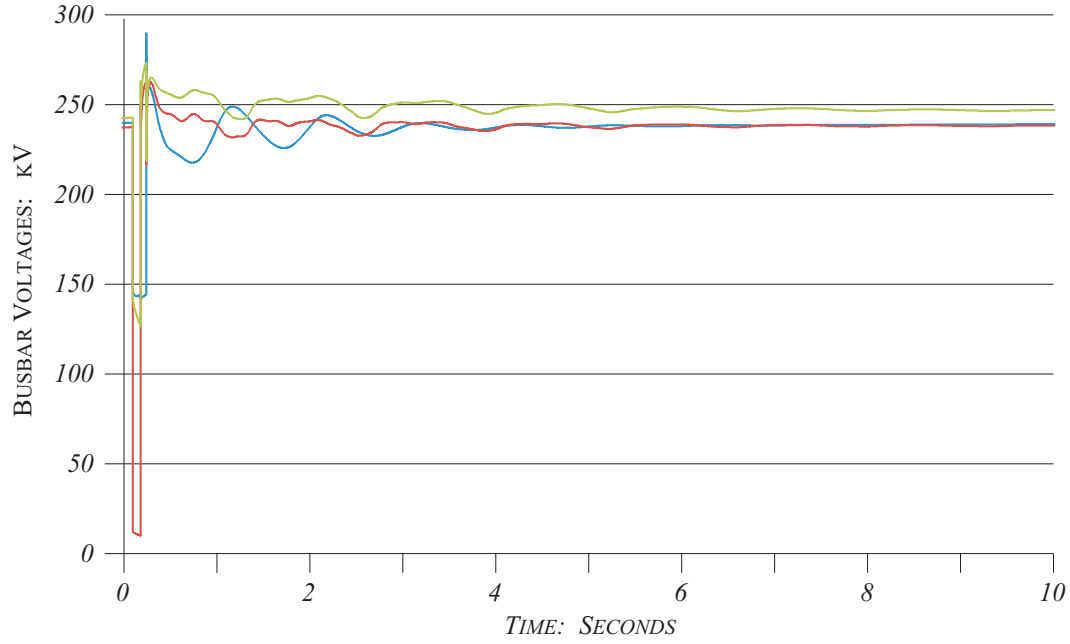
Case with a new HVdc Link between Wawa TS & Lakehead TS
*With a +250/-100MVAr SVC at Marathon TS & **No Capacitor at Lakehead***
Contingency: Loss of the Lakehead HVdc Converter & Filters

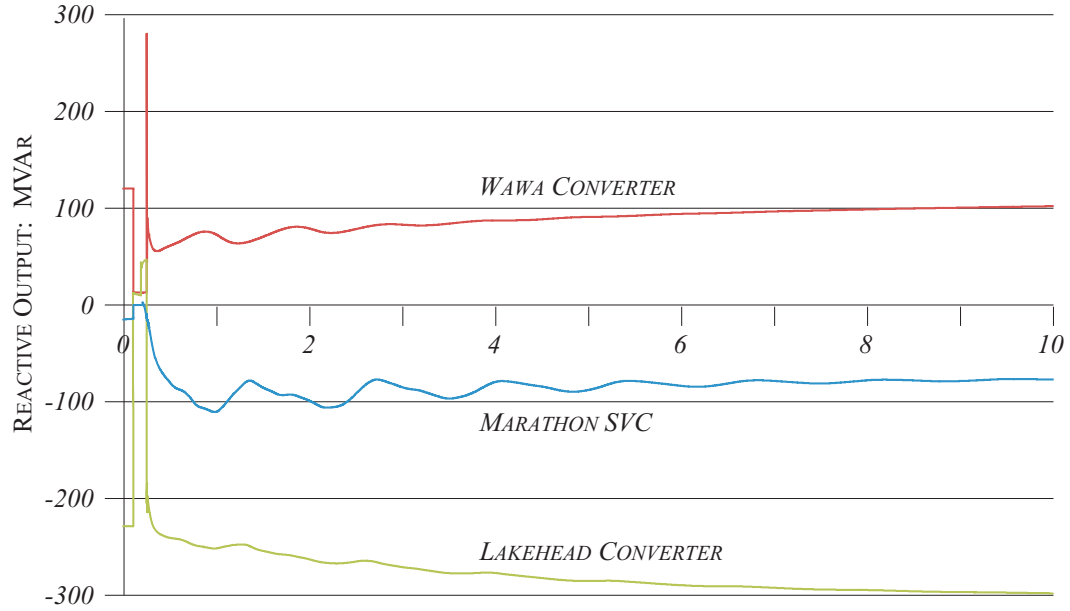
PV-analysis

Post-Contingency

DIAGRAM 23

4th December 2012





East-West Tie transfer increased to 715MW to provide a margin of 10% on the targeted transfer of 650MW

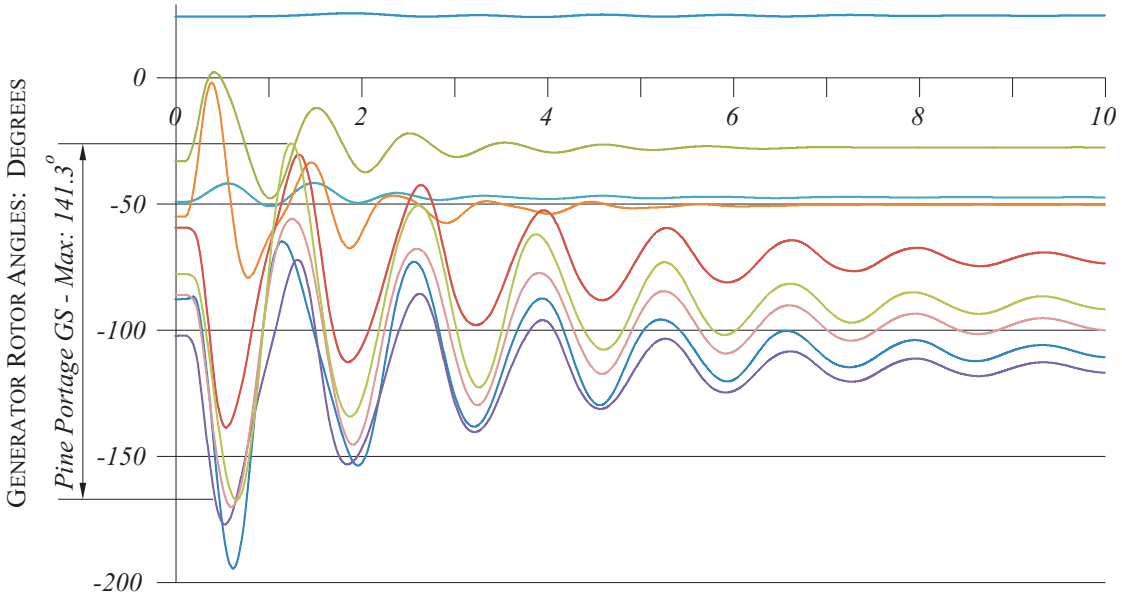


DIAGRAM 24

7th December 2012

Transient Stability Analysis for a double-circuit contingency at Marathon TS involving circuits W21M & W22M

Appendix 13: Burns & McDonnell Design Guide

The Burns & McDonnell Structural Analysis Report are attached as follows:

Appendix 13a - Professional Engineer Confirmation Letter; and

Appendix 13b - Burns and McDonnell Structural Analysis Report.

Filed: 2013-01-04
EB-2011-0140
Upper Canada Transmission, Inc. (o/a NextBridge)
East-West Tie Designation Application
Appendix 13

Burns & McDonnell Design Guide
Professional Engineer Confirmation Letter

TAB A13a

Upper Canada Transmission
Ontario East West Tie Project

Date: December 18, 2012

To: Ontario Energy Board

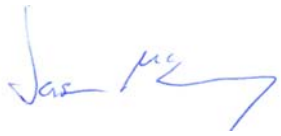
CC: Upper Canada Transmission

My name is Jason McCreary and I currently serve as a Department Manager within the Transmission and Distribution Division of Burns & McDonnell. I am a Professional Engineer registered with Professional Engineers Ontario (P. Eng #100191957).

Upper Canada Transmission utilized Burns & McDonnell for the preliminary engineering services on the Ontario East West Tie Project (OEWT), including the development of the preliminary design guide, preliminary line layouts, preliminary foundation designs, and evaluation of design alternatives.

As required by Section 2.1.4 of the Technical Requirements for the OEWT, this document shall serve as notice that all engineering design calculations and drawings were completed and reviewed under my supervision.

Sincerely,



Jason McCreary, P. Eng.
Ontario P. Eng #100191957
Department Manager
Transmission and Distribution Services
Burns & McDonnell

Burns & McDonnell Design Guide
Burns and McDonnell Structural Analysis Report

TAB A13b

SECTION A - GENERAL

PROJECT DESCRIPTION

The Ontario East West Tie Line (OEWTL) Project consists of preliminary design engineering of dual-circuit, 230-kV overhead transmission infrastructure capable of transmitting up to 600 MVA of power across Ontario, Canada. The proposed circuits would originate at Wawa TS in Wawa, Ontario, and would extend northwest to Marathon TS in Marathon, Ontario. From Marathon TS, the dual circuit transmission line would continue westward to Lakehead TS located near Thunder Bay, Ontario.

* * * * *

SECTION B - DESIGN CRITERIA

CLIMATIC LOADS

Design criteria for climatic loads are primarily based those defined in Appendix A of Ontario Energy Board (OEB) document "Minimum Design Criteria for the Reference Option". Additional climatic load cases are based on NextEra standard practices and maximum ACSR conductor operating temperature. These design criteria are presented below in Table B-1.

Table B-1. Climatic Loading Design Criteria

Case	Radial Ice Thickness	Wind Velocity	Wind Pressure (Conductor)	Wind Pressure (Tower)	Ice Density	Temperature	Reference or Standard
Wind and Ice Case 1	12.5 mm (0.5")	90 km/h (56 mph)	400 Pa (8.4 psf)	1200 Pa (25 psf)	900 kg/m^3 (56 lbs/ft^3)	-20°C (-4°F)	CSA 22.3 No. 1 Heavy Load Case
Low Temp Case 1*	-	-	-	-	-	-50°C (-58°F)	OEB Minimum Requirements
High Temp Case 1	-	-	-	-	-	140°C (285°F)	Max Operating Temp for ACSR
High Wind Case 1	-	120 km/h (75 mph)	770 Pa (16 psf)	2,110 Pa (44 psf)	-	10°C (50°F)	OEB Minimum Requirements
Ice Case 1	25 mm (1.0")	-	-	-	900 kg/m^3 (56 lbs/ft^3)	0°C (32°F)	OEB Minimum Requirements
Ice Case 2	25 mm (1.0")	-	-	-	900 kg/m^3 (56 lbs/ft^3)	-5°C (23°F)	CSA 22.3 No. 60826
Ice Case 3	25 mm (1.0")	-	-	-	600 kg/m^3 (38 lbs/ft^3)	-5°C (23°F)	CSA 22.3 No. 60826
Galloping Case 1	25 mm (1.0")	45 km/h (28 mph)	100 Pa (2 psf)	-	675 kg/m^3 (42 lbs/ft^3)	0°C (32°F)	NextEra Standard
Blowout Case 1	-	90 km/h (56 mph)	400 Pa (8.4 psf)	-	-	15°C (60°F)	

* The low temperature case is also applied for analysis of uplift (no observed uplift under this climatic load condition).

SAG AND TENSION CRITERIA

Phase conductor sag and tension criteria are based on those defined in Appendix A of OEB document "Minimum Design Criteria for the Reference Option", and are as follows in Table B-2.

Table B-2. Phase Conductor Sag and Tension Criteria

Case	Climatic Condition	Tension Condition	Maximum % RBS
OEB Vibration Limit	-30°C	Initial	25%
CSA 22.3 No. 1 Vibration Limit	3°C	Initial	35%
	3°C	Final	25%
CSA 22.3 No. 1	See "Wind and Ice Case 1" in Table 1	Final	60%

Sag and tension criteria for overhead shield wires (OHSW), including optical ground wire (OPGW), are based on those defined in Appendix A of OEB document "Minimum Design Criteria for the Reference Option", and are as follows in Table B-3.

Table B-3. Overhead Shield Wire Sag and Tension Criteria

Case	Climatic Condition	Tension Condition	Maximum % RBS
OEB Vibration Limit	-30°C	Initial	25%
CSA 22.3 No. 1 Vibration Limit	3°C	Initial	20%
	3°C	Final	15%
CSA 22.3 No. 1	See "Wind and Ice Case 1" in Table 1	Final	60%

INSULATOR SWING

Insulator swing criteria and associated minimum air gaps for 230-kV phase conductors are based on those defined in Appendix A of OEB document "Minimum Design Criteria for the Reference Option", and are as follows in Table 4.

Table B-4. Insulator Swing Criteria and Minimum Air Gaps for 230-kV Phase Conductors

Case	Wind Pressure (Pa)	Conductor Temperature	Tension Condition	Minimum Air Gap (m)	
CSA 22.3 No. 1	230	4°C	Bare Conductor Final Tension	1.586	
OEB 60 Hz Flashover (5 Year Gust)	350	4°C	Bare Conductor Final Tension	0.60	Phase to Ground
				1.020*	Phase to Phase
OEB Moderate Wind	230	-30°C	Bare Conductor Final Tension	1.20	

* This phase-to-phase clearance to be maintained for galloping clearances.

* * * * *

SECTION C - CONDUCTOR & OVERHEAD GROUND WIRE

CABLE CHARACTERISTICS

Table C-1 provides technical information for cables to be utilized for the reference route design.

Table C-1. Cable Characteristics

Application	Type	Diameter	Weight	RBS
Phase Conductor	1192.5 kcmil “Grackle” 54/19 ACSR	34 mm (1.337”)	22.3 N/m (1.53 lb/ft)	186.4 kN (41,900 lbf)
Shield Wire	19#10 Alumoweld	12.9 mm (0.509”)	6.56 N/m (0.449 lb/ft)	121.1 kN (27,190 lbf)
Optical Ground Wire	TBD	TBD	TBD	TBD

GALLOPING

The climatic load case “Galloping Case 1,” presented in Table B-1, is a NextEra standard. The galloping analysis to be performed will ensure that the required phase-to-phase separation (defined in Table B-4) is maintained between galloping ellipses for typical spans. As typical spans on this line are approximately 400 m, the maximum ellipse to be evaluated will be 12 meters on the long axis, 2.4 meters on the short axis, and the maximum angular rotation of the ellipse is assumed to be 5degrees. If galloping cannot be controlled economically by increasing phase spacing, the preferred mitigation for galloping will be to utilize galloping spoilers or equivalent hardware.

* * * * *

SECTION D - CONDUCTOR CLEARANCES

CLEARANCE TO SUPPORTING STRUCTURE

Clearances to the supporting structure shall be as defined by the required minimum air gaps defined in Table B-4.

VERTICAL CLEARANCES

The minimum vertical clearances for 230-kV transmission lines to be used in the design are presented in Tables D-1 and D-2, and are based on the clearance requirements of CSA 22.3 No. 1 and Appendix A of OEB document "Minimum Design Criteria for the Reference Option." These minimum required clearances are further increased by a design safety factor as specified by the OEB.

Vertical clearances are to be maintained in conditions producing maximum conductor sag. The conditions producing maximum sag are 1) maximum operating temperature of ACSR, 140°C, and 2) the ice-only climatic load case, presented as "Ice Case 1" in Table B-1.

As the terrain data available for structure spotting is based upon 10 m contour lines and no ground feature codes will be utilized, there will be an additional 2.0 m clearance buffer added to the clearances. For the purposes of preliminary engineering, structures will be spotted based upon land likely to be traversed by vehicles (where vertical clearances required by the OEB is 7.3m) with the additional (2m) buffer, or 9.3m total of vertical ground clearance.

Table D-1. Vertical Clearances for 230-kV Conductors Above Land

Nature of Surface Beneath Cables or Conductors	Minimum Required Clearance (m)	OEB Design Safety Factors (m)	Additional Increase[5] (m)	Total Required Design Clearance (m)
Above Land				
Over land likely to be travelled by road vehicles (including highways, streets, lanes, alleys, and driveways other than those leading to residences or residence garages)	6.1	1.2	2.0	9.3
Over the right-of-way of underground pipelines	6.1	1.2	2.0	9.3
Alongside land likely to be travelled by road vehicles§ or within the limits (with no overhang) of streets and highways	6.1	1.2	2.0	9.3
Over or alongside farmland likely to be travelled by vehicles[1]	6.1	3.9	2.0	12.0
Over driveways to residences and residence garages	6.1	1.2	2.0	9.3
Alongside roads and highways in areas unlikely to be travelled by road vehicles (with no overhang) and within 1.5 m of the limit of the road right-of-way[2]	5.5	1.2	2.0	8.7
Over walkways or ground normally accessible only to pedestrians, snow mobiles, and personal-use all-terrain vehicles[3]	4.6	1.2	2.0	7.8
Above top of rail at railway crossings[4]	9.0	0.6	2.0	11.6
Primary and secondary highways, unless part of a high load corridor	7.9	1.2	2.0	11.1
High load corridor for unescorted, 9 m high loads	11.5		2.0	13.5
Extra high load corridor for unescorted 12.8 m high loads	15.3		2.0	17.3

Notes

[1] Where a line runs parallel to land accessible to vehicles but is over land not requiring clearance for vehicles, the wire can swing out over the area accessible to vehicles or, at voltages over 200 kV, vehicles can be subjected to a hazard from induced voltages. These vertical clearances apply where the conductor (in the swing condition, where specified) is over, or within 1.7 m from the edge of, land accessible to vehicles.

[2] These areas are generally adjacent to fences and accessible to small vehicles, but are not likely to be travelled by high road vehicles or farm machinery.

[3] Seasonal conditions warrant additional clearance for snow depth. In certain cases, the vertical clearances are further increased to account for mean annual snow depth in areas where regular snow clearing is not anticipated. Based on information provided in tables included in CSA 22.3 No. 1, the maximum mean annual snow depth along the route occurs in Wawa, ON where the mean annual snow depth is 1.1 m.

[4] Because the rail level of a railway where ballast is used is not fixed, where any line that crosses a railway is constructed or altered, an additional 0.3 m of vertical clearance above rails shall be provided, unless a lesser amount is mutually agreed upon, to permit normal subsequent ballast adjustments without encroaching on the specified minimum clearance.

[5] The additional 2m clearance increase is utilized to mitigate inaccuracies associated with available survey data and to allow for flexibility for minor structure shifts without impacting clearances; it is expected this buffer will not be required at every location during final design or as-built conditions.

Table D-2. Vertical Clearances for 230-kV Conductors Above Water

Nature of Surface Beneath Cables or Conductors	Minimum Required Clearance (m)	OEB Design Safety Factors (m)	Additional Increases** (m)	Total Required Design Clearance (m)
Above Waterways				
Minor waterways	6.1	1.2	2.0	9.3
Shallow or fast-moving waterways capable of being used by canoes and paddle boats in isolated areas where motor boats are not expected Creeks and streams: W = 3-50 m and D < 1 m Ponds: A<8 ha and D < 1 m H = 4.0 m	7.3	1.2	2.0	10.5
Shallow or fast-moving waterways capable of being used by motor boats with antennas and unable to support masted vessels. Creeks and streams: W = 3-50 m and D < 1 m Ponds: A<8 ha and D < 1 m H = 6.0 m	9.3	1.2	2.0	12.5
Shallow lakes and rivers used by masted vessels. Rivers: W = 3-50 m and D > 1 m Ponds and lakes: A<8 ha and D > 1 m H = 8.0 m	11.3	1.2	2.0	14.5
Small resort lakes, medium sized rivers and reservoirs, rivers connecting lakes, and crossings adjacent to bridges and roads. Rivers: W = 50-500 m Lakes or reservoirs: 8 ha < A < 80 ha H = 10.0 m	13.3	1.2	2.0	16.5
Large lakes, reservoirs, and main rivers in resort areas. Rivers: W > 500 m Lakes or reservoirs: 8 ha < A < 80 ha H = 12.0 m	15.3	1.2	2.0	18.5
Main lakes on main navigation routes and marinas. A > 800 ha H = 14.0 m	17.3	1.2	2.0	20.5
Federally maintained commercial channels, rivers, harbors, or heritage canals.	*	*	*	*

* Clearances shall be specified by the appropriate Transport Canada office

** The additional 2m clearance increase is utilized to mitigate inaccuracies associated with available survey data and to allow for flexibility for minor structure shifts without impacting clearances; it is expected this buffer will not be required at every location during final design or as-built conditions.

HORIZONTAL CLEARANCES

The minimum horizontal clearances for 230-kV transmission lines to be used in the design are presented in Tables D-3, and are based on the clearance requirements of CSA 22.3 No. 1. The value for horizontal clearance to buildings will be used to assess right-of-way width requirements.

Table D-3. Horizontal Clearances for 230-kV Conductors

Nature of Surface Near Cables or Conductors	Minimum Required Clearance (m)	OEB Design Safety Factors (m)	Additional Increases (m)	Total Required Design Clearance (m)
Buildings	3.2	TBD	-	3.2
Conductors of other 230-kV circuits attached to the same supporting structure	5.2	TBD	-	5.2

Note: The OEB did not specifically state horizontal clearance requirements. Additional horizontal clearances are not expected to impact the preliminary design because no buildings are included in the terrain data available.

RIGHT-OF-WAY REQUIREMENTS

The estimated ROW widths will be calculated based upon the estimated blowout including insulator swing, electrical clearance, structure layout, and assumed structure deflection. The blowout and clearance criteria will be evaluated under two load cases. The building clearance from Table D-3 will be evaluated with the Blowout Case (400 pa) from Table B-1. MAID clearance to trees (1.5m) will be evaluated with a 50 year wind (770 pa). Structure deflection is conservatively assumed to be 5% under all configurations and loading criteria.

* * * * *

SECTION E - FOUNDATION DESIGN

FOUNDATION DESIGN

Two basic designs were developed for each structure type—a rock foundation and an all-soils foundation.

Rock Foundation

A rock anchor foundation, with concrete cap to provide a level base for structure base was developed. The rock anchor was designed with the assumption of 3ksi competent rock.

Soil Foundation

An all-soil, concrete drilled pier, will be developed as the alternative to the rock anchor foundation.

The soil parameters are based upon the Alston desk top study utilizing boring obtained from the Ontario Ministry of Transportation. The soils identified on the maps from the desk study were quite variable, ranging from loose sands to stiff clays. It is assumed that deep overburden soils would likely occur near stream/river crossings and areas of swampland or other low lying areas. As such, relatively conservative soil parameters were assumed as follows:

Strength Reduction Factor: 0.6

Loose to medium sand
Soil Unit Weight = 110 pcf
Friction Angle = 30 degrees
Groundwater at 10 feet below grade

Skin friction and end bearing calculated according to the Canadian Foundation Engineering Manual (4th edition) Section 18.2.1.1.

Beta = 0.3 (for calculation of skin friction – Beta = k*tan(phi)).
Nt = 30 (bearing capacity factor for calculation of end bearing)

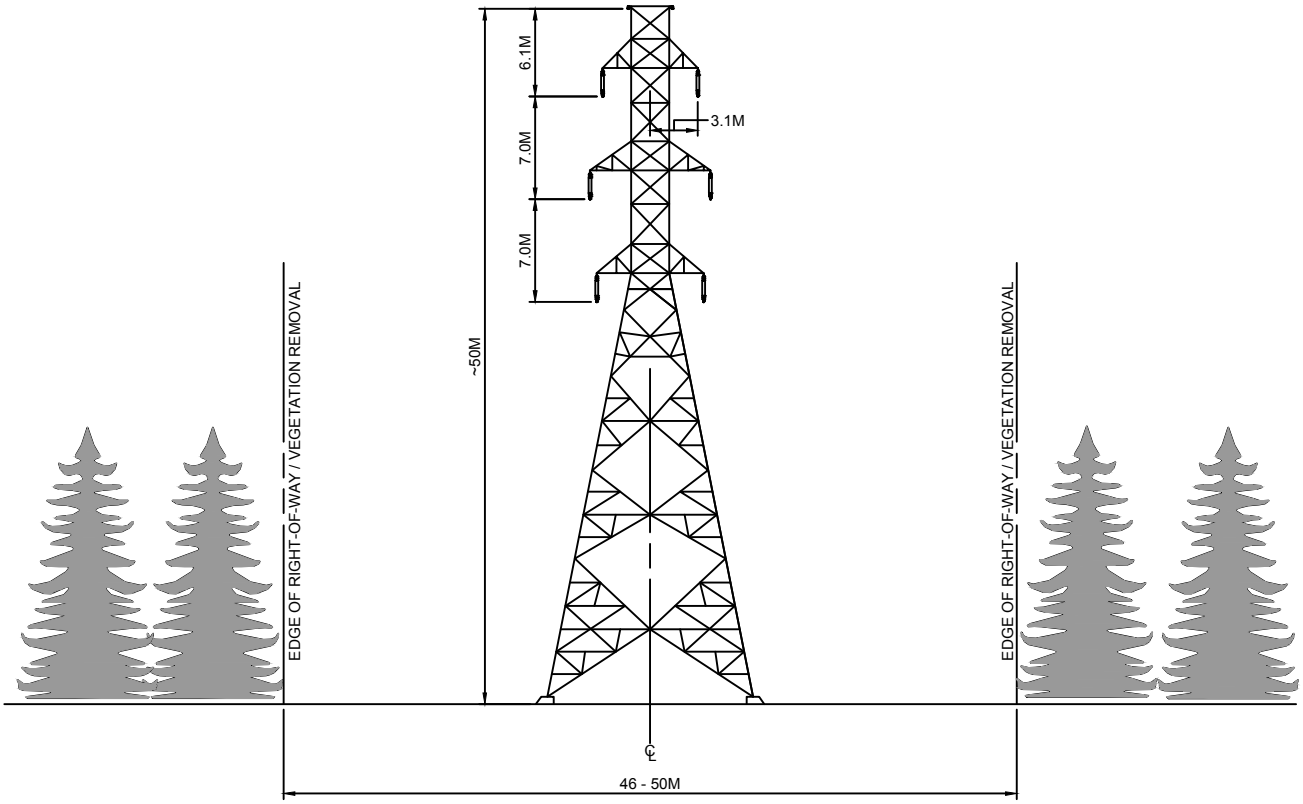
Lateral analysis will be completed using LPile.

SECTION F - REFERENCES

Design Criteria of Overhead Transmission Lines, CSA 22.3 No. 60826:06, Canadian Standards Association, October 2006.

Minimum Technical Requirements for the Reference Option of the E-W Tie Line, Ontario Energy Board, November 9, 2011.

Overhead Systems, CSA 22.3 No. 1-10, Canadian Standards Association, July 2010.



PRELIMINARY CROSS SECTION

NOT TO SCALE

NOTES:

1. PROPOSED STRUCTURE HEIGHTS ARE TYPICAL.
2. PROPOSED TYPICAL STRUCTURE HEIGHTS ARE SUBJECT TO CHANGE WITH THE COMPLETION OF FINAL LAYOUT DESIGN.
3. LATTICE TOWER SHOWN FOR INFORMATION ONLY. TUBULAR STEEL STRUCTURE OPTION MAY BE CONSIDERED.
4. RANGE OF RIGHT-OF-WAY WIDTHS BASED ON 500M MAX SPAN V-STRING (MIN) AND I-STRING (MAX).

PRELIMINARY

Figure 1

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
230-kV DOUBLE CIRCUIT LATTICE
I-STRING

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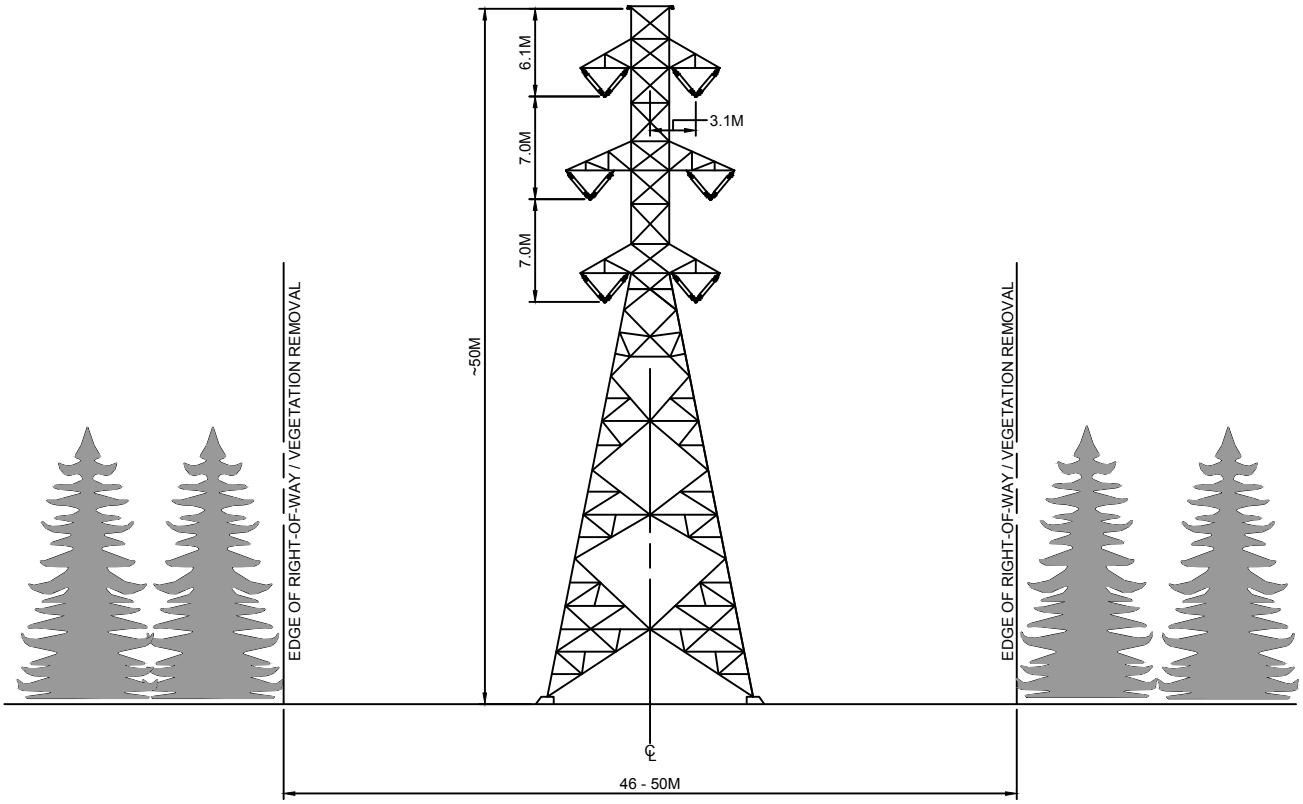

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4. RANGE OF RIGHT-OF-WAY WIDTHS BASED ON 500M MAX SPAN V-STRING (MIN) AND I-STRING (MAX).

PRELIMINARY

Figure 1

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
230-kV DOUBLE CIRCUIT LATTICE
V-STRING

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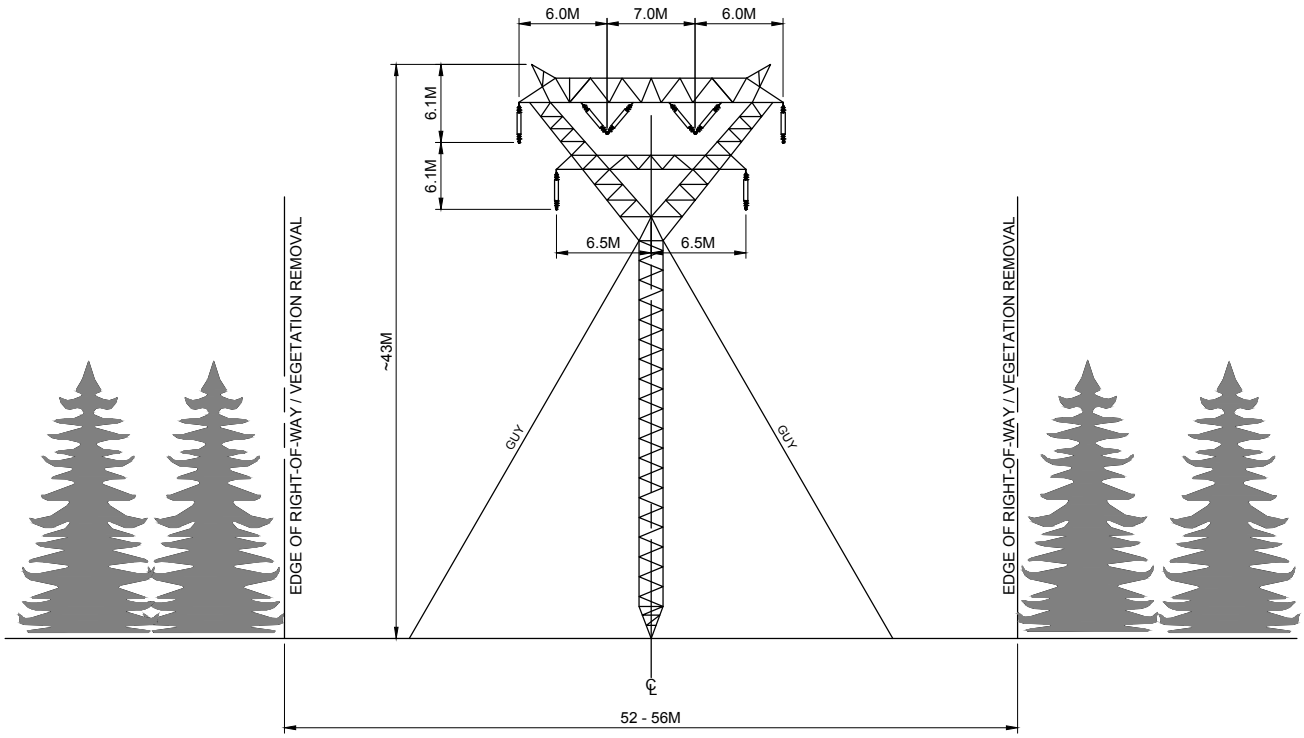

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3. LATTICE TOWER SHOWN FOR INFORMATION ONLY. TUBULAR STEEL STRUCTURE OPTION MAY BE CONSIDERED.
4. RANGE OF RIGHT-OF-WAY WIDTHS BASED ON 500M MAX SPAN V-STRING (MIN) AND I-STRING (MAX).
5. ANCHORS WILL TYPICALLY BE LOCATED WITHIN RIGHT-OF-WAY, BUT MAY REQUIRE GUY EASEMENTS WITH STEEP TERRAIN.

PRELIMINARY

Figure 2

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
230-kV DOUBLE CIRCUIT GUYED Y
I-STRING

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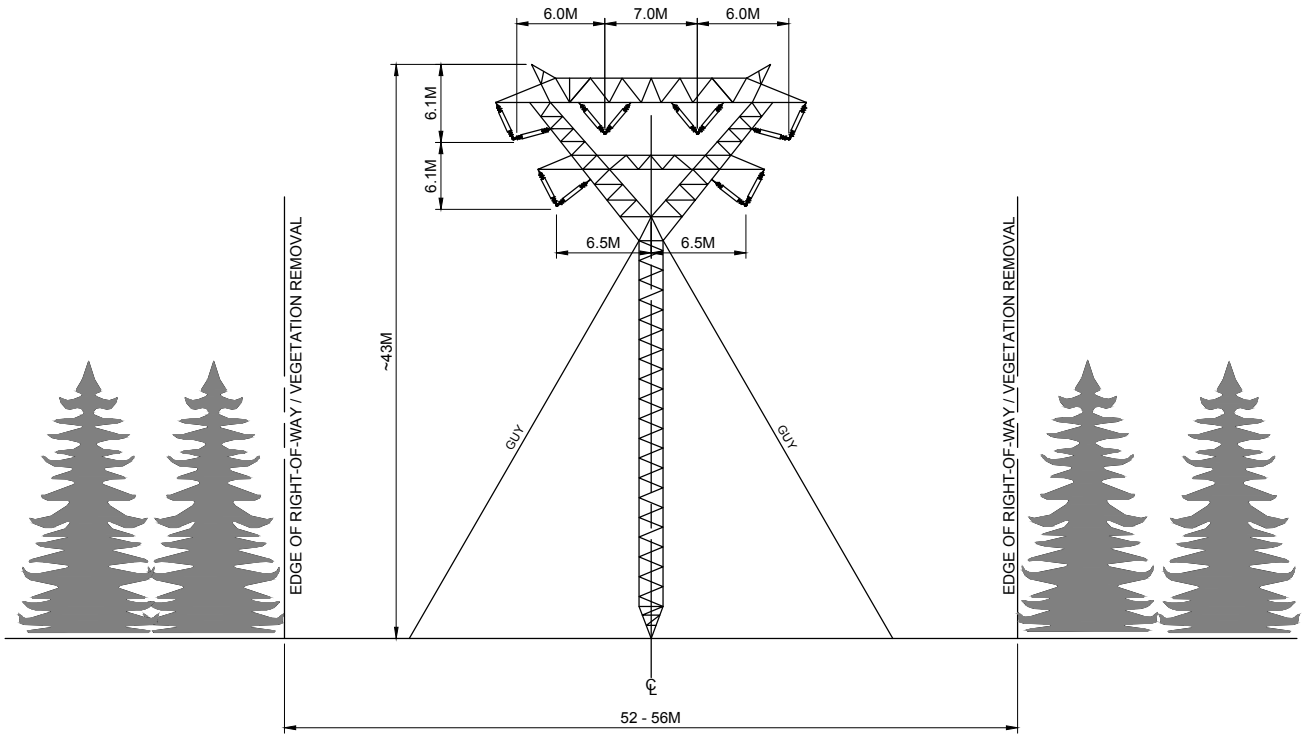

PRELIMINARY CROSS SECTION

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5. ANCHORS WILL TYPICALLY BE LOCATED WITHIN RIGHT-OF-WAY, BUT MAY REQUIRE GUY EASEMENTS WITH STEEP TERRAIN.

PRELIMINARY

Figure 2

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
230-kV DOUBLE CIRCUIT GUYED Y V-STRING

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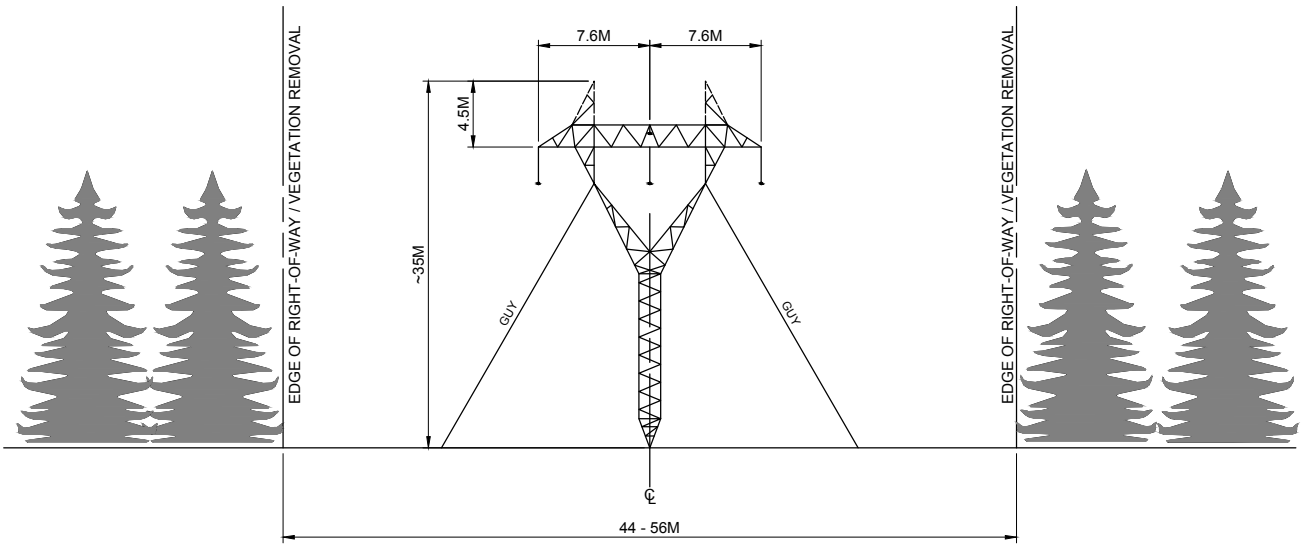

PRELIMINARY CROSS SECTION

NOT TO SCALE

NOTES:

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2. PROPOSED TYPICAL STRUCTURE HEIGHTS ARE SUBJECT TO CHANGE WITH THE COMPLETION OF FINAL LAYOUT DESIGN. LAYOUT BASED ON 287-kV AC STR,
3. LATTICE TOWER SHOWN FOR INFORMATION ONLY. TUBULAR STEEL STRUCTURE OPTION MAY BE CONSIDERED.
4. RIGHT-OF-WAY WIDTHS BASE ON CODE MINIMUMS. NO CONSIDERATIONS FOR FIELD EFFECTS INCLUDED.

PRELIMINARY

NEXTera ENERGY RESOURCES

Figure 3

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
±300-kV DIRECT CURRENT GUYED Y
I-STRING

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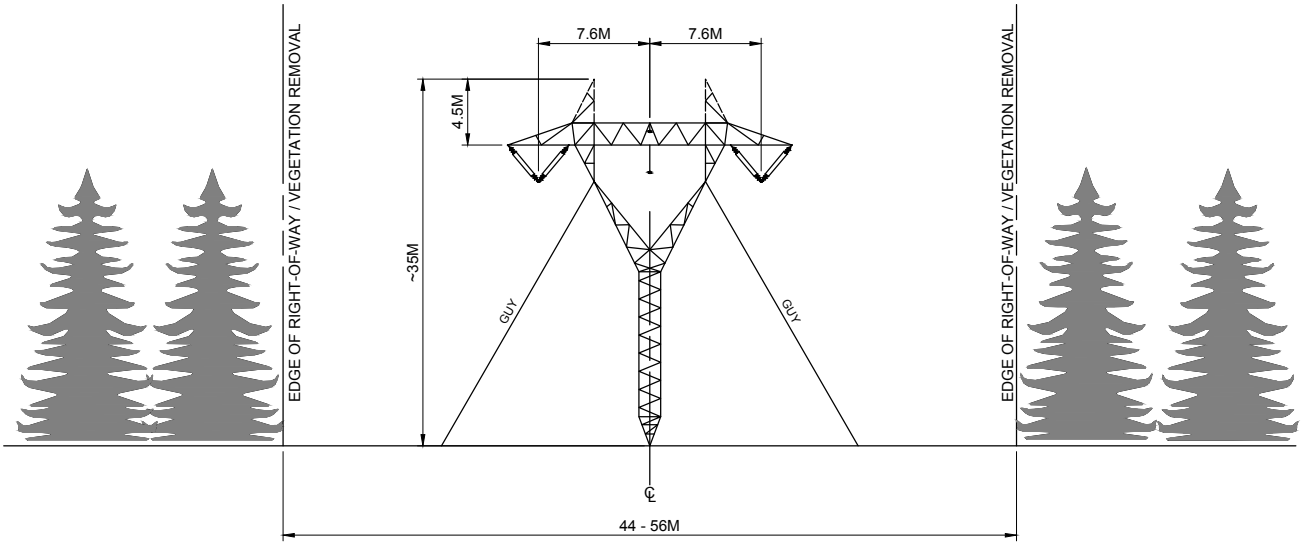

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4. RIGHT-OF-WAY WIDTHS BASE ON CODE MINIMUMS. NO CONSIDERATIONS FOR FIELD EFFECTS INCLUDED.

PRELIMINARY

Figure 3

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
±300-kV DIRECT CURRENT GUYED Y V-STRING

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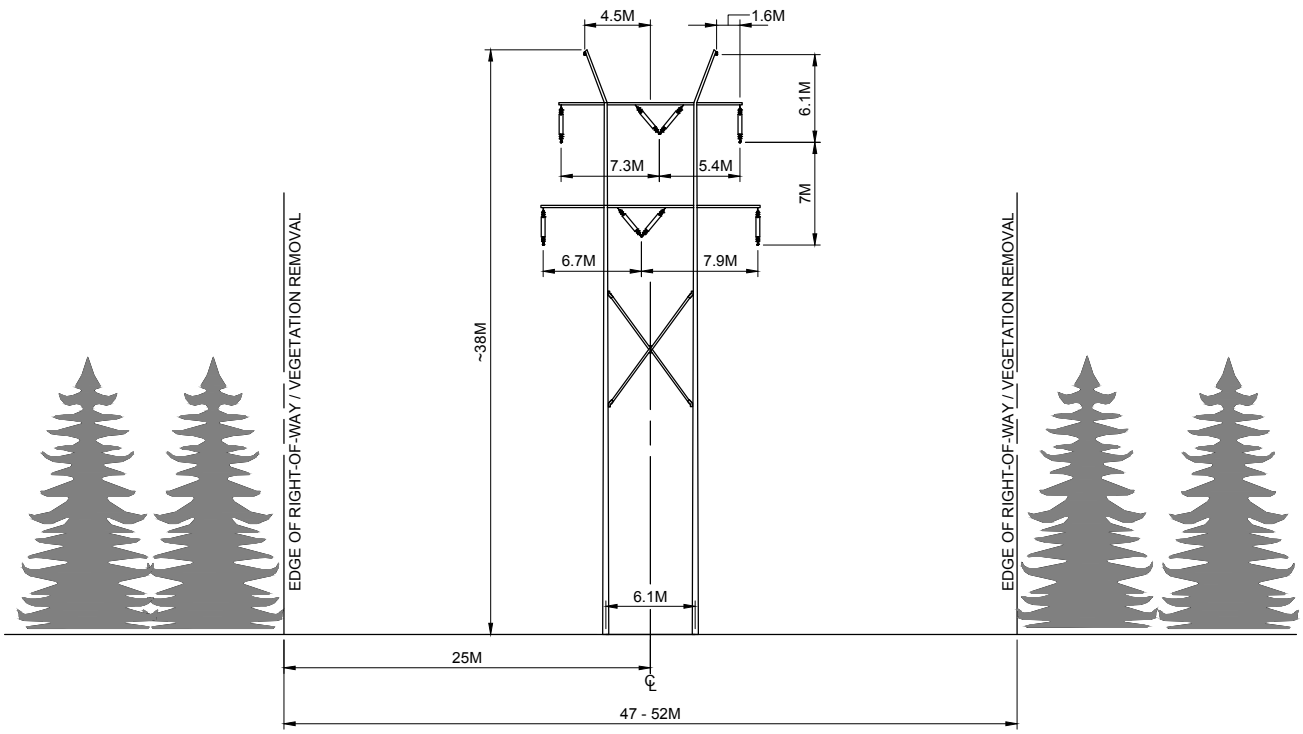

PRELIMINARY CROSS SECTION

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3. LATTICE TOWER SHOWN FOR INFORMATION ONLY. TUBULAR STEEL STRUCTURE OPTION MAY BE CONSIDERED.
4. RIGHT-OF-WAY WIDTHS BASED ON 500M MAX SPAN I-STRING AND V-STRING EVALUATED.

PRELIMINARY

Figure 4

ONTARIO EAST-WEST TIE
PRELIMINARY CROSS SECTION
230-kV DOUBLE CIRCUIT H-FRAME
I-STRING

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Appendix 14: Affidavit regarding Reliability Standards and Minimum Technical Requirements

The Affidavit regarding Reliability Standards and Minimum Technical Requirements is attached.

EB-2011-0140

ONTARIO ENERGY BOARD

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

Affidavit of Cindy Tindell

My name is Cindy Tindell. I am the vice president of transmission development for NextEra Energy Transmission, LLC, a wholly-owned subsidiary of NextEra Energy, Inc. ("NextEra"). NextEra wholly owns NextEra Energy Canada, ULC ("NextEra Canada"), which holds a 50% interest in Upper Canada Transmission, Inc., which has adopted the trade name of NextBridge Infrastructure ("NextBridge"). NextBridge is applying for designation as the developer of the East-West Tie Line. The remaining interests in NextBridge are held equally by Enbridge Inc., through Enbridge Transmission Holdings Inc. (ETHI), and Borealis EWT Inc., an OMERS entity. I am submitting this affidavit as an officer of NextBridge, and on behalf of all the owners of NextBridge.

As required by section 6.3 of *Filing Requirements East-West Tie Designation Applications* attached as Appendix A to the Ontario Energy Board's EB-2011-0140 *Phase 1 Decision and Order* dated July 12, 2012, I hereby confirm that NextBridge will:

- design the East-West Tie Line to meet or exceed the existing reliability standards of the North American Electricity Reliability Corporation, the Northeast Power Coordinating Council, Inc., and the Ontario Independent Electricity System Operator; and
- design the East-West Tie Line to meet or exceed the Ontario Energy Board's Minimum Technical Requirements *for the Reference Option of the E-W Tie Line* dated November 9, 2011 (Minimum

Technical Requirements), or, if in light of further development work NextBridge determines it appropriate to seek to differ from the Minimum Technical Requirements, then NextBridge will provide documentation of where NextBridge seeks to differ from the Minimum Technical Requirements and evidence as to the equivalence or superiority of the proposed alternative option.

This concludes my affidavit.

EB-2011-0140

ONTARIO ENERGY BOARD

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF a Board-initiated proceeding to designate an electricity transmitter to undertake development work for a new electricity transmission line between Northeast and Northwest Ontario: the East-West Tie Line.

VERIFICATION

I, the undersigned, being duly sworn, depose and say that the foregoing is the Affidavit of the undersigned, and that the statements made in such Affidavit to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said Affidavit as if given by me in formal hearing, under oath.

Cindy Tindell

Subscribed and sworn to before me

this 27th day of December, 2012

Notary Public

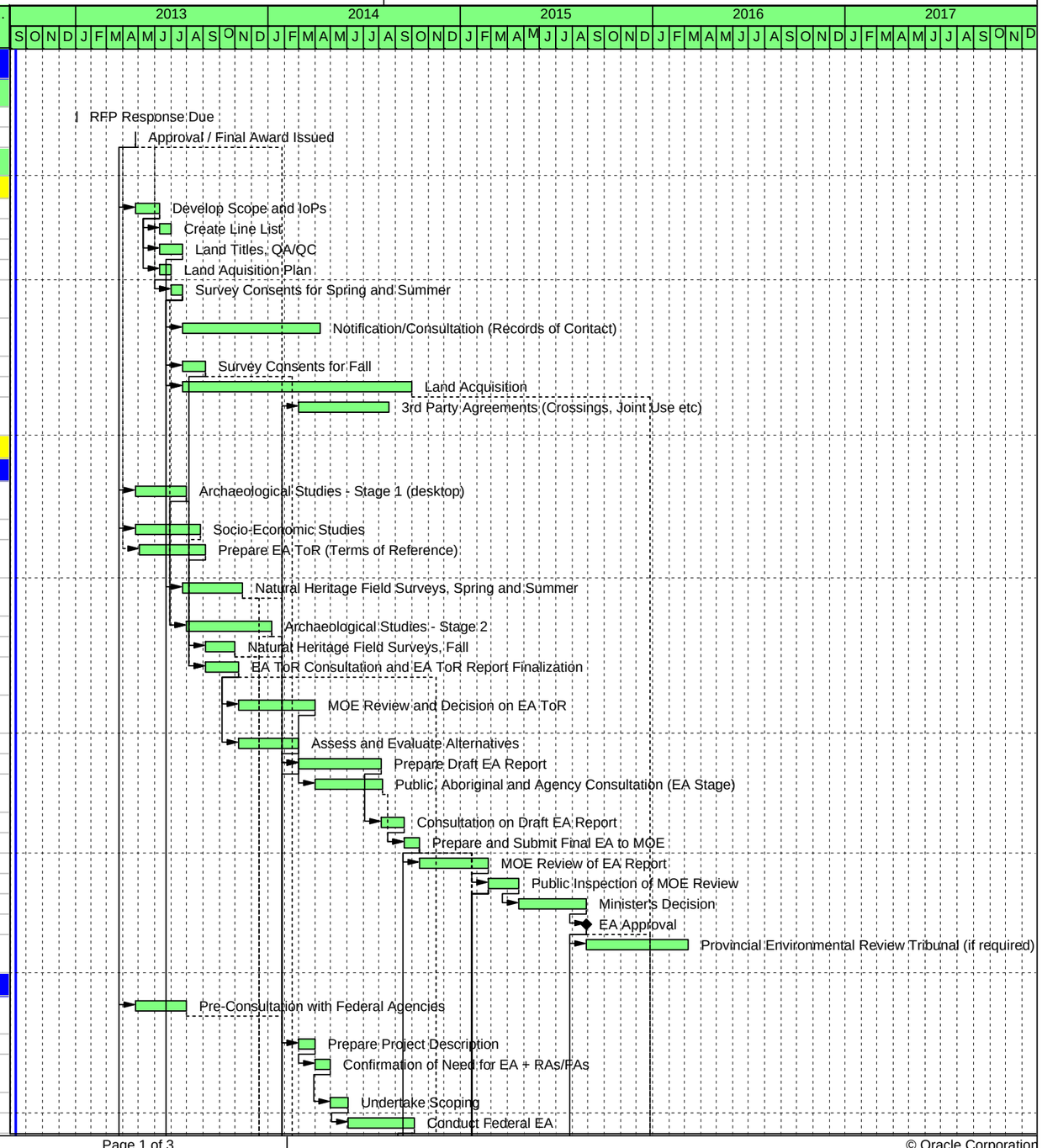
BRITTANY BRUCE
Notary Public - State of Florida
My Comm. Expires Jun 19, 2016
Commission # EE 209464

My Commission expires: 6/19/2016

Appendix 15: NextBridge Project Execution Chart

The NextBridge Project Execution Chart is attached.

Activity ID	Activity Name	Original Duration	Start	Finish	Total Float	Respons...
Ontario EW Execution		1242	04-Jan-13	11-Dec-17	0	
RFP		80	04-Jan-13	26-Apr-13	1162	
RFP111	RFP Response Due	1	04-Jan-13	04-Jan-13*	1241	..DEV
RFP999	Approval / Final Award Issued	1	26-Apr-13*	26-Apr-13	0	..DEV
Project Development Phase		719	26-Apr-13	08-Mar-16	443	
Land Aquisition		360	26-Apr-13	30-Sep-14	802	
LND1020	Develop Scope and IoPs	30	26-Apr-13	10-Jun-13	131	..LND
LND1030	Create Line List	15	10-Jun-13	01-Jul-13	1117	..LND
LND1040	Land Titles, QA/QC	30	10-Jun-13	23-Jul-13	427	..LND
LND1050	Land Aquisition Plan	15	10-Jun-13	01-Jul-13	131	..LND
LND1060	Survey Consents for Spring and Summer	15	01-Jul-13	23-Jul-13	131	..LND
LND1070	Notification/Consultation (Records of Contact)	180	23-Jul-13	10-Apr-14	922	..LND
LND1080	Survey Consents for Fall	30	23-Jul-13	04-Sep-13	181	..LND
LND1090	Land Acquisition	300	23-Jul-13	30-Sep-14	427	..LND
LND1000	3rd Party Agreements (Crossings, Joint Use etc)	120	27-Feb-14	18-Aug-14	832	..LND
Environmental Permitting		719	26-Apr-13	08-Mar-16	443	
Provencial EA		719	26-Apr-13	08-Mar-16	443	
PROVEA1000	Archaeological Studies - Stage 1 (desktop)	66	26-Apr-13	31-Jul-13	136	..ENV
PROVEA1010	Socio-Economic Studies	85	26-Apr-13	27-Aug-13	137	..ENV
PROVEA1020	Prepare EA ToR (Terms of Reference)	88	01-May-13*	05-Sep-13	131	..ENV
PROVEA1030	Natural Heritage Field Surveys, Spring and Summer	80	23-Jul-13	14-Nov-13	171	..ENV
PROVEA1040	Archaeological Studies - Stage 2	109	31-Jul-13	08-Jan-14	136	..ENV
PROVEA1050	Natural Heritage Field Surveys, Fall	40	04-Sep-13	30-Oct-13	181	..ENV
PROVEA1060	EA ToR Consultation and EA ToR Report Finalization	44	05-Sep-13	06-Nov-13	131	..ENV
PROVEA1070	MOE Review and Decision on EA ToR	97	06-Nov-13	31-Mar-14	159	..ENV
PROVEA1080	Assess and Evaluate Alternatives	75	06-Nov-13	27-Feb-14	131	..ENV
PROVEA1090	Prepare Draft EA Report	110	27-Feb-14	04-Aug-14	131	..ENV
PROVEA1100	Public, Aboriginal and Agency Consultation (EA Stage)	90	31-Mar-14	06-Aug-14	159	..ENV
PROVEA1110	Consultation on Draft EA Report	30	04-Aug-14	16-Sep-14	131	..ENV
PROVEA1120	Prepare and Submit Final EA to MOE	21	16-Sep-14	15-Oct-14	131	..ENV
PROVEA1130	MOE Review of EA Report	88	15-Oct-14	24-Feb-15	131	..ENV
PROVEA1140	Public Inspection of MOE Review	42	24-Feb-15	23-Apr-15	131	..ENV
PROVEA1150	Minister's Decision	89	23-Apr-15	28-Aug-15	147	..ENV
PROVEA1160	EA Approval	0		28-Aug-15	147	..ENV
PROVEA1170	Provincial Environmental Review Tribunal (if required)	129	28-Aug-15	08-Mar-16	443	..ENV
Federal EA (If Project is Designated)		568	26-Apr-13	29-Jul-15	219	
FEDEA1000	Pre-Consultation with Federal Agencies	66	26-Apr-13	31-Jul-13	363	..ENV
FEDEA1010	Prepare Project Description	23	27-Feb-14	01-Apr-14	219	..ENV
FEDEA1020	Confirmation of Need for EA + RAs/FAs	21	01-Apr-14	30-Apr-14	219	..ENV
FEDEA1030	Undertake Scoping	22	30-Apr-14	02-Jun-14	219	..ENV
FEDEA1040	Conduct Federal EA	88	02-Jun-14	06-Oct-14	219	..ENV



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Milestone

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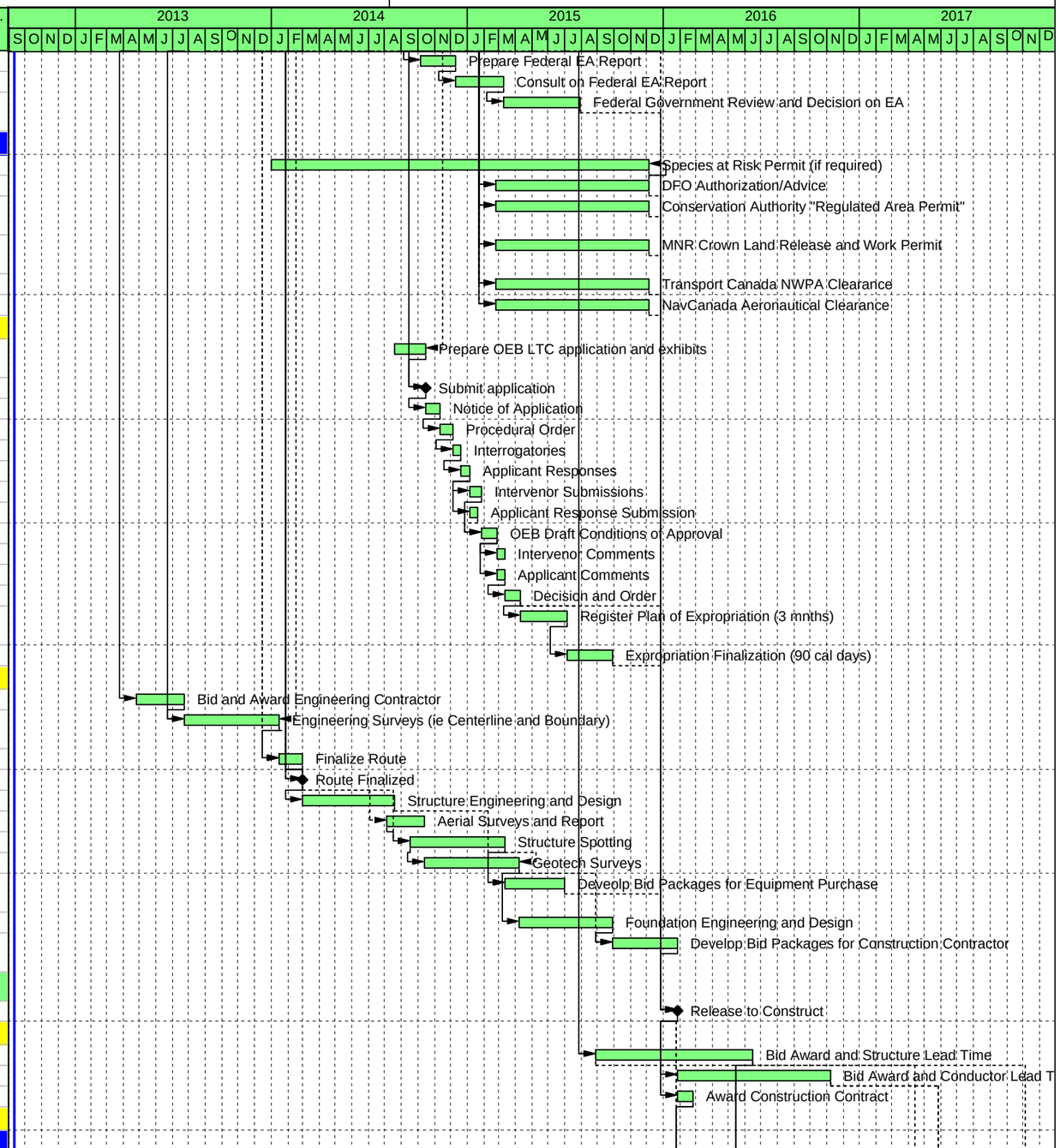
Activity ID	Activity Name	Original Duration	Start	Finish	Total Float	Respons...
FEDEA1050	Prepare Federal EA Report	44	06-Oct-14	09-Dec-14	219	..ENV
FEDEA1060	Consult on Federal EA Report	60	09-Dec-14	09-Mar-15	219	..ENV
FEDEA1070	Federal Government Review and Decision on EA	100	09-Mar-15	29-Jul-15	219	..ENV
Other Permits and Approvals		486	31-Dec-13	04-Dec-15	131	
ENV1000	Species at Risk Permit (if required)	486	31-Dec-13	04-Dec-15	131	..ENV
ENV1010	DFO Authorization/Advice	197	24-Feb-15	04-Dec-15	131	..ENV
ENV1020	Conservation Authority "Regulated Area Permit"	197	24-Feb-15	04-Dec-15	131	..ENV
ENV1030	MNR Crown Land Release and Work Permit	197	24-Feb-15	04-Dec-15	131	..ENV
ENV1040	Transport Canada NWPA Clearance	197	24-Feb-15	04-Dec-15	131	..ENV
ENV1050	NavCanada Aeronautical Clearance	197	24-Feb-15	04-Dec-15	131	..ENV
OEB Leave to Construct		280	19-Aug-14	29-Sep-15	551	
OEB1000	Prepare OEB LTC application and exhibits	40	19-Aug-14	15-Oct-14	176	..Reg
OEB1010	Submit application	0	15-Oct-14		176	..Reg
OEB1020	Notice of Application	20	15-Oct-14	12-Nov-14	176	..Reg
OEB1030	Procedural Order	15	12-Nov-14	05-Dec-14	176	..Reg
OEB1040	Interrogatories	10	05-Dec-14	19-Dec-14	176	..Reg
OEB1050	Applicant Responses	10	19-Dec-14	06-Jan-15	176	..Reg
OEB1060	Intervenor Submissions	15	06-Jan-15	28-Jan-15	176	..Reg
OEB1070	Applicant Response Submission	10	06-Jan-15	21-Jan-15	181	..Reg
OEB1080	OEB Draft Conditions of Approval	20	28-Jan-15	26-Feb-15	176	..Reg
OEB1090	Intervenor Comments	10	26-Feb-15	12-Mar-15	691	..Reg
OEB1100	Applicant Comments	10	26-Feb-15	12-Mar-15	176	..Reg
OEB1110	Decision and Order	20	12-Mar-15	09-Apr-15	176	..Reg
OEB2200	Register Plan of Expropriation (3 mnths)	60	09-Apr-15	06-Jul-15	176	..LND
OEB2300	Expropriation Finalization (90 cal days)	60	06-Jul-15	29-Sep-15	176	..LND
Engineering		690	26-Apr-13	26-Jan-16	97	
A1070	Bid and Award Engineering Contractor	60	26-Apr-13	23-Jul-13	131	
A1000	Engineering Surveys (ie Centerline and Boundary)	120	23-Jul-13	16-Jan-14	131	..E&C
A1190	Finalize Route	30	16-Jan-14	27-Feb-14	131	..E&C
A1010	Route Finalized	0		27-Feb-14	131	..E&C
A1170	Structure Engineering and Design	120	27-Feb-14	18-Aug-14	377	..E&C
A1020	Aerial Surveys and Report	50	04-Aug-14*	14-Oct-14	97	..E&C
A1030	Structure Spotting	120	16-Sep-14	11-Mar-15	97	..E&C
A1040	Geotech Surveys	120	14-Oct-14	08-Apr-15	97	..E&C
A1050	Deveolp Bid Packages for Equipment Purchase	80	11-Mar-15	02-Jul-15	237	..E&C
A1140	Foundation Engineering and Design	120	08-Apr-15	28-Sep-15	97	..E&C
A1060	Develop Bid Packages for Construction Contractor	80	28-Sep-15	26-Jan-16	97	..E&C
Project Execution Phase		572	28-Aug-15	11-Dec-17	0	
RTC	Release to Construct	0		26-Jan-16	97	
Contracts / Material Aquisition		300	28-Aug-15	08-Nov-16	157	
A1150	Bid Award and Structure Lead Time	200	28-Aug-15	16-Jun-16	147	..ISC
A1160	Bid Award and Conductor Lead Time	200	26-Jan-16	08-Nov-16	157	..ISC
A1180	Award Construction Contract	20	26-Jan-16	24-Feb-16	97	..ISC
Construction		452	24-Feb-16	11-Dec-17	0	
Thunder Bay to Marathon 232K (144 miles) long		452	24-Feb-16	11-Dec-17	0	



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Milestone

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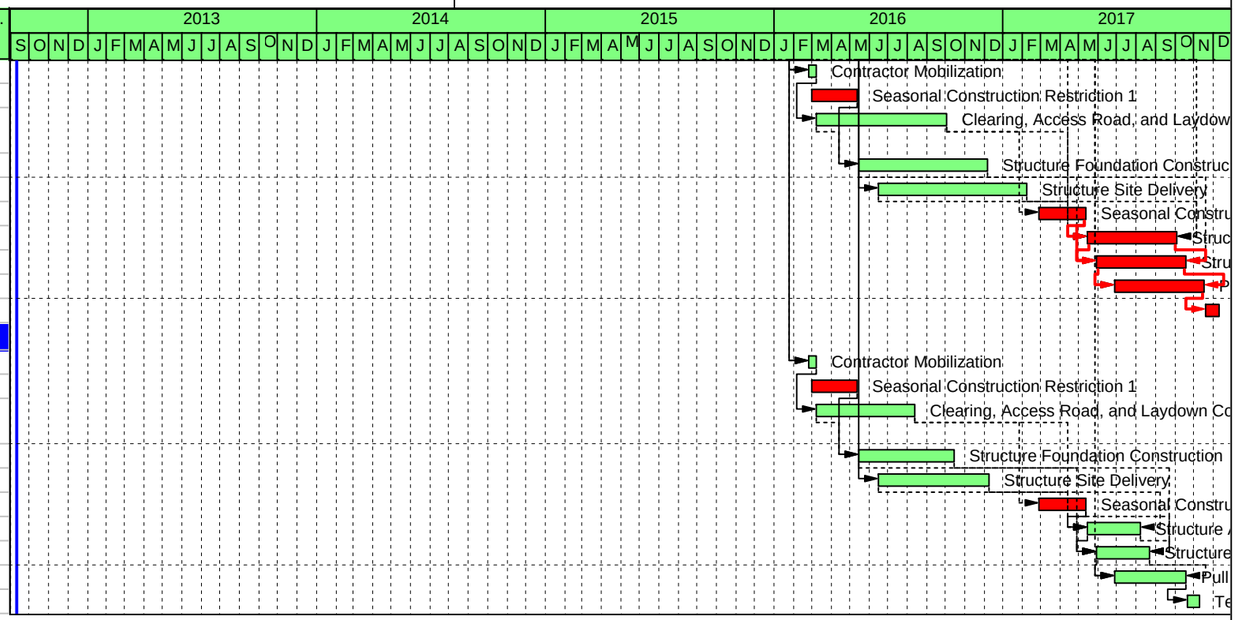
Activity ID	Activity Name	Original Duration	Start	Finish	Total Float	Respons...
TBM1010	Contractor Mobilization	10	24-Feb-16	09-Mar-16	97	..E&C
TBM1000	Seasonal Construction Restriction 1	55	29-Feb-16*	13-May-16	0	..E&C
TBM1020	Clearing, Access Road, and Laydown Constuction	145	09-Mar-16	03-Oct-16	97	..E&C
TBM1030	Structure Foundation Construction	140	16-May-16	05-Dec-16	190	..E&C
TBM1040	Structure Site Delivery	160	16-Jun-16	07-Feb-17	147	..E&C
TBM1050	Seasonal Construction Restriction 2	55	27-Feb-17*	12-May-17	0	..E&C
TBM1060	Structure Assembly	100	15-May-17	04-Oct-17	0	..E&C
TBM1080	Structure Setting	100	30-May-17	19-Oct-17	0	..E&C
TBM1090	Pull, Sag, and Clip Conductors	100	27-Jun-17	17-Nov-17	0	..E&C
TBM1100	Testing and Commissioning	15	20-Nov-17	11-Dec-17	0	..E&C
Marathon to Wawa 168K (104miles) long		432	24-Feb-16	09-Nov-17	20	
MWW1010	Contractor Mobilization	10	24-Feb-16	09-Mar-16	132	..E&C
MWW1000	Seasonal Construction Restriction 1	55	29-Feb-16*	13-May-16	0	..E&C
MWW1020	Clearing, Access Road, and Laydown Constuction	110	09-Mar-16	12-Aug-16	132	..E&C
MWW1030	Structure Foundation Construction	105	16-May-16	13-Oct-16	205	..E&C
MWW1040	Structure Site Delivery	120	16-Jun-16	08-Dec-16	167	..E&C
MWW1050	Seasonal Construction Restriction 2	55	27-Feb-17*	12-May-17	0	..E&C
MWW1060	Structure Assembly	60	15-May-17	08-Aug-17	20	..E&C
MWW1080	Structure Setting	60	30-May-17	22-Aug-17	20	..E&C
MWW1090	Pull, Sag, and Clip Conductors	80	27-Jun-17	19-Oct-17	20	..E&C
MWW1100	Testing and Commissioning	15	20-Oct-17	09-Nov-17	20	..E&C



Remaining Level of Effort
Actual Level of Effort
Actual Work
Remaining Work
Critical Remaining Work
Milestone

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Appendix 16: Guidelines for Consolidated Risk Matrix

FIGURE 61: GUIDELINES FOR RISK MATRIX

Item		Definition
Rick Category	D	Impact to the development phase of the Project
	C	Impact to the construction phase of the Project
Status	Open	Impact of Risk on project cost or schedule **HAS NOT** been reflected in the **CURRENT** Project commercial operation date and/or CapEx ($MM) forecasts.
	Closed	Impact of Risk on project cost or schedule **HAS** been reflected in the **CURRENT** Project commercial operation date and/or CapEx ($MM) forecasts.
PRIMARY Impact To	C	Risk, if not mitigated, will impact **CURRENT** CapEx ($MM).
	S	Risk, if not mitigated, will impact **CURRENT** Project commercial operation date.
Probability of Occurrence	L	Likely: > 50% estimated probability that the risk will impact either **CURRENT** Project commercial operation date or CapEx ($MM).
	U	Unlikely: < 50% estimated probability that the risk will impact either **CURRENT** Project commercial operation date or CapEx ($MM).
Impact of Occurrence	H	Significant impact on either **CURRENT** Project commercial operation date or CapEx ($MM) if the risk cannot be mitigated.
	M	Moderate impact on either **CURRENT** Project commercial operation date or CapEx ($MM) if the risk cannot be mitigated.
	L	Small or No impact on either **CURRENT** Project commercial operation date or CapEx ($MM) if the risk cannot be mitigated.

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Appendix 17: Major Steps in Environmental Assessment

FIGURE 62: MAJOR STEPS IN ENVIRONMENTAL ASSESSMENT

Major Steps in Environmental Assessment
1. **Prepare and Submit a Terms of Reference (ToR)**
The ToR is a framework or work plan to guide the preparation and of the EA documentation, which is to be submitted to the MOE for review and a decision. Consultation with the public, Aboriginal communities and government agencies is mandatory during the preparation of the Terms of Reference and must be documented and submitted to the ministry. Ministry staff coordinates a technical review of the ToR after submission, provides the opportunity for public comment, and forwards a recommendation to the Minister who decides whether or not to approve the ToR. The Minister must make a decision on the ToR within 12 weeks from the date of submission to the MOE. The proponent has an opportunity to take a "time out" to amend the ToR. The Minister can refer a matter to mediation prior to making a decision on the ToR or the proponent can initiate mediation. There is no ability to request that the Minister sends a ToR to a hearing.
2. Prepare the EA
Once the ToR is approved, the proponent may begin the EA. An EA needs to identify and evaluate the reasonable alternatives, their environmental effects, mitigation, management measures, and consultation. Consultation with the public, Aboriginal communities and government agencies is mandatory and must be documented in the EA report. To ensure compliance, the EA will need to outline how and when all commitments made in the EA will be fulfilled and how the proponent will report to the MOE about compliance. The proponent can take as much time as needed to prepare the EA document.
3. Proponent submits the EA Report to the MOE
The proponent formally submits an EA document to the MOE for review, which triggers the review timelines. Ministry staff will coordinate a review of the EA document. While not a requirement, the MOE encourages the submission of a draft report for review prior to the formal submission of the final EA Report.
4. **Ministry coordinates public and government review comments – 7 weeks**
During this step, government experts, Aboriginal communities, the public and any other interested party can provide comments on the EA document to the MOE. The public has seven weeks to comment on the EA. During this time, the proponent may revise the EA before the MOE completes its review. Note: at any time during the EA process, the proponent can initiate mediation.
5. Ministry prepares the Ministry Review – 5 weeks
During this step, MOE staff writes and publishes a review of the EA document, called a "Ministry Review". The Ministry Review includes an analysis of all public, Aboriginal community and government agency comments submitted during the seven week comment period, as well as the proponent's response to the comments. The Ministry Review also discusses how the proponent is in compliance with its approved ToR and how the proponent has met the requirements of the *EA Act*. The MOE has five weeks to write and publish the Ministry Review.
6. Public inspection of Ministry Review – 5 weeks
During this step, government agencies, Aboriginal communities, the public and any other interested party has five weeks to provide comments on the Ministry Review to the MOE. During this time, anyone, including the proponent may make a written request to the MOE identifying any outstanding issues with suggestions for how they might be resolved, or request a hearing.

Major Steps in Environmental Assessment
7. **Minister's Decision – 13 weeks**
Projects that go through the individual EA process require approval from the Minister and Cabinet. The Minister has 13 weeks to make a decision after the five-week comment period ends on the Ministry Review. The Minister has three options: 1. Refer the EA to mediation 2. Refer the EA to the Environmental Review Tribunal for a hearing 3. Make a decision to approve, approve with conditions, or refuse the EA All comments received are taken into consideration by the Minister prior to making a decision.
8. **Proponent implements the project and monitors for compliance**
Once the project has been approved, the proponent can proceed to obtain other required licenses, permits and approvals. At this point, the proponent can start construction and must report on how they have complied with their commitments in the EA and the conditions of their approval.

Appendix 18: Other Federal and Provincial Licenses, Permits and Approvals Applicable to the Project

FIGURE 63: FEDERAL AND PROVINCIAL LICENSES, PERMITS AND APPROVALS APPLICABLE TO THE EWT LINE

LEGISLATION / AGENCY / CATEGORY	DESCRIPTION OF APPROVALS PROCESS & TIMELINES
Provincial	
Environmental Protection Act Ministry of Environment (MOE) Certificate of Approvals (CoA) required from MOE under the Ontario *Environmental Protection Act*	**Description:** A CoA is required due to the potential for discharge of contaminants into the environment that will cause or is likely to cause an adverse effect under the Ontario *Environmental Protection Act*. A COA also pertains to any undertaking that involves air emissions or noise over a specified limit. A CoA would be required. **Process:** To obtain a CoA for a substation, a noise model would need to be completed to demonstrate that applicable noise limits are not exceeded for nearby receptor points. A storm water management plan would also be required to demonstrate how a transformer breach would be contained and managed. **Timelines:** Application occurs prior to construction, and immediately after Minister of MOE issues approval for the project to proceed under the Ontario *EA Act*. The CoA approval can be expected within 2 months after the issuance of the application.
The Heritage Act Ministry of Tourism, Culture and Sport (MTCS) Sign-off/acceptance of archaeological assessment report Completed as part of the EA process	**Description:** An assessment of the potential for impacts on archaeological resources is required as part of the approval process for a Transmission line project. The assessment is completed through a staged process (1-4): Stage 1 – Assessment of Potential, Stage 2-3 – Field Investigations, Stage 4 – Recovery of the Resource. The need to progress from stage to another is dependent on the results of the studies/investigations. **Process:** An assessment is initiated with a records review and site visit. Areas considered to have archaeological potential are then subject to Stage 2 survey work. If features are identified through the Stage 2 work, additional surveys and (Stage 3 and 4) may be warranted. **Timelines:** Archaeological studies for a project of this scale can take 1 year or more to complete. They are typically completed in parallel with the EA process. Stage 3 and 4 work map be deferred until after EA approval is received for the project.

LEGISLATION / AGENCY / CATEGORY	DESCRIPTION OF APPROVALS PROCESS & TIMELINES
Endangered Species Act Ministry of Natural Resources (MNR) Permits issued under clause 17(2) (c) of the *Endangered Species Act* prior to start of construction.	**Description:** Permits from the MNR may be required if the proposed project construction activity and siting of a transmission project has the potential to affect an Endangered, Threatened, Extirpated species (for which a reintroduction plan has been developed), or their habitat. **Process:** A screening of possible species at risk in Ontario that may occur in the area of the proposed undertaking should be completed during the initial stages of the EA. Where one or more species at risk or their habitat may be affected consultation with the local MNR district Species at Risk Biologist should occur. Once a screened list is developed, there may be a need to submit an Information Gathering, Avoidance Alternatives and Permit Application Form may need to be prepared and submitted to the local MNR District. Based on this information, the MNR will determine if conditions for a permit have been met. It is possible that species specific field work may be required. It is important that discussions with the MNR occur early in the planning process and design and mitigation for a species be incorporated into the undertaking and that this can be demonstrated in the permit application. Timelines: While the ESA permit application can be prepared and issued in advance of the EA approval, the permit would not likely be provided until after the EA has received its MOE approval. Timing for the ESA permit is dependent on the species that is requiring the permit. For planning purposes, the MNR has a 5 month service guarantee for the issuing of ESA permits once all of the information is received.
Conservation Authorities Act (Regulation of Development, Interference with Wetlands and Alteration to Shorelines and Watercourses) Conservation Authorities (CA) Water Crossing Permits. Prior to start of construction.	**Description:** For the sections of the route that are located within a Conservation Authority jurisdiction (e.g. Lakehead CA), a permit from the CA may be required for water crossings, including permanent and temporary road crossings. Only the crossing of CA regulated area would require permits (e.g. waterways, wetlands, floodplain). **Process:** Consultation with the applicable CA would be required in order to confirm the need for a permit(s). CAs are typically concerned with issues related to impacts on natural features and water flow restrictions (e.g. flooding). As the EA will have addressed the potential for effects on natural heritage features, the CA is likely to be most interested in water flow issues. To obtain a permit it will be necessary to demonstrate that the project components will not result in upstream flooding, contribute to stream channel alterations, and/or degrade natural features in the regulated area. **Timelines:** The CA permit cannot be issued until after the project has received EA approval. Most CAs are willing to participate in the preparation and review of the application in advance of the EA decision. Depending on the nature of the permit the approval is provided by either a Director level or by the CA Board. If board approval is required, permit timing will be dependent on the Board meeting schedule. For schedule planning, assume about 6 weeks after the application has been submitted.
Public Lands Act **(Provincial)** MNR Work Permits. Prior to start of construction.	**Description:** For the EWT Line, a Permit under Section 14 of the *Public Lands Act* would be required from the MNR for road works and new water crossings located on public lands. **Process:** A work permit application needs to be completed that outlines the nature and location of the works as well as measures to be implemented to reduce effects. It is expected that information contained in the EA Report can be drawn on to prepare the application. **Timelines:** Application occurs prior to construction, and immediately after Minister of MOE issues approval for the project to proceed under the Ontario *EA Act*. The issuance of permits from MNR is expected 6-8 weeks after the application is submitted.

LEGISLATION / AGENCY / CATEGORY	DESCRIPTION OF APPROVALS PROCESS & TIMELINES
Lakes and Rivers *Improvement Act* (Provincial) MNR Work Permit. Prior to start of construction.	**Description:** Pertains to regulating the management, protection, preservation and use of water contained in lakes and rivers of Ontario and lands under them. This permit is particularly relevant in the areas outside the jurisdiction of Conservation Authorities. **Process:** Unlikely to be required as a permit for crossings under the *Public Lands Act* also is required. Note that water crossings do not typically require a LRIA permit. Consultation with the MNR is recommended. Details on the permitting process are available at: **Timelines:** If determined to be required by the MNR, expect approximately a 6 week permit period.
***Ontario Water Resources Act* (Provincial)** Ministry of the Environment Permits. Prior to start of construction.	**Description:** Would apply to projects that result in a pollutant discharge to a water body and/or if water takings are in excess of 50,000 liters/day (e.g. for construction). **Process:** A Permit to Take Water application would need to be completed which outlines the location of the water taking and an assessment that the proposed source of water can accommodate the extraction of the proposed amount of water (water balance assessment). If the source of the water is to be a surface water body, then an assessment of potential fisheries effects may also be required. **Timelines:** Application occurs prior to construction, and immediately after Minister of MOE issues approval for the project to proceed under the Ontario *EA Act*. The timeline for the permit will depend on the amount of water to be extracted and the sensitivity of the water body. For planning purposes, assume that about 8 weeks is needed for the permit approval once the application is deemed complete

FEDERAL	
Navigable Waters Protection Act Transport Canada (TC) Authorization or Letters of Exemption from Transport Canada under the *Navigable Waters Protection Act* or approvals prior to start of construction.	**Description:** Authorizations or Letters of Exemption from TC addressing all proposed crossings of navigable water bodies is required for transmission projects that cross navigable waters in Canada. In the case of transmission line construction, an Authorization or a Letter of Exemption is required from TC due to the potential for conductor clearance to impede navigation in water bodies classified as navigable. **Process:** A comprehensive list of proposed crossings of navigable water bodies is provided to TC, along with an application for Authorization or Letter of Exemption. **Timelines:** Application occurs prior to construction and immediately after the MOE issues approval for the project to proceed under the Ontario *EA Act*. The issuance of the authorizations or Letters of Exemption from TC is expected 4 to 12 months after the application is submitted.
***Fisheries Act* (Federal)** Fisheries and Oceans Canada (DFO) Formal authorization or a "Letter of Advice" Approval is required prior to start of construction.	**Description:** Approval under the *Fisheries Act* would be required for the construction of new or improved crossing of a water body considered to contain fish habitat. The overhead crossing of conductors would not require approval if the support poles/structures are located outside of fish habitat. Depending on the nature of the project component, the sensitivity of the habitat and the potential for mitigation, full Authorization or a "Letter of Advice" may be required from DFO. DFO has issued several operational statements that may be suitable for the project. **Process:** An application is submitted to DFO that shows the locations of the proposed crossings, a concept design for the crossing, an assessment of the habitat, and proposed mitigation plans. If full authorization is deemed necessary by DFO, then a habitat compensation plan would also be required. **Timelines:** The work to support the application can be completed in parallel with the EA process.
***Species at Risk Act* (Federal)** Environment Canada (EC) Prior to start of construction.	**Description:** The Act applies to Endangered, Threatened and Special Concern species at risk and their critical habitats on federal lands. Only birds and aquatic species are protected by this Act outside of federal lands. Once a species is listed under the *Species at Risk Act*, it becomes illegal to kill, harass, capture or harm it in any way. Critical habitats are also protected from destruction. **Process:** Discussions with the Responsible Authority should occur as soon as reasonably possible where federal lands are crossed and species/habitat species listed on Schedule 1 of the Act are known to occur. It is likely that that the provincial *Endangered Species Act* will be more restrictive than SARA outside of federal lands and be the primarily instrument protecting of species at risk. This should be confirmed with the Responsible Authority where birds and aquatic species at risk occur outside of federal lands. **Timelines:** Prohibitions of the Act require that the design and mitigation of the undertaking achieve the protection of the species at risk and their habitat. Therefore, it is best that these requirements be considered in parallel with the project to prevent delays post EA approval.

Appendix 19: Detailed Issues and Mitigation Plans for Landowner, Municipal and Community Consultation

FIGURE 64: ISSUES AND MITIGATION PLANS FOR LANDOWNER, MUNICIPAL AND COMMUNITY CONSULTATION

Anticipated Issue	Potential Mitigation Plans
Property Ownership	
The proposed EWT Line will pass through a variety of privately owned, public and Crown land. The section between Lakehead TS and Nipigon is the most developed of the project area with scattered residential and commercial development located from the Township of Nipigon through the Township of Dorion, Municipality of Shuniah and accumulating as the alignment approaches the city of Thunder Bay. In the section between Nipigon and Marathon, there is much less development and the vast majority of land is designated as general use Crown land. The routes pass through or near several protected Parks and Conservation Reserves that are discussed below. Several cottage areas and protected areas such as the Prairie River Mouth Provincial Nature Reserve, Neys Provincial Park and Red Sucker Point Provincial Nature Reserve, and Craig's Pit Provincial Nature Reserve are close by. The section between Marathon and Wawa is the least developed – for either route. East of Marathon, a large portion of the Reference Route passes through Pukaskwa National Park. South of the Park, the existing corridor passes just South of Magpie River/Terraces ANSI earth science candidate and South of the town of Wawa before connecting with the Wawa TS.	• Discussions with Parks Canada staff, to confirm their position on the feasibility of paralleling the existing corridor through the Park. • Undertake personal consultation with the cottage areas and protected areas such as the Prairie River Mouth Provincial Nature Reserve, Neys Provincial Park and Red Sucker Point Provincial Nature Reserve, and Craig's Pit Provincial Nature Reserve.
Resource Use	
Forestry: Some potentially harvestable timber may need to be cut to facilitate power line construction (and for roads to access the Reference Route in more remote locations). The development and maintenance of the power line ROWs will result in the permanent loss of some forest production area as it will not be permissible to regrow trees within these areas during the operational life of the transmission line. Project development will result in a relatively small area of forest being removed which would equate to a small fraction of the total harvestable area in the affected Forest Management Units. The affected forest management units are: • Lakehead Forest • Black Spruce Forest • Lake Nipigon Forest • Kenogami Forest • Pic River Ojibway Forest • Big Pic Forest	• All associated forest companies will be consulted with prior to construction initiation. • Once the transmission line is operational, future forest harvesting activities should not be affected.

Anticipated Issue	Potential Mitigation Plans
• Black River Forest • White River Forest • Algoma Forest The communities of Nipigon and Marathon formerly had forest products processing industries, but the plants in both these communities are not operating.	
Mining: The project area includes several existing mining facilities as well as proposed facilities. One of the largest is the Hemlo Gold Mine, owned by Barrick Gold Corporation, which is located about 40 km East of Marathon along Hwy 17. The Hemlo property consists of David Bell, an underground mine, and Williams, an underground and open pit mine. The proposed Highway route for the transmission passes along the South side of the Hemlo Mine property. In terms of future mines, about 10 km North of Marathon is the proposed Stillwater Mine (copper, palladium, platinum and gold) that is undergoing environmental review. The location of the mine is understood to be to the North of the proposed transmission line. A second large proposed mine in the Marathon area is the MetalCorp owned Big Lake Copper Mine that is located approximately 20 km southeast of Marathon, and 10 km southwest of the Hemlo gold mines. The existing Hydro One transmission line crosses the western part of the property in a northwest-southeast direction. The West boundary of the property coincides with the boundary of Pukaskwa National Park. It is noted, that by agreement between the federal and provincial governments when the Park was established, a natural deep-water harbour occurring on Lake Superior West of the property boundary and within the Park, remains accessible to natural resource developers in the local area. On May 17, 2011 MetalCorp Limited announced that they are moving ahead toward development of the Big Lake copper-zinc-precious metal deposit. It is noted that in November 2009, MetalCorp signed a Memorandum of Understanding (MOU) with the Pic River First Nation to facilitate access to the drill locations. MetalCorp has other mining projects in the Marathon area including “Hemlo” East and “Playter”, of which the latter is located to the West of the above noted Big Lake mine project. Within the entire study area there is potential for land use conflict with respect to potential exploration programs and mine development.	• Claim and lease holders will to be contacted to provide information on the project and to discuss potential issues and solutions. • Specific concerns regarding mine claims will be addressed and all reasonable efforts made to come to business-to-business agreements with all mining claim holders who have claims staked prior to PLA notification, and this, prior to formal submission of Land Use Permit applications to the MNR. • Continued consulting with all claim-holders within the project area will take place throughout the development, and construction stages of the project with the objective to resolve any concerns of claim holders.
Recreational Areas	
The Lake Superior coastline is home to a number of recreational activities ranging from hunting and fishing, to outdoor exploration activities such as hiking, camping, canoeing and snowmobiling. Conditions during the construction phase, such as increased human activity and noise, could impact game populations, although this would be a temporary effect. Other	• Since it is proposed that the new transmission line parallels the existing transmission corridor (or highway), most of the aesthetic effects would be mitigated. • Additional mitigation measures such as notice of construction signs and public consultations will be

Anticipated Issue	Potential Mitigation Plans
recreational activities known in the area including hiking trails, canoeing, camping and snowmobiling could also be temporarily affected by the construction phase, as well have an effect on the aesthetics of the surrounding environment. The more known/used recreational canoe routes include: • Black Sturgeon River • White River • Pic River • Pukaskwa River • Dog/University River • Obatanga Provincial Park There will be minor disturbances during the construction phase to resource use such as trapping, fishing and hunting. However, this is temporary and construction areas will be rehabilitated and restored.	undertaken to ensure there is conflict between the construction of the transmission line and recreational activities is well managed and minimized.
Protected Areas	
Ruby Lake Provincial Park: The existing Hydro One 230 kV transmission corridor passes through the northern edge of this Park for a distance of about 350 metres. The existing transmission line crosses Ivan Lake which has not been assessed for fish species composition but has a connecting stream to Ruby Lake which is known to contain several species including brook trout. The transmission line crosses a trail connecting the western access zone of the park. Since the existing line borders the northern part of the park, the new ROW should be parallel North of existing corridor. East of the Park the existing transmission corridor passes approximately 500 metres South of a cottage subdivision on Fire Hall Lake. Public concerns are likely to occur regarding transmission line (e.g. construction effects, EMF and visual impact). According to the Ruby Lake Provincial Park Management Plant (2009), new non-park utilities should avoid park lands wherever possible, but may be permitted. This would allow for the construction of a new transmission line within the Park, and since the corridor would only encroach within the Park for a short distance and not pass through any significant features.	• Appropriate mitigation measures will be implemented to avoid any impact to fish communities and habitat. • Appropriate monitoring of the trail connecting the western access zone of the park during construction. • Design and construction plans will ensure no major disruption or impairment of the ecological integrity of the Park.
Kama Hill Provincial Nature Reserve and Kama Cliffs Conservation Reserve: The Kama Cliffs Conservation Reserve is located 18 km East of the Town of Nipigon along the North shore of Lake Superior. It is approximately 3713 ha in size. The most prominent feature of the Kama Cliffs is the vertical bedrock exposure with heights commonly exceeding 200 metres. Within the Conservation Reserve, the Kama Hills Provincial Nature Reserve is 1 ha in size, characterized by unusual, red-purple rock called mudstone. This outcropping of unusual rock is significant to geologists.	• This park lies just south of existing corridor and parallel would not encroach onto land.
Gravel River Provincial Nature Reserve: The existing corridor cuts through the southern tip of the Gravel	• Management of this provincial park is carried out in accordance with Ontario Provincial Parks:

Anticipated Issue	Potential Mitigation Plans
River Conservation Reserve (GRCR) which is 46,632 hectares of crown land surrounding the Gravel River. The Gravel River Provincial Nature Reserve is 763 hectares in size and lies between the GRCR and the Lake Superior shoreline. The existing corridor also cuts through the northern tip of the nature reserve for a distance of approximately 750 metres and passes 200 metres North of the Gravel River. The Gravel River Planning Area contains two dominant rivers: the Gravel River and the Pays Plat River. The Gravel River runs almost the entire length of the Gravel River Conservation Reserve, through the southern Nature Reserve, and finally terminates at Lake Superior. The Pays Plat River commences at Pays Plat Lake and runs along the southeastern boundary of the Gravel River planning area into Lake Superior. The Gravel River planning area also contains numerous small lakes, including at least 28 named and various other unnamed lakes. Some of the area's more familiar lakes include Gravel Lake, Paddy Lake, Buckaday Lake, Cavers Lake, and Upper Pays Plat Lake. According to the MNR Crown Land Use Policy Atlas (2006), new transmission line corridors should avoid park lands wherever possible and work permits under the *Provincial Parks and Conservation Reserve Act* (2006) would be required for any utility corridor development in the Park.	Planning and Management Policies (1992), the Ontario's Living Legacy Land Use Strategy (1999) and the Gravel River Interim Management Statement (1991). The Interim Management Statement provides direction to ensure custodial management of park resources until such time as a park management planning process is conducted, which includes public review of proposals. At that time, significant decisions regarding resource stewardship, operations, development and permitted uses are made.
Rainbow Falls Provincial Park: The Reference Route passes 1 km North of this Park.	• It is expected that the new transmission facility along this route would not encroach into this Park. There could however be proximity issues that would be examined.
Lake Superior Shoreline Enhanced Management Area: The existing corridor passes through the Lake Superior Shoreline Enhanced Management Area in several places. This is a scenic and highly traveled coastline, comprising of 19,605 ha of rugged cliffs and bays that provide habitat for representative and endangered wildlife and vegetation. The area has high tourism and recreational value, and many pristine environments. This area is intended to provide long term tourism and recreational benefits to local communities through conservation of the coastline's significant scenic, recreational and tourism attributes.	• Local municipalities, First Nation and resource stakeholders will play a major role in the future planning and management of this area. NextBridge will undertake personal consultation with the affected communities to discuss concerns, incorporate input and mitigate anticipated impacts.
Pukaskwa National Park: The existing Hydro One transmission line corridor passes through the Pukaskwa National Park as it connects the Marathon TS to the Wawa TS. The National Park is the largest ecological feature along the alignment and the only road access to Pukaskwa is at the North end, near Hattie Cove 15 km South of Marathon. Ontario's only wilderness park, Pukaskwa National Park covers 1880 square km of rugged terrain and frigid water along the rocky North shore of Lake Superior. Founded in 1978, it protects a representative sample of the Central Boreal Uplands and the Great Lakes coastline, while encouraging an appreciation of the area's natural and cultural heritage.	• Since the distribution of Peregrine Falcons is restricted to the coast within the National Park, the existing transmission line and any potential paralleling of its corridor has no effect on the species. • Since the population of caribou that are known to exist in the Park are along the coastline and not in proximity to the existing 230 kV transmission line, the paralleling the existing corridor would be expected to not have a direct impact on the Park population. If there are concerns from Parks

Anticipated Issue	Potential Mitigation Plans
Although 95% of the park is zoned as 'wilderness', a series of special preservation areas provides the highest level of protection to species at risk, acid-sensitive lakes and the early Aboriginal pits. Most of this protection occurs along the Lake Superior shoreline as the coastal zone's maritime climate supports a distinct species assemblage compared to inland areas. There are currently four species at risk within the Park, including Woodland Caribou, Peregrine Falcon, Pitcher's Thistle and Monarch butterfly. There are currently three Peregrine nesting sites along the Lake Superior shoreline in Pukaskwa National Park and the birds have been breeding regularly at each of these sites since 2004 (Parks Canada 2008). This species has displayed a consistent increase in abundance and has a stable population within the park. The survival of the small Woodland Caribou herd is of particular concern since their population has been steadily declining from an estimated historical population of 200 and may at present be as low as six (Parks Canada 2008). Caribou may be restricted to the coastal zone because higher moose densities inland can sustain high predation from wolves independent of caribou densities. Furthermore, linear corridors, such as transmission lines, may directly relate to increased mortality by wolves as they travel along these corridors. The Otter Cove area of Pukaskwa, which is along the coast and far away from the existing transmission line, is the most critical environment for the secretive caribou. Along with protecting Otter Cove, some other measures that are being taken to protect the woodland caribou in Pukaskwa include working with the Caribou Recovery Team to harmonize their efforts with provincial efforts. The Park surveys the animals through radio collars. Park officials suggest that the caribou within the Park may have been cut off from connected populations when industry, transportation routes and utility corridors blocked their movement patterns. Endemic to the Great Lakes coast, the Park is home to the most northerly population of Pitcher's thistle in the world. Two colonies are present within the coastal sand dune habitat, one naturally occurring at Creek Beach, and another created by the transplantation of seeds at Middle Beach. The Natural Heritage component of the Provincial Policy Statement under Ontario's *Planning Act* provides for the protection of significant habitat of endangered species. Additionally, the federal *Species at Risk Act* (SARA) protects Pitcher's Thistle on the federal lands on which it occurs. The Park offers many recreational activities such as camping at the Hattie Cove campground, coastal paddling routes in Lake Superior, a coastal hiking trail with backcountry camping, and two inland paddling routes on the White and Pukaskwa Rivers. *Although the majority of recreational use in the Park occurs along the coast, paddling routes along the White River and Pukaskwa River provides a visitor experience into the inland wilderness of the Park and as such, the visual effects of a new transmission line would likely be of public concern.*	staff/MNR that the development of a second transmission corridor further adds to development pressure in the area that has isolated this population to the population of Caribou to the North and inland, these will be discussed with Parks staff. • Since Pitcher's Thistle is endemic to coastal regions, it would not be affected by the development of a transmission line paralleling the existing corridor. • Although the majority of recreational use in the Park occurs along the coast, paddling routes along the White River and Pukaskwa River provides a visitor experience into the inland wilderness of the Park and as such, the visual effects of a new transmission line would likely be of public concern. NextBridge will seek to listen and learn about these concerns through the consultation process and will strive to address with mitigation strategies. • Watercourses within the park have the potential to carry contaminants downstream emanating from land use in the area, including practices associated with transmission lines such as the clearing of a corridor, construction and maintenance of transmission lines and access road construction: As above, NextBridge will seek to listen and learn about these concerns through the consultation process and will strive to address with mitigation strategies. • No culturally significant resources are found in the vicinity of the existing Hydro One transmission line.

Anticipated Issue	Potential Mitigation Plans
Although the majority of diverse and sensitive habitats are found along the shoreline of Pukaskwa National Park, the inland portion of the park represents a vast area of pristine wilderness with no development beside the existing Hydro One 230 kV transmission line and an access road leading to the transmission line, near Louie Lake. The existing transmission line passes through the Park for a stretch of about 35 km in a southeast to northwest direction with a ROW of 50 metres. This equates to a total disturbance of 175 ha. While most of the protection within the park occurs along the coast, rivers and inland lakes are important habitat features that are sensitive to disturbance. The existing Hydro One transmission line crosses a number of lakes in the National Park, including several large ones such as Willow Lake, Lower Birch Lake and Gornupkagama Lake. The transmission line also passes through a large wetland associated with the southern extent of Louie Lake at the inlet of the Cascade River. Watercourses within the park have the potential to carry contaminants downstream emanating from land use in the area, including practices associated with transmission lines such as the clearing of a corridor, construction and maintenance of transmission lines and access road construction. A significant cultural resource found within Pukaskwa National Park is the Pukaskwa Pits. These Pits are cobble stone formations that occur along the Lake Superior coastal zone in the park. These cobble stones have been piled up, removed, or shifted to form walled enclosures, simple pits, or flat floors. The Pukaskwa Pits are thought to represent a form of Aboriginal architecture dated back 5000 to 10 000 years ago. Such features occur in clusters of up to several dozen. The features in Pukaskwa are considered to be the most outstanding examples known to exist.	
Neys Provincial Park: Neys Provincial Park is a Natural Environment Class park on the North shore of Lake Superior, just West of Marathon. The park originally encompassed a 3,444 hectare area including the historic Coldwell Peninsula. As part of the Ontario Living Legacy Strategy, an additional 1,939 hectares were added to the park and included the surrounding island system consisting of Pic Island, Detention Island, and the Sullivan Islands. These additions protect woodland caribou habitat and breeding bird colonies. The main activities in the park are recreation, protection and interpretation of the natural environment.	• The existing corridor passes just north of the Park, as such it is expected that the new transmission facility would not encroach into this Park. However, there could be proximity issues that will be examined.
White Lake Provincial Park: White Lake Provincial Park is located on Hwy. 17, 35 km West of the town of White River and was regulated as a provincial park in 1963. White Lake Provincial Park serves as a staging area for backcountry canoeing on the White River and beyond to Pukaskwa National Park and contains many popular campgrounds for anglers and travelers. There are two areas to the Provincial Park 1) the lands in the vicinity of White Lake located adjacent to and South of	• The existing Hydro One transmission line crosses the waterway park just as it connects with the National Park. The proposed highway route would run along the northern edge of the Park. • Appropriate consultation and monitoring procedures will be implemented to reduce impact to recreation users of the park.

Anticipated Issue	Potential Mitigation Plans
Hwy 17, and 2) the waterway park along the White River that connects into Pukaskwa National Park. Commitments have been made to First Nation regarding potential hydro sites along the river section of the Park. Hydro activity as a result of these commitments will be treated as permitted non-conforming use. In 2008, the Umbata Falls Generating Station began commercial operations. This 23 MW hydroelectric generating facility is located on the White River within the White Lake Provincial Park, 30 km from Marathon and directly adjacent to the existing Hydro One transmission line. The development rights for the Umbata Falls site were granted by the Minister of Natural Resources to the Ojibways of the Pic River First Nation prior to the establishment the White Lake Provincial Park waterway addition. According to the MNR Crown Land Use Policy Atlas (2009), new transmission line crossings are permitted that may be necessary to maintain essential public services. The number of new crossings is to be minimized where possible and will be managed to reduce their impact on recreational and aesthetic values. MNR will consider the Land Use Intent and Management Direction outlined in the Crown Land Use Policy report when reviewing applications for permitted activities that require licenses, leases, permits, or other forms of approval. The review of individual applications involves the consideration of a variety of factors and requirements on a site-specific basis in addition to land use policy. Management of this provincial park is carried out under the provisions of the *Provincial Parks and Conservation Reserves Act* (2006) and within the context of provincial park policy. A Park Management Plan has yet to be developed for this provincial park.	
Pukaskwa River Provincial Park: Established in 2002, The Pukaskwa River Provincial Park is a 1465 ha Waterway class park which follows the Pukaskwa River and is linked to Pukaskwa National Park. The Pukaskwa River is a free flowing water way that has spectacular scenery, geology and contains lake(s) designated for lake trout management. The existing Hydro One transmission line passes through the Park for a distance of about 750 metres 1.8 km from the eastern boundary of Pukaskwa National Park. As with the White Lake Provincial Park, new transmission line crossings are permitted that may be necessary to maintain essential public services. The number of new crossings will be minimized where possible and they will be managed to reduce their impact on recreational and aesthetic values. Management of this provincial park is carried out under the provisions of the *Provincial Parks and Conservation Reserves Act* (2006) and within the context of provincial park policy. A Park Management Plan has yet to be developed for this provincial park.	• Appropriate consultation and monitoring procedures will be implemented to reduce impact to recreation users of the park.
Nimoosh Provincial Park: The Nimmoosh Provincial Park was established in 2002 and	• Paralleling the existing corridor should have no effect on the integrity of this Life Science ANSI.

Anticipated Issue	Potential Mitigation Plans
consists of a combination of several life and earth science areas including: the University River Terraces, the University/Dog River complex, and two ANSI's Makwa River Forest, and the Jimmy Kash River. The Dog River acted as a channel for the drainage of glacial melt waters during the Timiskaming Interstadial. Where these meltwaters encountered the shore of elevated glacial lakes in the Superior basin, sediments were deposited rapidly to form valley fill and delta deposits. Dropping water levels cut bluffs in these deposits creating the University River Terraces. These terraces are some of the best developed and non-impacted features along the North shore of Lake Superior. The Nimoosh River waterway links Obatanga Provincial Park to the Superior Coastline. The site includes two historical Areas of Natural and Scientific Interest (ANSI's): the Makwa River Forest and the Jimmy Kash River. The Makwa River Forest ANSI's most important feature is the presence of an open canopied black spruce-jack pine- lichen woodland that has developed on glaciofluvial sands and gravel of the river valley. The areas were identified as one of the preferred habitats for woodland caribou. The Dog River provides important spawning areas for lake trout. Dominant landform vegetation types within this site include broken ground moraine with mixed coniferous and sparse forest. Also present within this site is Denison Falls which provides spectacular scenery. The park is known for exceptional white water with unregulated flow and wilderness character. This site provides great potential for a wilderness recreation experience. The existing Hydro One transmission line passes through the Park for a distance of about 1 km, and is 1.5 km from the eastern boundary of the park. 750 metres North of the existing transmission line corridor is where the Makwa River ANSI is located. As with the other waterway parks in this area, new transmission line crossings are permitted that are necessary to maintain essential public services. Management of this provincial park is carried out under the provisions of the *Provincial Parks and Conservation Reserves Act* (2006) and within the context of provincial park policy. A Park Management Plan has yet to be developed for this waterway class provincial park.	• The number of new crossings will be minimized where possible and they will be managed to reduce their impact on recreational and aesthetic values. • Appropriate mitigation, consultation and monitoring procedures will be implemented to reduce impact to the ecological integrity and recreation users of the park.
Obatanga Provincial Park: Obatanga Provincial Park was regulated as a provincial park in 1967 and is located on Hwy. 17, 56 km West of Wawa and 37 km East of White River. This natural environment class park encompasses 9,409 hectares. The Park lakes which provide canoeing and wildlife viewing opportunities are on the headwaters of the Dog River which flows into Lake Superior. The Park is often used as a staging area for canoe trips down the Dog River. The Park provides recreation opportunities while protecting the parks natural values. Obatanga Provincial Park is managed according to Provincial Park policy and the Obatanga Park Management Plan (1988). There is currently no development in the Park except for a Forest Service Road providing access to cut	• Appropriate consultation and monitoring procedures will be implemented to reduce impact to recreation users of the Park.

Anticipated Issue	Potential Mitigation Plans
blocks outside of the park boundary. Resource extracting activities, such as trapping, collection of bait fish and harvesting of wild rice were phased out by 2010, except for Status Indians enjoying Treaty rights. Hunting continues to be permitted South of Hwy 17, but is prohibited North of the highway. According to the MNR Crown Land Use Atlas (2006), new transmission line crossings may be permitted through the Park; however they should be avoided wherever possible.	
Black Sturgeon River Provincial Park: Black Sturgeon River Provincial Park is located northwest of the Town of Nipigon. The Black Sturgeon River begins near Lake Nipigon and flows into Black Bay on Lake Superior. The park stretches approximately 72 km northerly along the Black Sturgeon River from Lyon Township to the top end of Black Sturgeon Lake. This results in the total area of the provincial park being 24,105 hectares in size. The provincial park serves as an important recreational waterway for canoeists, campers, anglers and hunters. There are arctic alpine disjunct plant communities in the park, angling opportunities, and various species at risk found within the park. Some of these include the bald eagle, peregrine falcon, eastern cougar, and the northern brook lamprey. The existing Hydro One 230 kV transmission line extends approximately 750 metres through the southern end of the Park and crosses the Black Sturgeon River about 300 metres North of the Black Sturgeon dam. Lake sturgeon have been blocked from migrating up the river as a result of the dam and efforts are being made to restore the natural fish migration patterns along the Black Sturgeon River. In total, there are two hydro transmission facilities that cross the South end of Black Sturgeon River Provincial Park, including the existing 230 kV line, and another transmission line crossing the middle of the Park. There are also 2 gas pipeline crossings of the Park, one at the southern boundary of the Park and the second is in proximity to the northern power transmission facility that crosses the Park. According to the Park Management Plan (2003), improvements or developments associated with the normal maintenance and operation of existing transmission facilities are permitted. Herbicide applications along these utility corridors will be discouraged for vegetation management. Instead, mechanical and hand tending of vegetation in utility corridors will be encouraged. The Management Plan indicates that while existing utility corridors that pass through the park will continue to be a permitted non-conforming use, new utility corridors will not be permitted. The MNR will consider the Land Use Intent and Management Direction outlined in the Park Management Plan when reviewing applications for permitted activities that require licenses, leases, permits, or other forms of approval. The review of individual applications involves the consideration of a variety of factors and requirements on a site-specific basis in addition to land use policy.	• Discussions are planned with the MNR to confirm the position of the MNR with respect to new transmission facility crossings of the Park. The widening of an existing corridor may be viewed more favourably that a completely new corridor.

Anticipated Issue	Potential Mitigation Plans
Human Health and Safety	
Electric and Magnetic Fields: Electric and Magnetic Fields (EMF) are invisible lines of force surrounding any wire carrying electricity and are produced by all electric tools and appliances, household wiring and transmission lines. A transmission line produces an electric field, a magnetic field and corona. Corona, an electric field, can cause electrical effects, the most common of which are radio interference, television interference, audible noise and induction on nearby metallic objects. The strength of EMF depends on the voltage level and the amount of current flow, respectively. The fields fall off sharply with increasing distance from a transmission line. Electric fields are easily blocked by vegetation, buildings or other obstacles, while magnetic fields are unaffected by such objects. The proposed transmission line would produce Alternating Current (AC) EMF that oscillates at an extremely low frequency range of 60 hertz (Hz). The EMF levels under AC transmission lines are higher than the levels under the distribution lines that run down local streets. Most people are exposed to an EMF level of 1 to 2 milligauss (mG) from everyday activities. Numerous scientific and health agencies have evaluated whether EMF cause adverse health effects. The conclusions of these scientific agencies have been generally consistent in concluding that the research does not show that electric or magnetic fields are a known or likely cause of any disease, including cancer. Research has also been conducted to study the effects of EMF on wild and domestic animals and crops and other plants. The results have also been consistent with the conclusion that there is no link between EMF and health, behaviour or productivity of animals and there are no adverse effects on growth or viability of plants. Ontario has no maximum EMF level standard, policy or requirement. EMF considerations tend to be more sensitive near schools and places frequented by children (e.g., playgrounds). It is possible that a local school board could have an EMF standard, although such a standard would not be legally enforceable. EMF levels from proposed transmission lines have not historically been modeled/provided as part of EA studies. There may be community requests for such modeling though.	• Routing of the transmission line will be sensitive to school locations, parks and playgrounds.

Appendix 20: EWT Line Route Statistics

FIGURE 65: EWT LINE ROUTE STATISTICS

Routing Factor	Reference Route	Reference Route with Variants
Line Length	**401 km**	**448 km**
Length following existing corridors		
Within 50m of Existing Corridor	*28 km*	*28 km*
Within 100m of Existing Corridor	*40 km*	*40 km*
Length following Greenfield Construction	**286 km**	**282 km**
No. of Dwellings within 800 metres	**15**	**17**
0 – 50 dwellings	*12*	*14*
> 50 dwellings	*3*	*3*
No. Watercourse crossing	**491**	**496**
No. Wetlands crossed	**57**	**82**
Areas of concern		
Wildlife	*1.69 km*	*1.69 km*
Historical Resources	*TBD*	*TBD*
Length crossing Forest Management Areas (Units)	**366 km**	**448 km**
Length crossing Pukaskwa National Park	**35 km**	**N/A**
Length crossing Provincial Parks	**4.41 km**	**2.96 km**
Black Sturgeon River Provincial Park	*1.06 km*	*1.06 km*
Ruby Lake Provincial Park	*0.35 km*	*0.35 km*
Gravel River Provincial Nature Reserve	*0.97 km*	*0.97 km*
Pukaskwa River Provincial Park	*0.95 km*	*0.58 km*
Nimoosh Provincial Park	*1.08 km*	-
Length of First Nation Reserved	**8.48 km**	**N/A**
Pays Plat FN Reserve No.51	*1.41 km*	-
Red Rock Indian Band (Parmachee Reserve)	-	-
Ojibway of the Pic River First Nation	-	-
Gros Cap FN Reserve No.49	*7.07 km*	-
No. of Municipalities	**9**	**9**

Appendix 21: Preliminary Corridor Development Metrics

FIGURE 66: PRELIMINARY CORRIDOR DEVELOPMENT METRICS

Metric	Potential or Perceived Impacts
Proximity to residences (150 metres of centerline and within 800 metres of ROW edge)	• Health, safety and EMF concern • Visual impacts • Property Value • Future Development Conflicts
Crown Land vs. Private Land	• Maximize the use of public lands were possible • Residential Impacts • Agricultural Impacts
Paralleling existing linear disturbances	• Minimizing disturbance • Minimize Landscape Fragmentation • Utilization of existing Access and ROW • Constructability • Operation and maintenance considerations
Fish and Wildlife	• Sensitive Habitat Areas (Caribou Management Areas) • Endangered or threatened species habitat • Species Specific Timing constraints • Recorded Bird Nesting Locations • Bird / transmission line Interactions • Sensory Disturbance of Wildlife
National and Provincial Parks, Ecological Reserves and Historic Resource Sites	• Cumulative Environmental Impacts • Access constraints • Rare plant habitats • Permitting Constraints • Public Perception and Recreation • Aesthetics • Construction constraints (timing, vegetation clearing, construction) • Operational and maintenance considerations • Archaeological and Paleontological sites • Cultural Sites
Watercourses and Wetlands	• Minimize Watercourse Crossings • Riparian Vegetation Disturbance • Vehicle Crossings • Waterfowl Use • Structure locations (100 metre buffers wetlands and 30metre buffers watercourses) • Cost
Mineral Lease Holders	• Impacts to mining operations • Cost • Potential for future relocation if mineral extraction required
Forest Management Areas	• Timber Salvage • Impact to FMA operations • Reduction in operating land base • Utilizing existing access and clearings • Cost

First Nation Reserve Land	• Permitting Process • Cost
Length and Deflections	• Agricultural impacts • Residential impacts • Disturbance Area • Cost • Electrical considerations • Reliability • Visual impacts • Special considerations

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Appendix 22: Enbridge Aboriginal and Native American Policy

The Enbridge Aboriginal and Native American Policy is attached.

Aboriginal and Native American Policy

Enbridge recognizes the history, uniqueness and diversity of Aboriginal and Native American Peoples. Positive relationships with Aboriginal and Native American Peoples, based on mutual respect and trust, will help them and us to realize our aspirations, and will help Enbridge to reach our strategic business objectives.

Enbridge commits to forging mutually beneficial relationships with Aboriginal and Native American Peoples in proximity to its projects and operations. To achieve this, Enbridge will be governed by the following principles:

- We recognize the legal and constitutional rights possessed by Aboriginal and Native American Peoples in the respective jurisdictions in which they reside.
- We respect the traditional ways, Aboriginal and Native American heritage sites, and the relationship that Aboriginal and Native American Peoples have with the land and the environment.
- We engage in forthright and sincere consultation with Aboriginal and Native American peoples about Enbridge's projects and operations which have an impact upon their legally and constitutionally protected rights.
- We commit to working with Aboriginal and Native American peoples to achieve sustainable benefits for them resulting from Enbridge's projects and operations, including opportunities in training and education, employment, procurement, business development, and community investment.
- We foster understanding and respect for local Aboriginal and Native American Peoples among Enbridge's employees and contractors.

In order to put the above principles into action, Enbridge commits to the following:

- Enbridge will offer the opportunity to First Nations and Native Americans to purchase equity in certain new green field projects, where appropriate.
- Enbridge will offer sole-sourced contracting opportunities to qualified Aboriginal and Native American suppliers and contractors where appropriate, and will encourage joint venture opportunities between Aboriginal/Native American

businesses and non-Aboriginal/Native American businesses when it builds capacity and supports mutual business interests.

- Enbridge will implement measures to enable Aboriginals and Native Americans to become part of our permanent workforce at a level that is representative of regional demographics, and encompasses a wide spectrum of career levels.
- Enbridge will enter into Agreements with Aboriginal and Native American peoples, where appropriate, to support training, environmental stewardship, community investment and other initiatives that will help build and sustain Aboriginal and Native American communities.
- Enbridge will continue to invest in Aboriginal and Native American communities in keeping with our broader commitment to Corporate Social Responsibility.

This commitment is a shared responsibility involving Enbridge and its subsidiaries, employees and contractors, and we will conduct business in a manner that reflects the above principles. Enbridge will provide ongoing leadership and resources to ensure the effective implementation of the above principles, including the development of implementation strategies and specific action plans.

Appendix 23: NextEra Energy First Nation and Métis Relationship Policy

The NextEra Energy First Nation and Métis Relationship Policy is attached.

NextEra Energy Canada, ULC

NextEra Energy Canada, ULC is an indirect, wholly-owned subsidiary of NextEra Energy Resources, LLC, North America's leading generator of renewable energy from the wind and sun with more than 8,800 wind turbines in operation in North America. NextEra Energy Resources is the largest generator of wind energy in North America with nearly 90 wind projects in 17 U.S. states and three Canadian provinces capable of generating more than 8,500 MW of energy, enough to power nearly two million homes.

NEXTera ENERGY CANADA

5500 N. Service Road, Suite 205
Burlington, ON L7L 6W6
905-335-4904
toll-free: 1-877-257-7330
www.NextEraEnergyCanada.com

012012 22358



NextEra Energy Canada, ULC

First Nation and Métis Relationship Policy

NEXTera ENERGY CANADA

PRINCIPLES

During the course of developing, constructing, operating and decommissioning its renewable energy projects in Canada, NextEra Energy Canada ("NEEC") **will be guided by the following principles:**

1. Fostering a collaborative working relationship with potentially impacted First Nation and Métis communities as early as practicable.
2. Understanding and recognizing applicable aboriginal and treaty rights and interests.
3. Understanding and respecting the cultural integrity of First Nation and Métis communities potentially impacted by NEEC's projects.
4. Fulfilling all delegated obligations to consult and (where applicable) accommodate First Nation and Métis communities.
5. Being open to discuss a broader relationship with potentially impacted First Nation and Métis communities and host First Nation and Métis communities.



In putting these principles into practice, NEEC is committed to the following practices:

PRINCIPLE 1
Forming a Collaborative Working Relationship

- » providing notification to potentially impacted First Nation and Métis communities as early as possible
- » providing relevant project information (including information about project impacts) to potentially impacted First Nation and Métis communities in a timely manner and in a format that is meaningful
- » establishing a mutually-agreeable schedule for regularly meeting with Chief and Council or Métis leadership (or their appointed representatives) through the project development and construction phase
- » offering to hold an open house in each potentially-impacted First Nation or Métis community
- » establishing a mutually-agreeable arrangement for the exchange of information during project operations and decommissioning

PRINCIPLE 2
Understanding and Recognition of Rights and Interests

- » early in the project development phase, assessing the nature of any existing aboriginal or treaty rights or unresolved First Nation or Métis claims in the project area
- » learning about First Nation and Métis interests and traditional practices (e.g., harvesting practices, sacred sites, etc.) in the project area
- » providing support to potentially impacted First Nation and Métis communities to allow such communities to undertake a meaningful review of the NEEC project
- » where applicable, employing mutually acceptable methods to identify the community interests of potentially impacted First Nation and Métis communities

PRINCIPLE 3
Understanding and Respecting Cultural Integrity

- » providing training on First Nation and Métis history and law to NEEC employees with project development responsibilities in Canada
- » ensuring that work at project sites does not cause avoidable impacts to archaeological resources
- » maintaining an archaeological protocol that can be tailored to individual projects depending upon circumstances
- » where feasible, involving local First Nation and/or Métis communities or individuals in archaeological field work and construction monitoring

PRINCIPLE 4
Fulfilling Delegated Consultation and Accommodation Obligations

- » meeting all legally-binding consultation requirements delegated from government
- » taking into consideration any consultation protocol or policy developed by any potentially impacted First Nation and Métis community
- » where applicable, accommodating impacted First Nation and Métis communities

PRINCIPLE 5
Considering a Broader Relationship

- » where applicable, considering opportunities for aboriginal scholarships, cultural funding and/or training in the renewable energy sector
- » where applicable, providing employment opportunities for communities (e.g., advance job postings, targeted recruitment, preferential hiring for qualified members, etc.) to: (a) members of potentially impacted First Nation and Métis; and (b) host First Nation and Métis communities
- » where applicable, providing business opportunities (e.g., communicating project needs, unbundling supply contracts, support for training, preferential contracting, subcontractor requirements, etc.) to qualified, cost-competitive First Nation and Métis businesses