Application
for
Designation

East West 230kV Tie
(Network Expansion)

Submitted by:

Canadian Niagara Power Inc.

A Fortis Company

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SUMMARY OF THE APPLICATION

Organization:

The applicant for the East-West Tie project is Canadian Niagara Power Inc. ("CNPI"), a licensed transmitter (ET-2003-0073) with transmission facilities in and around the area of Fort Erie, Ontario, as well as a transmission interconnection to New York State. CNPI is a subsidiary of FortisOntario Inc., which is wholly owned by Fortis Inc. ("Fortis"). Fortis is the parent company to a number of transmission and distribution utilities. Fortis is the largest investor-owned distribution utility in Canada, with total assets of $14 billion and fiscal 2011 revenues totaling $3.7 billion. Fortis serves approximately 2,000,000 gas and electricity customers, and currently operates 4,285 km of electricity transmission lines and associated substations, and 3,000 km of gas transmission pipelines. As part of Fortis, CNPI has access to a wealth of transmission experience and expertise that would ensure the successful development, construction and operation of the East-West Tie project.

In addition to drawing on the expertise and experience within Fortis, CNPI has assembled a team of experts who also bring relevant expertise to the East-West Tie project. Members of the CNPI team include Fortis employees, CNPI's First Nations partner (Lake Huron Anishinabek Transmission Company Inc.), and the engineering firms of Neegan Burnside, an Aboriginal owned firm, and TRC Engineers who will assist on, among other things: design; permitting; consultations; project management; and construction. The team also includes legal experts Davies Ward Philips & Vineberg LLP and Andrew Taylor. For more information on the organization of Fortis and CNPI's third-party consultants, and its First Nations partner, please refer to Section 2.

The applicant and its team have a great deal of recent experience managing projects relevant to the East-West Tie Project, including:

- **Waneta Hydro 230kV Transmission Project** is a $900 million partnership among Fortis, Columbia Power Corporation, and Columbia Basin Trust to construct a

335-MW hydroelectric generating facility and a new 230 kV transmission line on a new right-of-way.

- **Okanagan 230 kV Transmission Reinforcement** is a $104.8 million Fortis transmission project in BC.
- **Mt. Hayes Natural Gas Storage/Transmission Project** is a $193 million Fortis project to install a liquefied natural gas storage facility and connection to the transmission system in BC.
- **Nk'Mip (East Osoyoos) Transmission and Substation Project** is a $20 million Fortis transmission and substation project to construct, own and operate a new 63/13 kV substation in East Osoyoos, BC, which is supplied by a 63 kV transmission line.
- **Newfoundland Multi-Year Transmission Line Rebuild Project** is a multi-year transmission line rebuild project in excess of $80 million.

More details on these and additional projects are set out in Sections 2 and 4.

First Nation and Métis Participation:

CNPI has formed a joint venture with Lake Huron Anishinabek Transmission Company Inc. ("LHATC"). LHATC is made up of 21 First Nations who are signatories or are adherent to the Robinson-Huron Treaty of 1850. Two of the 21 signatories are on the Ontario Power Authority's East-West Tie list of affected First Nations. LHATC, along with other interested First Nations communities, will have the right to acquire in aggregate up to a 49% equity interest in the East-West Tie project.

As well, First Nation and Métis participation opportunities will include:

- employment opportunities;

- an apprenticeship training fund for Aboriginal candidates to become power line technicians;
- preferential consideration will be given to Aboriginal businesses; and
- a unique Skill Builder Program will be used for Aboriginal youth to educate and train them for potential employment with the utility construction industry.

For more information on these and additional First Nation and Métis participation opportunities, please refer to Section 2.

Technical Capability:

The CNPI technical team is comprised of employees from Fortis, LHATC, and CNPI's external consultants which include TRC Engineers and Neegan Burnside.

The Fortis component of the team includes multiple utility experienced persons. This team has expertise, experience, and the technical capability to engineer, plan, construct, operate and maintain the line. Members of this team have worked on projects of equivalent nature, magnitude and complexity.

TRC engineering has a power delivery staff of approximately 500 experienced project managers, engineers, planners, and support staff located in 20 offices across the United States. Its engineers have designed more than 3,000 miles of 69 kV, 115 kV, 138 kV, 230 kV, 345 kV, and 500 kV transmission lines.

Neegan Burnside has 15 Aboriginal employees in engineering, environmental and support services representing 15 separate Aboriginal communities in Ontario and Manitoba. Together with its partners R.J. Burnside and Associates, Neegan Burnside has access to over 330 professional staff. R.J. Burnside and Associates provides infrastructure, engineering and consulting services in Canada and internationally.

Financial Capability:

Fortis has sufficient capital resources under its $1 billion committed revolving corporate credit facility to finance the development and construction of the East-West Tie Project. There will be no requirement for new bridge financing or to initially access capital markets to raise funds. Fortis carries an investment grade rating of A- from Standard & Poor's and A (low) from DBRS. Over the past two-years, Fortis and its subsidiaries have made capital expenditures in excess of $2 billion while maintaining strong credit ratings.

Proposed Design for the East-West Tie Project:

CNPI is submitting this application based on the Reference Option as defined by the OEB in its letter to transmitters dated December 20, 2011, and as more particularly described in the *IESO Feasibility Study,* Report 0748, published August 18, 2011.

For the proposed 400 km line, CNPI's Plan is for 1,335 structures, which are required based on an average spacing of 300 m. The majority of this line is expected to be double circuit steel lattice towers. Double circuit steel monopoles will be considered for this project and will probably be utilized in several areas.

As proposed by the *IESO Feasibility Study*, Report 0748, CNPI's application is based on 1192.5 kcmil 54/19ACSR conductor. During the development phase, final conductor selection will be confirmed based on an economic analysis considering the initial cost, expected load, and cost of losses.

CNPI's new line, in conjunction with the existing tie, will provide total eastbound and westbound capabilities of the order of 650MW, while respecting all NERC, NPCC and IESO reliability standards. As an owner and operator of both transmission and distribution facilities in Ontario, CNPI would continue to own and operate the East-West Tie Project after it is constructed.

Schedule:

Assuming that designation occurs in April, 2013, CNPI estimates that it can complete development of the East-West Tie Project by June, 2017 upon approval of its Environmental Assessment ("EA"). CNPI estimates that it can have the line in service by December, 2019. If designated, CNPI will attempt to expedite the completion of the project to the best of its abilities. Please refer to Section 7 for a detailed break-down of CNPI's scheduling estimates and assumptions.

Costs:

CNPI estimates its development costs to be $24,828,000, and its construction costs to be $583,969,000, for a total development and construction cost of $608,797,000. Please refer to Section 8 for a detailed break-down of CNPI's estimated costs and cost assumptions. As set out in Section 8.10, Fortis has completed similar projects within planned construction budgets.

Landowner, Municipal and Community Consultation:

Fortis maintains access and land rights for thousands of kilometers of existing right-of-way. Establishing new right-of-way is a routine function at each Fortis utility. For the East-West Tie project, CNPI will create a property rights and acquisition office that will report to the existing Engineering Department. This office will identify all properties impacted by the East-West Tie Project, as well as property required for access and temporary working areas. The property rights and acquisition office will be respectful of existing land owner rights, as well as the rights of other interested parties. CNPI believes that it is the best interests of the successful execution of the project to have an open, fair and consistent process to deal with all land rights issues.

While the proposed route has been identified as primarily parallel to the existing 230kV line, the route has not been studied in detail levels similar to the EA process for purposes of this Plan. CNPI did complete a fly over of the existing line and observed several locations where the proposed line may be required to deviate from an absolute parallel line. Detailed engineering analysis will be required to determine the final route.

For more information on CNPI's proposed landowner, municipal and community consultation, please refer to Section 9.

First Nation and Métis Consultation:

Fortis has significant experience in several Canadian jurisdictions working with Aboriginal communities. Fortis has engaged in limited partnerships and long-term leases with Aboriginal communities and multiple other programs.

CNPI is committed to working closely and cooperatively with the Crown to ensure that the duty to consult with Aboriginal communities and groups is fulfilled. An Aboriginal Consultation and Engagement Plan will be developed at the start of the EA. LHATC will also provide advice and assistance as required during the consultations. CNPI has selected Neegan Burnside to perform First Nations and Métis consultations. Neegan Burnside has recently completed the National Water Study which took them into every First Nation community across Canada. The various associates of the firm have been providing services to First Nation communities for over 40 years and offer a true understanding of First Nation culture that allows effective and successful consultations with First Nation communities.

Consultation and engagement with Aboriginal groups will provide project-related information in an easily accessible and understandable format. Specifically, the project team will seek information from Aboriginal groups with regard to land use and treaty rights, traditional ecological knowledge, archaeological sites, sacred sites and burial grounds. Communities will be asked to comment on the proposed fieldwork methodologies to obtain baseline information. Aboriginal community members will be invited to form part of field teams, either as guides or assisting with archaeological fieldwork. Traditional knowledge of the study area by elders will be sought. The study team will endeavor to address all issues raised by Aboriginal communities with regard to potential impacts associated with their interests.

CNPI acknowledges the Ministry of Energy's expectation regarding the delegation of the procedural aspects of the Crown's duty to consult with Aboriginal communities, and confirms that as the designated transmitter CNPI will enter into a memorandum of understanding with the Ministry of Energy that will set out the respective roles and responsibilities of the Crown and CNPI in consultation.

Distinguishing Features of the Application:

- CNPI has existing First Nations participation and plan for further participation by First Nation and Métis communities.
- CNPI's plan for First Nations equity ownership will benefit a greater number of communities than the fourteen set out in the OPA's list of Crown identified First Nations.
- Fortis' experience and financial capacity associated with being the largest investor owned distribution utility in Canada.
- Fortis' long-term profile as an owner and operator of electricity transmission assets in Ontario and other jurisdictions.
- CNPI's smaller transmission presence in Ontario (compared to incumbent HONI) creates greater opportunity to increase competition in Ontario's transmission sector.

- Fortis' local knowledge of the transmission and distribution systems in the East-West Tie area of Ontario.
- Existing work centre located in Wawa, Ontario, staffed with Transmission experienced employees.
- Regulatory track record and experience in Ontario and other jurisdictions in which Fortis operates.
- An experienced team with an innovative approach to Aboriginal participation, communications, and project management.
- Fortis' established track record for successfully completing major utility projects.
- CNPI is an existing transmitter with all of the regulatory and operating requirements required to carry on business consistent with good utility practice in Ontario.
- Innovative information technology proposal to develop SAP and GIS inventory tracking system to increase efficiency and reduce cost to the rate payer.
- Fortis' successful track record for carrying out major financing.

FILING REQUIREMENTS

EAST-WEST TIE DESIGNATION APPLICATIONS

An application for designation will contain three main sections. Together, these sections of the application address the Board's decision criteria for the East-West Tie line designation process:

(A) Evidence addressing the capability of the applicant to carry out the East-West Tie line project;

(B) The applicant's Plan for the East-West Tie line; and

(C) Other factors.

(A) CAPABILITY OF THE APPLICANT

1. Background Information

The applicant must provide the following information:

1.1 the applicant's name; Canadian Niagara Power Inc. ("CNPI", or the "Company")
1130 Bertie Street
PO Box 1218
Fort Erie, Ontario L2A 5Y2

1.2 the applicant's OEB transmission licence number;

Canadian Niagara Power Inc.
Electricity Transmission Licence
ET-2003-0073
Valid until December 23, 2023

1.3 any change in information provided as part of the transmitter's licence application;

Not applicable to CNPI.

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

CNPI confirms that it has not previously had a licence or permit revoked and is not currently 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;

CNPI confirms that it 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.

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;

The statement from the senior officer of CNPI is attached to this application as Appendix A.

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.

CNPI is willing to be designated as the runner up. In the event that the designated transmitter fails to fulfill its obligations and the line is still needed, CNPI would be willing to accept the development opportunity, contingent upon CNPI being:

- permitted to amend its designation plan to include any incremental developmental costs caused by the delayed designation;
- given appropriate startup time;
- permitted to revise its development schedule; and
- CNPI being provided the necessary regulatory approvals.

1.8 a description of any co-ordination or co-operation with other parties that has contributed to this application.

CNPI has assembled a transmission development team comprised of internal Fortis resources and external consultants, to assist in preparation of this application. Contributing parties include:

- Fortis
- Neegan Burnside Ltd., an Aboriginal Owned Engineering and Environmental Company and their team of sub-consultants.
- TRC Engineers, a leader in engineering consulting services to electric utilities
- Davies Ward Phillips & Vineberg LLP ("Davies")
- Andrew Taylor of the Energy Boutique
- Lake Huron Anishinabek Transmission Company Inc.

More detail on each of these parties is included if the following sections. These same parties are expected to remain as consultants to CNPI during the development and construction of this project.

2. Organization

The applicant shall identify how, from an organizational perspective, it intends to undertake the East-West Tie line project. The applicant must file:

2.1 an overview of the organizational plan for undertaking the project, including:

- ***any partnerships or contracting for significant work;***
- ***identification and description of the role of any third parties that are proposed to have a major role in the development, construction, operation or maintenance of the line;***
- ***a chart to illustrate the organizational structure described.***

The CNPI organizational plan for undertaking the project involves the following participants:

- Fortis/CNPI,
- third-party consultants,
- Lake Huron Anishinabek Transmission Company Inc. ("LHATC"), and
- construction contractor(s).

Fortis/CNPI:

CNPI is owned by FortisOntario Inc. ("FortisOntario") which, in turn, is owned by Fortis Inc. Fortis Inc. is the parent to a number of energy industry companies, including:

- FortisAlberta
- Fortis BC
- FortisOntario
- Fortis Generation East Limited Partnership
- Fortis TCI (Turks and Caicos Islands)
- Caribbean Utilities
- Maritime Electric (Prince Edward Island)
- Newfoundland Power

Fortis Inc. and its operating subsidiaries are collectively and individually referred to in this application as “Fortis”.

Fortis is the largest investor-owned distribution utility in Canada, with total assets of $14 billion and fiscal 2011 revenues totaling $3.7 billion. Fortis serves approximately 2,000,000 gas and electricity customers. Its regulated holdings include electric distribution utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia.

Fortis has experience in planning, developing, constructing, and operating transmission facilities. An overview of Fortis’ transmission systems is attached to this application as Appendix B. Fortis currently operates 4,285 km of electric transmission lines and associated substations, and 3000 km of gas transmission pipelines. CNPI’s organizational plan is to rely on the expertise of the Fortis individuals as identified in Section 4.2 along with third party consultants for a successful East-West Tie project. The technical team will ensure that the line will be designed to meet or exceed reliability standards and technical requirements.

CNPI owns and operates Transmission, and Distribution facilities. CNPI is the only investor owned electricity distribution utility in Ontario. The CNPI transmission system is interconnected with Hydro One Networks Inc. (“Hydro One” or “HONI”) in Niagara Falls, Ontario and provides service in and around the area of Fort Erie, Ontario. The CNPI transmission system is also interconnected, through an emergency tie line, with the transmission system owned and operated by US National Grid in New York State.

Founded in 1892, Fortis began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River, and subsequently began transmitting and distributing electricity to the Town of Fort Erie in 1907. The Fortis electricity transmission and distribution businesses in Ontario are carried out through three subsidiaries – Canadian Niagara Power Inc. (Applicant); Cornwall Street Railway, Light, and Power Company Limited; and Algoma Power Inc. ("API")

CNPI can draw upon a wealth of energy industry experience and expertise from within CNPI, and Fortis, and from third-party consultants for undertaking the East-West Tie project (the "Project").

CNPI has approached the East-West Tie project based on consideration` of three utility contracting models: Traditional Utility Model, Full EPC Model, and Modified EPC Model. For further discussion, please refer to Section 8.11.

Third-Party Consultants:

CNPI has engaged the following third-party consultants to assist with the Project:

Neegan Burnside:

Neegan Burnside is a majority owned Aboriginal firm committed to assisting First Nations in meeting their development and economic goals while remaining sensitive to First Nation community, culture, values and beliefs. They have over 40 years of experience in consulting with stakeholders, the public, departments and agencies, First Nations and Métis communities. They have undertaken work in almost every First Nation community across Canada and thoroughly understand the intricacies of developing appropriate relationships and the requirements of successful consultation and engagement activities. Neegan Burnside works seamlessly with its corporate partner, R.J. Burnside and together can provide over 330 environmental specialists, scientists, engineers and eleven offices through Ontario and Manitoba. Neegan Burnside will also lead a highly qualified team of sub-consultants who add depth and enhance the team's capabilities. For more information on Neegan Burnside, please refer to Appendix C.

TRC Engineers:

TRC is a leader in providing environmental and engineering consulting, design, procurement, construction, and compliance services for electric utilities. TRC engineering has a power delivery staff of approximately 500 experienced project managers, engineers, planners, and support staff located in 20 offices internationally. TRC has provided Owner's Engineer services on multiple large Engineer, Procure, and Construct ("EPC") projects. For more detailed information on TRC Engineers, please refer to Appendix D.

Davies Ward Phillips & Vineberg LLP ("Davies"):

Davies is an integrated firm of more than 240 lawyers with offices in Toronto, Montréal and New York. The firm is focused on business law and is consistently at the heart of the largest and most complex commercial and financial matters on behalf of its clients, regardless of borders. Davies has extensive experience advising proponents and their finance providers on energy and infrastructure projects. Davies has also developed extensive experience in a broad range of complex energy projects including new construction and ongoing transmission, distribution, wind, solar, and hydroelectric projects. Davies has experience acting for a wide range of transmission and distribution industry participants, including developers, purchasers, governmental entities and financing entities, and has experience working with all of the key stakeholders.

For more information on Davies, please refer to the description of the firm's Energy practice and its list of representative work which is attached to this application in Appendix E.

Andrew Taylor of the Energy Boutique:

Andrew Taylor represents electricity transmitters, distributors, generators and stakeholders in respect of their regulatory obligations before the Ontario Energy Board in regard to the construction of electricity infrastructure, rates, licensing, and compliance.

For more information on Andrew Taylor of the Energy Boutique, please refer to Appendix F.

Lake Huron Anishinabek Transmission Company Inc. ("LHATC"):

CNPI has formed a partnership with LHATC, who represents 21 First Nations that are signatories or are adherent to the Robinson-Huron Treaty of 1850. LHATC was formed in 2009 to obtain part ownership in Ontario electric transmission expansion projects. LHATC took the initiative to form this company when the IPSP I indicated that there would be two priority transmission development projects in their territory: the new 500 kV Sudbury West Line, and the new 500 kV North South Tie. In the IPSP II, Planning and Consultation Overview, dated May, 2011, these two projects are now scheduled as projects required beyond 2018.

Construction Contractors:

Construction labour for the project represents a significant percentage of the total cost. Competitive bidding of line construction upon completion of engineering is essential to obtain the most competitive cost for the Project. Fortis companies have on-going experience with multiple construction contractors and will carefully prequalify all bidders. Multiple sub-contractors are expected for road construction, environmental controls, right-of-way clearing, and geotechnical.

Roles of the East-West Tie Project Team Members:

Fortis/CNPI:

- Project Manager
- Procurement services for major materials
- Operation and maintenance over the life of the facility
- Financing of the at risk development cost
- Financing the project
- Aboriginal Affairs

- Preparation and filing of all regulatory documents
- Reports to OEB
- Public Announcements
- Contract manager for all third-party services:
    - Engineering services
    - Environmental services
    - Project management services
    - Legal services
    - Right-of-way services
    - LiDAR
    - Geotechnical investigations
    - Line construction
    - Road construction
    - Right-of-way clearing
    - Installation and maintenance of environmental controls

Fortis employees working on the management and technical teams are identified in Sections 2.2 and 4.4. The average years of experience for the Fortis team members assembled for the East-West Tie exceeds 20 years.

As noted in Section 6.6, Fortis operates its existing generation, transmission and distribution in Ontario with an internal staff, supplemented with contractors as required, and fully plans to continue that practice with the East-West Tie.

Third-Party Consultants:

TRC will provide engineering services including:

- Section 92 Application
- Review the System Impact Assessment (SIA)
- Customer Impact Assessment (CIA)

- Design of lines
- Compliance with Transmission System Code (TSC)
- Project Management
- Owner's Engineer services
- Qualify construction bidders
- Safety Plans and Observations

The Neegan Burnside team will provide environmental, consultation, and engineering services including:

- Consultations
- Environmental Assessment (EA)
- Civil, Electrical and Structural Engineering services
- Geographic Information System (GIS) services
- LiDAR and surveying in support of LiDAR
- Easement drawings, access maps.
- Construction quality and safety services.
- Field Services including environmental monitoring
- Safety Plans and Observations

Neegan Burnside will utilize the following sub-consultants with the aim of supplementing and enhancing the team to provide a local presence and ensure that project budget and schedules are maintained:

- Hardy Stevenson and Associates Ltd. (Socio-economic and Consulting Services)
  HSAL has worked for most of the Province's energy suppliers and regulatory agencies related to pipeline routing and approvals, rates, rules for opening the electricity market, transmission line routing and approvals, alternative energy suppliers, electrical distribution companies and electricity generators and others involved in environmental assessments. Most of their work in the energy

sector has focused on: (1) assessing and evaluating proposed projects based on potential effects to the natural and social environment; and (2) consulting and engaging stakeholders and members of the public in discussions related to these projects.

- Northern Bioscience (Natural Environment)

  Based in Thunder Bay, this firm offers professional consulting services supporting ecosystem management inventory and research. They will provide local knowledge and additional staff to enhance Neegan Burnside's biological inventory capability for wildlife ecology and habitat assessment, wetland evaluation and aquatic resources, and species at risk. Northern BioScience is providing ongoing ecological inventory and assessment work to the proposed Little Jackfish River Transmission Line which will run approximately 200 km from the new hydroelectric structure south to Nipigon. This work included species at risk surveys, Woodland Caribou habitat modeling, cumulative effects assessment and forest and wetland habitat mapping. Northern BioScience has also completed ecological inventories for 65 Ontario provincial parks and conservation reserves, undertaken annual Peregrine Falcon surveys along the north shore of Lake Superior for over 20 years and completed 30 wetland evaluations using the Northern Ontario Wetland Evaluation System. They will provide local knowledge and additional staff to enhance Burnside's biological inventory capability for wildlife ecology, habitat assessment, wetland evaluation and aquatic resources, including species at risk.

- KBM Resources Group (Natural Environment and Forestry)

  KBM Resources was established in 1973 to provide forestry services to the forest sector in Northwestern Ontario. KBM is recognized as a leader in aerial photography, digital mapping, planning, inventory and environmental assessment support services for the natural resource sectors. The firm operates its own aircraft, field services, retail outlet, warehouse and repair shop at its main office in Thunder Bay, Ontario. KBM brings to this project a deep understanding of the social, economic and environmental context of Northern Ontario. KBM has intimate knowledge of the project area, completing the most recent forest resources inventory (FRI) for a 1 million hectare parcel in 2007 that includes nearly half of the Project's corridor length. The FRI relied heavily of KBM's ability to access and analyze complex data from state of the art remote sensing sources (i.e. ADS 40) available through the Ontario Ministry of Natural Resources. KBM also had a contract to clear the existing power-line and control vegetation along the proposed corridor. The firm maintains excellent business relationships with government agencies, businesses, communities and First Nations in the project area. The firm has also developed LiDAR analysis toolkits and one of its planes is fitted to accept LiDAR instruments.

- Western Heritage (Archaeology/Culture)

  This firm will provide the expertise to undertake the cultural, historical and archeological assessment for the Project. If required, Western Heritage can also support Neegan Burnside in undertaking First Nation and Métis Traditional Land Use and Traditional Ecological Knowledge Studies. They have considerable experience working with Aboriginal communities throughout much of Canada including Northwestern Ontario.

- TBT Engineering (Geotechnical)

  TBT is Northern Ontario's largest independent civil engineering consultant firm located in Thunder Bay who will offer services as required with transportation and geotechnical aspects of the project.

- Chimax Inc. (Electrical Engineering)

  Chimax's work on transmission and distribution lines typically includes the design and detailing of some or all of the following: plan and profile of transmission line route, bills of materials, caisson foundations, lattice steel structures, steel poles, and technical specifications for construction.

- Airborne Sensing Corporation (Aerial photography)

Airborn Sensing has its own aircrews and provides digital aerial photography using the newest generation of Vexcel digital aerial cameras and software.

Davies Ward Phillips & Vineberg LLP: Davies will provide legal advice with respect to transactional matters, including:

- The drafting and negotiation of commercial contracts for planning, developing, engineering, procurement and construction.
- Drafting and negotiation of partnership/participation agreements with First Nations and Métis
- Drafting other agreements with First Nations and Métis
- Tax advice
- Aboriginal law matters
- Advice related to acquisition of land rights
- Advice related to the negotiation and drafting of financing agreements
- Environmental law matters

Andrew Taylor of the Energy Boutique:
Andrew Taylor will provide energy regulatory legal services including:

- Obtaining leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (the "OEB Act")
- Providing a notice of proposal pursuant to Section 81 of the OEB Act
- Any other approvals required by the Ontario Energy Board

Lake Huron Anishinabek Transmission Company Inc. (“LHATC”)
LHATC will provide assistance as required to the proposed Joint Venture as set out in Section 3.1 concerning:

- Land and treaty rights
- Land uses
- Public opinion, public meetings

- Cultures and traditional practices
- Historical
- Financing the project

Construction Contractor(s)

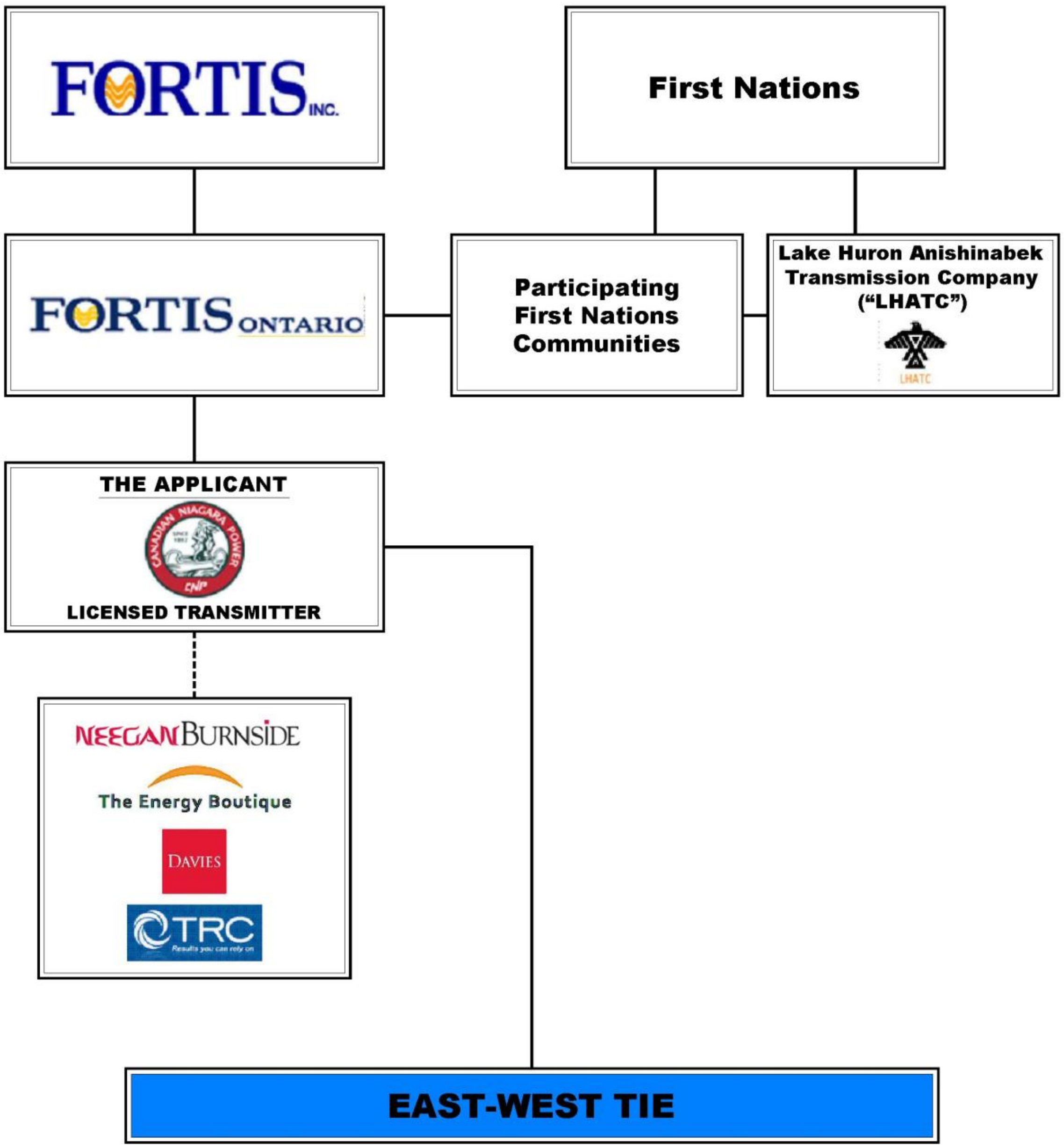
- Construction of line
- Environmental controls
- Material handling
- Safety

Organizational Structure:

For purposes of this application, "Canadian Niagara Power Inc.", "CNPI", "Joint Venture", and "Partnership" are occasionally used interchangeably. CNPI is the licensed transmitter for this application.

The following chart approximately indicates the relationship to the licensed transmitter to its partners and consultants.

Organizational Structure



2.2 identification of the specific management team for the project, with resumés for key management personnel.

Name	Company	Title
Bill Daley	Fortis	Executive
Glen King	Fortis	Financial
Angus Orford	Fortis	Operations
R. Scott Hawkes	Fortis	Corp Services, General Counsel
Tim Lavoie	Fortis	Regional Manager
Pierre Dufuour	Fortis	Manager Major Projects
Ross Assinewe	LHATC	LHATC Executive

Resumés for key management personnel are attached to this application as Appendix G.

2.3 an overview of the applicant's experience with:

- ***the management of similar projects; and***
- ***regulatory processes and approvals related to similar projects.***

The Ontario utility business was founded in 1892 and Fortis has 120 years of managing projects in Ontario. Similar recent Fortis projects are listed below. Each project is managed by Fortis and all projects required regulatory approvals.

- **Waneta Hydro 230kV Transmission Project.** This project is under construction and is a partnership among Fortis, Columbia Power Corporation, and Columbia Basin Trust to construct a 335-MW hydroelectric generating facility in BC at an estimated cost of $900 million. Also included are 230 kV transmission and station improvements required to connect the generation. Fortis owns a controlling 51 per cent interest in the Waneta Expansion and will operate and maintain the facility when it comes into service, which is expected in spring 2015. Federal and provincial environmental assessment approvals are in place for the project. For more details on the Waneta Expansion Project, visit www.columbiapower.org/wanetaexpansion.

- **Okanagan 230 kV Transmission Project.** This is a $104.8 million Fortis project that was placed in service in 2010. The project included the upgrade of 40 km of transmission line. Specifically, a 161kV transmission line was rebuilt to 230kV, 30 km double and 10 km single circuit. One new 230kV terminal was constructed and two existing terminals were converted to 230kV.
- **Mt. Hayes Natural Gas Storage/Transmission Project**. This is a $193 million Fortis project that was placed in service in 2010 at the Mt. Hayes site on Vancouver Island, which included the installation of the system facilities to connect the liquefied natural gas ("LNG") storage facility to the gas transmission system and allow for bi-directional flow. The facility is built to store 1.5 billion cubic feet of LNG. There was significant First Nations participation in the project with Chemainus Indian Band and Cowichan Tribes acquiring an ownership interest in the LNG facility. See Section 10.2 for those details.
- **Nk'Mip (East Osoyoos) Transmission and Substation Project.** This is a Fortis transmission and substation project to construct, own and operate a $20 million new 63/13 kV substation in East Osoyoos, BC. The new station was placed into service in 2007 and is supplied by an 18 km 63 kV transmission line. A reinforcement to a portion of the existing Osoyoos area distribution system was included in the scope. The project received regulatory approval and permitting. The substation became known as the Nk'Mip Substation and involved the very strong working relationship with the Osoyoos First Nation Indian Band ("OIB"), as the substation and the majority of the new transmission line were constructed on their reserve lands. Numerous OIB community members were employed during all phases of the Nk'Mip project.
- **Newfoundland Multi-Year Transmission Line Rebuild Project**. This is a multi-year transmission rebuild project in excess of $80 million, being carried out by Newfoundland Power pursuant its Transmission Line Rebuild Strategy filed with

the Newfoundland and Labrador Board of Commissioners of Public Utilities. The project commenced in 2006 with the first rebuild work placed in service by the end of 2006. The Strategy outlines a long term plan to rebuild aging infrastructure (66kV and 138kV bulk transmission lines), and prioritizes the investment in the rebuild based on physical condition, risk of failure, and potential customer impact in the event of failure. It is updated annually to ensure it reflects the latest reliability data, inspection information and conditions assessments.

- **Canadian Niagara Power Transmission System**. CNPI planned, designed, constructed, owns and operates single circuit 115kV transmission lines and transmission substations in the Niagara region of Ontario. These circuits are supported by lattice steel towers, steel monopole, and wood poles. CNPI's transmission system is connected to Hydro One's 115 kV circuits A36N and A37N between Murray transformer station and Allanburg transformer station.

Each utility in Fortis is regulated in its respective operating jurisdiction, creating eight different jurisdictions where Fortis has significant regulatory expertise. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been very good.

Specifically in Ontario, Fortis and its subsidiaries hold distribution, transmission and generation licences with the Ontario Energy Board as well as permits and approvals from other regulators. Collectively, these Fortis companies (CNPI, Cornwall Electric, and API) have appeared before the Ontario Energy Board on numerous occasions in matters related to Mergers, Acquisitions, Amalgamations and Divesture Applications, Cost of Service Applications and Incentive Regulation Applications. Fortis companies have both presented evidence directly to the Ontario Energy Board to attain a decision and on occasion reached a settlement with the intervenor community to attain a decision.

Fortis companies have also participated in various working groups established by the Ontario Energy Board and have contributed positively to several projects including but not limited to Cost Allocation design, Third Generation Incentive Regulation design and Cost of Capital review. Fortis has maintained a positive relationship with the Ontario Energy Board and strives to contribute positively to regulation of the electricity industry in Ontario.

The team of consultants assembled for this project also have experience on similar projects:

Regulatory counsel to the applicant has relevant regulatory experience obtaining leave to construct under Section 92 of the OEB Act for similar projects including:

- Counsel to South Kent Wind LP (part of the Samsung group) on obtaining leave to construct a 33 km transmission line to connect a 270-MW wind farm located within the Municipality of Chatham-Kent in southwestern Ontario.
- Counsel to Erie Shores Wind Farm LP on obtaining leave to construct a 30 km transmission line to connect a 99-MW wind-farm located on the north shore of Lake Erie.
- Counsel to De Beers Canada and Five Nations Energy Inc. on obtaining leave to construct a 414 km transmission line in Northern Ontario.

2011-12 – Neegan Burnside provided consultation services for the Grand Bend Wind Limited Partnership, c/o Northland Power Inc., in respect of the Renewable Energy Approval for the 100 MW Grand Bend Wind Farm. It includes 32 km of 230 kV transmission line running from the wind farm to the 230 kV, Hydro One, Seaforth connection point.

TRC Engineers has relevant engineering, design, and project management experience working on projects of similar size and complexity including:

- Laredo Area Improvement was an $80 million project that involved the construction of the first commercially operated variable frequency transformer to provide a synchronized tie from the US to Mexico. The project included the associated new 230kV line, relocations of 115kV line, and new 138kV switching station. The engineer had full project management responsibility to approve the design, bid the construction, coordinate outages, provide cost and schedule reporting, manage resource issues, and close out the project.

- Big Sandy Inez 230kV double circuit line, 37 miles. The engineer had full responsibility for route selection, acquisition of easements, including appropriations, line design, material procurement, construction management, cost and schedule reporting, and project closeout.

2.4 an explanation of the relevance of the applicant's experience to the East-West Tie line project.

Waneta Hydro 230 kV Transmission Project provides several examples of relevant experience:

- Organization: This project provides for a joint venture with Fortis owning a controlling 51 per cent interest, similar to the CNPI proposal for a joint venture with First Nations to jointly own the East-West Tie.
- Aboriginal Participation: First Nation consultations were completed on this project without any major issues or delays.
- Technical Capability: The same type of resources proposed for use on the East-West Tie were also utilized on the Waneta project, including the technical capability to construct, own, and operate the component of the generation project that includes a 230kV transmission line.
- Financial Capacity: The Waneta Hydro project is a $900 million project, approximately 50% greater than the estimated cost of the East-West Tie.
- Design: Waneta includes design of a 230kV transmission line.
- Schedule: Federal and provincial environmental assessment approvals are in place for the Waneta Hydro project. Work is progressing on schedule. Multiple

steps were required and managed, similar to the process that will be utilized for the East-West Tie.

- Costs: Cost projections indicate that the non-regulated project will be completed within budget. Internal cost reporting techniques and requirements for the East-West Tie will be similar.
- Consultations: This project places great emphasis on local and region communities with 80% of the current workforce coming from local communities. In addition, the project is providing $94 million to local businesses for the purchase of goods and services. Extensive consultations are underway including: a socio-economic monitoring program which ensures the impacts to the area are documented and available to the public, and monthly meetings of a Community Impact Management Committee which provides ongoing support to encourage positive community impacts and benefits.

Okanagan 230 kV Transmission Project provides several examples of relevant experience:

- Organization: The Okanagan Transmission Rebuild project was a major project requiring the organizational skills and experience to manage the design and construction of 230kV transmission lines similar to the East-West Tie.
- Aboriginal Participation: New key terminal substation to support this project was built on reserve lands managed by a First Nation.
- Technical Capability: Okanagan 230 kV project was completed with Fortis engineers, environmentalists, project managers, legal staff providing oversight to an EPC consultant. The project involves ties with BC Hydro similar to the required tie to HONI in the East-West Tie.
- Financial Capacity: The Okanagan 230 kV project is a $104.8 million project, financed in a manner similar to methods proposed for the East-West Tie.
- Design: Includes single circuit and double circuit 230kV which are similar to those to be designed for the East-West Tie 230kV line.

- Schedule: The project was completed on schedule. The tasks tracked for this line project will be similar to the tasks tracked on the East-West Tie.
- Cost: The project was completed under budget. The substantial completion report includes explanations for the variance. (Confidential Document)
- Consultations: First Nation consultations were completed with no major issues or delays.

Mount Hayes Natural Gas Storage/Transmission Project provides several examples of relevant experience:

- Organization: This project provides for a joint venture with Fortis owning a controlling interest, similar to the CNPI proposal for a joint venture with First Nations to jointly own the East-West Tie.
- Aboriginal Participation: Two First Nations members are limited partners in the project. First Nations also received multiple construction contracts and employment opportunities. More detail is provided in Section 10.2.
- Technical Capability: Mount Hayes was completed with Fortis engineers, environmentalist, project managers, legal staff and consultants. This is a complicated project that required multiple legal, environmental, and technical approvals. Full compliance with the regulatory conditions set out by the British Columbia Utilities Commission was obtained.
- Financial Capacity: The $193 million project is financed using methods similar to those proposed for the East-West Tie.
- Design: The project was completed to meet or exceed all applicable codes. Design of the transmission aspect of this project (gas line) includes the same "linear project" skills required for the East-West Tie.
- Schedule: The project was completed on schedule.
- Costs: The project was completed within budget.

- Consultations: Consultations with First Nations were in depth and resulted in two First Nation communities acquiring an ownership interest in the facility. Multiple landowner consultations were required also.

Nk'Mip (East Osoyoos) Transmission and Substation Project provides several examples of relevant experience:

- Organization: The Nk'Mip transmission and substation project was a major project requiring multiple organizational elements to coordinate the applications for regulatory and permitting approvals, acquisition of land rights/egress for the associated transmission and distribution lines, the engineering, procurement and construction of the lines and substation, development of working relations with First Nations, management of health, safety and environmental matters, and the management of costs and schedule.
- Aboriginal Participation: First Nation community members were involved and employed during all phases of the project.
- Technical Capability: The 63 kV/13 kV project was completed with Fortis engineers, environmentalists, project managers, legal staff and multiple consultants. The project involved construction of transmission lines, installation of power transformers and related equipment which required the design, engineering and construction skills similar to that required by the East-West Tie project.
- Financial Capacity: The Nk'Mip project is a $20 million project, financed in a manner similar to methods proposed for the East-West Tie.
- Design: Includes transmission line design processes similar to those required for the East-West Tie.
- Schedule: The project was completed substantially on schedule with delays due to actual filing and approval dates falling later than originally planned.
- Costs: The project was completed over budget by $2 million due primarily due to market conditions at the time the tender was issued. Stakeholder consultations

resulted in changes to pole alignment and placements, which resulted in increased civil costs and increased helicopter costs.

- Consultations: First Nations relations involved a very strong working relationship with the Osoyoos Indian Band, with numerous community members being employed during all phases of the Nk'Mip project. The line and station were constructed on reserve land.

Newfoundland Multi-Year Transmission Project

- Organization: This is a major transmission project requiring the organizational skills and experience that will be required for the engineering, design, and construction of the East-West Tie.
- Aboriginal Participation: Was not applicable on this project. All lines are being rebuilt on or near existing right-of-way. Additional right-of-ways are typically required from crown lands with some relocation onto privately owned land.
- Technical Capability: In addition to the design, permits, and consultations, this work requires load studies as related to outage planning. On radial systems this often also requires mobile generation to minimize customer power interruptions.
- Financial Capacity: Current capital expenditures are approximately $5-6 million per year and are financed similar to the method proposed for the East-West Tie.
- Design: Wood pole structures design by internal engineering staff. Designs are based the construction standard *CSA C22.3 No.1 - Overhead System.*
- Schedule: The project schedule is carefully monitored. The plan is revised annually to reflect all changes, if any, and filed with the regulator.
- Costs: This multi-year transmission line rebuild project is being completed within planned budgets. The $20 million expended to the end of 2012 on this project is consistent budgets filed with the regulator.
- Consultations: Additional rights of way, if necessary, will be obtained as needed. Community consultations and public announcements are ongoing.

Canadian Niagara Power Transmission System

- As a constructor, owner and operator of the CNPI transmission system, CNPI has all the relevant planner, designer, and developer skills required to obtain all the necessary land rights, multiple permits, environmental approvals, and to carry out consultations necessary to expand and operate its transmission system in Ontario.

The relevance of the consultant's experience for the projects listed above includes:

- Regulatory: Andrew Taylor represents electricity transmitters, distributors, generators and stakeholders in respect of their regulatory obligations before the Ontario Energy Board in regard to the construction of electricity infrastructure. This experience is needed for the East-West Tie.
- Engineering, Design, and Project Management: TRC engineers working on this project have experience with multiple line projects that are similar to the East-West Tie. Experience includes all aspects of line design, including selection of lattice towers, tubular steel structures, hardware, and conductor. These engineers have extensive experience in material and construction specifications and contracts. These engineers have managed the projects from start to finish. TRC also experience as Owner's Engineer on similar large projects.
- Environmental Assessments, Consultations: Neegan Burnside experience includes all aspects required to provide Environmental Assessments and consultants, being particularly experienced in Aboriginal consultations.
- Financial Capacity and Legal: Davies has advised project proponents and financers with respect to the financing of a broad array of infrastructure projects across Canada and internationally.

3. First Nation and Métis Participation

The applicant must address its approach to First Nation and Métis participation in the East-West Tie line project. To that end, the applicant must file evidence of one of the following:

3.1 If arrangements for First Nation and Métis participation have been made, a description of:

- ***the First Nation and Métis communities that will be participating in the project;***

Arrangements for participation have been made with certain First Nations communities that are affected by the East-West Tie, and participation opportunities are available to other First Nations in the Robinson Superior Treaty Territory. It is proposed that participating First Nations communities will acquire an equity interest in the project. Participation opportunities for Métis communities are anticipated, and are described in paragraph 3.2.

CNPI's parent company, FortisOntario has entered into a binding Memorandum of Understanding ("MOU") with Lake Huron Anishinabek Transmission Company Inc. ("LHATC"), representing 21 First Nations who are signatories or are adherent to the Robinson-Huron Treaty of 1850. LHATC was formed in 2009 to obtain part ownership in Ontario electric transmission expansion projects. The MOU has been amended to include the East-West Tie.

The following is a list of First Nations communities that are currently participating in LHATC pursuant to the binding memorandum of understanding. Two LHATC members, Ojibways of Batchewana, and Ojibways of Garden River, appear on the Ontario Power Authority's East-West Tie list of affected First Nations.

Lake Huron Anishinabek Transmission Company participants:

Aundeck Omni Kaning	Batchewana First Nation
Dokis First Nation	Henvey Inlet First Nation
M'Chigeeng First Nation	Magnetawan First Nation
Mississauga #8	Nipissing First Nation
Ojibways of Garden River	Sagamok Anishnawbek
Serpent River First Nation	Shawanaga First Nation
Sheguiandah First Nation	Sheshegwaning First Nation
Thessalon First Nation	Wahnapitae First Nation
Wasauksing First Nation	Whitefish Lake First Nation
Whitefish River First Nation	Wikwemikong Unceeded Indian Reserve
Zhiibaahaasing First Nation	

In addition the above list of First Nation communities, CNPI has a plan described below for equity participation by other interested First Nations referred to on the OPA's published list of fourteen "Crown-identified" First Nation communities.

- ***the nature of the participation (e.g. type of arrangement, timing of participation);***

Participation will involve granting equity rights to affected First Nations that are interested in participating in the development, construction, operation and ownership of the East-West Tie. LHATC, and certain interested First Nations communities will have rights in the aggregate to acquire up to a 49% equity interest in the East-West Tie line.

- ***benefits to First Nation and Métis communities arising from the participation;***

The MOU model provides for a number of benefits to affected and participating First Nations communities including:

- The parties acknowledge that a primary objective of the First Nations is to achieve long-term economic and social benefits resulting in an improved quality of life. An equity interest in the project serves that purpose.
- The MOU provides for an apprenticeship training fund for successful First Nations candidates to become power line technicians. Typically the candidate would attend lineman school then will receive "on the job training" to progress through the labour levels.
- Preferential consideration will be given to First Nations businesses in the award of material and labour contracts, assuming that the goods and services being provided are commercially reasonable and competitive, and the businesses are qualified.
- Employment opportunities become available to the affected First Nation communities, with First Nations expected to capture a significant percentage of those jobs. In addition to construction jobs, the community will also add support service jobs to the construction.
- The Fortis Skill Builder program will be used for First Nations youth to educate and train them for potential employment with the utility operation and construction industry. The objective will be to find positions with contractors that can continue to provide employment to such skilled First Nations persons on similar work following completion of this project. Please refer to Appendix V for additional details.
- During construction, there will be a number of trades, skilled labourer, and unskilled labourer support jobs available. During the operational life of the line, there will be a number of skilled positions required to maintain the line. In anticipation of this project, Fortis and LHATC have been actively promoting specific educational programs to the local community colleges, and universities. Discussions and

presentations to Sault College (Utility Arborist and Foresters), Cambrian College (Powerline Technician), and Algoma University (Environmental Sciences) have now started with a goal of training First Nations students to capture a significant percentage of the anticipated jobs.

- CNPI has budgeted for consultation services from First Nations during the project development and construction phases.
- Regulatory experience in the energy sector.
- Assistance in financing First Nations equity interest will be available from Fortis.

- ***whether participation opportunities are available for other First Nation and Métis communities in proximity to the line.***

Participation opportunities are available for other interested First Nations communities. Fortis has developed a confidential proposal involving the granting of equity rights to those interested First Nations communities whose traditional territories will be crossed by the East-West Tie, upon CNPI becoming the designated transmitter. The proposal includes the affected and interested First Nations communities in the Robinson Superior Treaty territory and LHATC entering into a New binding Memorandum of Understanding (the “New MOU”) with Fortis to develop the East-West Tie (the “Joint Venture”). LHATC is participating in these discussions in its capacity as an existing joint venture partner for transmission development in the Robinson Huron Treaty territory. As stated above, LHATC, and certain interested First Nations communities will have rights in the aggregate to acquire up to a 49% equity interest in the East-West Tie line. The terms of the New MOU would be approved ultimately by the boards of directors of the participating companies and the First Nations Councils.

3.2 If arrangements for First Nation and Métis participation have not been made but are planned, a description of:

- ***the plan for First Nation and Métis participation in the project, including the method and schedule for seeking participation;***
- ***the nature of the planned participation; and***
- ***the planned benefits to First Nation and Métis communities arising from the participation;***

- First Nations Participation

There are planned equity participation opportunities for the First Nations Communities. The nature of the planned participation is set out above in connection with the discussion around the New MOU. The planned benefits include those listed above in connection with the MOU model.

- Métis Participation

CNPI recognizes that the engagement and participation of the affected Métis in developments affecting their territories will enable them to maintain and strengthen their institutions and to promote their development in accordance with their aspirations and needs. CNPI has had a preliminary discussion with legal counsel of the Métis Nation of Ontario ("MNO") and is sensitive to and acknowledges the traditional harvesting rights and interests of the Métis in the East-West Tie territory. To facilitate participation, CNPI proposes to support Aboriginal application for capacity funding under such programs as the Ontario Power Authority *Aboriginal Energy Partnership Program*.

CNPI's plan for Métis participation is to work towards negotiations resulting in meaningful participation by Métis in the project. This will be achieved following designation through thoughtful discussions with MNO and Community Councils as necessary. In this regard, a preliminary meeting was held with legal counsel from MNO to discuss various forms of participation. Further meetings will be required and scheduled following designation to set out a method and schedule for seeking participation.

CNPI acknowledges that there is no "one size fits all" model for Métis participation. The details of Métis participation would evolve through a series of meetings and discussions between MNO (and Councils) and CNPI. The terms of participation would be approved ultimately by the board of directors of CNPI and Métis Community Councils. These terms of the participation could be set out in a participation agreement between CNPI and the affected Métis communities. Planned participation could take many forms including without limitation: contributions towards the Métis communities, construction work, and opportunities to build community business.

Planned benefits arising from Métis participation could include certain of the benefits listed above, including without limitation: employment opportunities, apprentice opportunities, Skill Builder program and opportunities to build community businesses.

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

Section 3.3 is not applicable to this application. CNPI has actively pursued First Nation and Métis participation in the project.

4. Technical Capability

The applicant must demonstrate that it has the technical capability to engineer, plan, construct, operate and maintain the line, based on experience with projects of equivalent nature, magnitude and complexity. To that end, the following must be filed:

The CNPI technical team is comprised of employees from Fortis, LHATC, and CNPI's external consultants, TRC Engineers, Neegan Burnside, Davies, and Andrew Taylor.

The Fortis component of the team includes multiple utility experienced persons. This team has expertise, experience, and the technical capability to engineer, plan, construct, operate and maintain the line. Members of this team have worked on projects of equivalent nature, magnitude and complexity. A few of those projects are discussed in this application including the following: Waneta Hydro 230 kV Transmission Project, Okanagan 230 kV Transmission Reinforcement Project, Mount Hayes Natural Gas Storage/Transmission Facility, NK' Mip Transmission and Substation Project, Newfoundland Multi-Year Transmission Line Rebuild Project, Canadian Niagara Power Transmission System, and various transmission new builds and rebuilds associated with the ongoing operation and maintenance of transmission and distribution systems as well as operation of hydro generation.

TRC *(NYSE: TRR)* is a leader in providing environmental and engineering consulting, design, procurement, construction, and compliance services for energy companies. TRC provides complete power delivery services from system and electrical studies to engineering, procurement, and construction (EPC) support, including testing and commissioning services for transmission lines and stations. TRC provides comprehensive environmental consulting services, including: site selection and critical flaw assessment; multidisciplinary licensing for brownfield and greenfield development

sites; acquisition due diligence and auditing services; compliance testing; site remediation support; and environmental management system development.
TRC engineering has a power delivery staff of approximately 500 experienced project managers, engineers, planners, and support staff located in 20 offices across the United States. Its engineers have designed more than 3,000 miles of 69 kV, 115 kV, 138 kV, 230 kV, 345 kV, and 500 kV transmission lines.

TRC Projects of equivalent nature to the East-West Tie include Laredo Area 230kV Transmission Improvements, Big Sandy Inez 230kV double circuit line, Tehachapi Renewable Resources 500 kV Transmission Project, Path-15 Los Banos to Gates 500 kV Transmission Line, 85 miles, Yellowhead Area 138kV Transmission.

The TRC Team offers a unique combination of resources and experience that is ideally suited to successfully meeting the needs of the East-West Tie 230kV line. Successful hands-on experience with the permitting and design of transmission projects, construction know-how, technical expertise, and depth of staff resources result in on-schedule, within-budget project deliverables.

Neegan Burnside is a majority owned Aboriginal firm committed to assisting First Nations in meeting their development and economic goals while remaining sensitive to First Nation community, culture, values and beliefs. Neegan Burnside takes pride in its Aboriginal employees and the communities they represent.

Neegan Burnside has 15 Aboriginal employees in engineering, environmental and support services representing 15 separate Aboriginal communities in Ontario and Manitoba. Together with its partners R.J. Burnside and Associates, Neegan Burnside has access to over 330 professional staff. R.J. Burnside provides quality infrastructure, engineering and consulting services in Canada and internationally. Burnside has several specialized divisions, including environmental assessment, renewable energy, remote sensing and geographic information systems (GIS), groundwater supply and contaminant hydrogeology, site assessment and remediation services and solid waste management. Other areas of expertise include development and management of water supply systems (surface and groundwater sources, treatment and distribution), individual sanitation schemes, wastewater collection and treatment, solid waste management planning, roads and bridges, and other municipal facilities. Similar services are also provided to private clients for institutional, commercial and industrial infrastructure. Neegan Burnside has also assembled a highly qualified sub-consulting team to assist with other components of the project including the extensive natural and human heritage and cultural studies that will be required. The team includes socio-economic and consultation expertise.

4.1 a discussion of the type of resources, including relevant capability (in-house personnel, contractors, other transmitters, etc.) that would be dedicated to each activity associated with developing, constructing, operating and maintaining the line, including:

- ***design;***
- ***engineering;***
- ***material and equipment procurement;***
- ***licensing and permitting;***
- ***completion of environmental assessment and other regulatory approvals;***
- ***consultations, both with First Nation and Métis, and other communities;***
- ***construction;***
- ***operation and maintenance; and***
- ***project management.***
- ***Other***

CNPI will utilize its existing Fortis staff to support the proposed project, including:

Task	In-House	Contract	Transmitters
Attorneys	✓	✓	
Engineers	✓	✓	
Regulatory Specialists	✓	✓	
Procurement Agents	✓		
Public Relations	✓	✓	
Manage Aboriginal Affairs	✓	✓	
Safety Specialist	✓	✓	
Right-of-Way	✓	✓	
Operations	✓		
Maintenance Crews	✓	✓	✓*

* CNPI recognizes that sharing a right-of-way with another transmitter may lead to some shared maintenance responsibilities to improve reliability and reduce costs to ratepayers. Additionally, other transmitters may be utilized for certain line maintenance tasks, specifically as related to outage restorations.

Specific project tasks of CNPI include:

- Prepare and issue contracts for engineering and construction services
- Contract right-of-way services to support its existing right-of-way staff
- Serve as Grantee on all right-of-way easements or permits
- Procurement services for major materials
- Issue press announcements
- Financing the at risk development cost
- Prepare and file all regulatory documents
- Report project status to OEB
- Operation and maintenance over the life of the facility as defined in the Transmission System Code (TSC)

CNPI plans to contract with TRC Engineers for design and engineering services at each phase of the project. TRC will supply multiple professionals to the project including:

Task	In-House	Contract
Project Manager/Owner's Engineer	✓	
Civil Engineers	✓	
Electrical Engineers	✓	
Electrical Designers	✓	
Cadd Operators	✓	
Environmental Specialists	✓	
Safety Specialist	✓	

Specific project tasks of TRC include:

- Development
  - Transmission line design
  - Create material and equipment specifications
  - Bill of Material
  - Assist with negotiation of material supply contracts
  - Issue construction specifications
  - Status reports to CNPI
  - Prequalify construction contractors
- Construction
  - Project management, cost reports and schedule status to CNPI.
  - Provide construction quality observations
  - Maintain record drawings
  - Health and safety observations

CNPI plans to contract with Neegan Burnside Engineers for engineering and environmental services. Neegan Burnside will supply multiple professionals to the project including:

Task	In-House	Contract
Project Manager	✓	
Aboriginal Consultant	✓	✓
Civil Engineers	✓	
Structural Engineers	✓	✓
Electrical Engineering	✓	✓
Cadd Operators	✓	
Environmental Specialists	✓	✓
Safety Specialist	✓	✓
Surveyors	✓	✓
GIS and LiDAR	✓	✓

Specific project tasks of the Neegan Burnside team include:

- Development
    - Develop a Terms of Reference (ToR) in consultation with MOE and other provincial and federal authorities
    - Obtain approval on ToR
    - Develop consultation strategies with landowners, First Nations, Métis, Municipalities, and the Crown
    - Determine environmental requirements
    - Determine existing field conditions with site specific studies – physical environment, terrestrial environment, aquatic environment, socio economic environment, cultural environment
    - Detailed analysis and evaluation of alternate routes

  - Implement consultation plans, including mailings, advertisements, meetings, workshops and public information centres
  - Determine impacts and mitigation measures and design environmental controls, establish procedures and specifications for construction
  - File the Environmental Assessment (EA)
  - Determine licensing and permitting requirements
  - Provide GIS, LiDAR and supporting survey data
  - Develop safety, risk, and construction resource plans
- Construction
  - Technical support and design review engineering support (civil, structural, electrical), to the TRC design team
  - Field Services, continued consultations
  - Track material shipments
  - Provide construction quality observations
  - Environmental monitoring observations, including post construction as necessary
  - Health and safety observations

Resources provided by the construction contractor(s) include:

Task	In-House	Contract
Project Manager	✓	
Supervision	✓	
Skilled Labour	✓	✓
Unskilled Labour	✓	✓
Equipment Operators	✓	✓
Equipment	✓	✓

Specific project tasks include:

- Right-of-way clearing
- Road Construction
- Installation of structures and conductor
- Material storage and handling
- Safety
- Environmental protection controls

4.2 resumés for key technical team personnel;

Resumés are included to this application in Appendix H.

Name	Company	Project Role
Bill Daley	Fortis	Exec. Lead
Scott Hawkes	Fortis	Exec Sponsor/Legal/Aboriginal Affairs
Doyle Sam	Fortis	Exec Sponsor/Major Projects
Pierre Dufour	Fortis	Major Projects Manager
Angus Orford	Fortis	Operations
Glen King	Fortis	Finance
Chief Paul Eshkakogan	Sagamok Anishnawbek	Aboriginal Political Advisor
Ross Assinewe	LHATC	Aboriginal Affairs
Bruce Falstead	Fortis	Aboriginal Affairs
Paul Chernikhowsky	Fortis	Engineering Services
Mike Jardine	Fortis	Engineering, Design and Construction
Jie Han	Fortis	Technical Services
Barry Smithson	Fortis	Network Operations

Doug Bradbury	Fortis	Regulatory
Tim Lavoie	Fortis	Regulatory/Land Rights/Procurement
Don Gilbert	Fortis	Health, Safety, Environmental (HSE)
Jennifer Rose	Fortis	HSE, Forestry, Rights-of-Ways
Kristine Carmichael	Fortis	Public Relations
Don Kendall	TRC Engineers	Project Manager
Ed Peace	TRC Engineers	Engineering Manager
John Fulton	TRC Engineers	Transmission Engineer
Lyle Parsons	Neegan Burnside	Project Manager and EA Specialist
Jennifer Vandemer	Neegan Burnside	EA Coordinator
Tricia Radburn	Neegan Burnside	Natural Heritage Assessment Lead
Chris Pfohl	Neegan Burnside	Natural Heritage, Aquatic Specialist
Merv Dewasha	Neegan Burnside	Aboriginal Advisory Consultant
Joy Rutherford	Neegan Burnside	Hydrogeologist
Ian Drever	Neegan Burnside	Project Management Advisor
Lorena Niemi	Neegan Burnside	Civil Engineer
James Walls	Neegan Burnside	Geoscientist
Sammy Elias	Neegan Burnside	Electrical Engineer
Carl Lankinen	Neegan Burnside	Structural Engineer
Mark Sheedy	Neegan Burnside	Field Services
Arunas Kalinauskas	Neegan Burnside	GIS and LIDAR
Paul Stubbert	Neegan Burnside	GIS Specialist
Bruce Clarida	Neegan Burnside	Transmission Engineeer

Dave Hardy	Hardy Stevenson	Public Consultation Socio Economic Assessment
Andrzej Schreyer	Hardy Stevenson	Public Consultation Socio Economic Assessment
Yuri Huminilowycz	Hardy Stevenson	Consultation Specialist in Rights-of-Ways and Acquisition of Real Estate Rights
George McKibbon	Hardy Stevenson	First Nations liaison Assistance and Socio-Economic Assessment
Robert F. Foster	Northern Bioscience	Natural Heritage Assessment.
Allan G. Harris	Northern Bioscience	Natural Heritage Assessment
Brian Ratcliff	Northern Bioscience	Natural Heritage Assessment
Laird Van Damme	KBM Forestry	Forestry Assessment
Peter Higgelke	KBM Forestry	Forestry Assessment
Terrance Gibson	Western Heritage	Archeology/Cultural Heritage Lead
Andrew Lints	Western Heritage	Archeological Assessment
Shabam Inanloo Dailoo	Western Heritage	Cultural heritage/Traditional Land Use
Wayne Hurley	TBT Engineering	Geotechnical Engineering
Gordon Maki	TBT Engineering	Geotechnical Engineering
Steven Sellers	TBT Engineering	Geotechnical Engineering
Kevin Wong	Chimax Inc.	Electrical Design Engineering
Calvin Ng	Chimax Inc.	Electrical Design Engineering
Edmund Kwong	Chimax Inc.	Transmission Design Engineering
Miuee Huang	Chimax Inc.	Transmission Line and Pole Analysis

Vicky Wu	Chimax Inc.	Transmission Structural and Civil Design
Raymond Leung	Chimax Inc.	Transmission & Structural Design Engineering

4.3 A description of sample projects, and other evidence of experience in Ontario and/or other jurisdictions in developing, constructing and operating transmission lines or other infrastructure and why these projects and experience are relevant to the East-West Tie line project. The evidence should include a description of experience with:

- ***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 East-West Tie line;***
- ***community consultation;***
- ***completion of the procedural aspects of Crown consultation with First Nation and Métis communities.***

The Fortis team has several recent projects that confirm its relevant experience with each of the requirements listed above.

Waneta Hydro 230kV Transmission Project is a partnership with Columbia Power Corporation and Columbia Basin Trust to construct a 335-MW hydroelectric generating facility in British Columbia at an estimated cost of $900 million. Also included are 230 kV transmission and station improvements required to connect the generation.

- Community Consultations: this project places great emphasis on local and regional communities with 80% of the current workforce coming from local communities. In addition, the project is providing $94 million to local businesses for the purchase of goods and services. Extensive consultations are underway including: a socio-economic monitoring program which ensures the impacts to the area are documented and available to the public, and monthly meetings of a Community Impact Management Committee which provides ongoing support to encourage positive community impacts and benefits.

Okanagan 230 kV Transmission Project is a $104.8 million project in British Columbia which included approximately 40 km of 230 kV line and multiple station upgrades.

- Land rights were in place for this line rebuild project. However, field staff resolved multiple issues related to:
    - road access locations
    - crop damages
    - disruption issues
- Multiple permits obtained include:
    - Ministry of the Environment
    - Department of Fisheries and Oceans Canada
    - Provincial Park
    - Canadian Wildlife Service
    - Integrated Land Management Bureau
- Environmental approvals, specifically the Federal and provincial Environmental Assessment were not required. Two assessments were submitted to the BC Utilities Commission.
    - Environmental Impact Assessment
    - Archaeological Impact Assessment
- Consultations were completed with several large property owners including:
    - Nature Trust B.C.
    - Land Conservancy
    - One cattle ranch
    - Multiple orchards

- Completion of the procedural aspects of Crown consultation with Aboriginal communities: The First Nations consultations were successfully carried out resulting in the new Bentley Substation being built on Osoyoos Indian Band land.

Mount Hayes Natural Gas Storage/Transmission Project is a $193 million project located near Ladysmith, BC. The project included construction of a liquefied natural gas (LNG) facility (1.5Bcf storage tank and 7.5 MMscf/d liquefaction capacity) and supporting infrastructure including a 138kV to 25kV substation, a 5 km 25kV power line, and two 5km natural gas transmission lines/valve stations.

- Land Rights:
  - Land for the LNG Facility was purchased from a private landowner.
  - Roads, substation, power line, and natural gas infrastructure were constructed predominantly on crown land, with rights-of-way coordinated with the BC Oil and Gas Commission.
- Permits
  - The LNG Facility did not require a review under the BC Environmental Assessment Office.
  - The BC Oil and Gas Commission issued the natural gas facilities approvals and coordinated permissions from various government departments, including Ministry of Forestry, Ministry of Environment and Ministry of Transportation.
  - FortisBC dealt directly with local logging companies to set up road use permits and approvals for road modifications.
  - FortisBC dealt directly with permitting from local agencies including the Cowichan Valley Regional District, Safety Branch, Boilers Branch.
- Community Consultation
  - Community consultation was initiated early and results fed into final site selection process

- First Nations Consultation
    - The LNG Facility was constructed on First Nation traditional territories. The Manager of First Nations Initiatives facilitated First Nations consultation and accommodation initiatives. The First Nations participated in aspects of the project construction and are partners in the LNG Facility.

Nk'Mip Substation Project in BC, is a $20 million project. The project included approximately 18 km of 63 kV line, the construction of a 63/13kV substation in East Osoyoos and associated distribution feeder egresses.

- Regulatory approval and permitting were received after a detailed environmental assessment and consultation with Indian and Northern Affairs Canada-Pacific region, the Canadian Wildlife Service, and Osoyoos Indian Band ("OIB") representatives.
- Environmental concerns were addressed as the line was constructed in in a protected desert area with many red listed (endangered or threatened) and blue listed (formerly vulnerable) species. The station construction included "visually neutral" perimeter walls.
- Land rights were acquired and procedural aspect of Crown Consultations were completed, which required a very strong working relationship with the Osoyoos Indian Band. This project was completed in its entirety on Osoyoos Indian Band Land. The Manager of Aboriginal Affairs managed all First Nations relationships, negotiated lease arrangements and coordinated associated approvals through Indian and Northern Affairs (INAC).
- Consultations were completed and numerous OIB community members were employed during all phases of the Nk'Mip project.

Newfoundland Multi-Year Transmission Line Rebuild Project

This project includes on-going processes involving the acquisition of necessary land rights as well as all necessary permitting, environmental approvals, and community consultations. This experience in other jurisdictions involves skills that are transferable to the East-West Tie project for the development, construction and operation of the line.

LHATC/Fortis First Nations Partnership. The recent partnership of Fortis and LHATC, which represents twenty-one First Nations in the Robinson Huron Treaty Territory is evidence of Fortis's experience and ability to carry out the procedural aspects of the Crown consultations with First Nations communities to develop transmission projects in Ontario. This existing joint venture relationship has been developed over many months of consultations and negotiations resulting in a binding memorandum of understanding that is directly relevant to the plans to develop the East-West Tie. Upon CNPI being designated as the transmitter to develop the East-West Tie, Fortis and LHATC have plans in place for the participation of the First Nations in the Robinson Superior Treaty Territory to develop, construct, own and operate the East-West Tie jointly with CNPI. It is the intention of the joint venture to complete the procedural aspects of the Crown consultation with First Nation and Métis communities in respect of the East-West Tie.

Canadian Niagara Power Transmission System. CNPI has in place and operates in compliance with all of the necessary land rights, permits, environmental approvals, and community consultations necessary for the development, construction and operation of its transmission system in the Niagara region of Ontario.

Fortis has recently completed smaller projects in Prince Edward Island, British Columbia, and the Caribbean.

The TRC engineers working on this project have design, engineering, and project management experience with multiple line projects that are similar to the East-West Tie. Experience includes all aspects of line design, including selection of lattice towers, tubular steel structures, hardware, and conductor. These engineers have extensive experience in material and construction specifications and contracts. These engineers have managed the projects from start to finish. Project experience that is relevant to the East-West Tie includes:

- Laredo Area Improvement was an $80 million project that involved the construction of the first commercially operated variable frequency transformer to provide a synchronized tie from the US to Mexico. The project included the associated new 230kV line, relocations of 115kV line, and new 138kV switching station. The engineer had full project management responsibility to approve the design, bid the construction, coordinate outages, provide cost and schedule reporting, manage resource issues, and close out the project.
- Big Sandy Inez 230kV double circuit line, 37 miles. The engineer had full responsibility for route selection, acquisition of easements, including appropriations, line design, material procurement, construction management, cost and schedule reporting, and project closeout.
- Tehachapi Renewable Resources 500 kV Transmission Project, 100 miles
- Path-15 Los Banos to Gates 500 kV Transmission Line, 85 miles
- Yellowhead Area 138kV Transmission, 80 km, Alberta, Canada

Neegan Burnside has many experiences with Individual EA's and Renewable Energy Approvals including:

- Sithe Energy Southdown Station Project, 880 MW natural gas fired combined cycle generating facility, Sithe Global
- Sithe Energy Goreway Station, 880 MW natural gas fired combined cycle generating facility, Sithe Global
- Aamjiwnaang First Nation (AFN) and Walpole Island First Nation (WIFN) Clean Harbours Hazardous Landfill, Independent Review.
- Detroit River International Crossing Study, Independent Review, WIFN.
- Grand Bend Wind Farm, 100 MW wind farm, REA approvals including 36 kV collector lines and a 32 kilometre 230 kV transmission line.

Hardy Stevenson and Associates Ltd. Project Examples:

- Study design, research, assessment of associated impacts, and preparation of the Social Environmental Assessment for the Hamner to Mississauga Transmission line approved by the Ministry of the Environment.
- Socio-economic impact assessment studies of Elliot Lake T.S. to Quirke Lake T.S. transmission line
- Social Impact Assessment Study of Algoma TS to Elliott Lake TS transmission line
- Scoping of the social impact assessment component of the South-West Ontario transmission expansion and the Supply to Ottawa (Approved by the Consolidated Hearings Board)
- Lead consultant for the strategic EA for OPA's Integrated Power System Plan.

Chimax Inc. Project Examples:

- Imperial Oil, Kearl Oil Sand Project Phase II, Alberta – Detail Engineering Design of 70 km of 240kV, 72kV, 13.8kV transmission Line and Station Gantries including mono-steel pole structure for 240 kV and wooden pole structure for 72kV and 13.8kV structure.
- Thorold Cogen. T-line – Thorold cogeneration project 230kV transmission line, including mono-steel pole and foundation design
- Halton Hills Generation Station - 230kV Switchyard design, Ontario - Station design and detail design of all required structural steelwork, foundation, electrical equipment layout and bill of material.
- South Greenfield Power Plant – 230kV Switchyard, including station layout, bill of material, station structures and transmission line mono-steel pole structures design
- Vale Inco - Frood Stobie #2 Substation – 230kV Switchyard upgrade

Davies has broad experience on the construction, financing and sale of many infrastructure projects across Canada and internationally. In particular, Davies has been involved in the following Canadian electricity projects:

Long Lake Hydroelectric Project on Cascade Creek, Stewart, B.C.; and Bear Creek Hydroelectric Project, B.C. Davies advised The Manufacturers Life Insurance Company in connection with the project financing of these hydroelectric projects. In addition to negotiating all financing and structure documents, Davies conducted due diligence on all aspects of the project, including:

- land rights acquisition
- Aboriginal consultation
- environmental impact assessment
- permitting

Okikendawt Hydroelectric Project on the French River, Ontario. Davies is advising the project proponent, Hydroméga Services Inc. on all aspects of the project. Hydroméga and the Dokis First Nations have formed the Okikendawt Hydro Limited Partnership in order to develop, build, own and operate a hydroelectric facility at the Portage Dam on the French River in Ontario. Davies' role has included:

- negotiating leases of the site from the Public Works and Government Services Canada, the Ontario Crown and private landowners
- acquiring water permits for the project under the *Dominion Water Power Act*
- acquiring easements for the transmission line that crosses land controlled by private landowners, the federal government, the Ontario Crown, and the First Nations communities
- acquiring necessary permits under the *Indian Act*

Kapuskasing North Waterpower Hydroelectric Project, Kapuskasing, Ontario. Davies is advising the project proponent, Hydromega Services Inc., on four 5.5 MW hydroelectric porjects (Big Beaver Falls; Camp Three Rapids, White Otter Falls; Old Woman Falls) which are currently under construction. Davies' role has included:

- negotiating all agreements for the construction and operation of the facilities
- acquiring land rights from the Ontario Crown and private landowners
- acquiring easements for the transmission line that crosses land controlled by private landowners, the Crown, and the First Nations communities
- acquiring the water power leases
- acquiring permits

Pattern Energy Group LP/Samsung Wind Farm Project. Acted for Pattern Energy Group LP in the establishment of its joint venture with an affiliate of Samsung C&T Corporation. The joint venture was formed to develop and operate up to 2,000 MW of wind power generation projects under the Ontario Feed-in Tariff Program and Samsung's Green Energy Investment Agreement with the Government of Ontario. Up to 600 MW of wind turbines will be supplied to the Pattern-Samsung joint venture. Davies role in the Pattern-Samsung joint venture has included:

- review of transmission and distribution line matters
- renewable energy approval compliance
- representation at Environmental Review Tribunal hearings on opposition to South Kent and Grand Renewable Wind project

Umbata Falls Hydroelectric Project, Ontario. Davies acted for BMO Nesbitt Burns Inc. in connection with its financing of the construction and operation of the run-of-the-river 23.6 MW hydroelectric facility at Umbata Falls in Ontario. Davies conducted due diligence on all aspects of the project including:

- Aboriginal consultation and agreements
- environmental impact assessment
- permitting
- transmission and distribution lines

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

- ***design;***
- ***engineering;***
- ***material and equipment procurement;***
- ***right-of-way and other land use acquisitions;***
- ***licensing and permitting;***
- ***consultations, both with First Nation and Métis, and other communities***
- ***construction;***
- ***operation and maintenance;***
- ***project management;***
- ***safety;***
- ***environmental compliance; and***
- ***regulatory compliance***

Founded in 1892, the Fortis utility business in Ontario has 120 years of providing quality service. Fortis currently operates 7,285 km of transmission lines, and 182,233 km of distribution lines.

- **Design**: Fortis is a member of Utilities Standards Forum ("USF"). USF enhances their member's ability to develop industry best distribution practices and meet legislated requirements. Fortis typically utilizes qualified consulting companies for transmission design.
- **Engineering**: Fortis maintains a staff of Professional Engineers in each of the individual utility members mentioned in Section 2.1. Engineers at those utilities manage the system planning, line and station designs, construction, and operation of its Transmission, and Distribution facilities. Engineering staff is responsible for compliance with applicable codes, guidelines, and standards including, but not

limited to NERC, CSA, ASCE, ASTM, ANCI, IEEE, IEC, and the Ontario Energy Board "*Transmission System Code*."

- **Material and equipment procurement**: Fortis operates both a central purchasing department and local purchasing agents. Storerooms are operated at multiple locations around the system. Evidence applicable to Fortis includes:
    - The staff participates and trains through the Purchasing Management Association of Canada (PMAC)
    - An Internal Purchasing Policy has been established which includes routine tendering and competitive bids for materials and equipment.
    - Fortis utilizes Engineer, Design, and Procure ("EPC") on certain larger projects.
    - Fortis occasionally completes the engineering and permitting and bids contracts for Procurement and Construction.
    - Inventory management is through its scalable SAP computerized system.
    - Inventory levels are established using standard materials and strategically located storerooms. CNPI's sister utility Algoma Power Inc. has an established storeroom, pole yard, and staging area established in Wawa Ontario. It is expected that this strategic location can be utilized to harbor materials and critical spare equipment for the eastern portion of the East-West Tie.
- **Right-of-way and other land use acquisitions**: FortisOntario operates approximately 3,300 km of Right-of-way, of which 1,800 km is located in northern Ontario. The Engineering Department is responsible for acquiring all permits, agreements and easements that will result in a continuous strip of constructible right-of-way.
    - Fortis has a set of guiding principles that are followed in negotiations.
    - Fortis has standard documents in place for multiple types of necessary acquisition.

  - Easements, permits and other agreements are managed in a GIS environment identifying fixed duration easements and agreements which need to be renegotiated.
- Fortis has an internal staff of technicians that perform the following key activities:
  - Search Registry and Land Titles office to confirm ownership and status of property title.
  - Determine the valuation of easements considering land costs, potential crop damage, disturbance damages and injurious affection.
  - Engage in property owner negotiations to secure agreements. Prepare agreement documents and produce sketches to deliver to property owners.
  - Assign value to, and establish temporary easements for work space to be used during construction and access agreements required for sections not accessible by road.
  - Coordinate survey resources for creation of reference plans, profiles plans and other necessary plans for use in permitting, agreements and easements. Ensure accuracy and manage timelines of surveying projects.
  - Permitting with the Ministry of Natural Resources of Ontario, Natural Resources Canada and Fisheries and Oceans Canada, where applicable, for construction and crossings over crown lands, rivers, waterways and streams.
  - Permitting with the Ministry of Transportation, municipalities or local roads boards for right-of-way which encroaches onto highway and road corridors.
  - Permitting and/or easements for crossings over or onto railway lands with applicable rail companies.

- **Licencing and permitting**: FortisOntario has extensive and varied experience in the areas of Licencing and Permitting.

Land Use Licensing and Permitting

Fortis attains all required licensing and permitting required for land use. Examples include:

- Land Use Permits for occupation of First Nation Reserve Lands,
- Land Use Permits for occupation of Crown Lands (Issued by the Ontario Ministry of Natural Resources),
- Encroachment permits for installations along the public roadway corridors (Issued by the Transportation Corridor Office, Municipalities or Local Roads boards),
- Railway permits or easements for encroachment or crossings (Issued by each rail company).

Specifically in Ontario, distribution circuits cross First Nations reserve land. Fortis maintains access for sub transmission circuits through *Indian Act* Section 28.2 permits. These permits have a term and require periodic updates. Experienced staff has been working with local First Nations as required. There is currently one permit that has to be renewed and another that is being updated to reflect a periodic land valuation review.

Energy Regulatory Licencing

FortisOntario holds current Ontario Energy Board Licences related to its Distribution Operations (ED-2009-0572, ED-2004-0405 & ED-2009-0072), its Transmission Operations (ET-2003-0073) and its Generations Operations (EG-2003-0107) in Ontario. FortisOntario has maintained compliance with these various Licences and executed all necessary requirements to keep them up to date.

Other relevant experience includes the negotiation and completion of:

- Water Licence Agreements
- Power Exchange Agreements
- Water Use Agreement with Ontario Power Generation
- Energy Supply Agreement

- Franchise Agreements

These are examples of Fortis's direct involvement with the negotiation and execution of various licencing and permitting instruments in Ontario. Fortis has similar extensive experiences in North America and the Caribbean.

- **Consultations, both with First Nation and Métis, and other communities**
  Fortis has a published policy for dealing with First Nation, Métis and other communities. Fortis employs personnel who are specifically responsible for consultations and compliance to the policy. Fortis also utilizes external consultants to engage in consultations with First Nation, Métis and other communities. Both the Leave to Construct application and the Environmental Assessment contain requirements for consultations. Fortis has completed those requirements multiple times on previous projects. The Neegan Burnside team assembled for this project has many years of experience in consultation and direct work with both First Nations and Métis right across Canada. As a recent example, Fortis has engaged in consultations with the Robinson Huron Treaty communities in connection with the MOU that it has entered into with LHATC. Numerous meetings with Chiefs and communities have occurred to discuss the opportunities to be provided by the CNPI transmission joint venture and to keep them apprised of the East-West Tie proceedings.

  Fortis in its northern Ontario region is engaged in annual community stakeholder meetings to share certain operational and capital plans and to receive comments on those plans.

- **Construction**: Fortis achieves quality in service through good planning and good construction. Some evidence of that includes:
  - To reduce the risk of construction issues, Fortis works only with well qualified contractors. The majority of construction is completed by internal

construction crews that are well equipped and well trained to provide quality construction in a safe and cost effective manner.

- Fortis also maintains construction managers and inspectors that monitor construction projects to confirm compliance with the approved designs and specifications and to discover areas where changes to standards and procedures may be applicable.
- Evidence of long term good construction practices is provided through the reliability metrics.
- Electrical Safety Authority letters verifying Compliance Assessment are attached to this application in Appendix I.

- **Operation and Maintenance:** Fortis owns multiple operation centers through Canada. Facilities located within Ontario include:
    - Fort Erie Service Centre
    - Gananoque Service Centre
    - Wawa Service Centre
    - Sault Ste. Marie Service Centre
    - Desbarats Service Centre
    - Cornwall Service centre

System Operations

Day to day system operations are managed by two segregated control rooms within FortisOntario. Utilizing a SCADA system, remote monitoring and control is managed along with day to day trouble calls and dispatch. These control rooms dispatch both transmission and distribution crews. Control room operators also communicate directly with both Hydro One and IESO concerning planned or forced outages that may impact the IESO controlled grid.

The experienced transmission and distribution crews located at the Wawa Service Center along with its helicopter partners in Wawa and Marathon will allow for a quick response to any trouble issues along the proposed East-West Tie. These crews will also be involved in the routine maintenance of the East-West Tie.

Asset Management

CNPI has policies and procedures in place to manage the maintenance of transmission assets. During the development stage of the East-West Tie project CNPI will develop a maintenance plan specific to the new line.

Management of the existing transmission asset includes:

Asset Condition Assessment, on a set schedule, utilizing the following tools and procedures:

- Steel structure corrosion surveys
- Ground and climbing inspections
- Detail helicopter inspections
- Infrared scans
- LiDAR data collection
- Conductor and shield wire assessment and testing
- Line and structure hardware assessment
- Insulator assessment
- Electrical clearances (using LiDAR and field measured data)
- Vegetation conditions and tree heights/ROW width assessment

Maintenance of transmission and distribution assets includes:

- Wood pole treatment to extend pole life
- Switch maintenance
- Access road maintenance
- Vegetation and Right-of-way Maintenance

Vegetation maintenance is a key reliability performance factor for transmission lines. Fortis has experienced personnel in both managing a Transmission Vegetation Management Program (TVMP) and performing the various work activities to achieve the objectives of a TVMP. This program is also utilized for access road and trail maintenance.

Currently in house vegetation managers and planners, who are experienced and certified in Integrated Pest Management (IPM) or commonly referred to as Integrated Vegetation Management (IVM), utilize industry best management practices, documented vegetation management programs, work procedures, specifications and processes to ensure vegetation around electrical equipment is managed in a safe and reliable manner. Utilizing these IPM/IVM best management practices and vegetation management programs would support Fortis in ensuring compliance with Transmission Vegetation Management NERC Reliability Standard FAC-003-1, as well other regulatory requirements such as but not limited to *Pesticide Act, Species at Risk Act, Migratory Birds Convention Act* affecting vegetation management activities.

Criteria for determining the scope of vegetation management

- Bush height and density
- Hazardous tree clearances
- Tree growth rates

A computerized Vegetation Management System (VMS) on a GIS platform is currently being developed to assist in managing the following information:

Activities and Land data:

- Number of tree removals
- Quantity of herbicide
- Landowner information
- Sensitive areas (ie wetlands, parks, migratory birds, etc)

Using the VMS maintenance activities are tracked and analyzed for reporting and to set annual work objectives and priorities.

Fortis has sections of their distribution system in Northern Ontario which are remote, off road and heavily forested. Fortis has local knowledge regarding forest type, tree species, characteristics and growth rates and manages these areas similar to a transmission system (annual line clearing and brush control projects, scheduled inspections, hazardous tree response process).

Fortis uses operational control procedures, which are based on the best management practices such as the ANSI A-300 in order to achieve the program objectives utilizing the following resources:

- Internal Utility Arborist Trades
- External contractors utilizing both Utility Arborist and general labour
    - Qualified Contractors
    - First Nations Contractors

Vegetation Environmental Leadership

API actively participates in the research project Corridors for Life (CFL). CFL focuses on assessing and developing improved management practices for maintaining utility corridors in Northern Ontario. The project incorporates IPM/IVM principles, recovery strategies for species at risk, Traditional Ecological Knowledge and has partnership between industry, government (MNR), educational institutions (Sault College and Algoma University), and First Nations. The CFL project is one of the mechanisms Fortis is involved with to ensure conformance with their Habitat Stewardship Program and lessons learn through this research project could be applied to other transmission corridors.

Asset Replacement and Capital Program

Criteria include the following:

- Asset replacement based on its condition

- Risk based asset replacement (safety, environmental, operational)
- Life cycle cost replacement
- End of life asset replacement

Fortis utilizes a systematic, long term capital replacement strategy for each of its utilities. Newfoundland Power recently filed their Transmission Line Rebuild Strategy, which is a plan to replace certain sections of aging transmission lines. The plan development includes a review of risk factors and risk mitigation through the use of industry best practices. This proactive approach to managing transmission assets is expected to improve reliability over the long term.

- **Project management**: Fortis maintains a Manager of Major Projects, who has responsibility for the project management process that fall into executing, controlling, and closing the project. Budget and schedule are traditionally the most monitored project constraints. CNPI has SAP software fully integrated as the system that facilitates budget controlling and reporting. On larger projects the schedule is monitored through scheduling software tools. The Manager is also responsible for management of the scope, risk, quality, and communications. Additional support is utilized for human resource and procurement, possibly through EPC type projects.
- **Safety, Environmental compliance**: An integral component of CNPI's operations is its Health, Safety & Environment ("HS&E") department and its systematic approach to proactively managing safety and the environment.

  CNPI utilizes an integrated management system for HS&E, consistent with the international standards of OHSAS 18001 (Health & Safety) and ISO 14001 (Environment) and developed within the context of CNPI's structure. The management system is based upon the premise of "Plan, Do, Check and Act". Fortis conducts regular independent audits which confirm that it is in compliance with Health & Safety and Environmental legislation, international standards, as well as conformance with its own policies and procedures.

Safety and Environmental compliance standards have been developed based on a foundation of a strong Internal Responsibility System. This is a key value contained in the *Occupational Health and Safety Act*. All HS&E responsibilities are identified through the management system and have been clearly assigned to constituents within CNPI including: the Board of Directors, the Executive, Departments (Managers, Supervisors and workers) and Committees (Executive Environmental & Safety Committee, Central Environment & Safety Committee, Joint Health & Safety Committee and Environmental Leadership Team). CNPI's HS&E department consists of full time employees with HS&E and combined Forestry and HS&E responsibilities managing the Fortis business units across Ontario. Each of these utilities and service territories inherently possess unique HS&E challenges associated with their geographical location and operational differences, and benefit from a standardized approach to managing HS&E. Fortis has published Health & Safety and Environmental manuals, procedures and policies.

The following is an overview of the CNPI HS&E departmental functions.

- Hazard Assessment
- Legal Compliance
- Performance Indicators
- Training
- Audits

One of the core principles consistent to both of the standards associated with the CNPI HS&E management system is the need for continual improvement. The HS&E department explores new ideas and facilitates recommendations to improve the system, and to promote HS&E responsibility. In an industry in which technology is evolving rapidly, and in an environment where CNPI's workers are exposed to risk, it is imperative that CNPI continues to commit the appropriate resources to sustain its current level of HS&E performance. In that regard, CNPI's transmission business has experienced zero (0) high risk lost time injuries in more than a decade.

- **Regulatory compliance**: The Regulatory department provides guidance on regulatory requirements for the company to maintain compliance. CNPI uses internal resources to perform the majority of these functions which also enhances the development of in-house regulatory competency rather than relying on third-party consultants for the core regulatory functions.

  Regulatory compliance is demonstrated through various documents ranging from permits to self-certification. For example, the self-certification of Affiliate Relationships Code compliance that was filed for 2012.

Additional evidence of the good utility practice of CNPI includes:

Human Resources

Headquartered in Fort Erie, the Human Resources department has corporate responsibilities throughout the organization. The priorities of the department are to ensure adequate staffing levels, succession planning with a focus on employee development and on-going labour relations.

A leadership coaching and development training program has been offered to a number of management and supervisory employees to further evidence their management and leadership skill set.

Health plan cost management, workplace safety and insurance board administration, and other benefit related activities are managed by the Human Resources department. The company maintains a modified return to work program and regularly tracks, reports and manages human resources in an effort to remain aligned with corporate objectives.

CNPI maintains positive labour relations with its represented employees and has a cooperative working relationship with union leadership.

Corporate Communications and Community Involvement (Community Relations)

Community involvement and public relations remain an important core value of CNPI. Continued local community involvement in selective focus areas will aid in achieving the goal of being recognized as a valued member of the community served.

CNPI has participated in a number of Conservation and Demand Management programs in conjunction with provincial programs. CNPI continues presenting School Safety and Conservation programs for local elementary students. Each school within the service territory is scheduled to have the presentation every fourth year.

Finance

The Finance department supports all back office operations of the company. Located centrally in the Fort Erie office, the Finance department is responsible for all company accounts payable, payroll and financial reporting. In addition, the department is responsible for all wholesale settlement, OEB data collection and reporting as well as monthly financial statements.

4.5 A description of:

- ***the challenges involved in achieving the required capacity and reliability of the East-West Tie line, including challenges related to terrain and weather;***
- ***the plan for addressing these challenges though the design and construction of the line (e.g. number and spacing of towers, planned resistance to failure).***

Four documents (collectively referred to in this application as the "Minimum Design Criteria") have been published that define the required capacity and reliability of the proposed East-West Tie:

- *IESO Feasibility Study*, Report 0748, August 18, 2011

- Ontario Energy Board *Minimum Technical Requirements for the Reference Option of the E-W Tie Line,* dated November 9, 2011
- *Appendix A, Minimum Design Criteria for the Reference Option of the East – West Tie Line (230kV Wawa to Thunder Bay Transmission Line),* dated 9 November 2011.
- Ontario Energy Board letter to registered transmitters dated December 10, 2011

IESO Feasibility Study, Report 0748, indicates the required capacity of the East-West Tie as follows: *"The new line in conjunction with the existing tie is to provide total eastbound and westbound capabilities of the order of 650MW, while respecting all NERC, NPCC and IESO reliability standards."* The design capacity is restated in *Appendix A, Minimum Design Criteria.*

The following is taken from the *Minimum Technical Requirements for the Reference Option of the E-W Tie Line:*

> *"The purpose of these Minimum Technical Requirements is to specify general design concepts to be used in the design and costing of the reference option of the E-W Tie transmission line.*
> *These Minimum Technical Requirements are supplemented by Appendix A to this document which provides further technical specifications for the reference option of the E-W Tie.*
>
> *This document is not intended as a detailed design specification or as an instruction manual for the E-W Tie Line and this document shall not be used for those purposes. The designated transmitter, its employees or agents must recognize that they are, at all times, solely responsible for the design, construction and operation of the E-W Tie."*

CNPI understands that good utility practices were followed by the IESO and OEB to determine the capacity of the existing line and to determine the correct conductor size (and reactive support at stations) for the proposed new parallel line. CNPI understands the requirement that all of the published data will be carefully checked, reviewed, and discussed during the Leave to Construct application.

Appendix A, Minimum Design Criteria dictates design safety factors that are appropriate for the terrain and weather conditions experienced in this area. However, the standards are considered as minimum. CNPI will consider additional standards above the minimum.

Access difficulties related to the terrain will increase the initial construction cost, but must also be considered in the reliability of the line. The restoration time for outages will likely be lengthy because of the multiple remote locations.

- The number of outage occurrences can be greatly reduced by proper right-of-way vegetation management. Also, wider, or extra width, cleared right-of-way contributes positively to reliability. Extra width right-of-way clearing will be considered, particularly in remote areas and areas with steep adjacent side hills. (Commonly described as producing “danger trees”). These issues will be studied and resolved during the design.
- Construction of “permanent” access roads to remote areas may be considered to reduce expected restoration times.
- The Wawa Service Centre of Fortis, located within a few kilometers of Wawa Transformer Station, is equipped with appropriate line maintenance vehicles for use in this terrain during multiple weather conditions. Additional staffing will be carried out as required during the project.
- Fortis has existing contracts in place with helicopter companies for quick line patrols during outage events.
- Fortis has contracts in place with construction contractors to supplement the crew located at Wawa.
- Fortis has contracts in place with HONI that will be expanded to allow support from HONI when or if it is appropriate.

- A capitalized inventory of towers may be maintained. CNPI will consider partial assembly of those towers to the point that is applicable for helicopter delivery to facilitate efficient tower restoration.

Loadings for extreme weather conditions are defined in the Minimum Design Criteria. Based on further analysis, additional loading areas may be defined for Ontario beyond those specified in CSA C22.3. Analysis may indicate that loading criteria or spacing criteria in excess of the Minimum Design Criteria is appropriate for all of the line or for particular sections of the line.

The Minimum Design Criteria indicate a maximum span of 385 meters. Cost estimates in this application consider 300 meters as an average. The existing double circuit Lakehead to Wawa 230kV line has a history of losing both circuits on a single event, which has been noted in the OPA's *Long Term Electricity Outlook for the Northwest and Context for the East-West Tie Expansion* dated June 30, 2011 (page 12 of 21). Reliability issues of the existing double circuit line will be carefully reviewed for "lessons learned" with a goal to reduce the probability of similar occurrences on the new line.

5. Financial Capacity

The applicant must demonstrate that it has the financial capability necessary to develop, construct, operate and maintain the line. To that end, the applicant shall provide the following:

5.1 evidence that it has capital resources that are sufficient to develop, finance, construct, operate and maintain the line;

The Applicant, CNPI is a wholly owned subsidiary of FortisOntario, which is wholly owned by Fortis. Interim financing for this project will be provided by Fortis.

Fortis is the largest investor-owned distribution utility in Canada, with total assets of $14 billion and 2011 revenues of $3.7 billion. Fortis shares are listed on the Toronto Stock Exchange and trade under the symbol FTS.

Fortis has sufficient capital resources under its $1 billion committed revolving corporate credit facility to finance this project. There will be no requirement for new bridge financing or to initially access capital markets to raise funds to finance this project. As utilization of the credit facility increases, Fortis will term-out the short-term debt with a combination of common equity, preferred equity and fixed rate long-term debt. Over the period January 1, 2008 and November 30th, 2012 Fortis Inc. has raised more than $2.3 billion in long-term capital including more than $1.2 billon in common equity.

In May 2012 Fortis filed a base shelf perspectus under which Fortis may, from time to time during the 25 month period from May 10, 2012, offer, by way of a prospectus supplement, common shares, preference shares, subscription receipts and/or unsecured debentures in the aggregate amount of up to $1.3 billion (or the equavalent in US dollars or other currencies). The base shelf perspectus provides the corporation with flexibility to access long-term Canadian capital markets in a timely manner. The nature, size and timing of any offering of securities under the Corporation's base shelf perspectus will be consistent with the past capital raising practices of the Corporation and continue to be dependent upon the Corporation's assessment of its requirements for funding and general market conditions.

5.2 evidence of the current credit rating of the applicant, its parent or associated companies;

Fortis Inc. carries an investment grade rating of A- from Standard & Poor's (Appendix J) and A (low) from DBRS (Appendix K). A copy of those reports and a copy of the 2011 Fortis Inc. Annual Report (Appendix L) and the 3rd Quarter 2012 Quarterly Report (Appendix M) are attached to this application as an appendix.

5.3 evidence that the financing, construction, operation, and maintenance of the line will not have a significant adverse effect on the applicant's creditworthiness or financial condition;

Over the past two-years, Fortis and subsidiaries have made capital expenditures in excess of $2 billion while maintaining strong credit ratings. The financial condition and creditworthiness is managed through targeting the long term capital structure of each regulated utility at its authorized regulated level.

Fortis maintains a consolidated structure of about 40% equity and 60% debt approximating the weighted average of the authorized capital structures of its regulated utility holdings. The maintenance of a capital structure at this level supports Fortis' strong investment grade credit ratings and its continuous access to capital markets at attractive rates.

5.4 the applicant's financing plan, including:

- ***the estimated proportions of debt and equity;***

To ensure its continued access to capital markets at attractive rates and the maintenance of strong investment grade credit ratings, Fortis targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt. This financing plan's targeted long term capital structure is consistent with the deemed capital structure for distributors and transmitters as outlined by the Ontario Energy Board.

- ***the estimated cost of debt and equity, including:***
  - ***the use of variable and fixed cost financing;***
  - ***short-term and long-term maturities; and***
  - ***a discussion of how the project might impact the applicant's cost of debt.***

Fortis will provide sufficient equity to fund the proposed project up to the level required to maintain a strong investment grade debt ratings profile. Fortis believes to achieve this objective that approximately 40% equity will be required.

Fortis continually provides equity to its operating subsidiaries to finance major capital projects. During 2011 Fortis provided approximately $180 million in common equity to its subsidiaries. In 2012, FortisBC was provided with an equity injection of $65 million in part to provide equity for its investment in a $193 million LNG storage facility. Fortis is also providing all of the debt and equity financing for Fortis's 51% partnership interest in the $900 million Waneta Hydro 230kV Transmission Project in British Columbia. Fortis will borrow approximately $300 million for its partnership share in the project the remainder will be funded with common equity.

Fortis' current indicative cost for 30-year debt ranges from 4.05% to 4.25% an attractive rate for a holding company. During November 2012, FortisAlberta, a regulated electric distribution utility subsidiary secured $125 million of 40-year debt at 3.98%. Rates will change with markets, including the underlying Canadian bond yields; however, Fortis and its regulated utility operating subsidiaries will continue to have access to these markets at attractive rates. Fortis would expect the equity return on any investment in regulated assets will be afforded a rate of return which is similar to that being set by the Ontario Energy Board.

Fortis accesses the equity capital markets on a regular basis to finance equity injections in subsidiaries, acquisitions, and for general corporate purposes. Fortis has publically issued in excess of $1.2 billion of common equity over the last 5 years. Additionally Fortis raises in excess of $60 million in new equity annually through its dividend reinvestment and other share plans.

Debt financing for the East-West Tie project will initially utilize short term credit facilities available through Fortis' $1 billion committed 3-year revolving corporate credit facility. The short term financing will be termed out with longer term 30 year financing. Financing of the East-West Tie project by Fortis will not impact Fortis' cost of debt.

5.5 if the financing plan contemplates the need to raise additional debt or equity, evidence of the applicant's ability to access the debt and equity markets;

Fortis has had and continues to have uninterrupted and solid access to long-term capital markets.

In June 2010, Fortis completed a $250 million offering of 10 million preference shares, Series H. The net proceeds of $242 million were used to repay borrowings under the Corporation's committed facility and fund an equity injection in Fortis Energy Inc.

In June 2011, Fortis issued 9.1 million common shares for gross proceeds of $300 million. The net proceeds of $288 million were used to repay borrowings under credit facilities and finance equity injections into the utilities in western Canada and the Waneta Hydro 230 kV Transmission Project in support of infrastructure investment, and for general corporate purposes.

In June 2012, Fortis issued 18.5 million subscription receipts for gross proceeds of $601 million. The proceeds will be used to finance a portion of the purchase price of CH Energy Group.

In November 2012, Fortis issued 8 million preferred shares for gross proceeds on $200 million. The net proceeds will be used towards repaying borrowings under the corporation's $1 billion committed corporate credit facility, which borrowings were primarily incurred to support construction of the Waneta Expansion hydroelectric generation/transmission facility and for other general corporate purposes.

Fortis' strong access to Canadian equity markets was best indicated when, during the financial turmoil of December 2008, the corporation was able to raise more than $300 million in common equity.

Fortis and its subsidiaries also have strong access to debt markets. In 2010, Fortis issued over $500 million in long-term debt. In 2011, Fortis issued over $300 million in long-term debt.

5.6 evidence of the applicant's 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;

Fortis is confident that it has sufficient capital resources under its $1 billion committed revolving corporate credit facility to finance the project including scope changes, cost overruns, delays, and other factors that may impact the project financing. Furthermore, Fortis has demonstrated its ability to access the capital markets should interim financing be required.

5.7 evidence of the applicant's experience in financing similar projects;

Fortis has grown from $750 million in assets to over $14 billion in assets during the last 15 years. Evidence of experience of financing similar projects to the East-West Tie includes the following:

- **Waneta Hydro 230kV Transmission Project** is a $900 million project where Fortis holds a 51% interest. The financing plan for Fortis' partnership interest is being carried out fully at the corporate holding company level and includes both the issuance by Fortis of new equity and long-term debt.
- **Okanagan 230 kV Transmission Reinforcement Project** is a $104.8 million project was financed through new long-term debt issued by the regulated utility (FortisBC) together with equity injections from Fortis.
- **Mount Hayes Natural Gas Storage/Transmission Facility** is a $193 million project being financed with the issuance of long-term debt by the regulated utility (FortisBC) together with an equity injection from Fortis and a 15% equity interest injection from the First Nations bands.
- **Nk'Mip (East Osoyoos) Transmission and Substation Project** is a $20 million project being financed with new long-term debt issued by the regulated utility (FortisBC) together with an equity injection from Fortis.

Davies has advised project proponents and financers with respect to the financing of a broad array of infrastructure projects across Canada and internationally. In particular, Davies has been involved in the financing of the following Canadian electricity projects:

- Acted for The Manufacturers Life Insurance Company in connection with the project financing of $167 million credit facilities to finance the construction of a 31MW hydroelectric project to be located on Cascade Creek north of Stewart, British Columbia.
- Acted for Hydroméga Services Inc. in connection with a bridge financing and project financing provided by Sun Life Assurance Company of Canada for the development and construction of four hydro projects on the Kapuskasing River in Ontario.
- Acted for BMO Nesbitt Burns Inc. in connection with its financing of the construction and operation of the run-of-the-river 23.6 MW hydroelectric facility at Umbata Falls in Ontario.
- Acted for General Electric Energy on its proposed construction and management of an 800 MW combined-cycle project in cooperation with Hydro-Québec Production, to be built in Beauharnois, Québec (known as the Hydro-Québec Suroît project).

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. (See Report of the Board on The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario.)

At this time, CNPI is not contemplating any alternate mechanism.

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(B) PLAN FOR THE EAST-WEST TIE LINE

6. Proposed Design

The applicant must provide an overview of its proposed design for the East-West Tie line including:

6.1 a summary description of how the Plan meets the specified requirements for the East-West Tie Line to the extent known at the time of the designation application. This could include the items listed below as well as any other relevant information the applicant may wish to provide. For items that are unknown, the applicant should describe the method and criteria for determination.

- ***length of the proposed transmission line;***
- ***number of circuits;***
- ***voltage class;***
- ***load carrying capacity;***
    - ***summer continuous rating (MVA); (Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 93ºC)***
    - ***summer emergency rating (MVA); (Based on an operating voltage of 240 kV, ambient temperature of 30ºC and conductor temperature of 127 ºC)***

For the purpose of this application, all known specified requirements in CNPI's plan for the East-West Tie Line ("CNPI's Plan") are the same as those set out in the Minimum Design Criteria referred to in the response to Section 4.5, unless otherwise specified herein.

400 km is the length of the transmission line proposed by CNPI to be constructed on a primarily parallel right-of-way to the existing 230kV line. After completing a fly-over of the existing line, CNPI has identified several locations where parallel construction may be

difficult. CNPI has considered an alternate route. Section 9.3 and 9.4 contain more detailed information on the route, including the approximate length of 425 km for the transmission line to follow the alternate route.

Consistent with the Minimum Design Criteria, CNPI's Plan would be for two (2) circuits to provide the required capacity while respecting all NERC, NPCC and IESO reliability standards.

Voltage class for CNPI's Plan is 230kV. The *IESO Feasibility Study*, Report 0748, page 9 of 86 mentions a contingency case with 250 kV, which is utilized in certain design requirements.

Capacity of the proposed conductor is taken from *IESO Feasibility Study*, Report 0748, page 11, which is 466 MVA summer continuous rating, and 599 MVA summer emergency rating.

- ***resulting total transfer capability for the East-West Tie line (MW);***

CNPI's Plan is for a total transfer capability of 650 MW, consistent with the *IESO Feasibility Study*, Report 0748, which indicates the required capacity of the East-West Tie as follows: *"The new line in conjunction with the existing tie is to provide total eastbound and westbound capabilities of the order of 650MW, while respecting all NERC, NPCC and IESO reliability standards."*

- ***anticipated lifetime of the line;***

CNPI's Plan for the anticipated lifetime of the line is 50 years.

- ***structures and conductors***
    - ***number and average spacing of towers;***

- ***tower structure types (lattice, monopole, etc.) and composition (wood, steel, concrete, hybrid, etc.);***

For the proposed 400 km line, CNPI's Plan is for 1,335 structures, which are required considering an average spacing of 300 m. The majority of this line is expected to be double circuit steel lattice towers. Double circuit steel monopoles will also be considered for this project and will probably be utilized in several areas. Double circuit steel H-frame, both tubular and lattice will also be investigated. Wood, concrete, and hybrid materials are not likely choices for this line.

After completing a fly-over of the line, a wide range of accessibility issues are expected. The installed cost of a particular structure type may vary along the route. Double circuit steel lattice towers traditionally provide the most cost effective installation. Monopole construction may be cost effective in limited areas where accessibility or other construction or right-of-way issues exist with the lattice steel.

Structure types may also be foundation specific based on the wide variety of rock or soil conditions that are expected to be encountered. From the fly-over, CNPI expects a significant portion of the foundations will be in rock. Several innovative foundation designs were recently presented at the Structural Engineering Institute of ASCE 2012 conference, *Electrical Transmission and Substation Structures Conference*, November 4-8, 2012, in Columbus, Ohio. Those designs will be considered for the East-West Tie design.

Modern design software will produce the least cost design as long as the cost of possible structure types are correctly determined. Longer spans yield fewer, but more expensive structures. Poles can be direct embedded or utilize concrete foundations. If access roads are high quality, and concrete is readily available either locally or with a portable batch plant, then concrete foundations may be preferred. Buried concrete usually produces a lower cost than buried structural steel. To insure the lowest possible cost, while maintaining structural reliability, this line will be optimized in sections with structure costs modified within the computer model to fit the specific conditions of the design section.

During the development phase, CNPI plans to consult with several line construction contractors. The final estimated cost of structure types considered in the design models will be largely influenced by input from the line construction contractors. The contractor's perceived cost and schedule risks will be mitigated as much as possible in the selection and design of structures, in efforts to obtain the lowest final project cost.

- ***conductor size and type;***

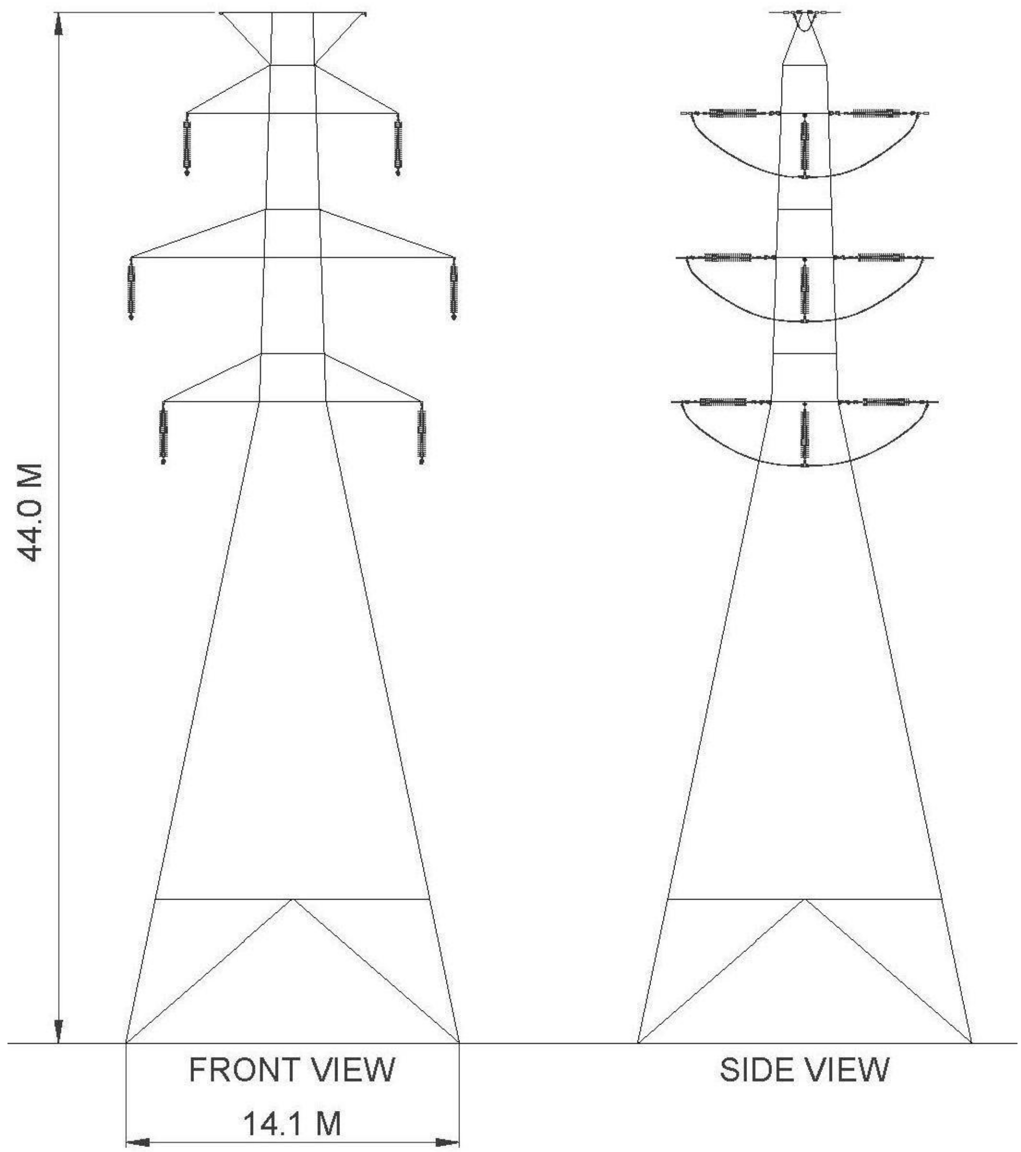
Conductor proposed by the *IESO Feasibility Study*, Report 0748, is 1192.5 kcmil 54/19 ACSR. During the development phase, final conductor selection will be confirmed based on an economic analysis considering the initial cost, expected load, and cost of losses. *Appendix A, Minimum Design Criteria for the Reference Option* lists values for several of the variables necessary to compute optimum conductor size. The criteria requests a 25 year evaluation period.

- ***protection against cascading failure and conductor galloping;***

Appendix A, Minimum Design Criteria for the Reference Option does not specify a spacing for dead end towers to limit the impact of cascade failure. As part of the development stage, CNPI will review the outage history of the existing line for cascade failure. Other utility standards for cascade failure will also be reviewed for best practice. CNPI will estimate the cost of the project based on multiple spacing criteria of dead end towers to review cost benefit ratios. After completing the fly-over of the existing line, CNPI expects that the new construction will include significantly more dead end towers than the existing line.

Tower design will include proper clearance between galloping conductor ellipses. *Appendix A*, *Minimum Technical Requirements for the Reference Option* indicate the analysis shall consider single loop galloping, regardless of span length. Line hardware designed to eliminate or reduce gallop will be considered. Operational procedures may also be reviewed for the possibility of high temperature operation to melt ice on an as needed basis.

Tower Design For Voltage Class 230 kV



TYPICAL DEAD END TOWER

- ***design assumptions;***

- A new tower series will not be developed for this project. CNPI has consulted with LocWeld, Inc., a leading manufacturer of lattice steel towers. Preliminary information indicates that modifications to an existing tower series is applicable for this project.
- Information on the existing line, station expansion plans, and outage requirements are available in a timely manner from HONI.
- Foundation requirements are unknown. Extensive geotechnical testing will be required.

- ***other relevant transmission facility characteristics.***

Installation of Optical Ground Wire (OPGW) will allow for high speed relay operation, and Supervisory Control and Data Acquisition (SCADA). Excess fiber capacity (dark fibers) may be utilized by the parallel transmitter to upgrade station relays and to replace legacy communication systems used for protection and control on the existing line and other parallel lines.

Additional excess fiber capacity may be utilized by communication companies to improve the quality and reliability of services in the adjacent areas.

6.2 confirmation that the line will interconnect with the existing transformer stations at Wawa and Lakehead, and an indication of whether the line will be switched at the Marathon transformer station.

The East-West Tie 230kV line will connect from Wawa TS to Lakehead TS, with ingress and egress at Marathon TS. HONI is responsible for station expansions required by this project. Line termination points will be carefully reviewed by CNPI with HONI to determine the correct physical location and appropriate line tensions. Preliminary design information, published by HONI, indicates that circuit breakers, breaker disconnect switches, and line disconnect switches are proposed at all three stations. Lock out, tag out procedures will allow CNPI to take planned maintenance outages independently on the two major line segments of each circuit.

6.3 a signed affidavit from an officer of the licensed transmitter to confirm:

- ***that the line will be designed to meet or exceed the existing NERC, NPCC and IESO reliability standards; and***
- ***that the line will be designed to meet or exceed the Board's Minimum Technical Requirements; or documentation of where the applicant seeks to differ from the Minimum Technical Requirements and evidence as to the equivalence or superiority of the proposed alternative option.***

The signed affidavit is attached to this application as Appendix N.

6.4 an indication as to whether the Plan will be based on the Reference Option for the East-West Tie line. Where the Plan is not based on the Reference Option, the applicant must file:

- ***a description of the main differences between the applicant's Plan and the Reference Option;***
- ***a description of the interconnection of the line with the relevant transformer stations; and***
- ***a Feasibility Study performed by the IESO, or performed to IESO requirements.***

CNPI is submitting this application based on the Reference Option as defined in the OEB letter to transmitters dated December 20, 2011, and as more particularly described in the *IESO Feasibility Study, Report 0748*, dated August 18, 2011. CNPI has reviewed the published data for alternatives, including the single circuit, and the DC circuit options, both of which require different reactive support or station additions. CNPI has also looked briefly at a submarine cable from Lakehead to Wawa. CNPI is willing to further develop those alternatives if requested. However, CNPI believes that the Reference Option is well chosen.

6.5 a brief description which highlights the strengths of the Plan, which may include:

- ***any technological innovation proposed for the line;***
- ***reduction of ratepayer risk for the costs of development, construction, operation and maintenance;***
- ***how the plan satisfies the identified need for the line at a lower cost than other options;***
- ***local benefits (e.g. employment, partnerships); and***
- ***enhanced reliability for the transmission grid.***

CNPI interprets the questions in 6.5 to relate to a plan proposed as an alternate to the Reference Option. CNPI agrees with the following: “The OPA, in their report on the *Long-Term Electricity Outlook for the North-West*, has identified scope for additional load growth in the North-West and, from their assessment of the long-term supply needs for the area, *“finds that expansion of the E-W tie is the preferred alternative based on economic, flexibility, technical, operational and other considerations.”*”.

CNPI has reviewed the Minimum Design Criteria and understands the OPA’s finding that the East-West Tie will also:

- Facilitate meeting current reliability standards in the Northwest
- Enhance operational flexibility
- Reduce losses and congestion along the East-West Tie
- Provide delivery capacity for connecting new resources in the Northwest

6.6 an indication as to whether the applicant's present intention is to own and operate the line once the line is in service.

CNPI intends to own and operate the line once it is in service. CNPI has been a long-term electricity transmission and distribution owner and operator, similar to the operating characteristics of other Fortis utilities. As an owner and operator the designated applicant develops a "hands on" working knowledge of the transmission system, unlike the circumstance where owning and operating have been contracted out once the construction has been completed. The working knowledge includes familiarity with the operating characteristics and requirements, as well as a greater ability to identify and manage risks associated with the system. This is in essence how good utility practice is developed and applied – by being the owner and the operator.

CNPI believes that owning and operating the line, as opposed to selling it after construction, demonstrates CNPI's long-term commitment to the project, as well as CNPI's confidence in quality of CNPI's construction.

The average years of experience of the members of the Fortis team assembled for the East-West Tie exceeds 20 years. Many of the management and technical team members will also continue on with the ongoing operation of the East-West Tie ranging from day-to-day operations to involvement in regulatory applications and proceedings.

Benefits to being both owner and operator include efficiencies in operations and maintenance, developing relations with landowners, First Nations and Métis, desire to maintain a professional reputation before the regulator, and dealings with other the transmission system players including Hydro One, the OPA and the IESO.

Fortis operates their existing generation, transmission and distribution facilities with an internal staff, supplemented with contractors as needed, and fully plans to continue that practice with the East-West Tie. CNPI expects to maintain existing contracts with construction companies to perform certain capital and maintenance functions. CNPI also expects to develop maintenance agreements with the parallel line owner, HONI. Fortis operates a control center that manages the existing station ties with HONI. That operation will also manage the proposed connections to HONI at Lakehead, Marathon, and Wawa.

The existing Wawa Service Centre will be the primary service location for the Wawa TS to Lakehead TS 230kV line. The Wawa facility is a fully functional maintenance centre with appropriate pole yard, material storage, truck and equipment bays, and an experienced transmission crews. These crews, working from this location, are fully capable of line patrol, inspection, trouble response, and repairs. Engineering and vegetation control support is available from the Sault Ste. Marie service centre.

7. Schedule

The applicant must file, as part of its Plan:

7.1 a project execution chart showing major milestones for both line development and line construction phases of the project.

The project execution chart for CNPI's Plan is attached as Appendix S to this application.

7.2 for the development phase of the project:

- ***a detailed line development schedule identifying significant milestones that are part of the development phase of the project, and estimated dates for completing these milestones;***

Significant Milestone	Date
Designation	Apr 2013
Begin Development	Jun 2013
Submit ToR	Jun 2014
ToR approved	Dec 2014
Submit Section 92 application	May 2015
Obtain leave to construct	May 2016
Submit Environmental Assessment (EA)	Sep 2016
Receive approval of EA	Jun 2017

- ***proposed reporting requirements for the development phase;***

Upon designation, CNPI will create a detailed schedule of development tasks (work breakdown structure) with associated estimates of hours to complete those tasks. Progress against the proposed baseline schedule will be reported as: Earned Value, Cost Variance, Schedule Variance, and other as requested or necessary. Quarterly reporting is probably sufficient, but can be adjusted as necessary or appropriate.

- ***proposed consequences for failure to meet the required performance milestones and reporting requirements for the development phase;***

CNPI proposes that failure to meet the required performance/significant milestones for the development phase resulting from the negligence of CNPI should result in loss of designation. However, milestones presented in this application are without the benefit of any detailed engineering. CNPI would expect to establish milestones with more detail and with more certainty shortly after designation. Milestones will be updated again following MOE approval of the ToR.

Failure to meet reporting requirements should result in consequences routinely asserted with failure to meet similar OEB reporting filing requirements.

- ***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***

The chart of risks includes items that have been experienced in past projects. Although the effect is classified below, small changes in project conditions can elevate one risk or another from minor to major.

	Likely	Effect
• Designation is delayed.	Somewhat	Major
• Financing not available.	Not	Major
• Legal or environmental challenges	Very	Major
• First Nation or Métis issues	Somewhat	Major
• Consultations Delays	Somewhat	Moderate
• Government review and approval delayed	Somewhat	Moderate
• Site access constraints associated with remote location and weather with resulting delays to environmental fieldwork programs	Somewhat	Moderate

- ***a description of the applicant's strategy to mitigate or address the identified risks.***

Designation is a function of the OEB, not the designated transmitter. A delay of two weeks would cause a minor effect, while a delay of two years would cause a major effect. CNPI expects that once Phase 2 of the designation process begins, interrogatories, interrogatory responses and submissions will be required from CNPI. As a mitigation, CNPI has an experienced staff in place that is prepared to process all OEB requests as quickly as possible to avoid delaying the designation proceedings.

Fortis is confident that it has mitigated any risk of financing the East-West Tie Project. Fortis has sufficient liquidity under its $1 billion revolving corporate credit facility to finance this project. No additional mitigation strategy is anticipated at this time for financing risk.

Legal, or environmental challenges typically occur for projects of this magnitude. As a proactive mitigation to address environmental and certain Aboriginal issues, CNPI has selected a highly qualified consultation team that is experienced working in Ontario to supplement its internal staff. Neegan Burnside will address environmental and certain Aboriginal issues. CNPI has retained Davies and Andrew Taylor to address legal and regulatory matters.

Consultations will be designed to promote cooperation in hopes of managing challenges to the project. As challenges do occur, they will be addressed as quickly as possible.

Government review and approval delays of both the EAA, Terms of Reference and EAA submission can be mitigated by advance consultation with reviewing authorities and the submission of complete and accurate documents. CNPI is not aware of any statement from regulatory authorities that this project will receive unusual treatment. Therefore the schedule is based on historical regulated MOE review times. Any delays in the EA approval, such as referral to the Environmental Review Tribunal shall be mitigated by the combined skills from Neegan Burnside and Davies.

Site access delays caused by weather and limited access can delay the submittal of the EA. Those issues will be addressed when they occur. Overtime and additional resources are common mitigation methods to recover from weather delays and CNPI plans to put several teams in the field to ensure schedules are met.

Allocation of appropriate resources will be essential, particularly given the length of the route. CNPI has ensured that adequate resources are available for a project of this magnitude. CNPI has multiple local on-the-ground experts including Neegan Burnside, Northern Bioscience, KBM Forestry, TBT Engineering, and Western Heritage to address fieldwork requirements. KBM Forestry has already worked on the existing 230 kV line, and has established working relationships with the local regulatory departments and agencies, and with First Nations and Métis.

Should work fall behind schedule, or an accelerated schedule be desired, then some key project components may be undertaken out of sequence. For example EA related fieldwork schedules could be accelerated by initiating some fieldwork activities prior to ToR approval. Because of added risk, approval by regulatory bodies and the proponent would be requested. Property access agreements to allow the field work would need to be in place early in the process.

7.3 for the construction phase of the project:

- ***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;***

Significant Milestone	Date
Obtain leave to construct	May 2016
Begin final design	May 2016
Begin acquisition of property rights	Jun 2017
Place preliminary material orders	Jul 2017
Begin clearing	Dec 2017
Begin foundation installation	Mar 2018
Begin structure installation	Aug 2018
Begin wire installation	Dec 2018
In service for line	Dec 2019

- ***proposed reporting requirements for the construction phase;***

Performance reports will be issued for:

- Planned versus actual schedule performance
- Planned versus actual cost performance
- Variance analysis on cost and schedule, with corrective recommendations if applicable
- Forecasts on cost and schedule completion
- Project Issues
    - Change orders
    - Easement issues
    - Material shortages
    - Environmental issues
    - Safety

CNPI will provide real time progress reporting on construction through its existing website.

- ***proposed consequences for failure to meet the required performance milestones and reporting requirements for the construction phase;***

CNPI expects that the Board's leave to construct decision and order will be subject to conditions of approval. Typically, such conditions of approval include performance milestones and reporting requirements for the construction phase. In the normal course, failure to meet such performance milestones and reporting requirements would be reviewed by the Board on a case-by-case basis and could result in the revocation of leave to construct. CNPI would expect to be treated in the same manner should it fail to meet the performance milestones and reporting requirements contained in the conditions of approval to its leave to construct.

- ***proposed in-service date for the line (can be 2017 or another date);***

An in-service date of December 2019 is expected by CNPI based on the typical schedule for a project of this size, and CNPI considers that as the appropriate schedule. If designated, CNPI will attempt to expedite the completion of the project to the best of its abilities.

The in-service date of 2017 proposed in HONI's planning documents assumed a starting date of late 2009. With three years of the originally proposed productive schedule passed, 2017 is not realistic under current legislative and regulatory requirements.

- ***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***

	Likely	Effect
• Prolonged adverse weather conditions	Very	Moderate
• Material Shortages	Somewhat	Moderate
• Skilled labour and equipment shortages	Somewhat	Major
• Difficult access to structure locations	Somewhat	Moderate
• Property acquisition	Somewhat	Moderate

- ***a description of the applicant's strategy to mitigate or address the identified risks.***

Risk strategy involves either acceptance of the risk, mitigation of risk, or transfer of the risk. Adverse weather cannot be avoided. The adverse impact will be minimized by proactively creating a construction schedule considering the average number of annual working days reasonably available, with full consideration given to weather. Prolonged, or days in excess of average will be addressed as if they occur, typically through overtime. Material shortages usually happen because of long lead times. An appropriate mitigation strategy is to proactively reduce the probability or impact of adverse events. Early identification of those issues is essential so that orders are placed allowing for the required extra time, reducing the probability of an adverse impact on the project.

The probability of a skilled labour shortage will be minimized:

- Because of the magnitude of the project, labour will typically recognize an opportunity for stable employment.
- CNPI has plans to operate a Skill Builder program for First Nations and Métis candidates to increase the size of the skilled labour pool. Please refer to Section 3.1 for a description of CNPI's Skill Builder program.
- Multiple construction contractors will be utilized by CNPI for this project. The line will be bid in logical sections. Only stable, well qualified contractors will be allowed to bid. Involving multiple contractors will reduce the probability of a skilled labour shortage.
- Cost incentives may be considered to promote a reliable and timely performance from construction contractors. Both a bonus for early completion and penalties for late completion could be considered.

Difficult truck and crane access to structure locations is a common problem. Certain structures may require more time to complete than others. Helicopters will likely be used to set several, if not all, structures. (Access is still required to install foundations and tower legs.) A variety of structure types will be uniquely considered to mitigate the impact of difficult location as much as possible. CNPI recently completed a fly-over of the existing transmission line. The section from Marathon to Wawa is particularly remote. CNPI will carefully analyze an alternate route after designation that will greatly enhance access to structures, thereby reducing the installed average cost of the structures.

The property acquisition team will be trained and correctly staffed to complete the work as scheduled. Standards will be established to insure that each property owner is treated in a similar fashion. Section 9 of this application details the plans for obtaining property rights. Expropriations are expected to occur in few (if any) cases. If necessary, construction in those areas can be deferred initially, but any expropriations must be resolved for final completion of all construction.

7.4 evidence of the applicant's past experience in completing similar transmission line or other infrastructure projects within planned time frames. Such evidence could include a comparison of the construction schedule filed with a regulator when seeking approval to proceed with a transmission line project and the actual completion dates of the milestones identified in the schedule.

- **Okanagan Transmission Reinforcement Project** is the most recently completed Fortis project. The substantially complete report was filed in October, 2011 (confidential document). The document includes the approved and actual values for cost and schedule. The project was completed on schedule and under budget. No significant issues were encountered with stakeholders, the public, or First Nations.

- **Newfoundland Multi-Year Transmission Line Rebuild Project** is a multi-year transmission line rebuild project that is being completed within planned time frames consistent with the schedules being filed with the regulator.

- **Mount Hayes Natural Gas Storage/Transmission Facility** achieved the original schedule to have a full tank of LNG available and ready for use on Nov 1, 2010. In addition to that, FortisBC met all key contractual milestone dates to supply construction power, permanent facility power and natural gas to the EPC

Contractor at site to facilitate construction and commissioning of the LNG Facility per the original schedule.

- **Nk'Mip Substation Project** was placed in service in 2006 and was completed in December 2007. The final completion report was filed in September 2008 (confidential document). The document includes the approved and actual values for cost and schedule. The project was completed on schedule. No significant issues were encountered with stakeholders, the public and First Nations.

- **Big Sandy – Inez 230 kV Transmission Project.** The original in service date of December 31 was extended by two weeks to avoid working through the Christmas holidays. The extension was easily approved because the terminal station, by others, was three months behind schedule. The project was completed on January 15, but not placed into service for an additional three months.

- **Laredo VFT Project.** The line and station projects were scheduled for completion on April 1, which is a summer critical date for southern Texas. The project was placed into service ahead of schedule on March 28.

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

CNPI has already begun obtaining project partners with First Nations to develop this project. Appropriate relationships with these partners are expected to be in place prior to initiating the ToR, which will accelerate completion of the Environmental Assessment.

CNPI has consulted with construction contractors and with the leading fabricator of lattice steel towers. CNPI plans to complete extensive consultations with these parties during the design stage in efforts to convert their expert judgment into a savings of time and money to be realized during construction.

CNPI plans to split the construction into sections and to engage multiple qualified and experienced construction contractors.

CNPI has fully integrated the SAP Business Suite which is currently used in its operations. Procurement, material tracking, contracts, and cost reporting for this project will all be managed through existing SAP functions in place at CNPI. Timely, accurate reporting will contribute to the efficiency of the project.

CNPI is proposing the use of innovations that leverage technology throughout the East-West Tie Project and beyond. Material tracking can be challenging with major projects that have large, high value assets spread over multiple sites or great distances. These assets can be misplaced or simply lost which leads to unplanned project costs. SAP Global Positioning System ("GPS") technology uses asset tags and smartphone scanning to mark the GPS location of such assets before they are deployed in the field. This form of asset tracking provides an ability to remotely monitor the location at any point in time and can be viewed with a user friendly Google Maps interface or through various mobile devices such as tablets or smartphones by operations personnel. CNPI is also proposing to use SAP Available to Promise ("ATP") functionality that can be programmed to track when certain items are scheduled to arrive or leave the warehouse. This enables more accurate delivery times when inventory is shipped while locating trouble spots where inventory is at risk. This is integrated with SAP's event management to invoke security alerts and provide notification if inventory is removed at the wrong time, either intentionally or by accident, thereby cutting down on loss from theft and/or mishandled assets. The combined impact of this innovation will minimize schedule delays.

A complimentary technology that also supports project management is CNPI's Global Information System ("GIS"). CNPI is planning to utilize this technology for the East-West Tie. The built-in project management tools allow project team members to access the same geospatial data for their own specific purpose including planning, construction, analysis, asset management, vegetation management, and operations. This graphic representation of the transmission assets and right-of-way provides data that is relevant to the operation of the equipment, reliability monitoring and controls, outage management, as well as planned preventative and predictive maintenance, resulting in lower costs to ratepayers.

8. Costs

As part of its Plan, the applicant must file a summary of the total costs associated with the Plan, divided into development costs, construction costs and operation and maintenance costs. In addition, the applicant must file:

Project Name:	**East West 230kV Tie Line**	***Date of Estimate:***		**1/4/13**
Project Location:	**Ontario, Canada**	***Proposed Service Date:***		**12/12/19**
Line Length:	**400 km**			
		Material	Labour	Total
Development:				
Environmental Assessment, Regulatory approvals			3,996,000	3,996,000
Section 92 Application				
Preliminary Engineering and Design			7,420,000	7,420,000
Consultations and Participation			5,760,000	5,760,000
R/W research and options			2,995,000	2,995,000
Financing, Legal			960,000	960,000
Project Managenment			1,440,000	1,440,000
Subtotal			22,571,000	22,571,000
Contingency	10%			2,257,000
Total Development				24,828,000
Construction:		Material	Labour	Total
Development				
Final Engineering and Design			3,741,000	3,741,000
Permits			1,408,000	1,408,000
LiDAR			1,780,000	1,780,000
Subsurface investigations		-	6,400,000	6,400,000
Subtotal		-	13,329,000	13,329,000
Construction				
Purchase R/W		18,212,000	540,000	18,752,000
Project Management		-	8,640,000	8,640,000
Consultations		-	1,900,000	1,900,000
Surveys		80,000	802,000	882,000
Clearing		455,000	9,105,000	9,560,000
Environmental		534,000	2,670,000	3,204,000
Roads		935,000	10,605,000	11,540,000
Foundations		27,570,000	41,910,000	69,480,000
Steel Structures		136,748,000	80,100,000	216,848,000
Structures assemblies		8,474,000	24,030,000	32,504,000
Conductor & Shield Wire		28,050,000	28,340,000	56,390,000
Stations (3 stations)		-	-	-
Inspection		-	3,600,000	3,600,000
Subtotal		221,058,000	212,242,000	433,300,000
Contingency (Risk acceptance)	20%			86,660,000
Total Construction				533,289,000
Interest during construction				50,680,000
Grand Total Construction				583,969,000
Total Development and Construction				608,797,000

A copy of the summary of total costs has also been included as Appendix X of this application.

Development:	24,828,000	4%
Construction:	583,969,000	96%
Total Project	608,797,000	
Average annual O&M	974,000	

Development cost above is all cost prior to receipt of the Leave to Construct.

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

CNPI has already spent $200,000 on the preparation of the designation application. CNPI estimates that, depending on the complexity and length of the Phase II designation proceedings, it will incur additional costs of $50,000 to $100,000 to achieve designation.

8.2 the estimated total development costs of the line, broken down by the following categories of cost:

- ***permitting, licensing, environmental assessment and other regulatory approvals***
- ***engineering and design***
- ***procurement of material and equipment;***
- ***costs of the acquisition of land use rights, First Nation and Métis participation, and consultations with landowners, municipalities, the public and First Nation and Métis communities;***
- ***contingencies; and***
- ***other significant expenditures.***

		Material	Labour	Total
Development:				
Environmental Assessment, Regulatory approvals			3,996,000	3,996,000
Section 92 Application				
Preliminary Engineering and Design			7,420,000	7,420,000
Consultations and Participation			5,760,000	5,760,000
R/W research and options			2,995,000	2,995,000
Financing, Legal			960,000	960,000
Project Managenment			1,440,000	1,440,000
Subtotal			22,571,000	22,571,000
Contingency	10%			2,257,000
Total Development				24,828,000

Cost of material procurement and permits is estimated in the construction costs.

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 basic assumptions are listed below. Significant additional detail to the assumptions, including an EA scope of work and a listing of required permits is included to this application as Appendix O.

- Terms of Reference will take one year to submit and receive approval.
- Environmental Assessment will take approximately 3 years to complete, including MOE review and approval.
- The Section 92 application will take 16 months to prepare, submit, and receive approval.
- HONI provides detailed site plans for the proposed station expansion projects in a timely manner.
- Environmental Review Tribunal Hearings or mediation if required would require additional time to achieve EA approval.

- Archaeology Stage 2, 3, 4 studies are undertaken outside EA process Stage 2 study is likely and is included in the estimate. Stage 3 and 4 studies may be required, and are typically covered by contingencies.
- Additional studies, prior to construction, may be required as a condition of permits.

Multiple project management tools will be utilized to manage the cost of development. After designation, a detailed baseline schedule of development tasks will be created. A budget will be associated with each task. Tools used to measure the performance will include:

- Earned Value (Assuring the value of work justifies the cost of spending.)
- Budget at Completion (Budget Forecast)
- Variance Reporting

The response to variances is critical.

- For work performance issues, the cause must be discovered and understood to allow changes or improvements to work procedures to be implemented.
- If scope changes have occurred or are discovered, then change requests will be promptly submitted for review. In the event that material follow up changes are required, stakeholders will be informed.

8.4 a schedule of development expenditures.

Year	Cost	Cumulative Cost
2013	5,693,000	
2014	8,763,000	14,456,000
2015	10,372,000	24,828,000

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.

	Likely	Effect
• ToR is late due to rejection and resubmission	Somewhat	Major
• Route Selection issues (Pukaskwa Park)	Very	Major
• Negative results of community consultations	Somewhat	Major
• Need for Project not approved	Not	Major
• Weather and access issues for EA field work	Somewhat	Minor

No timelines are prescribed in the EA development process, however government review times are regulated. (O. Reg. 616/98). A number of sources of delay to that process are possible including delays to regulated review times. Usually those delays are beyond the control of the applicant, although the EA process (including ToR approval) typically takes three years. Government review agency and approval time is in addition to the three years.

Each of these items is largely beyond the control of the design team and will be unknown until work begins, particularly the consultations with each class of stakeholder. Mitigation involves selecting qualified consultants to complete the work. Contingencies are included in cost estimates to offset the observed effects. The team assembled by CNPI has the capabilities and experience to ensure the development activities that are under our control will be managed as efficiently and effectively as possible. Our planning and consultation team efforts will identify critical path issues as early as possible in the work program. This will allow solutions and mitigation measures, as required, to be developed and avoid potential delays.

8.6 a statement as to the allocation between the applicant and transmission ratepayers of risks relating to costs of development. For example:

- ***if the costs of development are less than budgeted, does the applicant propose to recover only spent costs, or all budgeted costs (spent and unspent) or spent costs plus a portion of unspent cost (savings sharing)? and***
- ***if the costs of development exceed budgeted costs, does the applicant plan to seek recovery of the excess costs?***

CNPI has presented good faith estimates of cost to complete the development work. CNPI has selected experienced consultants to provide the services. However, at the time of this application, the exact scope of the work is impossible to determine, even by the most experienced staff.

If the costs of development are less than budgeted, CNPI proposes to recover only spent costs. If the costs of development exceed budgeted costs, CNPI proposes to seek recovery of its budgeted costs, as well as any incremental costs that are prudently incurred (i.e. necessary costs that are not reasonably foreseeable or are beyond CNPI's reasonable control).

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;

Construction:		Material	Labour	Total
Development				
Final Engineering and Design			3,741,000	3,741,000
Permits			1,408,000	1,408,000
LiDAR			1,780,000	1,780,000
Subsurface investigations		-	6,400,000	6,400,000
Subtotal		-	13,329,000	13,329,000
Construction				
Purchase R/W		18,212,000	540,000	18,752,000
Project Management		-	8,640,000	8,640,000
Consultations		-	1,900,000	1,900,000
Surveys		80,000	802,000	882,000
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Environmental		534,000	2,670,000	3,204,000
Roads		935,000	10,605,000	11,540,000
Foundations		27,570,000	41,910,000	69,480,000
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Structures assemblies		8,474,000	24,030,000	32,504,000
Conductor & Shield Wire		28,050,000	28,340,000	56,390,000
Stations (3 stations)		-	-	-
Inspection		-	3,600,000	3,600,000
Subtotal		221,058,000	212,242,000	433,300,000
Contingency (Risk acceptance)	20%			86,660,000
Total Construction				533,289,000
Interest during construction				50,680,000
Grand Total Construction				583,969,000
Total Development and Construction				608,797,000

The level of project definition for the East West Tie falls into the Proposed Project Stage, as defined below. Therefore the construction estimate should be considered as Conceptual with a target accuracy of negative 25% to positive 50%. CNPI has completed limited preliminary engineering and completed a fly over of the project in an attempt to refine project knowledge. The results of the fly over confirmed that detailed environmental study and engineering analysis will be required to further define the project scope and resulting cost. (CNPI believes that the level of engineering completed to date is appropriate for a project at this stage in the designation proceeding.)

Project Stage	Level of Project Definition	Estimate Type	Target Accuracy
Proposed	15% to 40%	Conceptual	-25% to +50%
Planned	40% to 70%	Planning	-25% to +25%
Final Design	70% to 90%	Engineering	-10% to +10%

Cost Estimate types per project phase from AACE definition.

CNPI expects to issue two additional estimates as defined in the chart above. The Planning Estimate will be issued as the scope is further defined through the EA and Section 92 process. Approvals to proceed with design would be issued at that time. The Engineering Estimate will be issued before material is ordered and construction bid. One last approval is issued before committing to the bulk of the project cost.

Contingency reflects an amount added to the project cost estimate for project unknown and risks identified. Accuracy reflects the probability that the estimate will come within a predefined parameter (e.g. 90% confidence for the Engineering Estimate). As additional design is completed, the target accuracy improves, and the contingency will usually be decreased.

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.

This application is based on the Reference Option.

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 major risks of exceeding the estimated line construction budget pertain to scope changes and pricing changes.

- Scope Changes: The line length is the most basic expression of project scope. The actual line length will be unknown until the EA is completed. If the EA determines that the line will deviate from parallel to the existing line, then the additional length will contribute to a higher project budget. Deviations from parallel could occur in any one of the environmentally or politically sensitive areas mentioned in Section 9.3. Changes to the scope that may be dictated by the EA process can be mitigated through proper change order management.
- Pricing Changes: The table above indicates a group of commodity prices that are assumed for this estimate. With material purchasing scheduled to begin in 2015, changes to those prices can be expected. Both increases and decreases are possible. To reduce the probability of exceeding the construction budget, mitigation is expressed in contingency dollars. This estimate was prepared with a 20% contingency.

Once the project route and design are completed, a revised estimate will be submitted as part of the Section 92 application. At that time CNPI can enter into agreements with suppliers that lock the price of steel and aluminum, the two largest material cost components. This procedure will largely mitigate cost impacts due to materials pricing changes from that point forward.

Changes in the price of labour may also have large impacts to the estimate contained in this application. Risk of exceeding the construction estimate due to labour increases is also mitigated through project contingency.

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.

Okanagan 230 kV Transmission Project is a $104.8 million project. The project includes approximately 40 km of single or double circuit 230 kV line and multiple station upgrades.

Quarterly Progress Report Number 9 filed with the BC Utilities Commission on September 30, 2011, indicates that all Fortis components of the project are in service. The project was estimated in 2008 utilizing actual costs from a 2007 project. The estimate at completion of $104.8 million indicated the project was under budget. A final budget comparison indicated that equipment, material, and labour tenders were all below the estimated budget due to favorable market conditions at the time of procurement. The completion report that reflects the initial and final budgets and schedule for each of the project components is confidential, but may be available on a confidential basis if requested.

Mount Hayes Natural Gas Storage/Transmission Facility in BC is a $193 million consortium of projects, the most significant of which was the construction of the LNG facility by an EPC contractor. FortisBC managed critical path site preparation work prior to the arrival at site by the EPC Contractor. In addition, FortisBC managed the design, procurement and construction of projects that were "outside the fence" including new roads and road upgrades, retention pond, substation, power and communication lines, gas pipeline tie-ins, measurement and odorization station facilities, pipeline laterals, and other projects to enable multi-direction gas flow on the natural gas transmission pipeline. The consortium of projects were delivered on time and on budget.

Nk'Mip Substation Project in BC is a $20 million project. The project included approximately 18Km of 63 kV line, the construction of a 63/13kV substation in East Osoyoos and associated distribution feeder egresses. The projects final report filed with the BC Utilities Commission on September 30, 2008, indicates that all Fortis components of the project are in service. The project was approved for $18 million; the final cost was $20 million, an 11% variance. The project variance was primarily due to market conditions: the labour portion of the lowest bid coming in over the estimate along with increased helicopter costs.

Newfoundland Power Multi-Year Transmission Line Rebuild Project is a multi-year transmission line rebuild project being completed within planned budgets. The $20 million expended to the end of 2012 on this project is consistent with the budgets filed with the regulator.

Big Sandy Inez 230kV is a double circuit line, 37 miles. Budget for this project was approved in stages. The construction budget of $12 million (excluding engineering, permitting, right-of-way, and stations) was approved upon completion of the design. The project was completed at 91% of the budget, indicating that 1% of the 10% contingency was utilized.

Laredo Area Improvement was an $80 million project that involved the construction of the first commercially operated variable frequency transformer to provide a synchronized tie from the US to Mexico. The budget for this project was approved after completing only preliminary design work. Due the large number of unknowns, particularly concerning the first commercially operated variable frequency transformer, 30% contingencies were included. The project was completed well under budget.

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

CNPI has approached this project based on the traditional cost allocation methodology. In this methodology, if the costs of construction are less than budgeted, CNPI proposes to recover only spent costs. If the costs of construction exceed budgeted costs, CNPI proposes to seek recovery of its budgeted costs, as well as any incremental costs that are prudently incurred (i.e. necessary costs that are not reasonably foreseeable or are beyond CNPI's reasonable control).

In addition, CNPI recognizes that there are three contract models for the East-West Tie: Traditional Utility Model, Full Engineer, Procure, Construct ("EPC"), and Modified EPC. In the Traditional Utility Model, CNPI and its consultants will design and permit the line. Detailed plans and specifications will be created for competitive bidding. Information provided for bidding will include exact quantities of towers for installation, foundation designs, tower weights, conductor and hardware quantities, and structure access information. By eliminating the construction unknowns, excluding weather, construction contractors will be able to provide very competitive bids.

Fortis has utilized full EPC contracts in the past and will consider a full EPC contract for the East-West Tie. This contract method allows CNPI to mitigate risk by transferring the responsibility to the EPC contractor by bidding the design, permitting, procurement, and construction as one package. However, the cost of transferring the risk may be higher and more difficult to actually quantify. In addition to the cost of risk, EPC contracts are usually higher cost based on the prime contractor applying a markup to all subcontractor labor and all material prices.

Fortis has also utilized Modified EPC by completing design and permitting with consulting engineers, then bidding the project for contractors to procure the material and complete the construction. This method transfers all risk involved with material handling to the contractor. With completed design and specifications, the risk of unknowns is greatly reduced.

Organizational charts for each method are attached as Appendix R of this application. CNPI has prepared the estimates in good faith with the risk expressed in contingency dollars.

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.

Estimated annual operation and maintenance cost, in 2012 dollars is $974,000. This includes annual inspections, by air, by ground, selective maintenance to access roads, vegetation management, and tower or conductor maintenance repairs. (As contrasted to capital repairs). Fortis currently operates a service centre in Wawa with a fully experienced transmission line crews.

Because this line is initially proposed as a parallel right-of-way, some sharing of maintenance expense between the two lines may later be realized.

9. Landowner, Municipal and Community Consultation

The applicant must demonstrate the ability to conduct successful consultations with landowners, municipalities and local communities. In addition, the designated transmitter will be required to satisfy environmental and other requirements that are outside the jurisdiction of the Board.

As part of its Plan, the applicant must file:

9.1 an overview of:

- ***the rights-of-way and other land use rights, presented by category, that would need to be acquired for the purposes of the development, construction, operation and maintenance of the line;***

CNPI expects to obtain land rights in several categories:

- Registered Permanent Easements will be the preferred option on privately held land. The rights acquired will include removal and control of vegetation on the entire easement width, access rights over existing or future roads, restrictions on buildings, and restrictions on excavations and fills. Rights for communications wires, with communication applications in addition to basic utility requirements, will also be included. Rights shall last in perpetuity unless not required and released.
- Fee Simple Acquisitions are occasionally in the best interest of the utility and the owner, and may be applicable to this project.
- Licenses of Occupation on Crown lands will be required. The rights acquired will be similar to those for easements.
- Agreements and permits for First Nation Reserves.
- Permits will be required at crossings including streams, highways, railroads, other electric and gas lines.

The Land Matters section of the *Ontario Energy Board Filing Requirements for Transmission and Distribution Applications* May 17, 2012 contains a detailed list of requirements and considerations that will be followed.

Additional easements may be required for access roads not within the centreline easement. This occurs when the access road connects to nearby public, or existing private roads, or when terrain requires the road to fall outside, but parallel to the easement. Also access may be required to manage trees outside the easement that are considered as danger trees.

Additional easements, fee simple acquisitions, or licenses may be required during construction for material storage yards, helicopter staging areas, and wire pulling operations that fall outside the easement. These rights are typically required during construction only.

- ***the applicant's plan for obtaining those rights;***

Fortis maintains access and land rights for thousands of kilometers of existing rights-of-way. Establishing new right-of-way is a routine function at each utility. For the East-West Tie, CNPI will create a property rights and acquisition office that will report to the existing Engineering Department. They will identify all properties impacted by the East-West Tie Project as well as property required for access and temporary working areas. The property rights and acquisition office will be respectful of the existing land owner's rights as well as the rights of other interested parties. CNPI believes that it is the best interests of the successful execution of the project to have an open, fair and consistent process to deal with all land rights issues. CNPI proposes to carry out the following:

- CNPI will enter openly and honestly into negotiations with property owners developing trust, listening to their concerns and fostering a positive relationship.

- Provide information about the requirements of the project, the affects of the acquisition on their property, the compensation offer and detail the administrative process that will occur during the acquisition.
- Develop a list of all problems, concerns, questions, disagreements, etc. arising from preliminary negotiations.
- Work with the property owner to search for solutions to resolve issues and concerns in order to reach a signed agreement.

The CNPI internal staff utilizes multiple right-of-way contractors and land rights lawyers over their entire system. These existing resources will be supplemented for completion of the East-West Tie. A high level view of a complicated process is listed below in approximate chronological order, although some overlap will occur in each step. Agents will be required throughout the life of the project to complete the following tasks:

- Select a route based on the technical criteria of the project. All preliminary data suggests that this line will be constructed primarily parallel to the existing line. However, after completing a fly over of the line, CNPI believes that several deviations from parallel may be considered as alternates to avoid very difficult structure locations, conflicts with houses, and conflicts with other utilities.
- Review existing easements and licenses on the parallel line. Preliminary information indicates that new easements will be required and that broader land use rights will be included.
- Develop standard documents, policy, and values. CNPI will develop a set of standard documents to obtain easement options and permanent easements. The documents will define the rights required during construction and the rights required to maintain the line over its life. CNPI will review similar projects to develop documents based on best practice.
- Policy will be defined for fee simple acquisition when required.

- Easement values will be determined on an individual basis but will follow an established procedure that maintains equality between grantors.
- Standard compensation principles will be established to apply fairly, consistently and transparently to all property owners with the goal of timely land acquisition.
- Compensatory offers will be based on reports from independent, AACI accredited appraisers. CNPI may fund additional independent appraisals at CNPI's limited expense if requested by property owners.
- Compensation payment is for interests being obtained, and may also include signing payments, execution payments, and payments to cover legal review of documents.
- Payment for easement or fee simple interest will be negotiated based on appraised fair market value of the land required. Appraisal reports will identify injurious affection to the interest in the remaining property and will provide compensation accordingly. Where the proximity of a primary residence, commercial or industrial building necessitates a buy-out, compensation must also be provided for disturbance damages and relocation costs.
- Determine ownership and jurisdiction for required easements. Through multiple methods, determine the individuals, agencies, and municipalities that will be required to be granted an easement, license, or permit. The property rights and acquisition office will obtain title information including contact information, encumbrances to property, and existing easements.
- Negotiations will begin with each individual. Details of the consultation methods are contained in the next section.
- Options to purchase an easement will be obtained in successful negotiations. Options provide an initial payment for an easement to be granted at a later date. The cost and the rights granted are all defined. The option will be exercised at a later date unless the entire project is later cancelled.
- Exercising the option to purchase an easement occurs when the project receives final approvals and prepares to begin construction.

- Initiate expropriations for easements that cannot be negotiated. While it may not be possible, in all instances, to reach an acceptable resolution, Fortis remains committed to using all reasonable means possible to reach an equitable resolution. As a last resort Fortis will initiate legal recourse available to it to secure outcome.
- Settle any damage claims during construction.

The property rights and acquisition office will manage all easements, permits and other agreements in a GIS environment identifying fixed duration interests which will need to be revisited.

- ***a description of any significant issues anticipated in land acquisition or permitting and a plan to mitigate them.***

- Construction will occur in several wilderness areas, suggesting that environmental permitting may cause significant issues. To mitigate schedule impacts, consultations with the Ministry of the Environment (MOE), the Canadian Environmental Assessment Agency (CEA), and relevant park authorities will begin immediately and the environmental assessment will be submitted as early as possible. Sub-consultants who have a strong local presence, experience on the existing 230 kV line, and relationships with the local approving bodies have been sourced. Consultation will be maintained with key regulatory departments and agencies thought the EA process with the aim of ensuring that the EA contains all relevant information required for permit applications.
- Another potential significant issue that could arise is difficulty in obtaining the necessary approvals to cross First Nation reserves. The participation of LHATC and potentially other interested First Nation communities as equity partners is expected to have a significantly positive impact on the acquisition of those land rights.

To provide communication and further promote cooperation, Fortis has established a Statement of Principles for Aboriginal Relations, a newsletter, and a website. The Statement of Principles for Aboriginal Relations is attached as Appendix W to this application and sets out key principles to guide the actions of Fortis in order to meet its commitments to build effective relationships with Aboriginal communities.

9.2 a landowner, municipal and community consultation plan for the line, including:

- ***identification of the categories of parties to be consulted;***

The *EA Act* s. 5.1 requires consultation to be undertaken during the preparation of an EA. The various consultation activities that will take place during the preparation of the EA are outlined in the ToR, and should include consultation with:

- The general public;
    - Owners and occupants (tenants) of property within the proposed ROW
    - Residents within 500 m of the widened ROW
    - Non-government organizations and groups with an interest in the project
- First Nations and Métis; and
- Government agencies;
    - Multiple agencies with an interest in the project
    - Government Review Team
    - Municipalities, Townships Districts and Unorganized Territories affected by the project
    - People who declared an interest during the ToR stage

- ***the applicant's plan for consultation for each party or category of party, including method and tentative schedule in relation to the overall project schedule;***

Consultations are expected to move forward independently with each party and will be undertaken throughout the key project phases: ToR preparation, EA, Permitting, Design, Construction, and Maintenance.

The General Public

The consultation plan should provide:

- A description of the plan objectives;
- Identification of who will be consulted and the methods to be used to obtain input from interested persons;
- The delineation of key decision-making milestones during the preparation of the EA;
- Where consultation will occur; and
- Provision of an issues resolution strategy.

The objectives of the consultation plan are to:

- Consult with all potentially affected and interested stakeholders in a user-friendly way;
- Provide opportunities for input before decisions are made;
- Provide appropriate, flexible and convenient opportunities for consultation that meet the needs of stakeholders;
- Be responsive;
- Document the consultation program; and
- Evaluate the effectiveness of the program on an ongoing basis and make changes for improvement.

Key activities for the consultation with the general public include:

- Notice of Commencement of the ToR and EA – This activity is a mandatory requirement of the EA process.
- Newsletter – Newsletters will be produced at each key decision points. Newsletters will be made available on the project web site and will be mailed to directly affected

property owners. Newsletters will be provided during the EA and construction stages of the project. They will likely be produced quarterly.

- Issues Workshops – Workshops may be held as appropriate with property owners.
- Public Information Centres (PICs) – The purpose of the PICs will be to provide an opportunity for face-to-face discussion among affected property owners, interested individuals and the project team. PIC's will be held in Thunder Bay, Nipigon, Schreiber or Terrance Bay, Marathon, and Wawa. Three sets of PICs are anticipated to be held in each of the locations during the EA process.
- Meetings with Property Owners – Property agents and EA team members will meet with directly affected property owners where environmental effects have been identified to provide updated information on the project, identify issues and discuss the property acquisition process.
- Interest Group Meetings – If required, meetings will be held with key interest groups to identify issues and discuss options for resolution of issues at EA initiation and as issues arise during the EA process.
- Public Notice of Submission of ToR and EA to MOE – CNPI will notify affected property owners and others on the mailing list that the ToR and EA document has been submitted to the Minister of the Environment for approval. The Notice will be published in local newspapers along the route.

First Nations and Métis: Detailed plans are presented in Section 10.

Government Agencies

Consultation with government agencies are typically undertaken during the project planning phase and maintained through project development and construction.

The objectives of the governmental agency consultations are to:

- Identify concerns and collect information related to the project
- Discuss appropriate fieldwork methodologies

- Identify issues related to the project, and where appropriate to propose mitigation
- Facilitate the development of a list of all required approvals, licenses or permits with their associated schedule
- Identify relevant guidelines, policies and standards
- List all the commitments, obligations, and responsibilities of the proponent

Key activities for the consultation include:

- Following the Notice of Commencement of the EA, an agency consultation package will be sent to all agency stakeholders from the federal, provincial and municipal governments and conservation authorities soliciting their input.
- Follow-up communications will occur with those agencies that request further meetings or involvement to discuss their input.
- Regular meetings are anticipated to discuss issues that arise.
- Agencies will also be notified when the EA is available for review.
- Newsletters will be made available on the project web site and will be mailed to all agency stakeholders.
- Issues Workshops may be held as appropriate with agencies, interest groups and municipal staff. These could address issues such as route refinements, biodiversity and effects and mitigation techniques.
- A Municipal Advisory Group (MAG) may be formed if appropriate.
- CNPI will notify agencies by mail that it has submitted the EA to the Minister of Environment for approval.
- Agency consultations will also dovetail with PIC events as avenues for further input to the process.
- All agency submissions and meetings will be documented and included in the Record of Consultation.

In addition to the methods of consultation discussed above, CNPI will utilize the following methods that are applicable to each group discussed above:

- The web site will continue to be updated throughout the project and will offer visitors the opportunity to comment.
- The project telephone hot-line will provide 24 hour voice mail access throughout the life of the Project.
- EA documents will be distributed to agencies, key interest groups, and municipal officials and staff of affected communities. CNPI will make documents available at local libraries and at government offices for review by members of the public. Documents will also be available for download from the Project web site.

- ***a description of any significant issues anticipated in consultation and a plan to mitigate them.***

During the development stage of the ToR and EA, all potentially affected residents will be provided with a contact telephone number for the community liaison representative. As a long-term presence in the community CNPI will continue to develop contacts and other local relationships and channels of communication, which could benefit the local area. First Nation and Métis consultations can take time and often proceed at their own pace. To mitigate possible delays that could occur as a result, CNPI will engage these stakeholders early and often in the process to ensure active communications and results. CNPI will also engage other stakeholders and approval agencies with frequencies that will ensure CNPI meets the schedule proposed and addresses any concerns identified with appropriate mitigation or avoidance measures.

CNPI will continue its contact with project stakeholders during construction of the Project for as long as this seems an effective two-way channel for communication. CNPI and the Construction Contractor will have a designated representative to maintain good community relations throughout the Project. The Project representative will address concerns (damage claims) expressed by stakeholders during construction in an expeditious and courteous manner.

Typically, complaints during construction can be a common occurrence. Agreements for timber value along the right-of-way can be negotiated in advance to mitigate concerns. Access roads are also planned in advance, but occasionally changes are required. Complaints may arise relating to traffic, mud, dust, and noise. Damage claims will be addressed. If agreed to by the owner, any nearby building foundations and wells will receive pre-construction inspections to allow complete assessment of potential damage claims.

Ongoing stakeholder communication will allow CNPI to receive and respond to community issues on an ongoing basis. The goal of the program is to further CNPI's strategy to be a good corporate citizen, protect the environment, and enhance the quality of life in the communities in which they operate.

9.3 If the applicant has identified a proposed route for the line, the applicant must file a general description of the planned route for the line and may include:

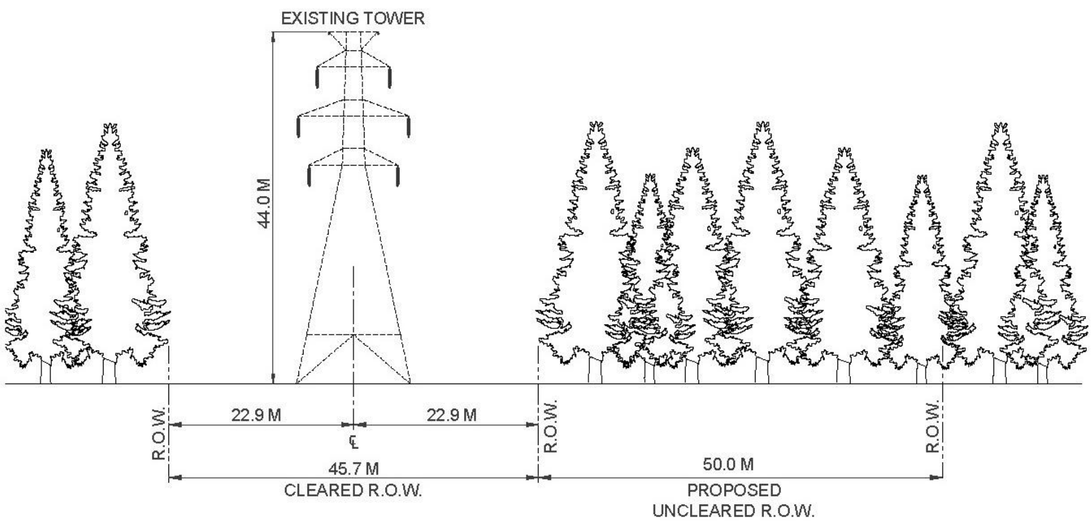
- ***approximate right-of-way width;***

CNPI understands that the right-of-way width of the existing 230 kV line, obtained in 1969, is 150 feet (45 Meters). CNPI's Plan includes an approximate right-of-way width of 50 meters (164 feet), which is the same as the proposed width set out in the Minimum Design Criteria.

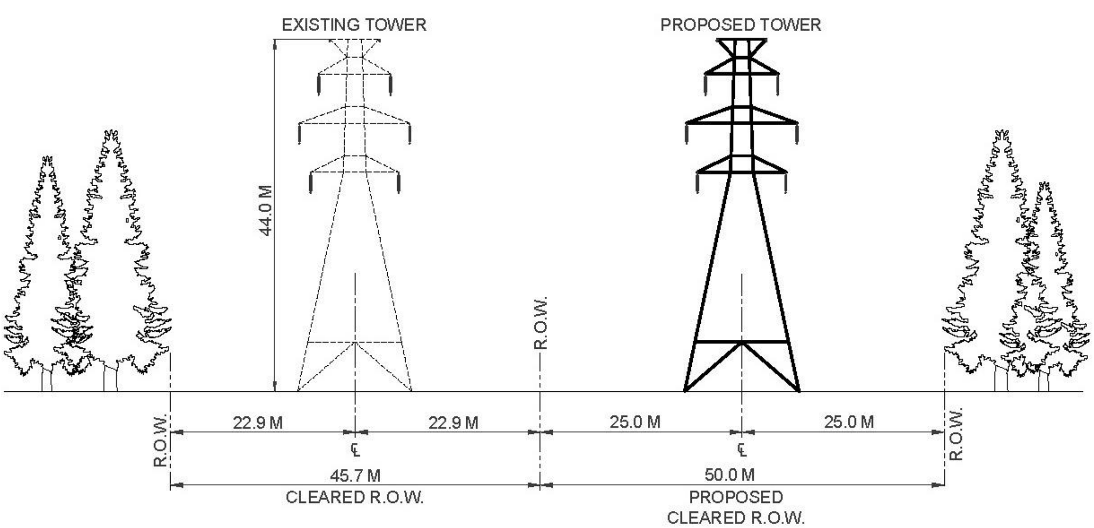
Many factors influence the width of right-of-way. Sections of line with double circuit monopoles may have shorter spans that require less spacing between conductors while still maintaining the reliability standards. More structures required equates to higher cost for structures. Less spacing required equates to less cleared right-of-way width required, with associated hard dollar savings on easement cost and clearing cost and less disturbance to the environment. The cost savings for reduced environmental disturbance is difficult to quantify. Steepness of adjacent side hills, height of native trees, and other environmental, cultural, or design parameters also impact the width cleared.

Below are two pages of four diagrams of Tower Designs For Voltage Class 230 kV. The first two diagrams are existing and proposed design based on the Minimum Design Criteria. The second two diagrams are variations of tower spacing using alternate arrangements.

TOWER DESIGNS FOR VOLTAGE CLASS 230 kV



EXISTING 240KV

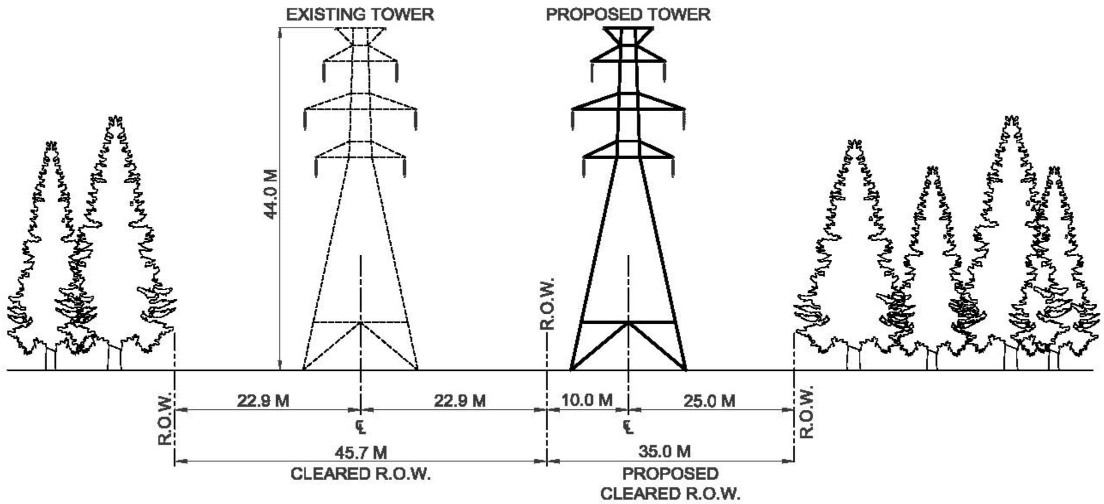


PROPOSED 240KV

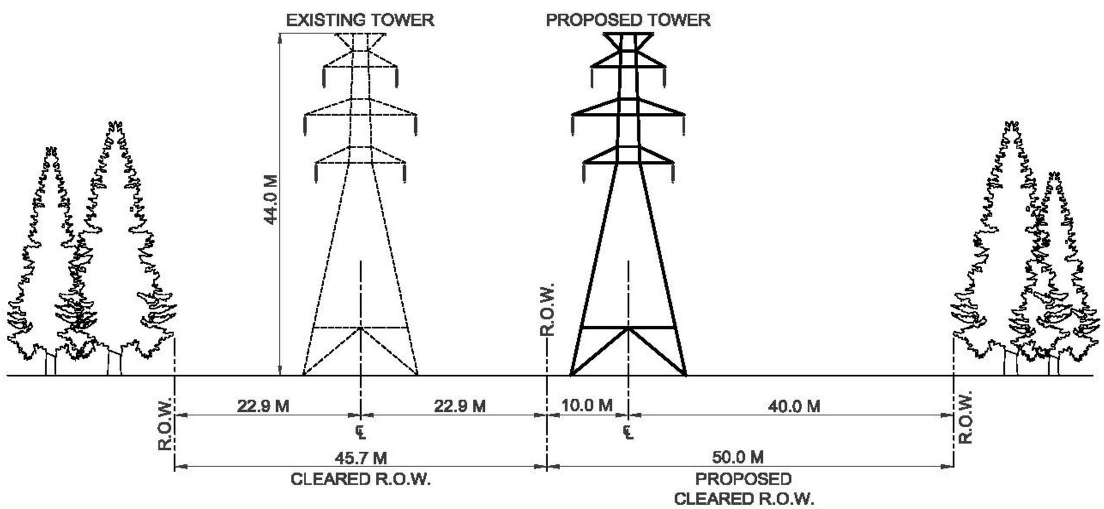
(STANDARD ARRANGEMENT)

(Based on Minimum Design Criteria)

TOWER DESIGNS FOR VOLTAGE CLASS 230 kV



PROPOSED 240KV
(ALTERNATE ARRANGEMENT)
LESS ENVIRONMENTAL DISTURBANCE



PROPOSED 240KV
(ALTERNATE ARRANGEMENT)
REDUCED TREE CONTACT

Proposed right-of-way width may be reduced to 35 meters where parallel to the existing right-of-way. Two pages later in this section, please see the attached sketch labeled as "*Less Environmental Disturbance*". All reliability minimum standards are maintained. Less right-of-way width produces the savings mentioned above. The reduced spacing between tower lines may hinder helicopter construction methods.

The sketch labeled as "*Reduced Tree Contact*" indicates the purchase and clearing of 50 meters right-of-way width. Improved reliability can be expected simply by the reduced probability of tree contact.

Both the "*Standard Arrangement"* and the "*Reduced Tree Contact"* proposed construction plans create natural corridors for future utilities. Perhaps gas lines or distribution voltage electric lines. Additional utilities in the corridor may or may not be desired by the transmission owners, but would likely be mandated based on public opinion.

CNPI will study these issues and receive comments from all stakeholders. It is possible that each alternative sketched will be appropriate at some point along the route. At this stage of the project, CNPI believes that flexibility is essential.

- ***approximate portion of the route that is:***
  - ***adjacent to the existing corridor (%); or***
  - ***along a new corridor (%):***

CNPI's proposed route for the line is for construction primarily adjacent to the existing double circuit HONI Wawa TS to Lakehead TS 230kV line. This is substantially the same route proposed by HONI in its Green Energy Plan filing EB-2010-0002 ("HONI's Green Energy Plan Filing") filed May 19, 2010 (Exhibit A, Tab 11, Schedule 4, Page 10 of 47). As well, this route was proposed by HONI in its AR18379 Project Definition Report – Study Estimate for Options – East-West Tie Expansion dated June 4, 2010 ("HONI's EWT Project Definition Report"). In order to form a better understanding of the existing route, the proposed route and consideration of an alternate route, CNPI carried out a complete a fly over of the existing line and the proposed line, and an alternate route. Several areas were identified where deviations from absolutely parallel may be required. This includes issues with terrain, other existing parallel lines, and even existing residences. Based on observation alone, it appears that the obstacles to parallel construction are equally split between the north and south side of the existing line. Since multiple relocations of the existing line would be required to avoid undesirable line crossings, the possibility of an entirely new corridor will be considered. However, only detailed environmental evaluation and engineering design can determine if the proposed line will deviate from parallel only in those identified areas or if an entirely new corridor is more appropriate.

Before the fly over, CNPI was tentatively considering an entirely new corridor from Marathon to Wawa. Observations from the actual fly over confirmed the consideration of the alternate route.

Several governance or cultural areas may also require relocations from parallel. Those areas will be defined during the completion of the EA and Leave to Construct.

Fourteen First Nation and four Métis Organizations are identified by the OPA as impacted by the East-West Tie project. In preliminary reviews for purposes of this application, CNPI has discovered some slight variance to the OPA provided list. Those issues will be fully resolved during the EA process. Based on the OPA list and preliminary identification by CNPI, the existing route traverses through the following areas, some of which may result in route adjustments to a new corridor:

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

Métis Organization

- Greenstone Métis Council
- Red Sky Independent Métis Nation
- Superior North Shore Métis Council
- Thunder Bay Métis Council

Municipalities/Townships:

- Municipality of Shuniah
- Township of Dorion
- Township of Red Rock
- Township of Nipigon
- Township of Terrace Bay
- Town of Marathon
- Municipality of Wawa

- ***a brief description of the environmental challenges posed by the proposed route;***

The existing 230kV line crosses the heart of Pukaskwa National Park. Special construction requirements may well be required to construct a new parallel line. The additional right-of-way clearing may be viewed as contributing to the bio diversity, improving fire barriers, and will improve existing access roads, possibly improving emergency response times for both line maintenance and park emergencies. The additional clearing and construction may alternatively be viewed as an unacceptable intrusion into the wilderness. The alternative case, presented in *IESO Feasibility Study,* Report 0748, for a new single circuit line requires series compensation at the midpoint of the Wawa TS to Marathon TS line section, which will be in the middle of Pukaskwa National Park. A new station, with appropriate road access for routine and trouble station visits, is probably not appropriate for that location.

Fourteen First Nation and four Métis Organizations are identified by the OPA as impacted by the East-West Tie. In preliminary reviews for purposes of this application, CNPI has discovered some slight variance to the OPA provided list. Those issues will be fully resolved during the EA process. Based on preliminary identification by CNPI, the existing route traverses through the following areas, some of which may result in route adjustments to a new corridor:

- Parks/conservation lands (9) –
  - Black Sturgeon River Provincial Park
  - Ruby Lake Provincial Park
  - Kama Cliffs Conservation Reserve
  - Kama Hills Provincial Nature Reserve
  - Gravel River Provincial Nature Reserve
  - White Lake Provincial Park
  - Pukaskwa National Park
  - Pukaskwa River Provincial Park
  - Nimoosh Provincial Park
- 32 wetlands
- 86 water bodies (lakes, ponds, wide river channels),
- 318 watercourses (streams, creeks, narrow river channels)
- 43 Roads
- 13 rail ways
- Other gas and electric transmission lines
- Mining Claims - 211 Active Disposition Parcels, 102 Active Claims
- Wind and waterpower applications
- There is a known population of Woodland Caribou which resides within Pukaskwa National Park. Woodland Caribou are listed as a Threatened species under the *Ontario Endangered Species Act*, 2007. In addition, Peregrine Falcon and Whip-poor-will (both Threatened species), Canada Warbler (designated as Special Concern) may also be present in the vicinity of the proposed transmission line route. Effects to these species will be considered in the selection of the preferred transmission route. If impacts cannot be avoided, a permit under the *Endangered Species Act* may be required and may necessitate the creation of an "overall net benefit" for these

species. The permitting process can be lengthy and may require detailed studies, beyond those required for the EA. This has the potential to delay the project schedule. If any additional species at risk, beyond those listed above, are identified during the EA process, delays may be experienced due to the seasonal constraints of many field surveys. In addition, in order to create a net benefit, habitat may need to be restored or created in new areas to compensate for any losses. Given the number of First Nation communities and parks along the route, CNPI anticipates that finding suitable locations for habitat creation will not be difficult. The potential presence of species at risk, effects, mitigation and compensation will be considered early in the route selection and design process in order to minimize permitting delays and challenges. Time for species at risk surveys and permitting has been included in the project schedule. There is nonetheless, a minor chance that survey and permitting requirements could cause delays of six months to a year if exceptional circumstances are encountered.

- ***an estimate of ownership by category of lands along the proposed route:***

○ ***Crown (federal or provincial) (%)****;*	56.4
○ ***Private (%);***	32.3
○ ***First Nation or Métis (%); and***	2.4
○ ***Other (%)*. Pukaskwa National Park**	8.7
	99.8

The percentages provided above are taken from EB-2011-0140 East-West Tie Line, Hydro One Networks Production of Documents, June 28, 2012. This information is required for the Leave to Construct application, and will be revised to reflect the actual route.

9.4 If a proposed route for the line has not been identified, the applicant must file:

- ***a list of alternative routes;***
- ***an explanation of the method and decision criteria for route analysis and selection;***
- ***the planned schedule for route selection.***

The proposed route has been identified by CNPI as primarily parallel to the existing 230kV line, similar to the route proposed in HONI's Green Energy Plan Filing and HONI's Project Definition Report, the route has not been studied in detailed levels similar to the EA process for purposes of this application. CNPI did complete a fly over of the existing line and observed several locations where the proposed line may be required to deviate from absolutely parallel (centerlines of the two lines approximately 50 meters apart). Several locations were observed where relocations of the existing line would be required to avoid undesirable line crossings (undesirable from a cost, reliability, and outage scheduling perspective). Detailed engineering analysis will be required to determine the final route. Some photos have been included at Appendix T to this application to show the rough terrain and challenging conditions for design and construction of the line on the proposed route.

CNPI is prepared to select and has considered an entirely new route around Pukaskwa National Park largely following existing corridors. The alternate route considered by CNPI follows an existing 115 kV line from Marathon to White River, which is roughly parallel to Highway 17, but not highly visible. A map that illustrates this alternate route is shown on Appendix U. This accounts for approximately 40% of the alternate route. Another 40% of the alternate route is either parallel to Highway 17 or an existing multiple line corridor heading north from Wawa. The last 20% of the alternate route is cross country. However the terrain is very appealing for line construction, multiple logging roads are evident, and it traverses the White River forest fire burn area, which initially implies that environmental impacts of line construction are less significant. Some photos have been included in Appendix T to this application to show the terrain of the alternate route. The increased length of the alternate route is approximately 25 km. There are several advantages to this route including:

- With associated ties at White River (or allowances for a mobile transformer), maintenance on the existing 115 kV line can be completed without outages to the White River community.
- Response time on outage situations is improved due to line proximity to the highway, especially when compared to the existing poor access within the park.
- Fiber optic communications will be available for the parallel transmitter to improve protection and control and SCADA at their facilities at White River.
- CNPI is also open to an expanded right-of-way for construction of parallel double circuit lines to allow the complete removal of the existing transmission line from the Pukaskwa National Park.

CNPI has flown the existing transmission line (ie, the proposed route), and the alternate route considered by CNPI. The section through Pukaskwa National Park is very rugged with remote location, which indicates relatively high cost line construction followed by a useful life of difficult maintenance. The alternate route will be through much less rugged areas with much improved access. During the design, a detailed analysis will be performed to determine the cost difference of the options. Preliminary thoughts are that the alternate route will be cost effective.

Criteria for routing will be developed at the ToR stage and typically include:

- cost for initial construction
- cost of maintenance
- system reliability
- environmental and socio-economic impacts

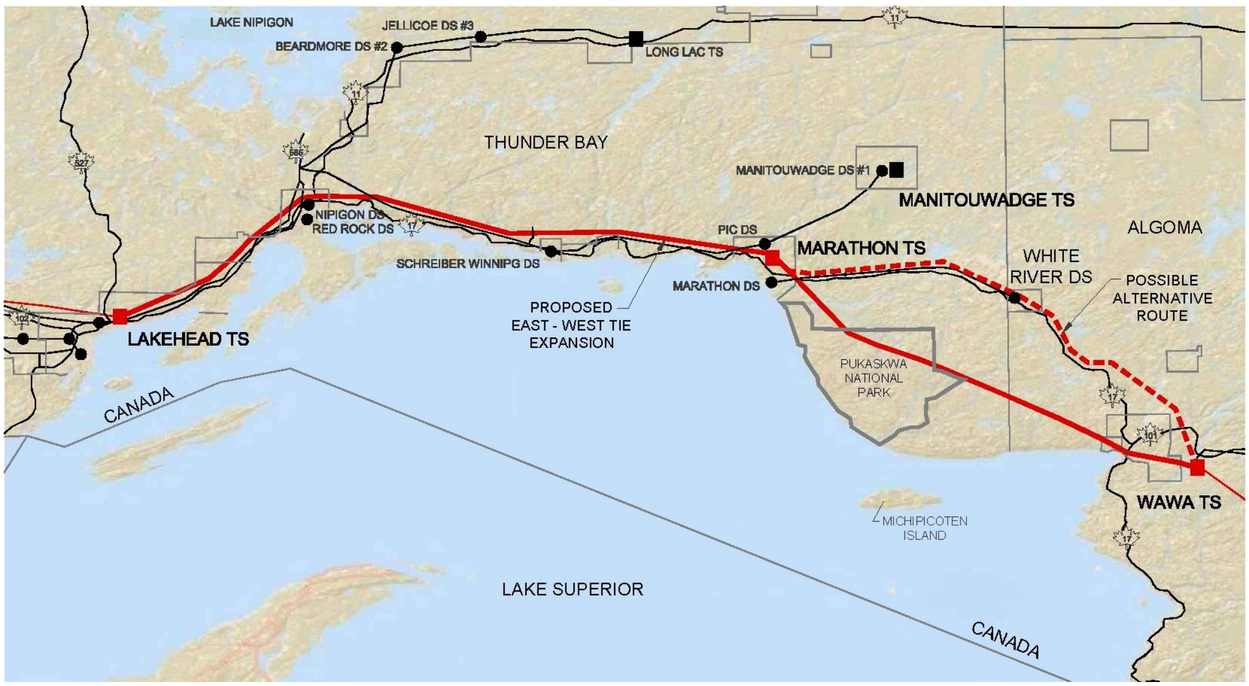
- archeological and cultural impacts
- existing land use
- Aboriginal and treaty rights
- impact to the general public
- impact to individual property owners
- results from public, government, and Aboriginal consultations

Additional criteria and sub-criteria may be developed through the ToR stage of the EA. Routing new transmission lines adjacent to existing transmission lines typically minimizes the negative impact of all of the environmental and cultural criteria listed. The existing land use already includes transmission facilities. Also, the increase to the width of existing right-of-way to add a second line is sometimes less than the width of all new right-of-way. Typically, access roads to structures can be shared rather than newly constructed. Both factors effectively reduce the area of new disturbance.

In addition to existing transmission lines, other natural corridors typically reduce impacts. Highways, railroads, and gas lines are examples.

Upon designation, CNPI would immediately start development of the ToR and alternate route evaluation.

MAP OF PROPOSED AND ALTERNATE ROUTES



A copy of the above map has also been included in Appendix U of this application.

10. First Nation and Métis Consultation

The applicant must demonstrate the ability to conduct successful consultations with First Nation and Métis communities, as may be delegated by the Crown. As part of its Plan, the applicant must file:

10.1 a proposed First Nation and Métis consultation plan, including:

- ***a list of First Nation and Métis communities that may have interests affected by the project;***

The Ontario Power Authority has published a list of "Crown-identified communities with respect to the May 31, 2011 delegation of certain procedural aspects" in the document *Role and Background/Highlights with the East-West Tie Project,* dated January 10, 2012. Fourteen First Nation and four Métis Organizations were identified, and listed below. In preliminary discussions and reviews, CNPI has discovered some slight variance to the OPA provided list. Those issues will be fully resolved during the EA process.

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 BayFirst Nation)
- Pays Plat First Nation

- Pic Mobert First Nation
- Red Rock Indian Band

Métis Organization

- Greenstone Métis Council
- Red Sky Independent Métis Nation
- Superior North Shore Métis Council
- Thunder Bay Métis Council

- ***an approach for engaging with affected First Nations and Métis communities, along with rationale or other justification for such an approach;***

CNPI is committed to working closely and cooperatively with the Crown to ensure that the duty to consult with Aboriginal communities and groups is fulfilled. An Aboriginal Consultation and Engagement Plan will be developed at the start of the EA.

Consultation and engagement with Aboriginal groups will provide project related information in an easily accessible and understandable format. Specifically, the project team will seek information from Aboriginal groups with regard to land use and treaty rights, traditional ecological knowledge, archaeological sites, sacred sites and burial grounds. Communities will be asked to comment on the proposed fieldwork methodologies to obtain baseline information. Aboriginal community members will be invited to form part of field teams, either as guides or assisting with archaeological fieldwork. Traditional knowledge of the study area by elders will be sought. The study team will endeavor to address all issues raised by Aboriginal communities with regard to potential impacts associated with their interests.

Public Information Centres will be offered within each Aboriginal community directly affected by the project.

In respect of Métis consultation, following designation, CNPI plans to enter into consultations with affected communities in accordance with the provisions of applicable Métis Consultation Protocols and the Fortis Statement of Principles for Aboriginal Relations. In this regard, a preliminary meeting with MNO has already been held to discuss protocols for consultation.

Further to the OEB's letter to electricity transmitters registered in the East-West Tie dated December 11, 2012, CNPI acknowledges the Deputy Minister of Energy's expectation regarding the delegation of the procedural aspects of the Crown's duty to consult Aboriginal communities, and confirms that as the designated transmitter CNPI will enter into a memorandum of understanding with the Ministry of Energy that will set out the respective roles and responsibilities of the Crown and CNPI in consultation. Such memorandum of understanding would be on terms and conditions to be determined by the Ministry and which will be similar in principle to the memorandum of understanding in the public record on the application for leave to construct the Bruce to Milton transmission reinforcement project.

- ***a description of any significant First Nation or Métis issues anticipated in consultation and a plan to address them;***

- CNPI expects that the First Nation communities in the immediate area will be interested in project ownership and/or revenues to help support their communities. CNPI's plan is to offer ownership share in the project and other benefits as more fully discussed in Section 3 of this application.
- The Métis will want to ensure hunting and fishing rights are preserved.
- Capacity issues within the community must be considered. CNPI anticipates supporting funding and other types of assistance to allow active engagement.
- Timing and participation can become an issue. Neegan Burnside has over 40 years of experience in consulting with a number of Aboriginal groups across Canada. Neegan Burnside has a unique understanding that the following principals must be anticipated:

    - Building a relationship takes time.
    - Successful consultation will only be achieved if the Aboriginal community is thoroughly understood.
    - A respectful and collaborative consultation process must be developed.
    - The process must particularly consider each individual community's interests.
    - The use of appropriate communication tools is key.
    - Establishing long-term relationships with the community, council, and chief are key factors.

- ***an overview of expected outcomes from the proposed consultation plan.***

- We anticipate development of a successful partnership agreement and shared project ownership.
- Relationships will be established where project related information will easily flow from the Aboriginal community to the project team.
- The project team will receive information on specific issues and concerns related to proposed construction on Aboriginal lands.
- The project team will interpret technical documents facilitating a broader more general understanding of technical issues.
- The Aboriginal community will develop an understanding of the technical aspects (engineering and environmental sciences) of the project.
- Assist in developing relationships and capacity building between CNPI and Aboriginal communities.
- The project team will facilitate peer reviews with regard to Aboriginal communities.
- The project team will produce required documents such as Memorandums of Understanding and Impact Benefit Agreements addressing project issues that are understood within the community.

10.2 evidence of experience in undertaking procedural aspects of First Nations and Métis consultation in the development, construction or operation of

transmission lines or other large construction projects. If applicable, previous engagement or existing relationships with the First Nation and Métis communities to be engaged.

Fortis also has significant experience in several Canadian jurisdictions working with Aboriginal communities. Fortis has engaged in limited partnerships and long-term leases with First Nation communities and multiple other programs as detailed below.

Some recent Fortis transmission line and large construction project related successes include:

- **New Bentley Substation**, part of the Okanagan Transmission Reinforcement project was built on Osoyoos Indian Band ("OIB") land through a long term lease agreement.

- **Nk'Mip (East Osoyoos) Transmission and Substation Project.** The $20 million project was completed in 2007 and was constructed on Osoyoos Indian Band First Nation reserve lands. The OIB was consulted on this project and a memorandum of understanding was developed to ensure that the interests of both OIB and Fortis were satisfied. The financial benefits to the OIB resulting from this project included a continuous taxation stream for the OIB, immediate cash injection into the community, and establishment of long term funding for community elders and youth. The major learning included the positive results of working with the OIB, the almost neutral visual impact of the substation and line, and the fact that the substation was successfully constructed not only in a destination resort but in a protected desert area with many endangered and vulnerable species.

- **Mount Hayes Natural Gas Storage Facility** completed in 2011, was a $200 Million project established as a Limited Partnership. Stz'uminus (Chemainus) First Nation and Cowichan Tribes First Nations participated as limited partners. Both invested $6 million and both earn the same regulated rate of return as Fortis. The two First Nations invested into the 40% equity portion of the project. This project began in 2008 and was overseen by the Fortis project team. Ground breaking followed a five-year planning and public consultation process involving the local community. A memorandum of understanding between Fortis and the Stz'uminus (Chemainus) First Nation community member resulted in over $4.6 million in construction work and over 18 person-years of employment for the community. Work included site preparation, road construction and power line installation. Several First Nations youth that participated in the Skill Builder program secured employment with local subcontractors completing work on Mt. Hayes.

Fortis' approach to building relationships with Aboriginal communities includes recognizing and respecting the uniqueness and diversity of their cultural heritage. Fortis is committed to preserving and building upon the steadfast alliances already created with Aboriginal communities through a number of cultural, economic, environmental, and educational initiatives.

- The Aph-cii-uk pilot project builds long-term relationships between First Nations, local corporations, and government to develop community economic and social projects at the grassroots level.
- The Residential Energy and Efficiency Works (REnEW) Program trains First Nations and Aboriginal candidates in retrofit construction that improves energy efficiency of structures.
- The Skill Builder Aboriginal training initiative prepares Aboriginal and First Nations candidates for potential employment opportunities in the fields of utility construction industry.
- Sponsorship of a traditional pow wow.
- Sponsorship of a national conference on Aboriginal economic development.
- A traditional village by Penticton Indian Band at the annual Penticton Peach Festival

- The Penticton Indian Band youth and elders program including traditional paddling
- The Lower Similkameen Indian Band Community Pit House Project
- The Osoyoos Indian Band Youth Centre.
- The PowerSense program encouraged bands to exchange their incandescent light bulbs for energy efficient compact fluorescent bulbs.

Fortis consults with Aboriginal groups at the first stages of all major infrastructure projects on traditional lands. Consultations include technical, environmental, historical and public opinion issues. These timely consultations promote mutual understanding, respect, open communication, and trust.

Specifically, in reference to transmission development in Ontario, Fortis and CNPI have conducted extremely successful consultations with First Nations that have culminated in a binding memorandum(s) of understanding for joint equity ownership with First Nations in the development of transmission projects in Ontario.

An example of these successful consultations can be seen in the press release attached to this application as Appendix P, which was issued jointly by Fortis and LHATC in February 2011 announcing the binding memorandum of understanding to develop, construct, own and operate regulated transmission projects in Ontario. This binding memorandum was the result of many months of consultations with First Nations, their Chiefs and negotiations with First Nations representatives of LHATC in respect of the terms. Further, following the announcement representatives from First Nations and Fortis jointly arranged for and met with representatives of the Ministry of Energy and the Ministry of Aboriginal Affairs to make them aware of this new partnership and to discuss the status of transmission development projects and the competitive designation process with the OEB.

Further to this joint venture to develop the Sudbury West Line and the North South Tie, Fortis and CNPI engaged in further consultations with Robinson Huron First Nations to develop the East-West Tie following the Ministry of Energy Directive that this project go to a competitive designation process. The joint venture's management structure includes a management committee comprised of First Nations representatives and Fortis representatives. This management committee engaged in consultations with First Nations Chiefs from the Robinson Huron Treaty territory with respect to the opportunity to develop the East-West Tie. Further to these meetings, Fortis and LHATC entered into an agreement to jointly approach First Nations from the Robinson Superior Treaty territory with a view of negotiating and entering into a binding memorandum of understanding to develop, construct, own and operate the East-West Tie. Discussions with the Robinson Superior Treaty First Nation communities will commence upon CNPI being designated by the OEB.

One of the keystones to the success of the First Nations partnership to date has been the commitment to foster effective consultations and communications between the joint venture and the First Nations communities. This involves not only face to face meetings with Chiefs and the communities, but also First Nations communications initiatives. Communications are important to maintain a high level of awareness of the joint venture's business, the status of the transmission project, as well as the status of changing regulatory and energy policies surrounding transmission development in Ontario. One aspect of these communications involves a newsletter entitled *The Transmission Times* which is attached to this application as Appendix Q, which has been created to communicate with First Nations community members about the designation process and the development of the East-West Tie. In addition, a new website has been created by the joint venture for LHATC to keep its stakeholders up to speed on transmission issues (see www.lhatc.ca) that will impact the communities. These mediums provide opportunities to build upon other consultations efforts and to advise First Nations and other affected communities of the impact of these lines on treaty territory, to develop energy sector knowledge and expertise, to create awareness of employment and procurement opportunities, to announce sponsorship programs for training, communicate on Skill

Builder program initiatives, to advise on preferred contractor opportunities during the construction phase, and to communicate other partnering opportunities during the development of the line as well as to highlight the numerous benefits from ownership in the project.

CNPI has selected Neegan Burnside to perform Aboriginal consultations. Neegan Burnside has recently completed the National Water Study which took them into every First Nation community across Canada. Recently, Neegan Burnside carried out a consultation with the Métis Nation of Ontario in connection with its Grand Bend Wind Farm Project. The various associates of the firm have been providing services to Aboriginal communities for over 40 years and offer a true understanding of Aboriginal culture that allows effective and successful consultations with First Nation communities.

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(C) OTHER FACTORS

The applicant should provide any other information that it considers relevant to its application for designation, for example, any distinguishing features of the application.

- Existing First Nations participation and plan for further participation by First Nation and Métis communities
- CNPI's plan for First Nations equity ownership will benefit a greater number of communities than the fourteen First Nations set out in the OPA's list of Crown identified First Nations
- Experience and financial capacity associated with being the largest investor owned distribution utility in Canada
- Long-term profile as an owner and operator of electricity transmission assets in Ontario and other jurisdictions
- Smaller transmission presence in Ontario (compared to incumbent HONI) creates greater opportunity to increase competition in Ontario's transmission sector
- Local knowledge of the transmission and distribution systems in the East-West Tie area of Ontario
- Existing work centre located in Wawa, Ontario, staffed with Transmission experienced employees
- Regulatory track record and experience in Ontario and other jurisdictions in which Fortis operates
- An experienced team with an innovative approach to Aboriginal participation, communications, and project management
- Established track record for successfully completing major utility projects
- Existing transmitter with all of the regulatory and operating requirements required to carry on business consistent with good utility practice in Ontario
- Innovative proposal to develop SAP and GIS inventory tracking system to increase efficiency and reduce cost to the rate payer

- Successful track record for carrying out major financing

Appendix List

Appendix List – Cont.

Appendix U - Map of Proposed and Alternate Routes

Appendix V – Skill Builder Presentation

Appendix W – Statement of Principles for Aboriginal Relations

Appendix X – Summary of Total Costs

APPENDIX A

Statement from Senior Officer

CANADIAN NIAGARA POWER INC.

A FORTIS ONTARIO Company

1130 Bertie Street
PO Box 1218
Fort Erie, Ontario L2A 5Y2

Subject: Statement from Senior Officer:

To Whom it May Concern,

As a Canadian-owned utility company, operating in Ontario since 1905, CNPI welcomes increased competition within the Ontario electric transmission sector. CNPI is a wholly owned subsidiary of FortisOntario Inc, which is wholly owned by Forts Inc. To prepare this designation application, Fortis has assembled a very capable team of professionals. The team includes a significant number of skilled and experienced in-house professionals from Fortis as well as multiple consulting engineers and specialists. CNPI has already reached agreements with First Nation partners to own and operate transmission lines in Ontario. CNPI is pleased to submit this designation application.

CNPI plans to complete this project in a manner that is respectful of the involved communities, landowners, Aboriginal and treaty rights, with the least possible impact to the environment, while adding value to rate payers and shareholders.

This development plan has been written based on the Ontario Energy Board document EB-2011-0140, *Filing Requirements, East -West Designation Application*.

I hereby certify, that to the best of my information and belief, this application for designation is complete and accurate.

W. J. Daley

January 4, 2013

Bill Daley, President and Chief Executive Officer
Canadian Niagara Power Inc.

Date

APPENDIX B

Overview of Fortis' Transmission Systems

Fortis Transmission Utilities

The following is a list of the Fortis Inc. group of wholly-owned subsidiary companies engaged in the business of electricity/gas transmission:

Canada

Newfoundland Power Inc. operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. Newfoundland Power serves approximately 86% of all electricity consumers in the province. The Company serves the Avalon, Burin and Bonavista Peninsulas and the major centres along the Trans Canada Highway, including: Gander, Grand Falls-Windsor, Corner Brook, Stephenville, and Port aux Basques. Throughout this service territory, Newfoundland Power Inc. has over 2,060 kilometres of transmission lines and operates 130 substations with a total installed capacity of 140.4 MW. The transmission lines consist of 69kV to 138kV lines.

Maritime Electric Company Limited ("Maritime Electric") operates under the provisions of the Electric Power Act and the Renewable Energy Act. Maritime Electric owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity to customers throughout Prince Edward Island. Maritime Electric has over 653 kilometres of transmission line ranging in size from 69kV to 138kV. Throughout the province, Maritime Electric has 21 substations or switching stations connected to the transmission and distribution lines.

FortisOntario Inc. (“FortisOntario”) wholly-owned subsidiary, Canadian Niagara Power Inc. (“CNPI”), is licensed by the OEB for the transmission and distribution of electricity in Ontario. FortisOntario’s other operating subsidiaries include Cornwall Electric and Algoma Power Inc.

CNPI’s transmission system is interconnected with Hydro One Networks Inc.'s ("Hydro One") transmission system in Niagara Falls, Ontario and provides service in and around the area of Fort Erie, Ontario. The transmission system is also interconnected, through an emergency tie line, with the transmission system owned and operated by US National Grid in New York State. The transmission line consists of 36 kilometres of double and single circuit 115kV line connected to three transmission stations.

Cornwall Electric owns and operates 15 kilometres of high-voltage 115 kV transmission line, which connects 6 substations by tap lines to the Cedar Rapids Transmission line, owned by Hydro Quebec.

FortisBC is an integrated energy solutions provider. FortisBC owns and operates four regulated hydroelectric generating plants and approximately 1,500 kilometres of transmission power lines. FortisBC's transmission system consists of:

- Approximately 1,500 km of lines comprised of:
  - 760 km of 63 kV lines
  - 220 km 132/138 kV lines
  - 270 km of 161/170 kV lines
  - 200 km of 230 kV lines

Caribbean

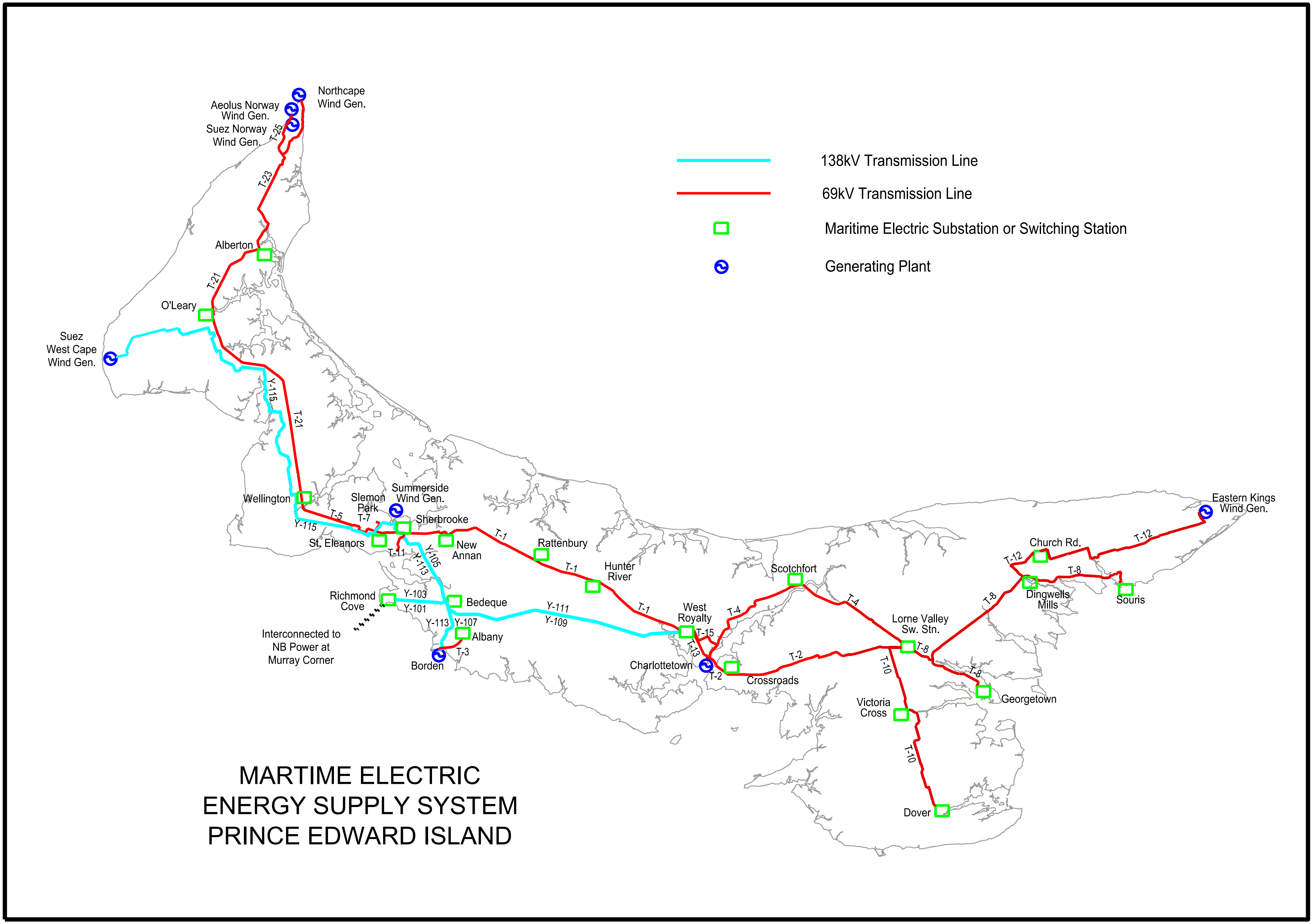
Caribbean Utilities Company, Ltd.'s power system is comprised of 19 generating units (18 diesel and two gas turbine) with a combined capacity of 151 megawatts. The Company's system is comprised of eight major transformer stations, 58 kilometres of 69 kV overhead transmission and 27 kilometres of 69 kV high-voltage submarine cable in Grand Cayman.

FortisTCI serves more than 9,000 customers, or 88 per cent of electricity consumers, on the Turks and Caicos Islands. It owns and operates a fully integrated system providing for the generation and distribution of energy in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. It also owns and operates an independent generating station and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036. Fortis Turks and Caicos owns and operates 325 kilometers of transmission and distribution lines.

Attached are maps of the transmission systems for the above transmission utilities.

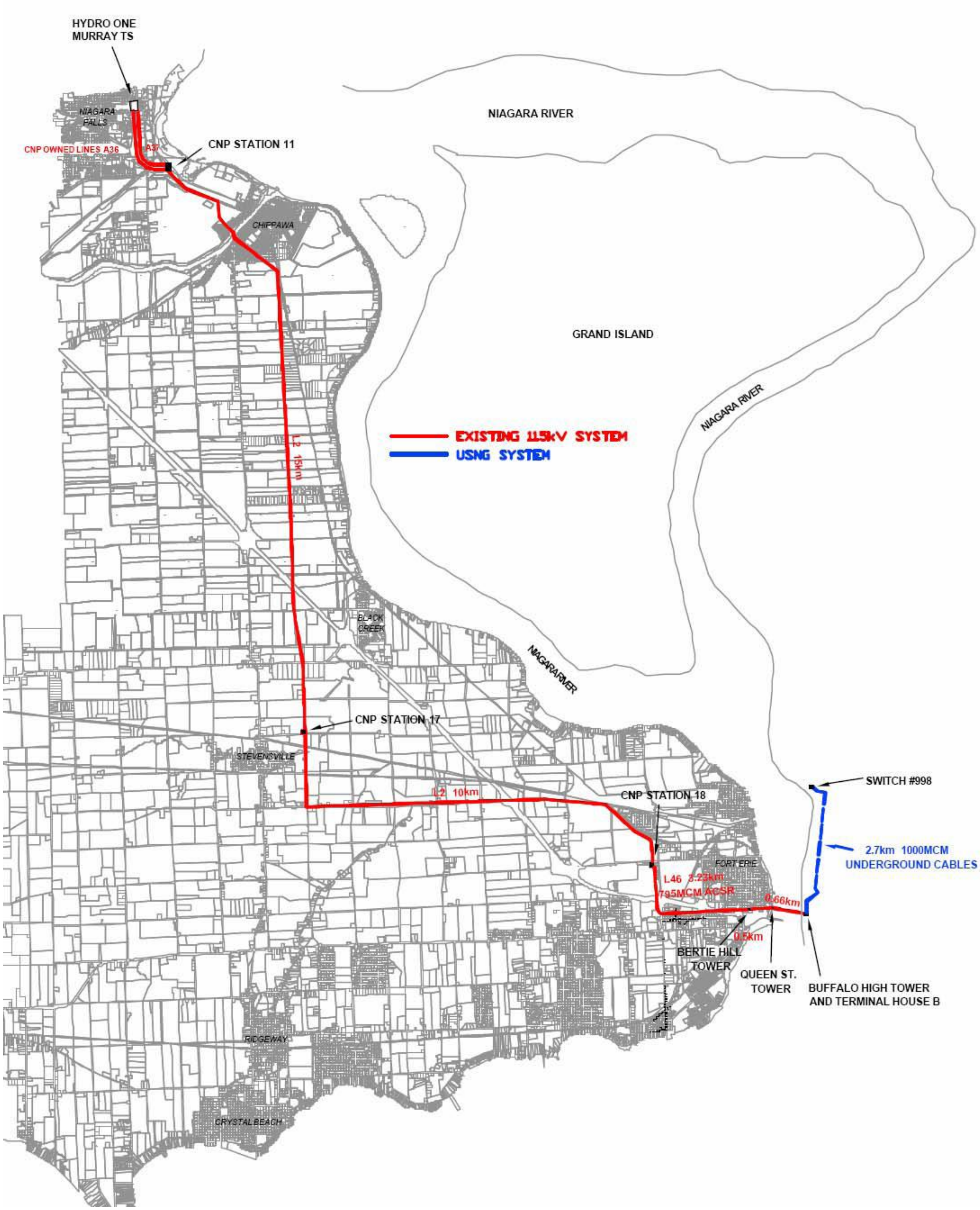
ISLAND GENERATION AND TRANSMISSION GRID

REV. 10/04/23

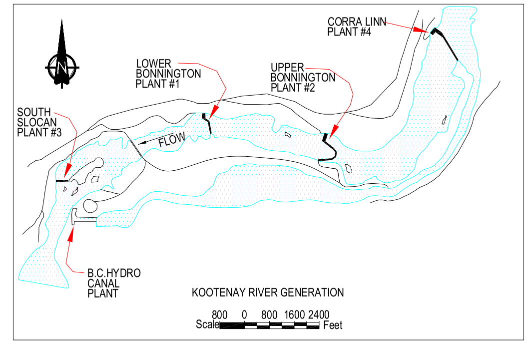


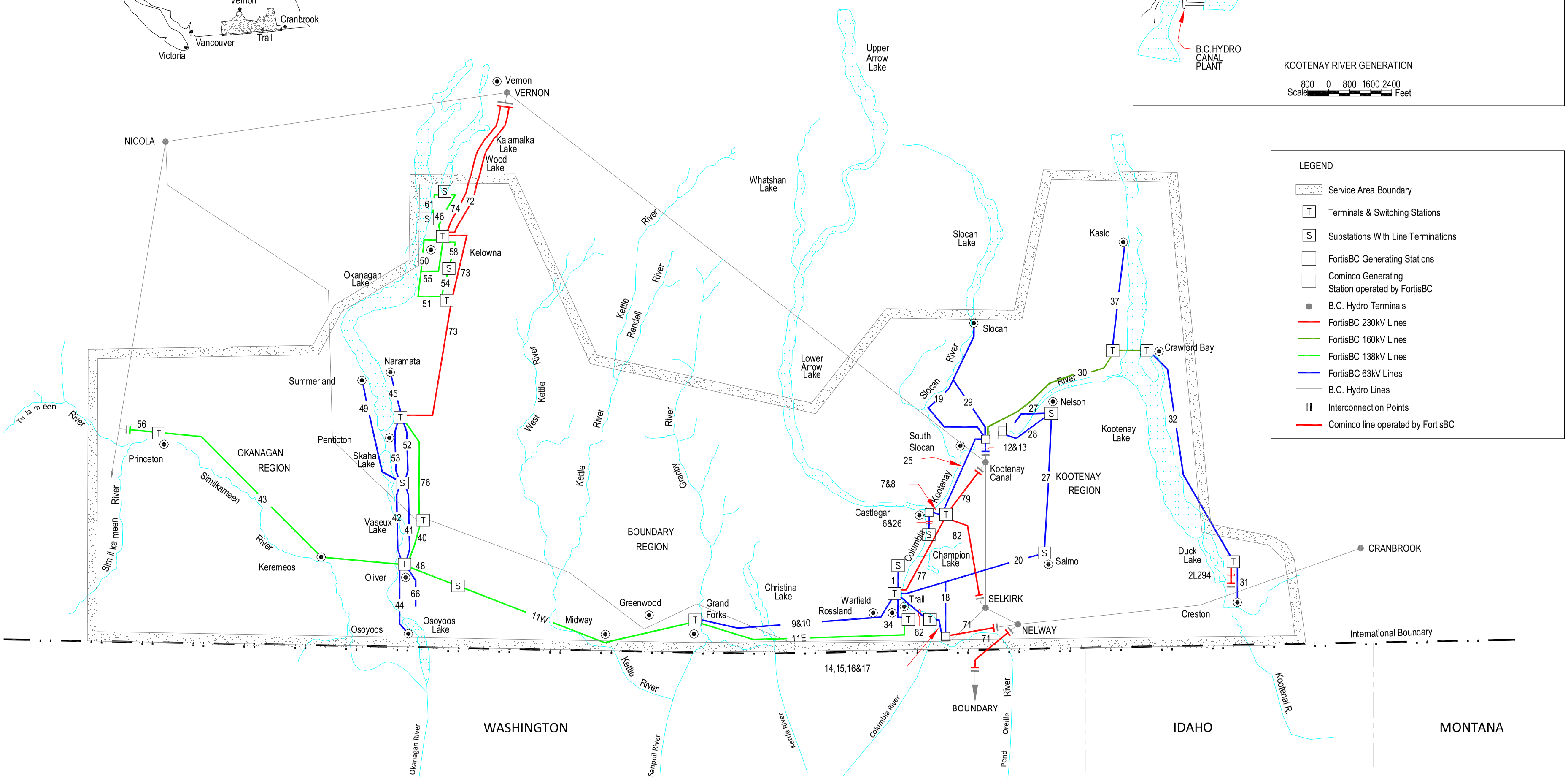
138kV Transmission Line
69kV Transmission Line
Maritime Electric Substation or Switching Station
Generating Plant
Northcape Wind Gen.
Aeolus Norway Wind Gen.
Suez Norway Wind Gen.
Alberton
O'Leary
Suez West Cape Wind Gen.
Wellington
Slemon Park
Summerside Wind Gen.
Sherbrooke
St. Eleanors
New Annan
Rattenbury
Hunter River
Richmond Cove
Bedeque
Interconnected to NB Power at Murray Corner
Albany
Borden
West Royalty
Charlottetown
Crossroads
Scotchfort
Lorne Valley Sw. Stn.
Victoria Cross
Dover
Georgetown
Church Rd.
Dingwells Mills
Souris
Eastern Kings Wind Gen.
MARTIME ELECTRIC
ENERGY SUPPLY SYSTEM
PRINCE EDWARD ISLAND

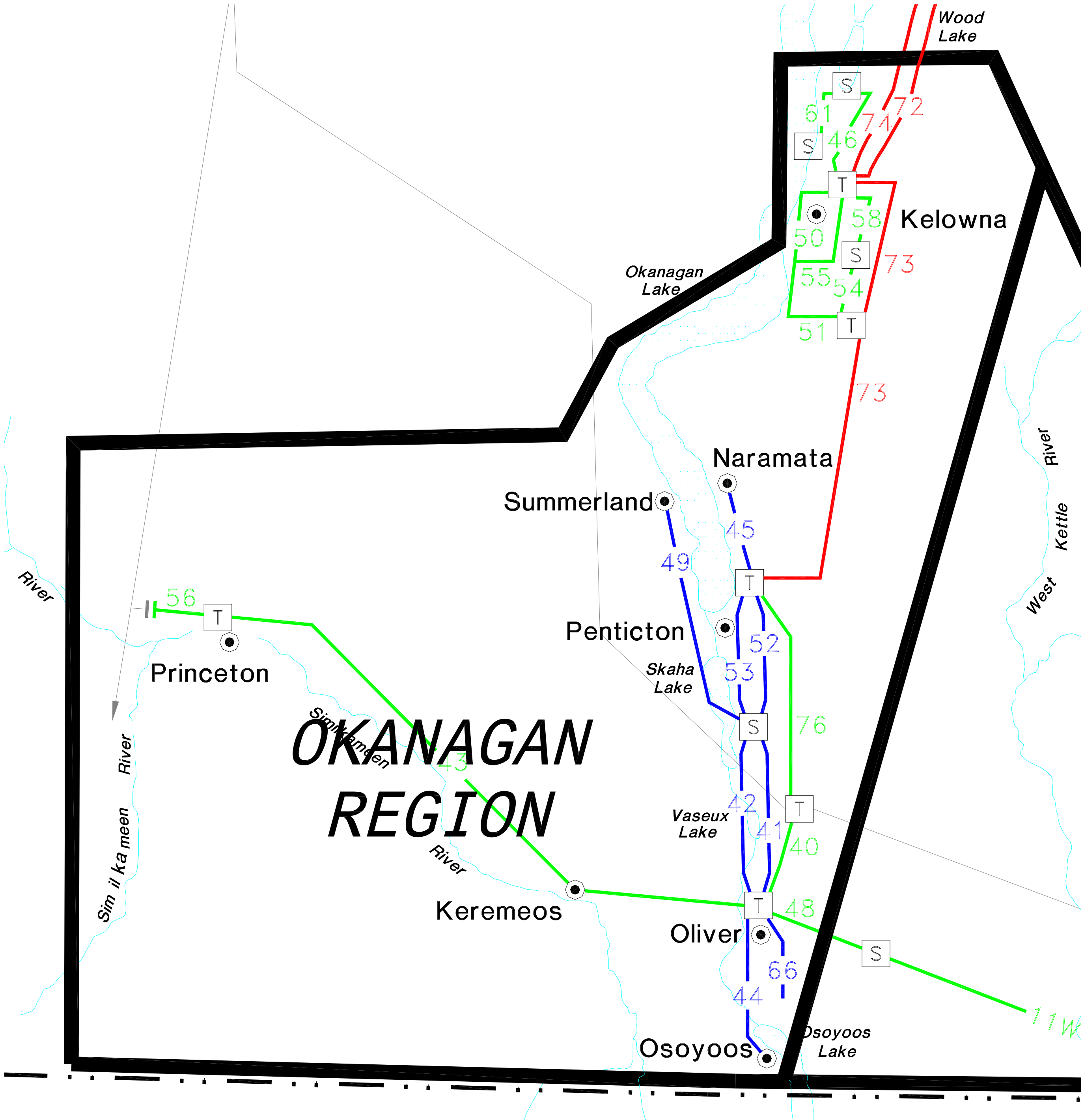
Canadian Niagara Power Inc.

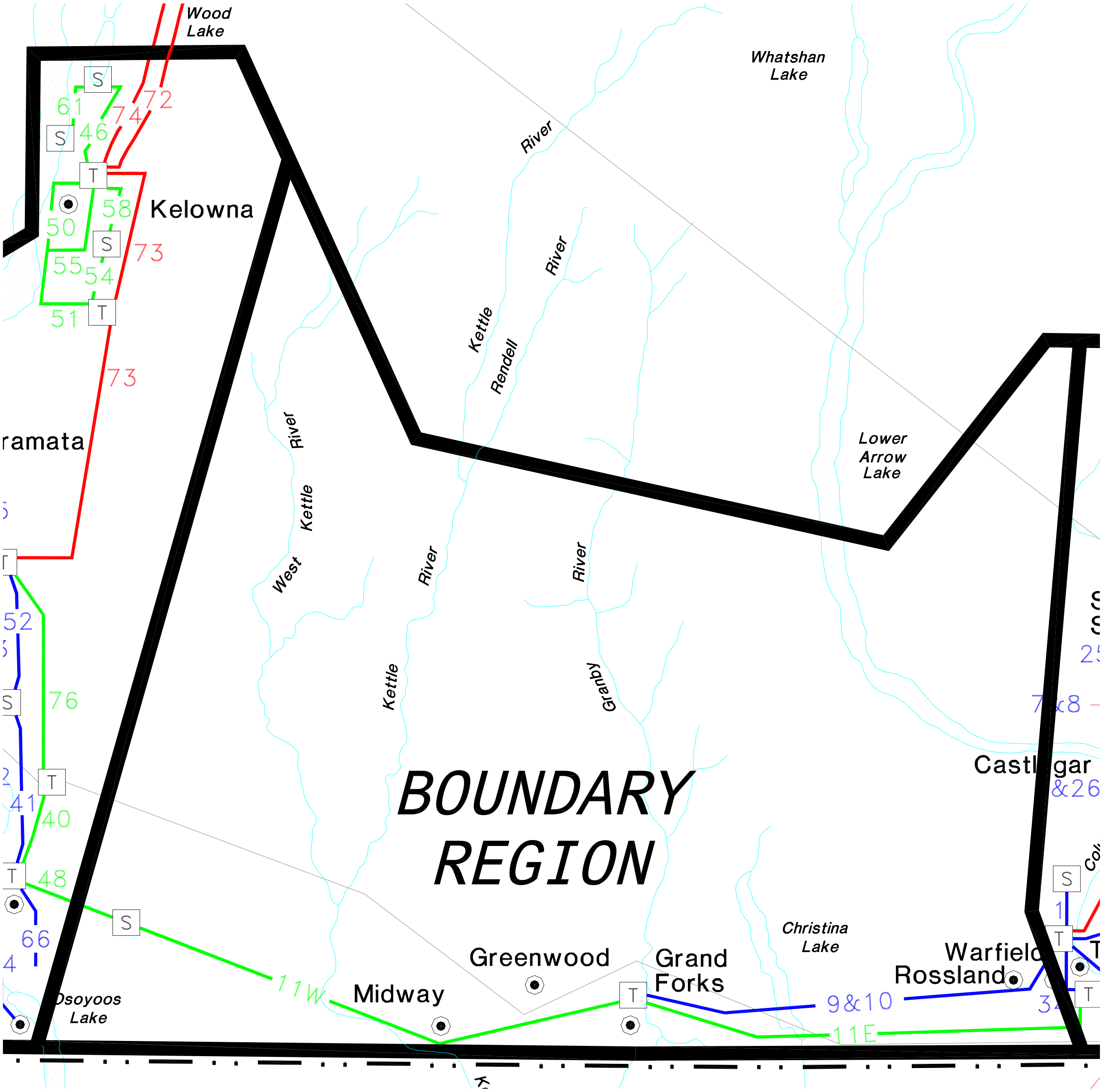


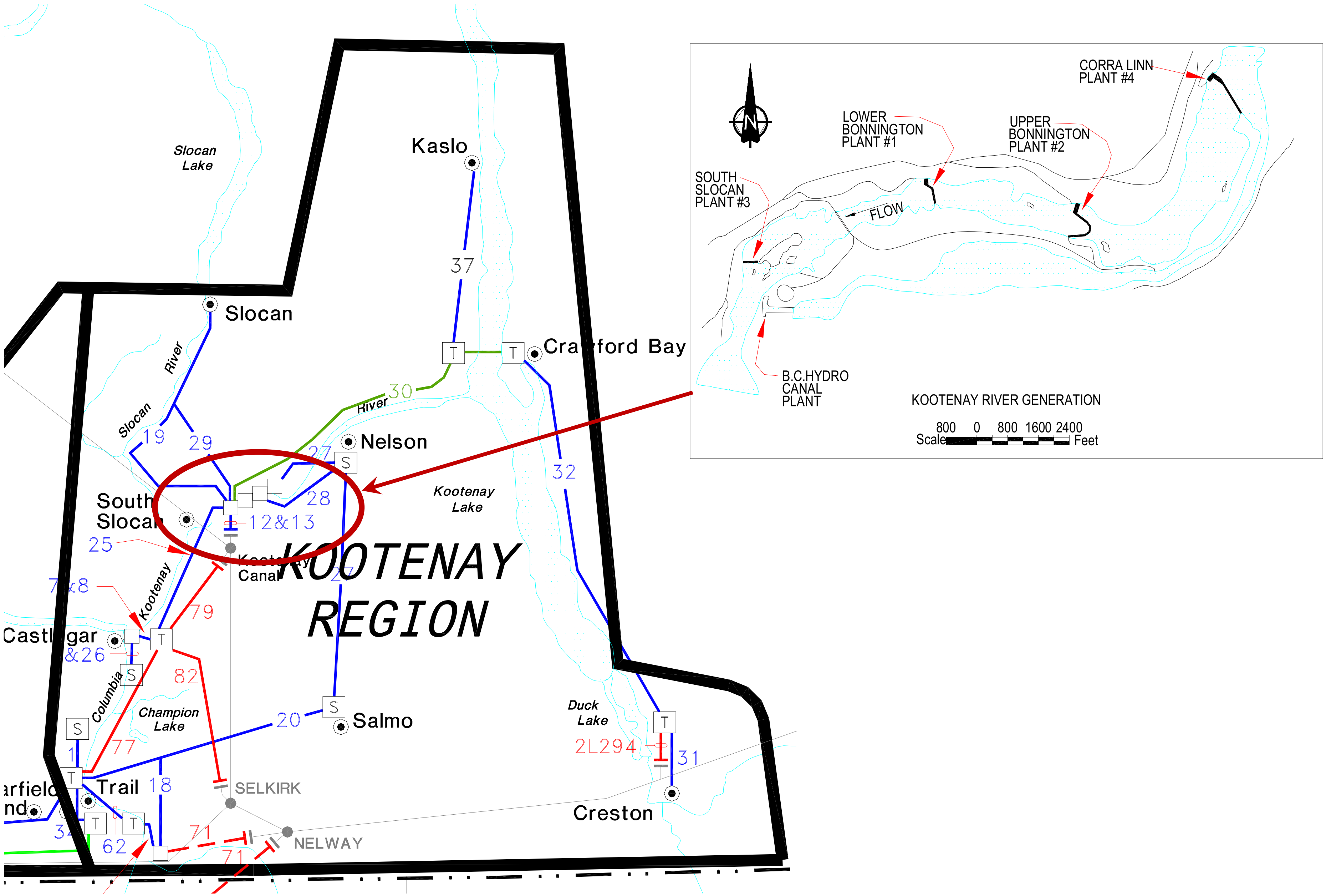
FORTISBC SERVICE AREA






Wood Lake
Kelowna
Okanagan Lake
Naramata
Summerland
Penticton
Skaha Lake
Vaseux Lake
Princeton
OKANAGAN REGION
Similkameen River
Similkameen River
Keremeos
Oliver
Osoyoos
Osoyoos Lake
West Kettle River
River
61
46
74
72
58
50
55
54
73
51
45
49
52
53
76
42
41
40
48
66
44
56
43
11W
S
T


Wood Lake
Kelowna
Whatshan Lake
River
Kettle
Rendell
River
Lower Arrow Lake
River
Kettle
West
River
River
Kettle
Granby
BOUNDARY REGION
Castlegar
Christina Lake
Greenwood
Grand Forks
Midway
Warfield
Rossland
Osoyoos Lake
61
46
74
72
58
50
73
55
54
51
73
52
76
41
40
48
66
11W
9&10
11E
7&8
&26
S
T


Slocan Lake
Kaslo
37
Slocan
Crawford Bay
River
Slocan
30
River
19
29
27
Nelson
28
12&13
32
Kootenay Lake
South Slocan
25
Kootenay Canal
KOOTENAY REGION
7&8
Kootenay
79
Castlegar
&26
82
Columbia
Champion Lake
20
Salmo
Duck Lake
2L294
31
77
Trail
18
SELKIRK
Creston
62
71
NELWAY
SOUTH SLOCAN PLANT #3
LOWER BONNINGTON PLANT #1
UPPER BONNINGTON PLANT #2
CORRA LINN PLANT #4
FLOW
B.C.HYDRO CANAL PLANT
KOOTENAY RIVER GENERATION
Scale 800 0 800 1600 2400 Feet

DISTRIBUTION SUBSTATION	# OF 13 KV FEEDERS	AIS / GIS	INDOOR / OUTDOOR	TXR MVA
HYDESVILLE	4	GIS	INDOOR	44.8 MVA
N.S.P. 13KV	10	GIS	INDOOR	201.2 MVA
SOUTH SOUND	4	GIS	INDOOR	44.8 MVA
PROSPECT	2	AIS	OUTDOOR	22.5 MVA
BODDEN TOWN	2	AIS	OUTDOOR	14 MVA
FRANK SOUND	2	AIS	INDOOR	22.4 MVA
RUM POINT	1	AIS	OUTDOOR	14 MVA

69KV TRANSMISSION LINES		
SECTION #	NAME	MILEAGE
1	FRANK SOUND TO BODDEN TOWN	6.6
2	BODDEN TOWN TO PROSPECT	6.3
3	PROSPECT TO SOUTH SOUND	3.7
4	SOUTH SOUND TO N.S.P.	1.6
5	N.S.P. TO HYDESVILLE	6.9
6	HYDESVILLE TO N.S.P,	8.7
7	N.S.P. TO RUM POINT	8.4
8	RUM POINT TO FRANK SOUND	10.8

Legend

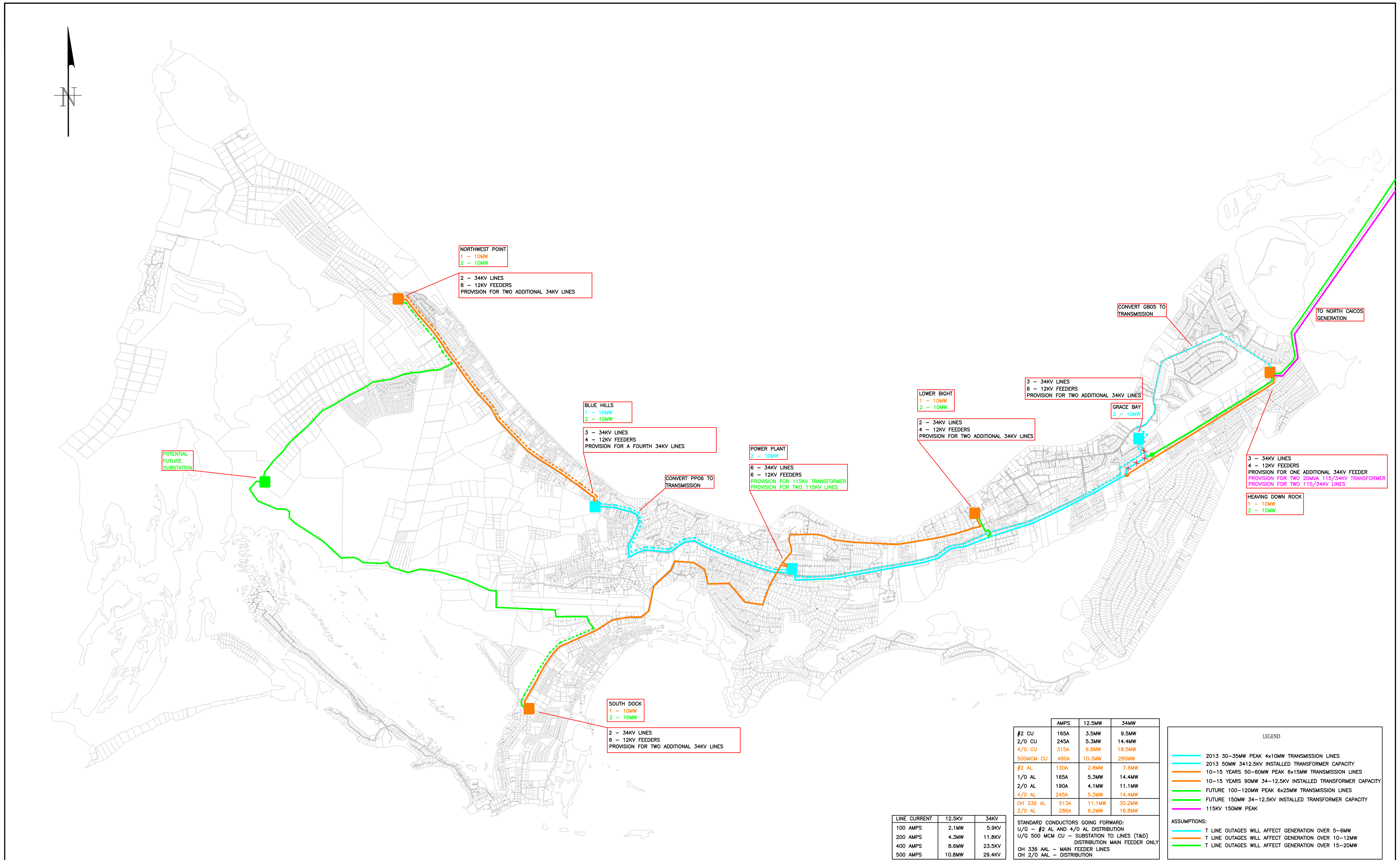
- Overhead Transmission 69KV
- Underground Transmission 69KV
- Distribution Substations

N
W E
S

0 1 2 4 6 8 Miles

CUC
You've got the power

CARIBBEAN UTILITIES CO, LTD. GRAND CAYMAN CAYMAN ISLANDS, BWI.	
69KV LINES AND SUBSTATIONS	
DRAWN BY:	J.BRODERICK
DATE:	23, October 2012



LINE CURRENT	12.5KV	34KV
100 AMPS	2.1MW	5.9KV
200 AMPS	4.3MW	11.8KV
400 AMPS	8.6MW	23.5KV
500 AMPS	10.8MW	29.4KV

	AMPS	12.5MW	34MW
#2 CU	165A	3.5MW	9.5MW
2/0 CU	245A	5.3MW	14.4MW
4/0 CU	315A	6.8MW	18.5MW
500MCM CU	480A	10.3MW	280MW
#2 AL	130A	2.8MW	7.6MW
1/0 AL	165A	5.3MW	14.4MW
2/0 AL	190A	4.1MW	11.1MW
4/0 AL	245A	5.3MW	14.4MW
OH 336 AL	513A	11.1MW	30.2MW
2/0 AL	286A	6.2MW	16.8MW

STANDARD CONDUCTORS GOING FORWARD:
U/G – #2 AL AND 4/0 AL DISTRIBUTION
U/G 500 MCM CU – SUBSTATION TO LINES (T&D)
DISTRIBUTION MAIN FEEDER ONLY
OH 336 AAL – MAIN FEEDER LINES
OH 2/0 AAL – DISTRIBUTION

LEGEND

- 2013 30–35MW PEAK 4x10MW TRANSMISSION LINES
- 2013 50MW 3412.5KV INSTALLED TRANSFORMER CAPACITY
- 10–15 YEARS 50–60MW PEAK 6x15MW TRANSMISSION LINES
- 10–15 YEARS 90MW 34–12.5KV INSTALLED TRANSFORMER CAPACITY
- FUTURE 100–120MW PEAK 6x25MW TRANSMISSION LINES
- FUTURE 150MW 34–12.5KV INSTALLED TRANSFORMER CAPACITY
- 115KV 150MW PEAK

ASSUMPTIONS:

- T LINE OUTAGES WILL AFFECT GENERATION OVER 5–6MW
- T LINE OUTAGES WILL AFFECT GENERATION OVER 10–12MW
- T LINE OUTAGES WILL AFFECT GENERATION OVER 15–20MW

REVISIONS

REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE
5						
4						
3						
2						
1			D.R.	UPDATES REFLECTING ONGOING DISCUSSIONS		

PROJECT:

PROJECT No:

FORTISTCI
1030 LEEWARD HIGHWAY
PROVIDENCIALES
TURKS AND CAICOS ISLANDS

FORTIS TCI

DEPARTMENT: TRANSMISSION – DISTRIBUTION

TITLE: TRANSMISSION AND SUBSTATION LONG TERM PLAN
SHEET 1 OF 1

SCALE: NTS | Date: 2011–17–11 | Drawn: SHELDON SANTIAGO

APPROVAL: DOUG RUSE | CHECKED: | DRAWING No. 00001

REVISION 1

APPENDIX C

Neegan Burnside

Statement of Qualifications

Proposal for

Neegan Burnside Qualifications

Submitted by:

Neegan Burnside Ltd.
15 Townline Orangeville ON L9W 3R4

Submitted to:

Canadian Niagara Power Inc.

December 2012

File No: FEO020829

Table of Contents

Appendices

Corporate Profile

Neegan Burnside Ltd.

Neegan Burnside Ltd. (Neegan Burnside) is a majority owned Aboriginal firm committed to assisting First Nations in meeting their development and economic goals while remaining sensitive to First Nation community, culture, values and beliefs. Together with partners, R.J. Burnside & Associates Limited (Burnside), and Nuna Burnside Engineering and Environmental Ltd., our success can be seen in the over 1,400 completed projects for First Nation clients in North America in every province and territory in Canada. The various associates of the firm have been providing services to First Nation communities for over 40 years and offer a true understanding of First Nation culture that allows effective and successful facilitation with First Nation communities.

Under the leadership of Chief Executive Officer Mervin Dewasha, P.Eng., from Wahta Mohawk First Nation, Neegan Burnside offers a unique combination of technical capacity and innovative thinking to provide superior project control and personal responsiveness to clients. Our partnership with Burnside enables a seamless sharing of human resources and equipment and access to a team of over 330 professionals, including engineers (civil, structural, electrical, mechanical), environmental scientists (environmental assessment, natural environment, hydrology), technicians, and specialized support staff. We believe in establishing strong local partnerships and working within Aboriginal communities to implement well-adapted and effective solutions. Among other staff, Neegan Burnside has 14 Aboriginal employees in engineering and support services representing 14 separate Aboriginal communities in Ontario and Manitoba. We have the knowledge, experience, resources and high quality of service to assist with any energy project, irrespective of its size or complexity. Our broad spectrum of experience and expertise in balancing the environmental, economic and social responsibilities associated with power generation, coupled with our local presence, provides a unique opportunity to service clients throughout all phases of energy projects from planning through decommissioning.

We continue to be guided by a client- and community-focused approach. We understand and value the need for community engagement to respond appropriately with solutions that mitigate environmental and social impacts. This is evident, for example, in all capital planning studies we undertake, in which an examination of the suitability of existing assets is greatly enhanced by community involvement. Our experience has revealed that consultation and continuous liaising with various stakeholders within the community is an effective application of the client-specific ‘first principles’ philosophy to problem definition and needs analysis. Our team also understands the added value of knowing local government and funding institutions’ processes. Refer to Appendix A1 for additional information.

R.J. Burnside & Associates Limited

R.J. Burnside & Associates Limited (Burnside) is an engineering and science-based consulting firm of over 335 professional, technical and support staff, and works in partnership with Neegan Burnside Ltd. We provide our clients with a comprehensive range of skills including design, project management, construction administration, and plant operations. Burnside was incorporated in 1970 in the Town of Orangeville, Ontario, Canada. Our firm currently operates from 10 offices in Canada and overseas in Barbados and Mozambique.

Burnside consistently provide quality infrastructure, engineering and consulting services to a progressively expanding number of clients in Canada and internationally. Our staff often assists our clients on projects with short deadlines, extensive approval requirements including securing necessary financing. While providing our clients with personal attention, we, at Burnside combine innovative and new technologies with our extensive consulting knowledge.

This reputation has enabled Burnside to represent more municipalities than almost any other consultant in Ontario. Our staff often becomes integrated with our client’s team, particularly in small municipalities where we effectively act as the municipality’s engineering department. We also work extensively on behalf of the private development community; in fact, Burnside has one of the most well respected golf services teams in Canada.

Sub Consultants

Hardy Stevenson and Associates Limited

Hardy Stevenson and Associates Limited (HSAL) is a firm of social scientists, environmental planners, and public consultation specialists. We operate as a network of companies centred on the 15 staff and associates comprising HSAL.

Our staff and associates have extensive experience in the energy sector, having worked on projects dealing with energy generation, including: wind, solar, biomass, natural gas, nuclear, hydroelectric power, and coal, and energy transmission. Since 1990, HSAL has worked for most of the Province's energy suppliers and regulatory agencies related to pipeline routing and approvals, rates, rules for opening the electricity market, transmission line routing and approvals, alternative energy suppliers, electrical distribution companies and electricity generators and others involved in environmental assessments.

Most of our work in the energy sector has focused on: (1) assessing and evaluating proposed projects based on potential effects to the natural and social environment, and (2) consulting and engaging stakeholders and members of the public in discussions related to these projects. We have used this set of skills to complete Master Plans for other infrastructure projects, including transportation, landfills and water / waste water, as part of the Ontario Environmental Assessment process.

Northern Bioscience

Northern Bioscience offers professional consulting services supporting ecosystem management, inventory, and research. Based in Thunder Bay, Northern Bioscience was established in 1996 and has undertaken over 250 projects for government, industry, First Nations, and non-government organizations. We have carried out projects in Canada and the United States, with a focus on boreal ecosystems.

Our principals combine strong academic backgrounds and experience working for government with an extensive network of professional associates. We are among the leaders in understanding the boreal flora, fauna and ecosystems in Northern Ontario. Since we are a small company, personal attention of the principals is ensured. We have full in-house GIS capability for mapping and spatial analysis. Northern Bioscience can assemble a multi-disciplinary team of environmental professionals to provide a full range of ecological services.

Western Heritage

Western Heritage is a firm offering archaeology, near surface geophysics (ground penetrating radar, gradiometry, magnetic susceptibility) and remote sensing services across western Canada and in northwestern Ontario. While many of the senior staff can hold permits and licenses across Canada, the company provides local services through offices in Grande Prairie, St. Albert, Calgary, Saskatoon, Swan River, Winnipeg and Thunder Bay. Western Heritage is a private, Canadian owned corporation with its Head Office in Saskatoon, Saskatchewan. Founded in 1990, Western Heritage staff have completed thousands of archaeological projects, from one day site inspections to multi-year, multi-disciplinary management and mitigation programs. The company regularly undertakes projects on both federal and provincial land, and has completed projects at all stages from initial historical overviews (Stage 1) to archaeological mitigation (Stage 4). Western Heritage is currently completing a large scale mitigation project for Ontario Ministry of Transport, currently the largest set of archaeological excavations underway in Canada. Western Heritage works with clients at all stages of their requirements, from Stage 1 to 4. The company is actively involved in developing client-specific heritage management plans. Western Heritage maintains a rigorous quality control system. All projects are reviewed and approved by an internal panel of Senior Archaeologists. This insures a constant professional approach taken for all projects across each provincial jurisdiction, even though there are often differences in provincial requirements. Western Heritage staff carry $2,000,000 in errors and omissions insurance, and $5,000,000 in general liability insurance. Western Heritage has a rigorous safety program that is certified by Enform, with an average score of 94%.

KBM

KBM was established in 1973 to provide forestry services to the forest sector in Northwestern Ontario. Today, KBM is recognized as a leader in aerial photography, digital mapping, planning, inventory and environmental assessment support services for the natural resource sectors in Central Canada and the Midwestern US. The firm operates its own aircraft, field services, retail outlet, warehouse and repair shop at its main office in Thunder Bay, Ontario and has satellite offices in Toronto, Manitoba and Saskatchewan.

KBM brings to this project a deep understanding of the social, economic and environmental context of Northern Ontario. KBM has intimate knowledge of the project area, completing the most recent forest resources inventory (FRI) for a 1 million hectare parcel in 2007 that includes nearly half the corridor length in 2008. The FRI relied heavily of KBM’s ability to access and analyse complex data from state of the art remote sensing sources (i.e. ADS 40) available through the Ontario Ministry of Natural Resources.

KBM also had a contract to clear the existing power-line and control vegetation along the proposed corridor. The firm maintains excellent business relationships with government agencies, businesses, communities and First Nations in the project area.

KBM staff are experienced in route planning for transmission lines to minimize environmental and stakeholder impact as well as construction cost. KBM has located approximately 200 km of transmission line for 18 waterpower projects in the past year. Routes were optimized through comparison with known natural heritage values, potential archaeological sites, existing access routes, patent land and water crossings. A rapid assessment technique was used to predict the occurrence of Provincially Significant Wetlands along the corridor. A virtual inspection of the route using 3D work stations and high resolution imagery will be used to assess the corridor for areas of high likelihood for Significant Habitat requiring intensive field studies.

The imagery was acquired by KBM's aircraft equipped to capture high resolution digital photographs. KBM can create geomatic products (i.e. maps, terrain models) provided by custom image and data acquisition from its aircraft and its archived data from public and project based sources. The firm has also developed LiDAR analysis toolkits and one of its planes is fitted to accept LiDAR instruments.

KBM staff is experienced in access route planning for transmission line construction and maintenance. KBM's experience in forest management helps us in access planning and in working with the Sustainable Forest License (SFL) holder for each forest along the proposed corridor. Use of existing and planned forest access roads usually reduces access costs and impacts.

The firm has developed cutting edge decision support systems that illuminate effects on bio diversity and other ecosystem services (water and soil nutrient pools) arising from proposed development alternatives in large scale forest and land use planning projects. In addition to a staff of professionals with advanced degrees in a natural science programs, the firm maintains a large network of interdisciplinary professionals from across Canada. KBM excels at managing these networks to provide an optimal level of services to its clients. KBM also works with local engineering and survey firms within the region on a project by project basis.

The firms also has natural resource field personal with backgrounds in biology and forestry that can complement Neegan Burnside and Northern Biosciences field service teams. KBM's natural science field services team recently completed environmental reports for Union Gas's red Lake extension and Thunder Bay OPG upgrade lines. KBM's forestry services team are currently working on several forest inventory projects. Consulting projects have also been completed for new start-up firms in the project area with an interest in the forest resource. These experiences and data will help with forest valuation and habitat interpretation exercises for the proposed corridor.

TBT Engineering

TBT Engineering Limited is Northern Ontario's largest independently owned civil engineering consulting firm based in Thunder Bay. TBT Engineering (TBTE) and its predecessors have been serving our customers since 1968. Since reorganization in 1995, TBTE has grown to include over 120 professional and technical staff.

We address the requirements of our clients by providing a wide range of geotechnical services. From preliminary studies to detailed design and analyses, we can tailor our services to meet your needs and budget. Our team of engineers, geologists and technologists has experience in providing geotechnical services to a wide range of clients. We pride ourselves on providing innovative solutions in dealing with the diverse and often complex subsurface conditions encountered within our region. TBT Engineering also provides a wide range material testing and laboratory services to the construction industry. Our laboratory and technologists are fully certified to meet the needs of our clients. Our corporate commitment to health and safety standards is reflected in all of our services.

Chimax Inc.

Established in 1989, Chimax Inc. has since grown into a highly-regarded engineering firm excelling in the design of electrical generation, transmission and distribution systems, and industrial buildings. Our dedicated staffs include a core of highly motivated and experienced professional engineers, designers and CAD operators.

Our engineering expertise, which continues to expand and grow, reflects the diverse assignments and hard work of our diligent staff over the years. Our dedicated staffs have extensive power utility experience, technical expertise and are committed to providing services of the highest calibre. Our extensive field experience working with construction contractors and keen eye for detail have allowed us to continually provide practical and cost effective solutions and recommendations for our clients.

Chimax Inc. offers a variety of engineering services including civil, structural and electrical engineering. Previous work has included the design of high voltage substations, transmission and distribution lines, switch yard design, protection and control systems, industrial buildings, overhead cranes, conveyors, mobile units for equipment transport and unique custom designs for special situations.

Clarida Green Energy

Clarida Green Energy has progressive experience in planning, design, and project management, of large Civil infrastructure projects in Hydroelectric Generation and Transmission facilities, Wind and Solar PV Energy, Dams, and Reservoirs. Clarida Green Energy completed 190 MW of Wind energy and 66 MW of ground mount Solar PV; Business Development Manager for Peter Kiewit Infrastructure Co., a large North

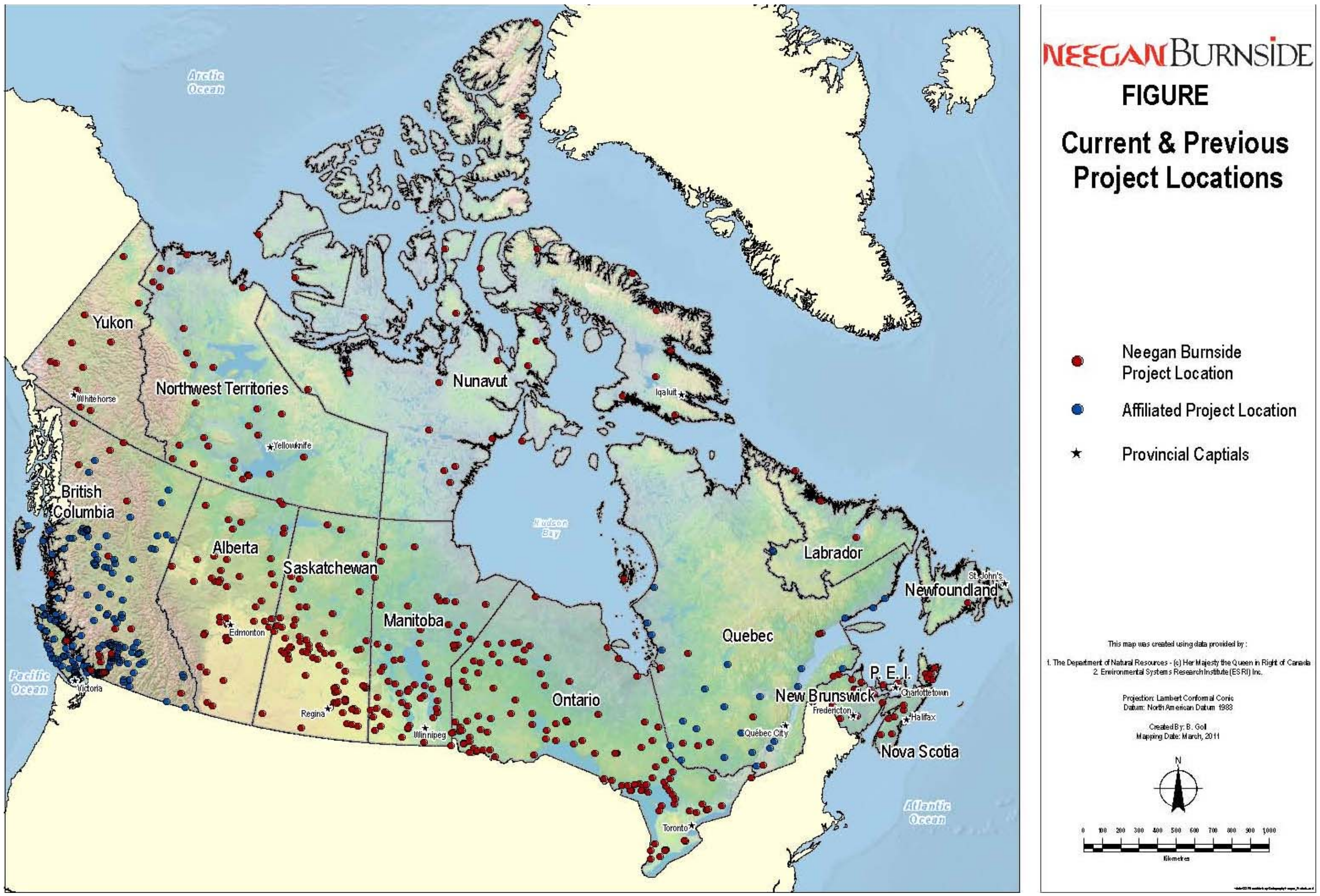
American contractor; Director, Major Projects for Brookfield Power, an independent power producer, responsible for a program of power facility construction and expansion projects including large Earth fill dams and composite Spill control facilities, Concrete gravity dams, Hydroelectric generation facilities, Wind Generation facilities and 115 and 230 kV Transmission Lines and Substations.

Airborne Imaging

Airborne Imaging is a Clean Harbors company and will supply LiDAR corridor mapping, digital terrain, and elevation models along with orthophotography for this transmission project.

Refer to Appendix A2 for additional information on our sub consultants.

Project Locations



Environmental Assessment and Planning

Our Environmental and Assessment Group understands the environmental permitting and regulatory challenges facing our clients today. Our team is highly conversant with the environmental approvals required for projects, be they under the Canadian Environmental Assessment Act, the Ontario Environmental Assessment Act, the Federal Fisheries Act, the Ontario Planning Act, or the host of other approvals processes that may apply to a given project. Many of these approvals can occur in tandem and we have proven experience coordinating the process.

Services

Neegan Burnside's Environmental Planning and Assessment Group consists of environmental assessment specialists, environmental planners, environmental engineers, and biologists (terrestrial and aquatic) who contribute a broad range of experience in providing solutions to project challenges.

With more than 85 years of combined experience, our team has worked in such diverse areas as:

- Federal EAs (CEAA) screenings and comprehensive studies;
- Provincial EA's (OEA) including Individual and Class EA's such as MOE, Municipal Class EA, MTO Class EA, MRN Class EA, Class EA for Minor Transmission Facilities, ORC Class EA, Conservation Ontario Class EA, Go Transit Guidelines, etc.;
- Multi-jurisdictional EA's under the 2004 Canada-Ontario Harmonization Agreement;
- Environment Impact Statements (EIS) for development under the Planning Act;
- International Financial Institution EA Requirements;
- Wildlife habitat assessments and inventories;
- Flora inventories;
- Fisheries habitat assessments and inventories;
- Wetland evaluations and boundary delineation;
- Ecological Land Classification (or equivalent);
- Natural areas management;
- Peer review and expert testimony;
- Multi-stakeholder government agency and First Nation public consultation;
- Securing development approvals and permits;
- Natural Environment Technical Reports for development under the Aggregate Resources Act.

Geomatics

In 1996, to better serve our client needs, Burnside developed technical expertise in the area of Geomatics, which includes Geographic Information Systems (GIS) and remote sensing. Burnside is a business partner of ESRI – the world's largest GIS software company. We have been providing top-level GIS products and services to local, national, and international clients for the past twelve years and have received two prestigious awards for our work:

- Business Partner of the Year 2004 from ESRI Canada; and
- 2008 ESRI International Business Partner of the Year Award.

The second award is given to recipients who have developed innovative GIS solutions that make a significant impact in the marketplace.

Services
Our GIS group has developed software solutions such as:

- Burnside GIS Tools;
- Land Use Manager;
- Notification Manager;
- Route Patrol Manager;
- Winter Patrol Manager;
- Fleet Manager;
- Sidewalk/Trail Maintenance Manager;
- Burnside Asset Data Model;
- Burnside Asset Manager;
- Burnside Asset Analytics.

Employing industry-leading geomatics professionals, we follow an innovative process that enables ongoing research and development into solutions and best practices. We offer our clients a variety of data collection techniques, customized maps, on-line services, custom designed software and personalized training.

A Geographic Information System's primary purpose is to manage, analyze, and disseminate spatial data and phenomena. The types of data the GIS is capable of managing is as varied as the methods of collecting the data. Most GIS projects and datasets utilize vector, raster, and tabular data. With the introduction of the ESRI Geodatabase, all these forms of data can be integrated into a relational database. Burnside has extensive experience in the collection, integration, and processing of data in all types of industry formats and from many sources and agencies ranging from government to private industry. Burnside employs a wide range of Airborne and Space borne platforms including the Global Positioning Satellites (GPS) constellation, Ikonos, Landsat, Radarsat, Hyperspectral Sensors, traditional Aerial Photography, terrestrial surveying, and borehole geophysics.

The creation and provision of specialized datasets to support environmental projects such as groundwater protection studies, hydrological and floodplain analysis, and solid waste management is a staple of our expertise.

Consultation and Accommodation Services

Consult and Accommodate is a new legal framework set out by the Supreme Court of Canada. The new duty requires governments to consult Indian, Inuit and Métis peoples and accommodate their interests whenever considering an action that might adversely affect Aboriginal rights or interests.

Services

Neegan Burnside staff can assist in the following areas:

Developing an understanding of the technical aspects (engineering and environmental sciences) of the project as well as the practical requirements of the Duty to Consult and Accommodate process as it affect the community.

Explain specific issues related to projects proposed on Aboriginal lands such as – hydro, water/wastewater, environment, archaeology, landfills, sewage lagoons, pipelines and mines. These projects can range from small traditional projects to larger projects involving meetings and report reviews, where we can be fully engaged in the process working beside community representatives.

Interpret technical documents and bridge the gap facilitating a broader more general understanding of technical issues to members of the community not versed in these matters.

Assist in developing relationships between project proponents and First Nations.

Peer Reviews with regard to First Nations.

Produce required documents such as Memorandums of Understanding and Benefit Agreements addressing project issues that are understood within the community.

Engineering Services

Neegan Burnside Ltd. provides complete consulting and professional engineering capability to commercial, industrial, institutional, manufacturing process industries, commercial sectors and Municipalities. Our team includes professional engineers with industry-leading experience in the disciplines of mechanical, electrical, process, and manufacturing engineering. Services offered may range from the construction of a new facility to the expansion of an existing building or the assessment and alteration of existing mechanical and electrical systems to accommodate a new user/tenant or occupancy type. Every client receives individual attention from our knowledgeable team, which is available on an as-and-when-needed basis.

Civil Engineering

Burnside has served the land development industry for over 40 years. Over that time, the regulatory environment and the complexity associated with securing a permit or approval has changed significantly. What has not changed however, is our commitment to service and value – allowing us the privilege of working with many industry leaders.

Our clients are as diverse as Burnside. From downtown high rise to small rural development, we have done it, and have a comfort level operating in each environment. And, as the needs of our clients change, so too does Burnside. Initially, we prepared site plan and subdivision designs and administered construction for residential, commercial and industrial developers. Our capabilities expanded to include expertise in stormwater management and hydrogeology as water resources took on greater importance. Added skill sets in environmental sciences allow us to meet our client's needs in the preparation of environmental impact studies.

Structural Engineering

Neegan Burnside and R.J. Burnside & Associates Limited have a full time staff in the structural group of 90 qualified Professional engineers and additional supporting technicians and technologists.

We anticipate that our in house staff will be able to assist on this project in the following areas:

- Site investigations along the proposed routes to assist with project issues such as the demolition of existing structures and identification and design of associated temporary works required to facilitate the construction of the transmission line;

- Our bridge group will be able to design temporary access roads and bridges, as applicable. These may be required to facilitate transportation to the site of construction materials and work crews;

- The structural and bridge group may also be retained to design or review the design of proposed foundations, for the towers and any other structures;

- Act as a liaison between the tower designers and the contractors and local communities;

- To provide assistance with quality assurance and quality control issues, as it relates to design or during construction;

- Although our staff has experience in a wide range of structures, buildings and bridges, we are not known for transmission tower designs. We are aware however of the local building codes and bridge design codes as well as the environmental design loading involved.

Neegan Burnside Ltd. can assist communities obtain an accurate assessment of their infrastructure, set up an appropriate system for maintenance management and equip them with any necessary training. We are acutely aware of the need to maintain technical standards; the development of local expertise and administrative capacities; and the establishment of operation and maintenance systems to ensure asset sustainability.

Infrastructure Evaluation – Through extensive evaluations, Neegan Burnside Ltd. identifies constraints and opportunities to extend the life of infrastructure components. We provide technical coordination for identifying, rating and prioritizing infrastructure needs to facilitate efficient and sustained operational systems.

Maintenance Management Systems – A Maintenance Management System (MMS) is a systematic approach to determining the level of effort and expenditure required for infrastructure. It is essential to ensure that current assets provide their optimum level of performance and reach their designed life expectancy. Each MMS is customized to address the unique needs and requirements of the community. From asset condition reporting to the development of work orders, staff schedules and budgets, to system implementation and maintenance, Neegan Burnside Ltd. is experienced in helping a client sustain and maximize the infrastructure potential.

Training – Institutional capacity development is essential to effective infrastructure operations. Through human resource development and the establishment of operation and maintenance procedures, public works staff are educated on how to operate and maintain their systems. For remote projects, Neegan Burnside Ltd. can implement a remote monitoring system and assist with on-going support to trouble shoot any operational difficulties.

Mechanical Engineering

System Design, Construction Review, Commissioning
Process Engineering Review and Analysis
Custom Machinery and Plant Equipment Design
LEED ® Certified Design
Government Approvals (MOE, MOL, TSSA, etc.)
Energy Analysis, Audits and Retrofits
Hazardous Area Classifications
Equipment Condition and Operation Audits
HVAC Systems
Fire Protection (Sprinkler Systems)
Fire Code Compliance Audits
Materials Handling, Conveying and Storage Systems Design
Pneumatic, Hydraulic and Motion Systems Design
Plant and Equipment Modification and/or Upgrade
Pre-start Health and Safety Reviews
Asset Assessment and Management Systems
Fuel Delivery
District Energy (combined heat and power)
Medical and Compressed Gas
Air Blowers, Compressors and Vacuum Systems
Heat and Ventilation (plumbing and drainage)
Air Conditioning, Coolers, Chillers (pumping and piping)
Building Automation Systems Design

Electrical and Controls Engineering

Hydro and Interconnection Coordination
Power Distribution (medium and low voltage)
Emergency Power (generator and uninterruptible power supplies)
Arc Flash Assessments
Lighting (roadway, interior and outdoor applications)
Fire Alarm Systems
Communications
Controls (motor control centres, SCADA, PLC and HMI systems)
Security
Equipment Condition Assessments
Traffic/Railway Signals
Motion and Control Open and Closed Loop Servo Systems

Communications and Systems Integration
Custom Software Development
Ontario Health & Safety Pre-start Reviews and Approvals
Contract Administration
Project Management
Field Services
Renewable Energy Pre-feasibility Studies
Renewable Energy Systems Designs for Solar and Wind Projects
Coordination and Local Authority
Facility Lighting Design
Street Lighting Design
Substation Commissioning

Representative Projects

Grand Bend Wind Limited Partnership

Neegan Burnside provided consultation services for the Grand Bend Wind Limited Partnership, c/o Northland Power Inc., in respect of the Renewable Energy Approval for the 100 MW Grand Bend Wind Farm. It includes, a 32 Km, 230 kV transmission line running from the wind farm to the 230 kV, Hydro One, Seaforth connection point.

Sithe Energy Southdown Station Project

Sithe Southdown Ltd. (Sithe) is the proponent of the Southdown Station project. The company initially invested in the Ontario power market when the Province first announced their intention to deregulate the power industry. Sithe recognized the critical need for additional power generation in the western GTA, and assembled a project team to achieve their objective of being the first to market with a new clean gas fired generating facility.

Burnside was originally retained by Sithe Southdown Ltd. to assist with site servicing related issues associated with the development of the 880 MW natural gas fired combined cycle generating facility. The site is located on a 35 acre parcel on Winston Churchill Boulevard in the City of Mississauga. Total building area to accommodate the plant is in the order of 150,000 sq. ft. As the project developed, the scope of Burnside's retainer grew to include additional services.

The project team provided services in:

- Public consultation process;
- Assistance with environmental approvals and reporting;
- Site servicing and grading;
- Stormwater management and floodline impact analysis;
- Transmission line routing;
- Gas line routing;
- Tender package and review of bids for underground transmission line;
- Preparation of easement agreements, site plan agreements, licensing agreement, etc.;
- Securing of associated permits and approvals.

Sithe Energy Goreway Station

Burnside was originally retained by Sithe Canada Ltd. to assist with site servicing related issues associated with the development of the 880 MW natural gas fired combined cycle generating facility. The site is located on Goreway Drive in the City of Brampton. Total building area to accommodate the plant is in the order of 150,000 sq. ft. As the project developed, the scope of Burnside's retainer grew to include additional services.

Our staff provided services in the following areas:

- Public consultation process;
- Assistance with environmental approvals and reporting;
- Site servicing and grading;
- Stormwater management;
- Floodline impact analysis;
- Transmission line routing;
- Gas line routing;
- Tender package and review of bids for overhead transmission line;
- Preparation of easement agreements, site plan agreements etc.;
- Securing of associated permits and approvals.

Social and Environmental Assessment for the Bujagali Hydropower and Interconnection Projects, Bujagali Energy Limited, Uganda

Uganda has long suffered from lack of electricity, and the problem has become acute in recent years. While the emergency thermal generation program of the Government of Uganda will help to address short-term needs, there is a greater need to address medium – and long-term needs for economical, large-scale power generation in Uganda. The Bujagali Hydropower Project (HPP) will help to alleviate this need. The HPP involves the construction and operation of a 250 MW hydropower facility on the Victoria Nile River. The project site is located at Dumbbell Island, approximately 8 km downstream (i.e. north) of the Town of Jinja and Lake Victoria. The sponsor of the HPP is Bujagali Energy Limited (BEL), a project-specific partnership of SG Bujagali Holdings Ltd. and IPS Limited (Kenya).

BEL retained Burnside as the Prime Consultant of a multi-discipline international consulting team to prepare and deliver an SEA for the proposed Bujagali HPP. Burnside was also charged with the task of coordinating and preparing a companion SEA for the Interconnection Project (IP) to evacuate power from Bujagali and move it to Kampala. The SEA requirements for this project were based on Government of Uganda regulations and the policies and procedures of international lenders sponsoring the project. With the aim of starting construction in Summer 2007, BEL's main objective was to complete all SEA documentation for the project by end of 2006, thus allowing time for the international public review and approval of the project by Ugandan agencies and lenders. The complexity of this project required the Burnside-led team to diligently consult with communities, businesses and individuals directly and indirectly affected by the project. The Burnside-led team provided services including coordinating terrestrial and aquatic ecological assessments, socio-economic and tourism impact assessments, optimization of transmission routing, public, agency and lender consultations, development of social and environmental actions plans, and preparation of a substantive suite of SEA documentation. Burnside continues to assist BEL with the planning of their social and environmental commitments for this project and the ongoing stakeholder consultations during the months leading up to the project's construction.

Burnside provided services in the following areas:

- Terms of Reference (TOR);
- Individual Environmental Impact Assessment (EIA);
- Terrestrial and Aquatic Ecological Assessments;
- Socio-economic and Tourism Impact Assessments;
- Public, Agency and Lender Consultations;
- Social and Environmental Action Plans;
- Stakeholder Consultation.

Ontario Power Authority, Advisory Services for Aboriginal Renewable Energy Fund Development

Neegan Burnside provided advisory services to the Ontario Power Authority for the development of this fund. Our team including London Economics, developed cost estimates for every type of renewable energy project as background to help develop the framework and size of the fund. We provided advisory services with respect to development of a request for statements of interest. Our team also provided advice on development of the rules documents for the fund.

Class 4, 100 MW Wind Power Project – Confidential Client

Burnside is in the process of undertaking a Renewable Energy Approval (REA) for a 100 MW wind farm and associated transmission line in Ontario. The project is categorised as a Class 4 wind facility and will require the following technical documentation: Project Description Report, Natural Heritage Evaluation, Archaeology and Cultural Assessment, Wind Turbine Specification Report, Noise Assessment, Design and Operations Report, Construction Report, Decommissioning Plan Report and Consultation.

Class 2 Wind Projects (numerous)

Burnside has successfully obtained REA approval on numerous Class 2 wind projects. Project components included Feed in Tariff (Fit) Program application, Hydro One connection assessments and Renewable Energy studies required under the Environmental Protection Act.

Geilectric – Wind Power Projects (numerous)

Burnside has prepared numerous environmental constraints analysis reviews for potential wind farm projects located both on and off First Nations reserve lands and has prepared an Environmental Screening Report for a proposed 10 MW wind farm and associated transmission line. The ESR incorporates the requirements of the Environmental Screening Process (Category B), Ontario Regulation 116/01.

Indian and Northern Affairs Canada (INAC), Compendium of Training Resources and Self-Assessment Tools for First Nations Public Works, First Nations of Canada

Best Practice Case Studies – Good Public Works Governance:

- **Comprehensive Community Planning;**
- **Renewable Energy and Energy Efficiency.**

Neegan Burnside worked with Indian and Northern Affairs Canada on several undertakings associated with good governance of public works functions, including water and wastewater infrastructure in First Nations communities. The first project involved the preparation of a National Compendium of Training and Information Resources, in addition to a self-assessment tool to assist First Nations in making Public Works management decisions. These tools are available on the Government of Canada's website. The second project involved the preparation of case studies to document success stories in public works in First Nation communities across the country. Site visits were taken to six selected First nation communities and interviews completed with key members of the public works department, senior administration, council and the community. A two day workshop was held with participants in order to discuss lessons learned and common elements of success.

Similar profiles were subsequently prepared documenting experiences of First Nation and northern communities in Comprehensive Community Planning. A total of 17 communities were interviewed, covering issues such as the focus or rationale, format, planning tools, regulatory tools and enforcement, visioning process, community involvement, partnerships, use of resources, external stakeholders, implementation, successes and hurdles, innovations, environmental and cultural protection, and integration of traditional knowledge. Neegan Burnside assisted with the facilitation of a workshop bringing together representatives from each of the participating communities, along with the scripting for a video and final report as a result of the workshop.

Métis Nations of Ontario Standing Offer for Environmental Services

Burnside is responsible for providing consulting services to the Métis Nation of Ontario (MNO). A sampling of the services that we will provide to MNO are as follows:

- Federal Environmental Assessment (including workshop design and facilitation services);
- Watershed Management Planning;
- Environmental, Resource and Land Use Planning;

- Policy and Regulation (including public and agency consultation, council representation and aboriginal consultation/facilitation).

Call-ups completed under the standing offer to date have included and evaluation of Potential Impacts to the Métis way of Life in the Hudson Bay Lowlands and development of a Métis Land Use Planning Guide.

Indian and Northern Affairs Canada and NRCAN, Formative Evaluation First Nations Forestry Program

As part of a standing offer for evaluation services, Neegan Burnside completed a program evaluation for the First Nation Forestry Program, which provides funding to encourage First Nation involvement in the forestry sector. According to the review, the financial assistance provided by the program has had a significant impact on assisting First Nations to develop institutional and technical capacity, acquire skills for employment in the forest sector and develop partnership arrangements with members of the forest industry. The evaluation involved interviews with over 75 First Nation leaders, national and regional government staff and facilitation of several national focus group sessions.

Walpole Island First Nation (WIFN), Expert Representation and Environmental Review

Neegan Burnside has provided technical, advisory and review services to the First Nation as part of a multi-disciplinary team created by the Heritage Centre of Walpole Island First Nation, primarily to address Traditional Territory issues. Neegan Burnside has, for more than 15 years, worked with the Heritage Centre and WIFN in addressing issues affecting the traditional territory and the St. Clair watershed.

Neegan Burnside assists WIFN in implementing the practical aspects of the guiding environmental philosophies and principles established by the community. Often, these principles are applied in relation to ‘External Projects’ proposed or undertaken by proponents in WIFN’s traditional territory. This role is described as follows:

> “*The First Nation is also actively engaged in applying its own high standards of environmental concern and management to a range of external issues, including the proposed project activities in the disputed territories. One of WIFN’s long-term goals is to gain recognition as a respected and principled advocate for sustainable practices. As a result, it is equally committed to building bridges with industry by engaging in continuous dialogue and consultation on environmental issues*” (‘Bkejwanong Territory, Environmental Policies, Guidelines and Information for External Project Proponents’, February 11, 2000, Walpole Island Heritage Centre’).

External projects have included:

- Hazardous waste landfilling, dredging activities, disposal of contaminated dredged materials, sediment remediation, municipal and industrial wastewater effluents, road and river crossings, natural gas pipeline crossings and power generation facilities.

Neegan Burnside provides a broad range of technical, review and support services dealing with External Projects, including:

- Technical review of proponent information, including proposed project details, potential impacts (social, economic, environmental), mitigative measures (this has included reviews of many Terms of Reference and Individual EA documents) etc.;

- Identification of issues, based on WIFN unique perspective, including aspects such as effects on environment, social conditions, and cultural perspective (traditional knowledge, hunting, fishing, recreation, resource management, land use etc.);

- Preparation of documents and communication materials to assist in community decision-making processes;

- Involvement in community meetings, presentations and workshops;

- Liaison and coordination with multi-disciplinary experts (legal, historical, biological, toxicology, air quality, geotechnical, information systems etc.);

- Assessment of need for supplemental technical expertise; co-ordination of technical team;

- Technical representation at formal hearings;

- WIFN representation in interactions with proponents of External Projects, including the strategic development of:
  - Memoranda of Understanding;
  - Environmental monitoring programs;
  - Environmental criteria, trigger levels, response mechanisms;
  - WIFN notification and contingency/emergency planning;
  - WIFN employment, contracting, capacity building and/or training opportunities.

Ontario First Nations Technical Service Corporation, Tendering Guidelines for First Nation Construction Projects

Neegan Burnside prepared a document entitled "*Tendering Guidelines for First Nation Construction Projects*", on behalf of Ontario First Nation Technical Services Corporation for use by First Nation communities. The document provides guidance to tendering procedures and practices for construction projects and is essentially a "how to" manual incorporating the maximization of socio-economic benefits for the community. Neegan Burnside presented to a First Nation audience outlining the contents of the document, including a discussion regarding how each community can develop the capacity to further participate in the opportunities available within the construction industry.

Economic Renewal Secretariat, Maximizing Socio-Economic Benefits to First Nations Communities During Construction

Neegan Burnside was invited by the Economic Renewal Secretariat to participate in an Economic Renewal Workshop. Neegan Burnside provided a presentation entitled "*Maximizing Socio-Economic Benefits to First Nations Communities during Construction*". The presentation included methods to incorporate local labour, equipment, trainees and other First Nation resources in a construction contract document. A detailed review of the many examples of employment opportunities and local resource utilization was provided to the audience including sample specifications and information regarding Joint Ventures.

Department of National Defense (DND), Former Camp Ipperwash – Unexploded Ordinance (UXO) Environmental and Cultural Resource Investigations

Neegan Burnside was responsible for the community consultation aspects of the UXO/environmental investigation at this former military training base (12 team meetings, 12 community consultations, 4 focus sessions and reporting). The project involves the development and implementation of a framework for project communication and consultation including: consultative structural protocol, investigative and site energy protocol, aboriginal involvement, project tracking, environmental protection, health and safety, and communication tools such as newsletters, technical bulletins and presentation material. The process is being documented in a 'Community Consultation Report'.

Representative Sub-Consultant Projects

Little Jackfish Transmission Line Environmental Assessment (in progress)
Completed assessment of terrestrial and aquatic environment for a proposed approximately 200 km transmission line to support an environmental assessment. Components included (i) assessment of fish populations and habitats at potential crossings, (ii) species at risk population surveys, (iii) forest and wetland habitat mapping, (iv) compilation of species lists, (v) identification of potential impacts on valued ecosystem components and mitigation measures. This project included Woodland Caribou habitat modelling and cumulative effects assessment.

Stillwater Mine Environmental Assessment (in progress)
Completed assessment of terrestrial environment for a proposed mine near Marathon, Ontario to support a federal environmental assessment. Components included (i) species at risk population surveys, (ii) forest and wetland habitat mapping, (iii) compilation of species lists, (iv) identification of potential impacts on valued ecosystem components and mitigation measures. This project included Woodland Caribou habitat modelling and cumulative effects assessment.

Peregrine Falcon Surveys
Brian Ratcliff has completed annual Peregrine Falcon surveys on the north shore of Lake Superior for over 20 years and has banded over 500 young Peregrines.

Life Science Inventories for 65 Ontario Provincial Parks and Conservation Reserves
These projects involved designing a sampling program, organizing logistics, reviewing background information on biological, physical, and human values, conducting the fieldwork, and writing a summary report. The fieldwork component involved sampling soils, forest inventory, vegetation composition, significant habitats, surveys for species at risk, and compiling species lists for flora and fauna, culminating in a report synthesising biophysical information, significant features, and management recommendations.

Status of Habitat in the Lake Superior Basin
Conducted literature review of the status of plant and wildlife habitat in the Lake Superior basin. Conducted interviews with resource professionals in Ontario, Wisconsin, Minnesota, and Michigan, as well as federal counterparts. Developed databases for ecological values, relevant literature, and contacts. (Harris, A.G. and R.F. Foster. 2000. Status of Habitat in the Lake Superior Basin. Lake Superior Lakewide Management Plan. Unpublished report prepared for Lakewide Management Plan Habitat Committee. 250 p.).

Science and Technical Support for the Proposed National Marine Conservation Area (NMCA) on Lake Superior

Compiled diverse ecological, physical, and cultural data, developed spatially explicit databases, and conducted GIS-based gap analysis for marine representation. Also compiled and synthesized information on anthropological effects on Lake Superior to prepare report on status and trends within the Lake Superior Basin. We also conducted a survey and review of human use and recreation in the proposed NMCA.

Wetland Evaluations

We have completed 30 wetland evaluations following the Northern Ontario Wetland Evaluation System. Reports included digital (Arcview) annotated wetland maps. These include the Nipigon River, Kabitotikwia River, and Poshkokagan River wetlands in the Lake Nipigon Basin.

Ecological Strategy for Great Lakes Heritage Coast – Ontario's Living Legacy

As part of a multi-disciplinary team, helped develop a strategy for the Great Lakes Heritage Coast on Lake Superior and Lake Huron. Compiled over 100 geospatial data layers from a wide range of sources, developed ecological framework, identified sensitive sites and values, and recommended management and zoning strategies to maintain ecological integrity while allowing economic and tourism opportunities. The strategy included discussion of exotic species as ecosystem stresses.

Namewaminikan River Environmental Assessment

We conducted a baseline inventory of aquatic and terrestrial resources of the Namewaminikan River on the east shore of Lake Nipigon. Specific studies include fish index netting, spawning surveys, radio telemetry, breeding bird, amphibian, and benthic monitoring, terrestrial, wetland, and aquatic habitat mapping, as well as analysis of potential impacts.

Other Relevant Projects

- Fisheries, rare plant, mollusc, benthic invertebrate, and herptile surveys on the Aguasabon River (OPG/Brookbank);
- Rare plant and herptile surveys in the White Lake Area (OMNR);
- Black River fisheries and wetlands (Regional Power);
- Forest audits (IFA/SFI) for Nipigon, Kenogami, Black River, Nagagami, and Algoma forests.

Project Team

Key Technical Team Personnel (Resumes Provided in Appendix B1)

Lyle Parsons, B.E.S., Vice President Environment

Mr. Parsons is Vice President, Environment and a Senior Project Manager with R.J. Burnside and Associates Limited. He is technical head of our Renewable Energy Services group. He has over 38 years of experience in environmental assessment and planning and direct environmental management of multi-disciplinary projects in Ontario including international experience. Lyle has developed an extensive knowledge of the FIT and MicroFit Programs and its rules. He is also project manager for wind power projects in Southwestern Ontario and leads Burnside's anaerobic digestion team for renewable energy generation on farms. Lyle managed the Ontario Power Authority's (OPA) Aboriginal Renewable Energy Fund advisory service project in association with London Economics Inc. (LEI). He also worked with LEI on development of a municipal funding program for the OPA.

Mr. Parsons brings with him a wealth of experience from both the private sector and government. He has managed many projects involving approvals under the federal, provincial, and municipal statutes, often resulting in the development of unique, creative, and cost-effective solutions for private and public sector clients. He leads many strategic planning projects with the objective of finding cost effective, creative and environmentally sustainable solutions.

Lyle's has extensive experience with the Ontario Ministry of the Environment managing diverse projects while working with the Environmental Assessment Branch, Waste Management Branch, and Regional Operations. He was a member of the team that developed the Province of Ontario's "Blue Print for Waste Management in Ontario" and the "Environmental Assessment Act". Lyle's past experience while with the Ministry of the Environment (MOE) included both Head Office and Regional review functions. Lyle's experience also includes work on individual as well as Class EA's. Work included reviews of a number of Hydro One transmission line individual EA applications. He has been the key environmental advisor at well over 30 hearings held before the Environmental Assessment Board (now Environmental Review Tribunal), the Ontario Municipal Board, Ontario Energy Board, and the National Energy Board and has testified before these Boards.

Mervin Dewasha, P.Eng. – CEO, Neegan Burnside

Mervin Dewasha is Vice-President Aboriginal Business Development for Neegan Burnside. Merv is a member of the Wahta Mohawk First Nation and has served with Indian and Northern Affairs Canada in various capacities. Mr. Dewasha has over 30 years' experience working with First Nations in project management and operation, and maintenance of facilities and services. He also has extensive experience with project development, technical management systems, and the development of codes and regulatory requirements for First Nations projects. He also has been a leader in native human resources, capacity development and careers in technical areas. He is a skilled presenter and able to explain technical processes in a manner easily understood by the general public.

Ian Drever, P.Eng., Senior Vice President

As a Senior Vice President at R.J. Burnside & Associates Limited, Mr. Drever has been involved in a wide variety of public and private sector projects. Mr. Drever has acted in the role of both project manager and project director/liaison, depending on the scope of the project and the needs of the client.

Mr. Drever's private sector development experience is extensive. His background planning knowledge and technical experience combine to form an excellent base from which development management/ project management services are provided. Ian has completed design and/or provided management direction on commercial, industrial and residential site plans and subdivisions. He has completed or participated in the completion of Functional Servicing Reports, Master Servicing Studies, Stormwater Management Reports and Floodline Analyses. Mr. Drever has participated on Ontario Municipal Board files, successfully settling servicing issues prior to the Hearing. With this wide background, Mr. Drever provides clients with effective and timely advice.

Ian was Project Manager of the civil works portion of an 800 MW natural gas fired generating station (Goreway Station) and overhead transmission line on a 50-acre site. Services provided include, site servicing and grading, stormwater management design, securing of approvals for a 2 km overhead transmission line, crossing permits for Highway 407 and appearance at an Ontario Energy Board Hearing. In addition, he was Project manager of the civil works portion of an 800 MW natural gas fired generating station and buried transmission line on a 35-acre site (Southdown Station). Services provided included, site servicing and grading, stormwater management design, and securing of approvals for a 1 km buried transmission line.

Arunas Kalinauskas, B.Sc. Manager, Geomatics

Arunas Kalinauskas has over 25 years of remote sensing and GIS experience. Arunas has undertaken many diverse remote sensing and GIS application projects. Arunas has led the development of many new applications and models using a variety of geomatics sensors and platforms.

Arunas has focused his work on industry applications and commercialization of remote sensing and GIS technology. One of the key areas where Arunas has focused his commercialization efforts has been in the design and implementation of local government GIS applications modules. As well, he has worked on Municipal GIS software products to provide cutting-edge industry-specific solutions.

Recently, Arunas has lead Burnside developers, and strategic partners in the development of effective asset management and capital planning tools. In this role Arunas has been formulating solutions that combine client expectations, with engineering expertise gathered from Burnside's engineering staff.

Lorena Niemi, P.Eng., Manager, Development Engineering and Approvals
Lorena is a senior design engineer and manager with over 10 years' experience in all aspects of civil infrastructure. Lorena has been involved in projects ranging from subdivisions, municipal infrastructure and site plans in all stages of development including Master Servicing through Detailed Design. Lorena was extensively involved in multiple aspects of both the Sithe Goreway and Southdown Station gas fired power generation projects including civil design, underground transmission line routing and duct bank design. Lorena has recently been involved in the civil and project management components of renewable projects including wind farm developments responding to the Standard Offer Contracts and more recently the Feed-in Tariff (FIT) Program in Ontario.

Sammy Elias, B.A.Sc., EIT., Manager, Electrical Engineering
The majority of Sammy's experience has been in the field of building services for utility services, pump station design for water and wastewater control, electrical design and layout for medical centres, emergency/standby generator systems, indoor & outdoor lighting, fire alarm design/upgrades, building assessments, cost analysis and tender specifications preparation. Sammy has extensive energy experience in energy feasibility studies, and has been focused on North America's first Renewable Energy Feed-in Tariff (FIT) Program in Ontario, which includes delivery of FIT consultations, contracts, developing the scope of renewable projects, and technical designs. Sammy's main focus in the field of renewable energy is photovoltaic and wind systems in the form of stand-alone and grid-connected generation solutions. Grid-tied experience includes the electrical design & review of two grid-tied, ten megawatt, fixed axis, photovoltaic solar farms in Southern-Ontario, multiple rooftop solar designs, and small to medium sized wind turbine systems. Sammy has an extensive background in dealing with multiple hydro utilities with regards to securing interconnection capacity and technical requirements for generation.

Carl Lankinen, P. Eng., Manager, Building Sciences
Carl has built 15 years of structural engineering experience since starting his career at R.J. Burnside & Associates Limited. He has leveraged his proven engineering abilities on over 1800 projects ranging from small residential to large industrial, commercial and

institutional. Carl is the Technical Leader of Structural Engineering at Burnside. In his role, he has spearheaded the acquisition and implementation of Robot Structural Analysis, MathCAD and Revit Structure. He is responsible for quality control and assurance of the structural group at Burnside and maintenance of the quality standards library for the structural group.

Carl seeks challenges and has worked on a number of unusual projects such as wind turbines & foundations, solar trackers, solar farms, strawbale buildings, water standpipes, zip-lines, smoke stacks, industrial bridges, air supported structures, air inflated structures and even a yurt. During this experience, he has designed cast-in-place concrete, precast concrete, prestressed concrete, hot rolled steel, cold-formed steel, wood, timber, masonry, aluminum and glass components. He has also worked on reinforcing a concrete girder bridge with fibre reinforced polymer reinforcement.

Mark Sheedy, Manager, Field Services

As Vice President, Field Services, Mark Sheedy heads up the Field Services Team throughout the company and is responsible for Quality/Control for that group. During his 25 years of consulting experience, Mr. Sheedy has been involved in an extensive number of projects for a wide variety of significant clients. As a Project Manager, Mark is involved with variety of projects and clients. This includes many private residential developments, commercial site plans, numerous municipal infrastructure projects as well as energy projects and First Nation projects.

Jennifer Vandermeer, P.Eng., Environmental Assessment Specialist

Ms. Vandermeer has a wide range of project experience servicing the needs of both Canadian and global clients. Jennifer provides an environmental engineering perspective to environmental and social impact assessment projects undertaken at both federal and provincial levels in Canada. Jennifer has completed several Class Environmental Assessments for transportation, transit, bridge and water / wastewater projects and has been involved with wind power development projects for the private sector. Internationally, she served as a project coordinator for the social and environmental assessment of a large hydropower facility situated on the Victoria Nile in Uganda and has also worked on projects in Egypt, Oman, Brazil, Barbados, St. Lucia and Trinidad. Jennifer is currently working on the Environmental Impact Assessment for the expansion of the Mangrove Pond Landfill in Barbados. Ms. Vandermeer demonstrates excellent communication and organizational skills, and is able to converse easily within multi-disciplinary environments.

Jennifer has five years of project experience in the solid waste management sector. She has successfully completed projects for conventional municipal solid waste landfills and bioreactor landfills at conceptual design, tender and construction phases as well as landfill liability assessments, landfill operation and maintenance plans and site closure projects in Canada and overseas.

Tricia Radburn, M.Sc. (Plan), MCIP / RPP, Environmental Planner

Tricia Radburn is a Professional Planner and Ecological Restoration Specialist. She has over ten years of experience working on projects involving public participation, consultation and the creation of partnerships between industry and agricultural organizations, community groups and First Nations. Tricia has prepared constraints analyses, feasibility studies and Environmental Assessments for a variety of energy and renewable energy projects. She has conducted initial interviews with community leaders to identify concerns, resources and traditional knowledge. She has successfully prepared applications under the Renewable Energy Approval Regulation and has a strong working knowledge of the Aboriginal Renewable Energy Fund guidelines and application process. She recently completed a Master's degree in community renewable energy planning with a focus on First Nation energy development.

Christopher Pfohl, C.E.T., Aquatic Resources Specialist

Mr. Pfohl is an Aquatic Resources Specialist with over 12 years of experience in the environmental field. He has developed a diverse background in Environmental Assessments (EAs), Baseline Studies, Aquatic Habitat Restoration, Fish and Fish Habitat, Species at Risk, Environmental Monitoring, and Environmental Protection Plans. Mr. Pfohl has worked with British Columbia and Ontario government agencies to obtain permits related to transportation, energy, infrastructure and development projects for a variety of clients including First Nations. He has assisted in the preparation of technical reports that interpret data collected as part of fish, amphibians, benthos, water, and sediment collection programs for a variety of projects in BC and Ontario. Chris is responsible for liaison with government officials, aboriginal groups, large corporations and stakeholders.

Dominique Evans

Ms. Evans is an Environmental Technologist with over seven years' experience in the environmental consulting field. She has been involved in a range of projects throughout the transportation, utility, waste management, and development sectors. Ms. Evans has been involved in the data management, mapping and field preparation for a hydro corridor in Northern Ontario. Ms. Evans has exceptional project coordination skills, analytical and problem solving capabilities, and excellent verbal and graphic communication skills. Ms. Evans' experience has covered ecological surveys, ecological land classification (ELC), sustainability appraisal, regulatory permitting, environmental baseline studies, environmental audits, environmental management, municipal environmental assessments, comprehensive environmental assessments and CEAA Screenings. Her experience has also covered a wide range of public consultation including: open houses, interest surveys, educational training sessions, and auditing.

Paul Stubbert, B.A., Geomatics Specialist

Paul's primary focus has been divided between municipal infrastructure, hydro-geology, hydro-technical, and environmental services.

Paul has trained in the Canadian Forces where he was responsible for supporting the operations and planning staff through the coordination, collection, processing and dissemination of information. This included the development of situational awareness through the use of ground, airborne, and space-borne reconnaissance assets, geomatics products, and information collected from various sources and agencies.

Paul has specialized in projects that cover large geographic areas, often in remote locations spanning thousands of square kilometers. His intimate knowledge of GIS and remote sensing data available through private and governmental sources have allowed him to quickly assemble geographic datasets for large project areas and incorporate this added value to support project requirements. He is experienced in projects involving First Nations throughout Canada and has taken part in infrastructure route planning between distant northern communities.

In 2007, Paul utilized his GIS skills to help plan a major hydro-electrical transmission corridor through both rural and urban areas in Bujagali Uganda. Recently his skills have been used for numerous renewable energy projects in Ontario and Newfoundland and Labrador.

Maxwell (Max) McCormick, C.Tech., Community Consultation

Max McCormick is affiliated with the Serpent River community in Ontario. He has several years of experience in consultation, facilitation and project management working on a number of projects in First Nation communities. Max has provided specific expertise as part of a project to supply Inuit staff resources from Resolute Bay and Grise Fiord for the operation and maintenance of Canadian Forces Station (CFS) Alert where he was responsible for project reporting, financial management and liaison with the client and stakeholders. As a direct result of these initiatives and management skill, he gained the complete support of the two Inuit communities at Resolute Bay and Grise Fjord, NU, for the CFS Alert project. The support from these communities is so strong that the CFS Alert project is now widely viewed throughout Nunavut as the "best practice" in undertaking community consultations. Another example of Max's consultation expertise is demonstrated through the completion of a remediation project at The Chippewas of Nawash First Nation, where he provided presentations to the Chief and Council on project deliverables and cost estimates. Max also participated in a focus group for Standards on Environmental Site Assessment Assistants for First Nation Communities with BEAHR (Building Environmental Aboriginal Human Resources). Max will be responsible for consultation activities as may be required.

Allen Hare, Field Services

Allen Hare provides inspection services and is part of the construction inspection team for Neegan Burnside. He is responsible for ensuring that the construction of various types of projects is completed to set standards. This involves a variety of aspects such as inspection of structures such as manholes and drainage pipes; construction of watermains servicing; and road construction. Mr. Hare acts as liaison between client and contractor and must also deal with the general public. He also assists with mechanical design aspects and contract drawing preparations using AutoCad for various projects including but not limited to municipal water design and sewage treatment facilities. Allen will be responsible for field services required for this project.

Ernie Groskopfs, P.Eng., Site Services

Mr. Groskopfs is a Senior Design Engineer with over 25 years of experience in the design of new roads and road reconstruction projects, several large transmission watermain projects and various sanitary trunk sewers. He is a fully conversant CADD designer who also manages and supports the CADD group. His transmission line civil works includes work for Sithe Energies. Goreway Power Station, where he was responsible for design of routing, maintenance access roads and structure grading for a 4km long 230KV aerial transmission line to support a 900MW combined cycle natural gas generating station. The route included structures within a floodplain and obtaining approvals from TRCA. Several road crossings were required including Hwy 407 where approvals had to be secured from the MTO. Contract administration and supervision of the constructions was included as well. He also was responsible for design of routing and securing of PUCC approval for a 2km long Honeywood 230KV buried transmission line to support a 900MW combined cycle natural gas generating station for Sithe Energies at their Southdown Power Station facility. The route included an existing built out road section as well as a major rail and pipeline crossing. Approvals were secured from the Region of Peel, the City of Mississauga, Trans Northern Pipelines and the CNR. Mr. Groskopfs was also responsible for preliminary design of maintenance access roads and grading to support a 10MW wind farm as well as improvements to municipal roads to permit transport of turbine components at the Mulmur Wind Farm.

Brian Boyle, P. Eng.

Brian has 29 years of structural engineering experience including buildings in the ICI sector, municipal infrastructure such as sewage and water treatment plants, and transportation structures including bridge spans up to 30m. His work involves new structures, investigations and rehabilitation of existing building and civil works. Brian has worked for several consultants in the past, ran his own firm for 7 years and also been employed in Building Departments. Brian is the most senior structural engineer in the firm and is often consulted with regarding Code related issues and their interpretation.

Stephen Riley P. Eng.

Stephen has 26 years of experience primarily with respect to bridge and related engineering. He is responsible for all aspects of bridge projects from assisting clients with funding applications and preliminary studies, public consultations, environmental assessment coordination, hydraulic studies through to final design and construction administration. Stephen is well known in central Ontario as one of the key bridge engineers. One of his projects includes the pedestrian bridge at the Collingwood Scenic Caves which is a 126 m suspension bridge, the longest such pedestrian bridge in Ontario. Stephen is the Manager for the Bridge Group for the firm.

Glenn E. Clarke, S.T.

Glenn Clarke has extensive experience in design of municipal services for municipalities and First Nation communities. Glenn has worked as a Party Chief for topographic surveys and contract layout, inspection and has been in the design field for the past thirty years. Glenn's field background has provided him with practical experience, which is an asset when working on design projects.

Sub Consultants (Resumes Provided in Appendix B2)

Hardy Stevenson and Associates Limited
David Hardy, B.A. (Hons.), M.E.S., M.C.I.P, R.P.P.

David Hardy is a Principal of Hardy Stevenson and Associates Limited, ("HSAL"). HSAL specializes in land use planning, project development and management, socio-economic and environmental impact assessment, public consultation, and strategic planning. Dave is a Registered Professional Planner and trained facilitator and has extensive experience in all of these areas. Dave has participated in over 75 environmental assessments. He has also facilitated close to 1000 strategic planning meetings and public consultation plans for public and private clients; conducted multi-stakeholder consultation and mediation in numerous sectors; and completed environmental planning assignments for a variety of nuclear waste management projects.

He has extensive experience in facilitating the public approvals process for housing, water and waste water, transportation and energy infrastructure projects. Dave has also led project development activities (conception, design, finance, pre-feasibility studies, feasibility studies) for a variety of energy, housing and infrastructure projects. He has completed numerous socio-economic impact studies related to plans, policies and infrastructure. Dave has facilitated Ontario Energy Board hearings and provided expert advice at the: Ontario Energy Board, Ontario Court of Appeal (Discovery Hearing), Ontario Municipal Board, Ontario Environmental Assessment Board, Consolidated Joint Board and the Federal CEAA and EARP Panels.

Andrzej Schreyer, B.A. (Hons.), M.A.

Andrzej is senior planner with Hardy Stevenson and Associates Limited and a provisional member of the Ontario Professional Planners Institute and the Canadian Institute of Planners. His experience includes developing public consultation and communications plans, preparing social impact assessment and land use planning studies in support of major infrastructure projects in the GTA, preparing community-based strategic plans, and helping private sector clients with the planning approvals process.

Prior to working at Hardy Stevenson and Associates, Andrzej was Senior Planner at Office for Urbanism (now Dialog) where he played a key role during the City of Mississauga Official Plan review process. He was also the Inaugural Town Planner and Conservation Agent for the Town of Swampscott, Massachusetts where he established the Town's development review process protocols and initiated the successful review of the Township Zoning Bylaw and the Planning and Conservation Department's Site Plan Review Guidelines.

Andrzej's approach to planning recognizes that: (i) no urban environment exists in isolation; socio-economic, behavioral, cultural, political, physical and historical particularities have to be considered when developing strategies in view of creating environments that enrich the lives of its users; (ii) collaborative approaches free of pre-determined notions are critical to high-quality results; and, (iii) a delicate balance exists between individual and community aspirations, quality of life and economic affluence and the natural and built environment.

His work can be distinguished by his balanced and comprehensive approach, creative energy and, devotion to the achievable and the imagined. He has held positions in the private and public sectors, both in Canada and the U.S. in areas including urban planning, economic development, environmental conservation and policy analysis.

Yuri Huminilowycz, B.A. (Urban Planning), R.P.P.

Yuri is a Vice President at Hardy Stevenson and Associates Limited. He has 35 years of work experience including 25 years in the electric utility business. He has worked as an urban planner, environmental assessment specialist, real estate asset manager, finance analyst, business development specialist and corporate strategic planner. Most recently he has become involved in mediation and conflict resolution.

Northern Bioscience
Allan G. Harris, B.Sc, M.Sc.

Al Harris is a biologist with 24 years' experience in northern Ontario. He also spent seven years as a biologist with Ontario Ministry of Natural Resources. His most recent focus has been on land classification and wetland ecology in northwestern Ontario. As leader of Ontario's northern Ontario wetland classification program, he coauthored *Wetland Ecosystem Classification for Northwestern Ontario, Terrestrial and Wetland Ecosites* for Northwestern Ontario and *Wetland Plants of Ontario*. Al has also been heavily involved in woodland caribou population monitoring, habitat assessment and management guidelines development in northwestern Ontario. He is past president of the Thunder Bay Field Naturalists, served as regional co-ordinator for the Atlas of the Mammals of Ontario, and coauthor of *Checklist of the Plants of Thunder Bay District.*

Dr. Robert F. Foster

Dr. Foster brings over 20 years of research and work experience in boreal and tropical ecosystems to Northern Bioscience. Dr. Foster has excellent analytical capabilities and has expertise in the development of digital databases and the use of geographic information systems (ARCVIEW) for natural resource management and protected areas planning. He has been the lead investigator for the gap analysis and related studies supporting the National Marine Conservation Area initiative on Lake Superior. Dr. Foster played a lead role in the analysis and development of the ecosite and wetland ecosystem classifications for northwestern Ontario. He has also conducted data analysis and interpretation for a variety of projects on boreal forest ecology, wildlife habitat, and fisheries. Dr. Foster has a very strong background in the design and implementation of field studies involving vegetation inventory, invertebrate and wildlife monitoring and wetland evaluation and mapping. He has excellent written and oral communication skills, having authored or co-authored numerous popular, technical and scientific reports. Dr. Foster holds academic degrees from the University of Oxford (Zoology) and Lakehead University (Biology) and has been the recipient of over 30 academic awards and scholarships, including the prestigious Rhodes Scholarship.

Brian D. Ratcliff, B.Sc.

Brian Ratcliff is a wildlife biologist with more than 25 years of experience. Research projects conducted for both federal and provincial agencies, have mainly focused on threatened and endangered species of birds such as Piping Plovers, American White Pelicans Peregrine Falcons, and Burrowing Owls. He spent 15 years setting up and building wildlife rehabilitation centres in Ontario, Quebec and Manitoba. Since moving to Northwestern Ontario, Brian has worked as a private consultant on contracts for Parks Canada, Canadian Wildlife Service, Ontario Ministry of Natural Resources, Geomatics International, and Northern Bioscience. Contracts have involved data collection on Northern Pike, Lake Sturgeon, Smallmouth Bass, threatened and endangered species, breeding bird monitoring, bird migration monitoring, and land ownership information for the National Marine Conservation Area on Lake Superior. Currently, Project Coordinator of Project Peregrine (Thunder Bay Field Naturalists) that monitors the recovery of peregrine falcons nesting in Northern Ontario, and also bands young peregrines at cliff nest sites.

Western Heritage
Dr. Terrance (Terry) Gibson

Dr. Terrance (Terry) Gibson has over 36 years archaeological and anthropological experience working with the petroleum, forestry, transportation and residential development industries, and with First Nations organizations from Northwestern Ontario to British Columbia. He has a Ph.D. in Anthropology, specializing in Archaeology. He currently serves as an adjunct professor at the University of Alberta and the University of Saskatchewan. Much of his time is spent supervising corporate staff as they deal with developer and regulator heritage management concerns. He also supervises Western Heritage’s Research and Development program, which seeks to develop and incorporate advanced methods and techniques in archaeology and other field to improve corporate scientific expertise in the heritage and related disciplines. His geographic region of specialization in archaeology and anthropology extends from northwestern Ontario westward to the plains, parkland and boreal forest of Western Canada. Current research interests include the application of geophysical methods on archaeological sites, heritage management in the forestry and oil and gas industries and the advancement of data management and geospatial analysis methods on large archaeological sites and in cultural resource management and traditional land use studies.

KBM
Laird Van Damme, MScF, R,P,F,

Laird is Co-owner of KBM Forestry Consultants Inc., an adjunct professor at Lakehead University and past president of the Ontario Professional Forester's Association. His interests lie in applying the art, science and business of the forestry profession to solve natural resource management problems in the forest, mining, transportation and energy sectors. As an advisory committee member to the Canadian Climate Impacts and Adaptation Research Network he has contributed to an understanding of how forest tenure systems are linked to innovation and adaptation under a changing climate. He oversees KBM's own innovation advances through constructive public-private partnerships that take ideas and technology through to market delivered solutions. In addition to business development activities involving bio-mass harvesting projects (wood and peat) in North-western Ontario and Chile, he has recently provided consulting services to the Ontario government on forest tenure/pricing reform and serves as a member of Ontario's Provincial Forest Technical Committee.

TBT Engineering
Wayne Hurley., P.Eng.

Wayne has more than 25 years Consulting Engineering experience providing geotechnical design, materials testing, construction supervision, environmental and inspection services for a wide variety of clients. He spent two years with MTO providing regional geotechnical services for pavement design and rehabilitation. Wayne is a designated consultant in Ontario and qualified by MOE for Environmental Record of Site Condition.

Gordon Maki., P.Eng.

Gordon has 20 years' experience providing geotechnical/foundations design, construction supervision and inspection services for a wide variety of clients. He is a member of the Professional Engineers of Ontario and the Canadian Geotechnical Society.

Steven Sellers., P.Eng.

Steven has 11 years of geotechnical experience in the North-western Ontario region. His experience includes design of preloads, embankment stability, tower foundations, building foundations and small dams. Steve is qualified in advanced modelling and analysis for slope stability, seepage and flows, thermal analysis and stress analysis, settlement and bearing pressure. He also undertakes inspection and supervision of construction projects, drilling operations, subgrade inspections, test pitting and pile installation. His materials testing experience includes concrete, compaction, soil sampling and analysis.

Chimax Inc.
Kevin Wong, M.A.Sc., B.A.Sc., P.Eng.
Mr. Wong has over 30 years of engineering and management experience in the Civil / structural / transmission line / substation design field. His experience and knowledge covers many aspects of industrial structures, heavy or light equipment foundations, stress analysis, conveyor support structures, high voltage substation and transmission line & support structural design. Extensive experience in the application of computer aided technology for structural and foundation design analysis, transmission line and transmission line structure design and drawing production.

As the President of Chimax Inc., he built the company to become one of the premium engineering firms for the power industry. In the last seventeen years, Chimax Inc. completed more than five hundred design projects for various clients in the utilities, contractors, independent power producers and mining companies. These projects include engineering design, feasibility study in high voltage substation, high voltage switch yard, transmission line, distribution line and high voltage capacitor bank station.

As the Chief Civil Engineer in Markham Electric, Mr. Wong managed and completed more than fifty projects in the power sector. These projects include high voltage substation, high voltage switch yard and transmission line design.

Mr. Wong's first nine years in the profession were spent working for Stone & Webster Canada Limited where 70% of the projects were in the power sector. These projects were piping support structures design for nuclear stations, majority of these projects are in U.S.A.

Kevin Wong, M.A.Sc., B.A.Sc., P. Calvin Ng, M.Sc., B.T.
Mr. Ng has over 5 years of engineering and management experience in the transmission line / distribution line / substation design. His experience and knowledge covers many aspects of transmission / distribution lines and substation design. He is highly proficient in the use of powerline design program such as PLS-CADD and various structural analysis programs. His experience is also enriched by his familiar knowledge on Canadian Electrical Standards for substation and transmission line design.

As a project coordinator, Mr. Ng manages the project schedule, technical deliverables, and coordinates with clients for their specific needs. He has taken part in more than 20 engineering projects with strong communication skill.

Edmund Kwong

Mr. Kwong has over 12years engineering and management experience in the area of high voltage substation and transmission line projects. He is responsible for the work schedule, feasibility study for the transmission lines including information for leave to construct, layout of equipment arrangement according to single line diagrams, design of structures, conductors, transmission line's plan and profile, sag & tension, specification of equipment requirement, etc. He is highly proficient in the use of specialized programs such as PLS-CADD, PLS-POLE, PLS-TOWER and STADD Pro programs to perform the aforementioned tasks. Most recently, for the past five years, he has been heavily involved in the design of transmission line and distribution lines, dealing with clients, Hydro One, Provincial line, contractors, suppliers, etc. Mr. Kwong has completed over two hundred projects consisting of high voltage substations, high voltage switch yards, transmission lines, distribution lines and high voltage capacitor bank stations.

Miuee Huang

Ms. Huang has over 9 years extensive experience in using Computer Aided Design software including AutoCAD and Solidwork, she has 3 years design experience in the area of transmission line and distribution line projects. She is responsible for the design for the transmission / distribution lines including information for leave to construct, layout of equipment arrangement according to single line diagrams, design of structures, conductors, transmission / distribution line's plan and profile, sag & tension, specification of equipment requirement, etc. She is highly proficient in the use of specialized programs such as PLS-CADD and PLS-POLE programs to perform the aforementioned tasks. Most recently, for the past three years, she has involved in the design of transmission line and distribution lines, dealing with clients, Hydro One, Provincial line, contractors, suppliers, etc.

Vicky Wu, P.Eng., B.A.Sc.

Ms. Wu has over 14 years of international engineering and management experience in various civil and structural engineering projects including residential and industrial buildings.

With his diverse field experience and knowledge of civil engineering design, Ms. Wu is responsible for the project technical deliverables that includes foundation design and analysis, high voltage switchyard and substation design, transmission and distribution line structural design. She is highly proficient in the use of specialized engineering tools such as STADD PRO and various structural analysis programs.

Ms. Wu joined the company in 2006 and has been heavily involved in the design of high voltage substation and distribution lines; providing technical advice to clients; coordinating technical requirements between the clients, owner, contractors and power authorities or local power utility companies. Her recent projects include a distribution system upgrade for a local distribution utility and substation design for power developers.

Raymond Leung, M.Eng., B.A.Sc.
Mr. Leung has over 14 years of international engineering and management experience in various civil and structural engineering projects including precast segmental vehicular viaducts, underground subway stations, marine and offshore structures, residential and industrial buildings.

With his diverse field experience and knowledge of civil engineering design, Mr. Leung is responsible for the project technical deliverables that includes foundation design and analysis, high voltage switchyard and substation design, transmission and distribution line design. He is highly proficient in the use of specialized engineering tools such as STADD PRO and various structural analysis programs.

Mr. Leung joined the company in 2010 and has been heavily involved in the design of high voltage substation and distribution lines; providing technical advice to clients; coordinating technical requirements between the clients, owner, contractors and power authorities such as Hydro One or local power utility companies. His recent projects include a distribution system upgrade for a local distribution utility and a transmission line and substation design for power developers.

Clarida Green Energy
Bruce E. Clarida, P. Eng. FEC
Thirty two years of progressive experience in planning, design, and project management, of large Civil infrastructure projects in Hydroelectric Generation and Transmission facilities, Wind and Solar PV Energy, Dams and Reservoirs. VP Engineering and Development, Clarida Green Energy, completed 190 MW of Wind energy and 66 MW of ground mount Solar PV; Business Development Manager for Peter Kiewit Infrastructure Co., a large North American contractor; Director, Major Projects for Brookfield Power, an independent power producer, responsible for a program of power facility construction and expansion projects including large Earth fill dams and composite Spill control facilities, Concrete gravity dams, Hydroelectric generation facilities, Wind Generation facilities and 115 and 230 kV Transmission Lines and Substations; Professional Engineer, (Civil) registered in Ontario, (PEO); Twenty five years of service to PEO in elected positions of Regional Councillor and Councillor-at-Large; Inducted as an Officer in PEO Order of Honour in April, 2007, Inducted as a Fellow of Engineers Canada, November, 2009.

NEEGAN BURNSIDE

A1 Neegan Brochures

A1 Neegan Burnside

A2 Sub Consultants

A1 Neegan Burnside Brochures

NEEGAN BURNSIDE

A2 Sub Consultant Brochures

NEEGAN BURNSIDE

B CVs

B1 Neegan Burnside

B2 Sub Consultants

NEEGAN BURNSIDE

B1 Neegan Burnside CVs

B2 Sub Consultant CVs

A1 Neegan Burnside Brochures

NEEGAN BURNSIDE

Aboriginal Owned – Providing Engineering and Environmental Solutions

Value **Innovation** **Service**

Value Innovation Service

Our Company

Neegan Burnside Ltd. is not just another engineering firm. We are a majority owned aboriginal firm committed to assisting both First Nations and Industry meet their development and economic goals while remaining sensitive to culture, values and beliefs. Our success can be seen in the over 1,400 completed projects for more than 200 First Nation clients in North America. Under the leadership of Mervin Dewasha, P.Eng., from Wahta Mohawk First Nation, we offer a unique combination of technical capacity and innovative thinking to provide professional project control and personal responsiveness to clients.

Neegan Burnside Ltd. has a corporate partnership with R.J. Burnside & Associates Limited, a company that has been providing engineering services to First Nations for over 40 years. This partnership operates under a Joint Venture concept with aboriginal and non-aboriginal ownership being reciprocal between the companies to enable a seamless sharing of human resources and equipment. Through this unique structure, Neegan Burnside Ltd. has the ability to draw from over 335 staff members within Burnside with professional qualifications in engineering, hydrogeology, environmental assessment, and land planning. Our remaining staff comprises the necessary support personnel to carry out project management, financial administration, drafting, tendering, construction contract administration, surveying, site inspection, and related specialized clerical skills.

Neegan Burnside Ltd. provides core services in the following areas:

- Land Development
- Environmental Assessment and Planning
- Water Resource Management
- Consultation & Accommodation
- Building Engineering
- Transportation Engineering
- Capacity Development for Communities
- Geographical Information Systems (GIS)

Services

Development

Whether your project is a recreational, industrial or residential development, Neegan Burnside can add value to your land development project through our experience and knowledge of the overall development process. We understand the need for responsiveness in dealing with all levels of government, regulatory agencies and can navigate through complex approval processes. In addition, we facilitate the consultation process with all stakeholders. In short, we manage the process for you; saving you time and money. Our projects have included golf courses, resorts, recreational facilities, schools, hospitals, and rural developments.

- Site Due Diligence & Environmental Assessments
- Preliminary Engineering
- Development Proforma Analysis
- Cost Share Analysis
- Functional Servicing
- Water Management Strategy
- Detailed Engineering
- Design Construction Management

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Environment

Neegan Burnside Ltd. offers a full range of environmental consulting services. We provide a fresh look at current systems to determine the most appropriate solutions. Our professionals work with you to address your exact needs, whether your project involves an environmental assessment, landfill site development, problems with an existing facility, improving solid waste management, soil remediation, wind energy generation, or climate change. Our team is also highly conversant with the host of federal and provincial environmental regulations and the necessary approvals required for First Nation, municipal and private development projects. A key element of our approach is ongoing consultation and the participation of informed stakeholders and community members in the decision-making process.

- Environmental Assessments
- Habitat Assessments
- Natural Areas Management
- Waste Management Planning & Operator Training
- Landfill Design & Approvals
- Contaminated Site Remediation
- Wind Power
- Contract Administration
- Peer Review & Expert Testimony
- Consultation & Accommodation
- Approvals & Permits

Water Management

We offer services that cover virtually every aspect of water management. Our experience includes the full spectrum of project development from feasibility, planning and impact studies, to conceptual and final design, permit applications, construction management and operator training. We often assist clients in locating, developing and protecting new water resources. Our remote sensing capabilities provide a low cost solution to identifying water resources before test drilling begins. Our projects have involved comprehensive servicing plans, requiring specialized support, project development and funding strategies to maximize project advancement. We know INAC funding procedures and ensure that all documents comply with these requirements during project development.

- Master Servicing Plans
- Surface / Groundwater Studies
- Assimilative Capacity Evaluations
- Long-Term Water Taking
- Stormwater Management
- Engineering Design - collection & distribution systems, treatment facilities, water storage & pump systems
- Computerized Mapping & Database Management

Building Engineering

Neegan Burnside's experienced team can assist you in addressing all aspects of your building projects. Our team consists of experienced licensed professionals in the areas civil, structural, mechanical, and electrical engineering as well as certified engineering technicians, LEED certified professionals and environmental engineers. We have experience on a wide array of architectural building projects including golf course clubhouses, schools, community centres, residential sites, recreational facilities, historic buildings, farm buildings and industrial sites. We have a proven track record working with leading industry professionals in land planning, building architecture, interior design and landscape architecture.

- Building Condition Assessments
- Detailed Engineering & Working Drawings
- Technical & Feasibility Studies
- Structural Audits & Reviews
- Peer Reviews
- Failure Investigations
- Green Building Development
- Contract Administration
- Expert Witness

Transportation

We offer a full range of transportation services that meet the challenges of any project involving transportation systems and related structures. We bring fresh insight and proven experience to your project and above all, we listen to your needs to provide the most cost-effective and appropriate methods. By applying innovative engineering techniques, we deliver safe and functional transportation systems. Our team has expertise in program development, master planning, engineering design, construction administration, and asset management. Working closely with our clients, neighbouring communities and key stakeholders, we can ensure that your project is successfully completed in a timely manner.

- Transportation Infrastructure
- Transportation Planning
- Road Asset Management
- Traffic Impact Studies
- Road, Bridge, Culvert Design
- Walkways & Bikeways
- Surveying Services
- Transportation Economics & Regulatory Framework
- Contract Administration

Capacity Development

Our specialized staff have assisted First Nations in planning for future community requirements to develop capacity. We assess existing infrastructure, future needs, develop concepts to meet future demand, and set a plan in place to manage anticipated growth. You benefit from action plans that establish a process to meet infrastructure needs in a fiscally responsible manner. Our housing specialists develop long-term solutions for On-Reserve housing that focus on housing backlog, financing arrangements, building quality, ownership options, and resource plan development. This provides a solid base for future infrastructure requirements and reduce housing densities to acceptable norms.

- Capital Planning Studies
- Asset Condition Reporting
- Comprehensive Community & Housing Plans
- Growth Studies
- Project Development & Financing Opportunities
- Community Relocation Studies
- Maintenance & Management Training

GIS

We offer clients a variety of surveying, mapping, evaluation and operating services using our expertise in Geographic Information Systems (GIS), Satellite and Airborne Remote Sensing services. The creation and provision of specialized datasets is key in the implementation of groundwater protection studies, hydrological and floodplain analyses, and solid waste management projects. By managing, analyzing, and disseminating spatial data information, our clients can obtain critical information necessary to record, manage and report on existing assets. We can assist in land management and community planning for housing, infrastructure, and other large capital projects.

- Data Integration, Mapping & Remote Sensing
- Regional Analysis, Assessment & Impact Studies
- PSAB
- Land Use Planning
- Land Use Management
- Asset Condition Reporting System (ACRS)
- Asset Management

Aboriginal Employment Strategy

At Neegan Burnside Ltd., we take pride in our Aboriginal employees and the communities they represent. To continue this legacy and commitment to our First Nation people, Neegan Burnside Ltd. has developed an employment strategy that is dedicated to elevating the profile of Aboriginal people throughout our company. By providing opportunities for qualified candidates, we have the ability to meet our corporate mandate; creating dynamic Aboriginal leaders that will help shape the future.

Our employment strategy follows a simple four step process:

1) Identify talented Aboriginal students, graduates and professionals.
2) Provide career counselling, internships and assistance to students prior to graduation.
3) Offer opportunities to qualified candidates throughout the company.
4) Mentor junior employees and assist in professional development.

We are always interested in speaking with qualified candidates and we have capacity for growth in the following areas:

- Engineering (Civil, Structural, Mechanical and Electrical)
- Environmental Sciences and Planning
- Finance and Accounting
- Information Technology (CADD and GIS)
- Field Services (Survey and Inspection)
- Administrative Services

Value Innovation Service

ORANGEVILLE
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BURNSIDE

- Engineering
  - – Structural
  - – Mechanical
  - – Civil
  - – Electrical
- Water Resource Management
- Environmental Planning and Assessment
- Solid Waste Management
- Renewable Energy
- Infrastructure Development
- Transportation Engineering
- Land Development
- Building Design
- Geographic Information Systems

About Burnside

R.J. Burnside & Associates Limited provides services in engineering and environmental consulting. Today, Burnside is an established and recognized provider of quality services to an expanding number of clients. In addition to conventional engineering disciplines, we have specialized experience in various technical fields including water resources, site remediation, energy efficiency, solid waste management, environmental impact assessment and geomatics. We offer these same services to our First Nation clients through our sister companies – Neegan Burnside Ltd. and Nuna Burnside Engineering and Environmental Ltd., and internationally through R.J. Burnside International Limited. Our firm Well Initatives provides long-term maintenance and sustainability of groundwater supply wells for Municipalities.

In the over 40 years we have been in operation, Burnside has grown to a firm of over 335 professionals offering services from 9 locations in Ontario, an office in Manitoba and two overseas offices in Barbados and Mozambique. Our exceptional professional team of civil, structural, mechanical, and electrical engineers, scientists, hydrogeologists, biologists, and technologists have a proven track record in providing practical and cost-effective solutions to our clients.

Benefits to You

Our team can offer you professional expertise to:

Design appropriate engineering systems and administer bids

Manage your project from design to construction and final operation

Conduct technical assessments to determine project feasibility

Clarify regulatory requirements

Obtain approvals and permits

Minimize your efforts by liaising with regulatory agencies throughout project implementation

Secure the necessary financing

Train your staff on project technologies and systems

Complete your project on time and within budget

In short, we remove the confusion and manage the process for you.

Our Commitment

Our project managers are committed to developing close working relationships with their clients, providing professional services for the most appropriate, cost-effective and innovative solutions. We have experience meeting the diverse demands of our clients be they with municipal or federal government; in commercial, industrial, or institutional operations; developers of residential, recreational, resorts or golf communities; or members of First Nation communities. Our staff becomes integrated with our client's team, particularly in small municipalities where we effectively act as the municipality's engineering department, and for private clients where we are often invited back to work on subsequent projects.

Our Clients

Local Municipal and Regional Governments

Commercial, Industrial and Institutional Clients

Residential, Resort, Recreational, and Golf Developers

First Nations

International Clients

Our Services

Integrated Water Resource Management

Burnside has been delivering cost-effective and innovative solutions covering virtually every aspect of water resource management for over 40 years. Our hydrotechnical professionals provide expertise in hydrologic investigations, environmental monitoring, flood protection, environmental surveying and mapping, hydrogeologic investigations, hydraulic investigations, stormwater management, and water quality protection. Our engineers, hydrogeologists, geoscientists, environmental planners, biologists and technologists have experience in addressing increasingly complex planning, design, licensing, and permitting requirements.

Transportation Engineering

We understand the need to maximize design, maintenance and construction dollars for each project to ensure long-term value. Our transportation team has extensive experience managing diverse transportation projects to meet your needs. From project conception to completion, we offer a range of services including: traffic engineering and impact studies, transportation needs studies, design-build project management, contract administration, bridge and culvert design, bridge rehabilitation, design engineering for rail, streetscape and trailways, road asset management system, class environmental assessments, and funding analysis. We are experienced in managing transportation projects through complex approval processes, saving our clients time and money.

Solid Waste Management

Burnside professionals have experience investigating methods for reuse, recycling, resource recover, waste processing and residuals management. We have proven experience working through all stages—planning, waste composition, quantification, waste reduction, recycling strategies, economic evaluation, site selection, design construction, operations, environmental monitoring, operator training, closure and post closure care – developing comprehensive and sustainable waste management systems.

Environmental Planning and Assessment

Our environmental engineers, planners and biologists conduct Phase I, II, and III environmental site assessments, site investigations to assess soil and groundwater contamination, site remediation, environmental impact assessments, and fisheries habitat assessments for diverse land developments and projects. Our team is highly conversant with the various environmental assessment approvals required under federal and provincial legislation.

Land Development

Our private sector team supports industrial, manufacturing and institutional clients from greenfield or brownfield right through the construction phase. We add value through our experience and knowledge of the overall development process. Our projects include large urban residential subdivisions and rural estate developments, golf courses and resorts, superstores and plazas, schools, and industrial sites.

Structural Engineering and Building Design

Burnside structural design expertise includes the development of arenas, schools, residential buildings, and hospitals. We design effective building structures that use current technology and construction practices and pay specific attention to culture requirements of the community. Our projects use energy-efficient heating, ventilating, air conditions, plumbing and drainage designs.

Renewable Energy

Our professional consultants offer complete engineering and environmental services for wind, solar, water and biomass/biogas projects from inception through to approval.

Geographic Information Systems

Burnside has extensive experience in the collection, integration, and processing of data in all types of industry formats and from many sources and agencies ranging from government to private industry. Employing industry-leading geomatics professionals, we follow an innovative process that enables ongoing research and development into solutions and best practices. We offer our clients a variety of data collection techniques, customized maps, on-line services, custom designed software and personalized training.

Look for these Burnside Services Brochures

ORANGEVILLE *(Main Office)*
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fax (519) 941-8120

BARRIE
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fax (905) 686-9652

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Elora, Ontario N0B 1S0 Canada
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fax (519) 846-8281

BARBADOS
R.J. Burnside International Limited
15 Greenidge Drive, Payne's Bay
St. James, Barbados
telephone (246) 432-7456
fax (519) 941-8120

MOZAMBIQUE
R.J. Burnside International Limited
Rua Xavier Botelho 53, Andar Unico
Maputo, Mozambique
telephone/fax +258 21 30 20 75

- Water Resources Management
- Solid Waste Management
- Rivers and Watersheds
- GIS
- Environmental Planning
- Transportation
- Drainage
- Land Development
- Groundwater
- Renewable Energy

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www.rjburnside.com

Burnside

NEEGAN BURNSIDE

Consultation and Accommodation Services

Consultation and Accommodation Services

What is Consult and Accommodate?

Consult and Accommodate is a new legal framework set out by the Supreme Court of Canada in 2004 and 2005, in the Haida Nation, Taku River, and the Mikisew Cree cases. (The duty flows from the honour of the Crown and s.35 of the Constitution Act, 1982.) The new duty requires governments to consult Indian, Inuit and Métis peoples and accommodate their interests whenever considering an action that might adversely affect Aboriginal rights or interests.

The duty could be triggered in all circumstances where the province has actual or constructive knowledge of an Aboriginal right or title claim and is considering actions that might negatively affect those rights or title. Broad areas could be affected such as:

- **The environment**
- **Natural resources**
- **The management and sale of Crown lands**
- **Local works and undertakings**
- **Protection of heritage and cultural property**

Your Responsibility

The purpose of the duty is achieved when both parties demonstrate good faith in addressing aboriginal concerns as they are raised. The consultation must be meaningful. Although there is no obligation to reach an agreement, there is a strong incentive on the part of both parties to negotiate.

What Neegan Burnside Can Do For You

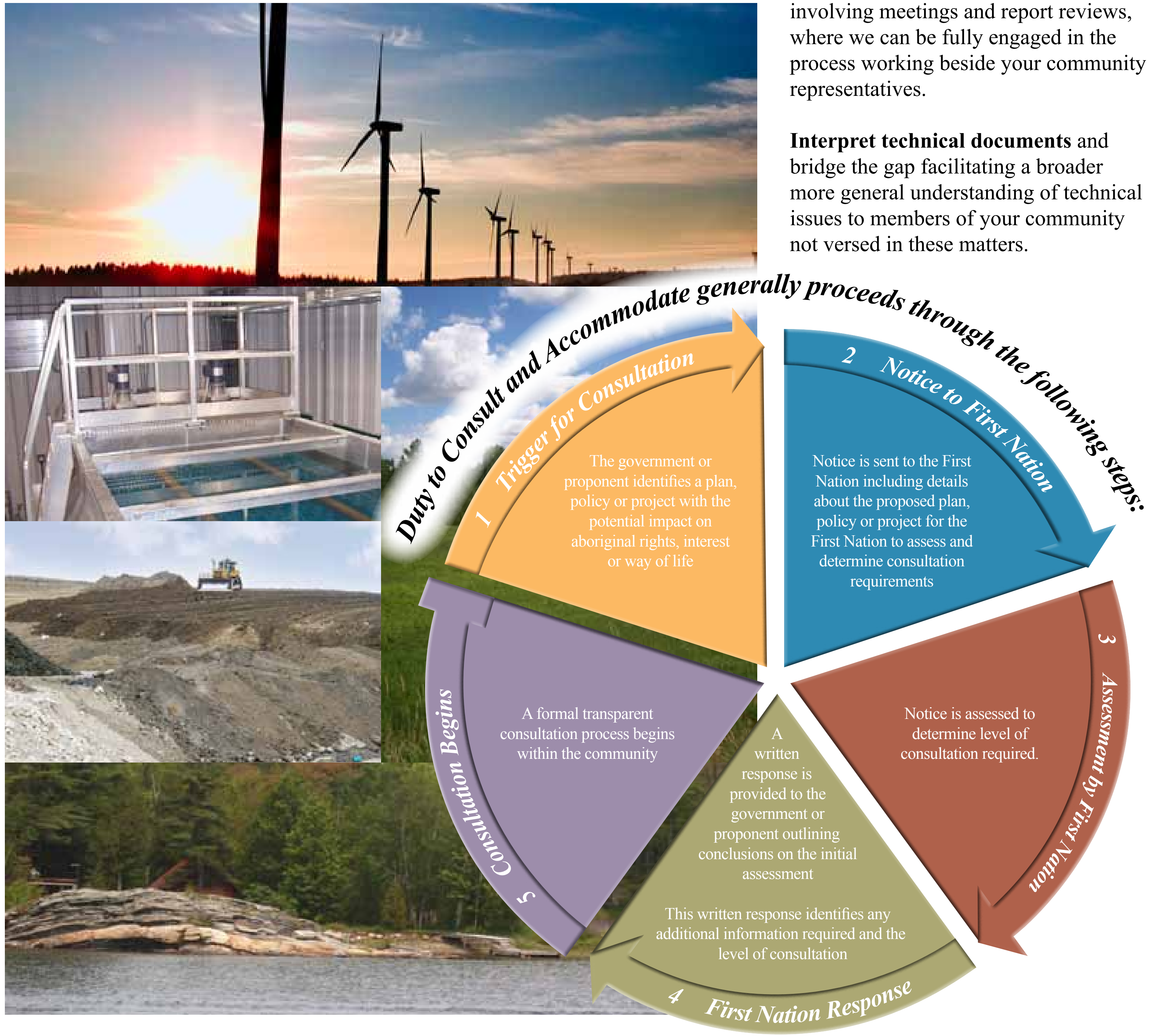
Neegan Burnside staff can assist you in the following:

Developing an understanding of the technical aspects (engineering and environmental sciences) of the project as well as the practical requirements of the Duty to Consult and Accommodate process as it affects your community.

Explain specific issues related to projects proposed on Aboriginal lands such as:

- hydro
- wind
- water/wastewater
- environment
- archaeology
- landfills
- sewage lagoons
- pipelines
- mines

These projects could range from small traditional projects to larger projects



involving meetings and report reviews, where we can be fully engaged in the process working beside your community representatives.

Interpret technical documents and bridge the gap facilitating a broader more general understanding of technical issues to members of your community not versed in these matters.

Assist in developing relationships between project proponents and First Nations

Peer Reviews with regard to First Nations

Produce required documents such as Memorandums of Understanding and Benefit Agreements addressing project issues that are understood within the community.

How Do You Benefit?

Neegan Burnside staff have extensive experience working on more than 1200 projects with over 200 First Nation communities in Canada. We understand governmental requirements and regulations and can assist First Nations in dealing with federal and provincial government processes required within the Consult and Accommodate framework.

We can provide assistance through Memorandums of Understandings outlining First Nation benefits and have an impact on Benefit Agreements offering advice on what might be reasonable.

While time would be required from members of your community to participate in the process; there would be no out-of-pocket expenses for your First Nation.

Let Neegan Burnside benefit your First Nation providing complete understanding of the Consult and Accommodate process.

NEEGAN BURNSIDE

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(705) 797-2047

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Wingham
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Winnipeg
(204) 949-7110

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(246) 432-7456

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+258 21 30 20 75

Look for these related services

- Environmental Planning
- Wind Energy
- Mining
- Building Engineering
- Land Development

Neegan Burnside Ltd. has a corporate partnership with R.J. Burnside & Associates Limited. In addition to conventional engineering disciplines, Neegan Burnside has specialized experience in various technical fields including water resources, site remediation, energy efficiency, solid waste management, environmental impact assessment, geographic information systems (GIS) and geomatics. Our exceptional team of civil, structural, mechanical and electrical engineers, scientists, hydrogeologists, technologists, and support staff has a proven track record in providing practical and cost-effective solutions to our clients.

www.neeganburnside.com

NEEGAN BURNSIDE

A2 Sub Consultant Brochures

HSAL Qualifications

Hardy Stevenson and Associates Limited (HSAL) is a firm of social scientists, environmental planners, and public consultation specialists. We operate as a network of companies centred on the 15 staff and associates comprising HSAL.

Our staff and associates have extensive experience in the energy sector, having worked on projects dealing with energy generation, including: wind, solar, biomass, natural gas, nuclear, hydroelectric power, and coal, and energy transmission. Since 1990, HSAL has worked for most of the Province's energy suppliers and regulatory agencies related to pipeline routing and approvals, rates, rules for opening the electricity market, transmission line routing and approvals, alternative energy suppliers, electrical distribution companies and electricity generators and others involved in environmental assessments.

Most of our work in the energy sector has focused on: (1) assessing and evaluating proposed projects based on potential effects to the natural and social environment, and (2) consulting and engaging stakeholders and members of the public in discussions related to these projects. We have used this set of skills to complete Master Plans for other infrastructure projects, including transportation, landfills and water / waste water, as part of the Ontario Environmental Assessment process.

Socio-Economic Impact Assessment

Through 22 years of professional practice, HSAL has gained a reputation for successfully completing Socio-economic Impact Assessments (SEIAs) for large infrastructure and transportation projects throughout Ontario. The firm's principal, Dave Hardy, is nationally recognized as an expert in the field and has provided expert testimony and peer advice on social impacts for a wide range of infrastructure projects and clients.

Social effects can be positive or negative and have impacts that affect people's: way of life (how they live, work, play and interact with each other on a daily basis); cultural traditions (shared beliefs, customs and values); and community (its population structure, cohesion, stability, character, aesthetics, facilities, services and values). SEIAs are designed to enhance our understanding of the social effects and consequences of implementing proposed policies, programs and projects. They are initiated in the early stages of Environmental Assessments (EAs) to better enable project managers to anticipate possible impacts before significant resources are invested into proposed initiatives.

SEIAs involve identifying effects and evaluating the level of impact on affected communities. Our team conducts a detailed inventory of community features including land uses and the planning policy context; transportation and circulation systems; locally-significant environmental conditions; community characteristics and overall quality of life. The evaluation of alternatives involves the application of a tested set of criteria or decision rules. This application allows the team to predict both the positive and negative impacts of a particular policy, program or project. Cumulative impacts are identified and a comprehensive set of mitigation strategies for use in implementation is put forward.

In the case for transmission studies, it will be critical to obtain input from all stakeholders as to their view of the relative importance of the various impacts. The First Nations communities are one of the most important stakeholders. Municipal governments, Provincial agencies and area residents are also key stakeholders.

Public Consultation

HSAL has been retained by public and private sector clients across Canada to facilitate public consultation sessions on a broad range of sensitive and often controversial topics. The firm's principal, Dave Hardy, is a trained facilitator and mediator who has facilitated more than 1,000 meetings and workshops. As a team, HSAL recognizes the important role communication and public engagement play in land use planning and environmental assessments. Through experience, the firm's team of highly-skilled consultation specialists have developed an approach to facilitation that succeeds in building confidence and trust; avoiding and managing conflict; and optimizing dialogue and participation among key stakeholders and members of the public. Our experience includes working with First Nations and building successful and meaningful First Nations consultation programs for both government and private sectors.

At HSAL, we believe that a successful Public Engagement Program should be solution-based, rather than problem-based. We believe it should include a mix of tried and true and novel and innovative public engagement approaches. This mix includes traditional Public Consultation or Information Centres (PCCs or PICs); stakeholder focus groups, workshops or meetings; internal consultations with government staff; youth or high-school workshops; online surveys; use of new social networking sites; community partnerships; and discussion panels and symposiums. Our communication vehicles include key messages and media strategies; websites and blogs; social networking site 'groups'; graphic design; brochures and newsletters. We draw on a wealth of experience and knowledge to build a program that is custom designed for each project, we do not believe that there is a 'one-size fits all' approach to public consultation as each community and project team has different needs and goals.

Public consultation is a very important part of a transmission study process. HSAL specializes in engaging the public with a view to ensuring a smooth approval process in informed communities. Capacity building will be an important component throughout the duration of the project and once the project is complete. This will be accomplished through thoughtful and comprehensive liaison with the affected municipalities as well as First Nation communities, the sharing of all information collected during the study and meaningful involvement in all decision making to ensure a full understanding of how the study was conducted and how the results were determined**.** Moreover HSAL work well with local communities' and we are committed to environmental sustainability. We believe it is important to respect traditional values toward balancing the needs of the people, the economy and the needs of the land upon which we all depend. We also acknowledge the interaction and inevitable tensions between the land, economy and society. HSAL' s approach to this assignment is based on our desire to foster mutual trust, respect and understanding.

Relevant Project Experience:

Electricity Transmission

- Study design, research, assessment of associated impacts, and preparation of the Social Environmental Assessment for the Hamner to Mississauga Transmission line approved by the Ministry of the Environment.
- Socio-economic impact assessment studies of Elliot Lake T.S. to Quirke Lake T.S. transmission line
- Social Impact Assessment Study of Algoma TS to Elliott Lake TS transmission line
- Scoping of the social impact assessment component of the South-West Ontario transmission expansion and the Supply to Ottawa (Approved by the Consolidated Hearings Board)
- Lead consultant for the strategic EA for OPA's Integrated Power System Plan.

Project: Strategic Environmental Assessment for Transmission in Ontario

Client: OPA

Date: 2007 – 2009

Strategic Environmental Assessment for Transmission in Ontario - The Ontario Power Authority (OPA) filed an application for approval of the Integrated Power System Plan (IPSP) with the Ontario Energy Board (OEB) in 2007. HSAL was retained to conduct a Strategic Environmental Assessment (EA) for the OPA. The Strategic EA was used to help inform the siting and routing of transmission lines across Ontario and was used as a tool for assessing plan, policy and program level effects of new transmission enhancements in Ontario. This project also included a study of the transmission of electricity from the Darlington Nuclear Generating Station to Toronto.

Each transmission project was required to have an Individual EA. Our scope was to determine if there were any red flags or environmental impediments to bringing on new transmission with respect to new generation requirements. HSAL led a team of multidisciplinary consultants to complete this work. We defined each study area and conducted a desk top/ secondary data analysis (supported by GIS data). More specifically, we conducted a baseline study of socio-economic and natural features as well as identified constraints and opportunities. We also identified transmission corridors and determined if there were a reasonable number of corridor alternatives that could proceed to Individual EA and if those corridors met sustainability objectives. For this assignment, we developed community benefits and indicators for the Strategic EA of most of central Canada at a high level of quality that would be defensible at an Ontario Energy Board Hearing. We concluded that there were a number of alternatives that could be constructed in a sustainable manner. Our work was published on the OPA website as part of the 'IPSP i'. Our studies included:

- North-South Transmission Reinforcement
- Manitoulin Island Renewable Resource Development
- Bruce Peninsula Renewable Resource Development

- Central and Downtown Toronto
- Little Jackfish and East Lake Nipigon Renewable Resource Development
- Quebec/Labrador Purchase Integration
- East Lake Superior Transmission Reinforcement
- Sudbury North Transmission Reinforcement

Northern Bioscience

Northern Bioscience can assemble a multi-disciplinary team of environmental professionals to provide the following services:

Biological Inventory and Monitoring (Including Species at Risk)

Northern Bioscience provides biological inventory and monitoring services on a range of taxa Depending on the needs of the client, we can provide species level determinations for most groups.

Some of our inventory/monitoring services include:

- botanical and floristic surveys and inventories;
- bird surveys and monitoring e.g., Forest Bird Monitoring, Breeding Bird Surveys, waterfowl and raptor counts, owl surveys;
- mammal and herpetofaunal surveys and monitoring using a variety of techniques;
- insect surveys and monitoring (e.g. Lepidoptera, Odonata, Homoptera);
- molluscs and other benthic invertebrate surverys and biomonitoring;
- invasive and exotic plant monitoring, assessment, and management plans;
- vegetation community classification, analysis, aerial photo interpretation, and mapping;
- biodiversity analysis/indices; and
- data collection, compilation, and database creation

Wildlife Ecology and Habitat Assessment

Northern Bioscience has extensive expertise and experience in conducting a wide range of wildlife ecology and habitat studies. Where necessary, multi-disciplinary teams consisting of professional biologists, ecologists, foresters and geographic information systems analysts are assembled to conduct habitat modeling projects.

Some of our wildlife ecology and habitat services include:

- mammal, bird, herpetofaunal and invertebrate field studies;
- wildlife population monitoring and statistical analysis;
- habitat modelling of marten, moose, caribou and other taxa for forest management planning;
- critical habitat identification;
- species at risk (rare, threatened, endangered) reviews and status reports.

Wetland Evaluation, Inventory, and Monitoring

Northern Bioscience has extensive experience in wetland evaluation, inventory, classification and monitoring. As co-authors for the Field guide to the wetland ecosystem classification for northwestern Ontario, Terrestrial and wetland ecosites of northwestern Ontario, and Wetland Plants of Ontario, the principals of Northern Bioscience are extremely knowledgeable about boreal and Northern Ontario wetlands and wetland flora.

Some of our wetland services include:

- wetland evaluation using the Northern Ontario Wetland Evaluation System;
- wetland inventory and sampling;
- wetland monitoring for water level regulation;
- statistical analysis of wetland data and development of wetland classification; and
- aerial photograph interpretation and mapping of wetlands and wetland boundaries.

Fisheries and Aquatic Resource Management

Together with our associates, Northern Bioscience can provide comprehensive fisheries and aquatic resource management services. Jon Tost of North Shore Environmental Services has extensive field and aging experience, and Dr. Peter Colby provides over 40 years of fisheries research experience. We have the expertise to evaluate impacts from bridge and highway developments, hydroelectric projects, pulp and paper mills, and other development.

We can provide the following services:

- baseline aquatic studies and inventory;
- short and long-term monitoring related to water quality, fish populations and benthic community composition;
- mark/recapture, fish spawning and migration studies;
- effects monitoring and impact assessment in riverine and lacustrine environments;
- fish/aquatic habitat identification, monitoring, restoration and development;
- assessment of water crossing structures;
- aging of fish structures (scales, otoliths, fin rays);
- statistical analysis of recreational and commercial fisheries data; and
- preparation/review of fisheries management and rehabilitation plans.

Forest Resource Management and Science

Northern Bioscience can assemble a team of professional foresters, technicians, ecologists, biologists and GIS specialists to provide a complete range of services supporting forest management and science.

Some of the services offered include:

- forest management planning;
- forest auditing;
- strategic forest management modelling (SFMM);
- guideline development and review;
- ecological and forest inventory analysis;
- statistical analysis;
- field trials and studies; and
- compliance monitoring.

Protected Areas Management

Northern Bioscience has worked in and provided expertise to national parks in both Canada and the United States (Voyageurs National Park, Minnesota), as well as in Ontario's provincial parks, conservation reserves, and enhanced management areas. Over the past 9 years, we have played a lead role for the proposed National Marine Conservation Area (NMCA) on the north shore of Lake Superior in Ontario.

Our range of services includes:

- preparation and review of park management plans and resource-specific plans;
- gap analysis and identification of biodiversity "hotspots";
- identification of environmentally sensitive areas (ESA);
- wildlife and vegetation inventory, research, and management ;
- natural and cultural resource studies and inventory;
- human use / recreation / human impact studies;
- mapping, GIS services and technology transfer; and
- public consultation.

Environmental Impact Assessment and Restoration Ecology

Northern Bioscience biologists have experience and training in legislated and proponent-driven environmental impact assessment for forest management, industry, corridors, cottage development and other development. Where larger projects warrant, Northern Bioscience can provide terrestrial, wetland and/or aquatic biological and ecological expertise to larger planning and engineering firms. We can also provide cost-effective assessments for more limited development by private landowners.

We can assist with:

- scoping and baseline studies supporting environmental assessments (EA) under the Canadian Environmental Assessment Act (CEAA);
- identification of potential environmental impacts;
- integration of EIA and decision-making processes;
- post-EIA monitoring research and process development;
- preperation of environmental impact statements and studies (EIS);
- conducting environmental site assessments (ESA);
- development of mitigation and environmental protection plans; and
- botanical and vegetation expertise for remediating and restoring disturbed environments.

Workshops and Training

Northern Bioscience can provide a range of workshops, training, and presentations related to natural resources and outdoor recreation. Using a variety of media (e.g. slides, Powerpoint, static displays), we can effectively communicate the desired message to lay, technical or scientific audiences. We have extensive experience in public consultation for natural resource issues and protected areas management. We can also provide expert advice and consultation for technical and working committees. Where possible, we incorporate practical and field components to facilitate information transfer and learning.

Archaeological Investigation Experience

Western Heritage is a firm offering archaeology, near surface geophysics (ground penetrating radar, gradiometry, magnetic susceptibility) and remote sensing services across western Canada and in northwestern Ontario. While many of the senior staff can hold permits and licenses across Canada, the company provides local services through offices in Grande Prairie, St. Albert, Calgary, Saskatoon, Swan River, Winnipeg and Thunder Bay. Western Heritage is a private, Canadian owned corporation with its Head Office in Saskatoon, Saskatchewan.

Founded in 1990, Western Heritage staff have completed thousands of archaeological projects, from one-day site inspections to multi-year, multi-disciplinary management and mitigation programs. The company regularly undertakes projects on both federal and provincial land, and has completed projects at all stages from initial historical overviews (Stage 1) to archaeological mitigation (Stage 4). Western Heritage is currently completing a large scale mitigation project for Ontario Ministry of Transport, currently the largest set of archaeological excavations underway in Canada.

Western Heritage works with clients at all stages of their requirements, from Stage 1 to 4. The company is actively involved in developing client-specific heritage management plans.

Western Heritage maintains a rigorous quality control system. All projects are reviewed and approved by an internal panel of Senior Archaeologists. This insures a constant professional approach taken for all projects across each provincial jurisdiction, even though there are often differences in provincial requirements. Western Heritage staff carry $2,000,000 in errors and omissions insurance, and $5,000,000 in general liability insurance. Western Heritage has a rigorous safety program that is certified by Enform, with an average score of 94%.

For more information, please visit the Western Heritage web site at www.westernheritage.ca

Company Profile

KBM RESOURCES GROUP

Laird Van Damme
KBM Resources Grooup

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Thunder Bay, Ontario

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Cell: 807 473 7226

www.kbm.on.ca

Services and Client Base

- Services
  - Consulting & Technical Services
  - Geospatial Services
  - Sales and Service
  - Chemical warehousing
  - Site Preparation & Contracting

Serving since 1973:

- Government
- Forest Industry
- NGOs, World Bank, CIDA
- Private Land Owners
- First Nations
- Renewable energy sector
- Mining sector

KBM: Consulting & Technical Services

- Expertise in such fields as forestry, ecology, biology, and environmental assessment
- Core of experienced senior consultants and a skilled group of junior consultants and support staff
- Strategic partnerships and networks with professionals across North America, Sweden, Finland, and Chile

Expertise

- Forest & Land Use Planning
- Strategic Forest Management Modelling
- Statistical Analysis
- Environmental Impact Assessment (EIA)
- Forest Auditing
- Ecological and Forest Inventory Analysis
- First Nations Business Development
- Forest/Wildlife Modelling
- Image Analysis

Forestry Technical Services

& Seedling Testing Lab

- Provide services for industry, government, and the general public

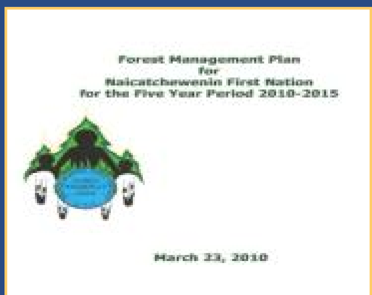
- Regeneration Surveys
- Free To Grow Surveys
- Digital Aerial Photography and Interpretation
- GPS and Electronic Field Data Collection

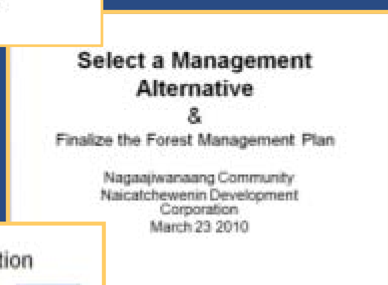
Seedling Testing Lab

- Shoot Frost Hardiness
- Stock Quality Assessment
- Custom Crop Monitoring

www.kbm.on.ca

First Nations Capacity Building and Services





Forest management plan for Naicatchewenin First Nation

- Successful joint ventures in site preparation and business development
- Negotiated co-management of new forest operations in traditional territory
- Training and community development projects
- Forest management planning

www.kbm.on.ca

KBM Site Preparation & Contracting

- Provider of site preparation services for Canadian forest industry
- Staffed by skilled mechanics, operators, and subcontractors
- Over 10,000 ha treated annually in NW Ontario when demanded
- Specific types of equipment used to suit different applications
- Introduced environmentally sensitive intermittent patch scarification to North America
- Pioneered simultaneous site preparation and seeding
- Former distributor of Bracke forestry equipment

www.kbm.on.ca

PROFILE

TBT ENGINEERING CONSULTING GROUP

- **PROJECT MANAGEMENT**
- **GEOTECHNICAL ENGINEERING**
- **ENVIRONMENTAL ENGINEERING**
- **TRANSPORTATION ENGINEERING**
- **LEGAL SURVEYS**
- **ENGINEERING SURVEYS**
- **MATERIALS TESTING AND INSPECTION**
- **DRILLING SERVICES**
- **GEOLOGICAL SERVICES**
- **SUBDIVISIONS**
- **AGGREGATE INVESTIGATIONS & PERMITTING**








TBT Engineering Limited is a fully qualified civil and environmental engineering consultant firm with offices centrally located in Canada.
Initially founded as Thunder Bay Testing in 1968, TBT Engineering has grown to over 100 highly qualified professional and technical staff dedicated to providing unparalleled quality services on a wide range of projects through planning, design, investigation, and construction phases.

Our Clients

- Architects
- Commercial
- Developers
- Energy
- Engineers
- Forestry
- Government
- First Nations
- Industry
- Insurance
- Lawyers
- Realtors
- Mines
- Railways
- Ports
- Private
- Municipalities

MATERIAL TESTING

- Concrete
- Asphalt
- Soils
- Permeability Testing
- Consolidation Testing
- CSA Certified
- CCIL Certified
- MTO Qualified

GEOTECHNICAL ENGINEERING

- Slope Stability Analyses
- Geotechnical Investigations
- Dam Design
- Pavement Design
- Embankment Design
- Lagoon Berms / Dyke Design
- Settlement Analysis
- Liquefaction Assessments
- Pit & Quarry Licensing
- Earth Retaining Systems
- Geological Studies

FIELD SERVICES

- Drilling Services
- Compaction Testing
- Piling Inspection
- Vibration Monitoring
- Aggregate Testing
- Concrete Testing
- Profilograph Testing
- Roof Inspection
- RMCAO Certifications
- ACI Concrete Training

SURVEYS

- Legal
- Engineering
- Subdivisions
- Reference Plans
- Topographic Surveys
- Digital Terrain Modeling
- Boundary Surveys
- Construction Layout

ENVIRONMENTAL ENGINEERING

- Phase I & 2 Site Assessments
- Environmental Screening
- Site Clean Up Assessments
- Landfill Permitting
- Groundwater Monitoring
- Certificate of Approvals
- Record of Site Conditions
- Monitoring Well Installation
- MOE Reg. 903 Certified
- Fisheries Studies

CIVIL ENGINEERING

- Project Management
- Route Studies
- Traffic Studies
- Preliminary Design
- Detail Design
- Tender Preparation
- Municipal Design
- Construction Administration
- Aggregate Permits
- Recreation Facilities

ONTARIO
1918 Yonge Street
Thunder Bay, ON, P7E 6T9
Tel: 807-624-5160 Fax: 807-624-5161
Toll Free Ph: 1-866-624-8378

From Testing Through to Consultation,
We Are Your "Down to Earth" Consultants

www.tbte.ca

MANITOBA
110 Paramount Road
Winnipeg, MB, R2X 2W3
Tel: 204-633-6008 Fax: 204-633-6620
Toll Free Ph: 1-866-998-4750

GEOTECHNICAL

- PROJECT MANAGEMENT
- GEOTECHNICAL ENGINEERING
- ENVIRONMENTAL ENGINEERING
- TRANSPORTATION ENGINEERING
- LEGAL SURVEYS
- ENGINEERING SURVEYS
- MATERIALS TESTING AND INSPECTION
- DRILLING SERVICES
- GEOLOGICAL SERVICES
- SUBDIVISIONS
- AGGREGATE INVESTIGATIONS & PERMITTING

We address the requirements of our clients by providing a wide range of geotechnical services. From preliminary studies to detailed design and analyses, we can tailor our services to meet your needs and budget. Our team of engineers, geologists and technologists has experience in providing geotechnical services to a wide range of clients. We pride ourselves on providing innovative solutions in dealing with the diverse and often complex subsurface conditions encountered within our region.

- Detailed Geotechnical Investigations
- Pavement Design
- Terrain Analyses
- Desktop Studies
- Geothermal Modeling
- Seepage Analyses
- Finite Element Stress Analysis
- Bearing Capacity
- Forensic Studies
- Embankment Design
- Earth Dam Design
- Tailings
- Soft Clays
- Aggregate Studies
- Friction Piles
- End Bearing Piles
- Rock Socketted Piles
- Micro Piles
- Laterally Loaded Pile Analysis
- Breakwaters
- Revetments

- Field Investigations
- Monitoring Plans
- Inspections
- Pit and Quarry Licensing
- Mat Foundations
- Compensated Raft Foundations
- Shallow Footings
- Insulated Foundations
- Frost Protection
- Design with Light Weight Fills
- Earth Retaining Systems
- Laboratory Testing
- Frost Heave Assessment
- Construction Monitoring
- Vibration Monitoring
- Construction Staging
- Water Treatment Plants / Reservoirs
- Clarifiers / Aeration Basins
- Anchors
- Sheet Piling
- Excavation Assessments

- Slope Stabilization
- Ground Improvements
- Site Preloads
- Lagoon Berms / Dykes
- Pavement Management
- Comparative Site Studies
- Settlement Performance Analysis
- Liquefaction Assessments
- Instrumentation

Our Clients

- Architects
- Commercial
- Developers
- Energy
- Engineers
- Forestry
- Government
- First Nations
- Industry
- Insurance
- Lawyers
- Mines
- Railways

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MATERIAL TESTING

- PROJECT MANAGEMENT
- GEOTECHNICAL ENGINEERING
- ENVIRONMENTAL ENGINEERING
- TRANSPORTATION ENGINEERING
- LEGAL SURVEYS
- ENGINEERING SURVEYS
- MATERIALS TESTING AND INSPECTION
- DRILLING SERVICES
- GEOLOGICAL SERVICES
- SUBDIVISIONS
- AGGREGATE INVESTIGATIONS & PERMITTING

TBT Engineering provides a wide range material testing and laboratory services to the construction industry. Our laboratory and technologists are fully certified to meet the needs of our clients. Our corporate commitment to health and safety standards is reflected in all of our services.

LABORATORY SERVICES

- Grain Size Analyses
- Atterberg Limits
- Unconfined Compression Soil Testing
- Consolidation Testing
- Direct Shear Testing
- Asphalt Testing – Super Pave
- Concrete Testing
- Concrete Admixture Testing
- Aggregate Physical Property Testing
- Soil and Aggregate Permeability
- Point Load Testing – Rock
- Training
- Petrographic Analysis
- Rock Core Logging

CERTIFICATIONS

- Canadian Standards Association
- Canadian Council of Independent Laboratories
- Ministry of Transportation - RAQS

FIELD TESTING AND INSPECTION SERVICES

- Concrete Testing
- Compaction Testing
- Roofing Inspection
- Core Drilling
- Structural and Reinforcing Steel Inspection
- Bolt Torque Inspection
- Tensile Bond Strength Testing
- Fireproofing Inspection
- Pile Inspection
- Subgrade Inspection
- Material Sampling
- Vibration Monitoring
- Profilograph Analysis
- On Site Field Technicians
- Concrete and Nuclear Gauge Training
- Aggregate Prospecting, Evaluation, Permitting

Clients

- MTO
- MNR
- ORC
- OPG
- Architects
- Engineers
- Consultants
- Project Managers
- Industry
- Railways
- Forestry
- Mines
- Contractors

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Chimax Inc.
Engineering Company

Chimax Inc.

Company Profile

2012

Chimax Inc.
3950 14th Avenue, Suite 506,
Markham. Ontario. L3R 0A9

Tel: (905) 305-6133
Fax: (905) 305-6132
e-mail: chimax@chimax.ca

Table of Contents

Introduction

Established in 1989, **C**himax Inc. has since grown into a highly-regarded engineering firm excelling in the design of electrical generation, transmission and distribution systems, and industrial buildings. Our dedicated staffs include a core of highly motivated and experienced professional engineers, designers and CAD operators.

Our engineering expertise, which continues to expand and grow, reflects the diverse assignments and hard work of our diligent staff over the years. Our dedicated staffs have extensive power utility experience, technical expertise and are committed to providing services of the highest calibre. Our extensive field experience working with construction contractors and keen eye for detail have allowed us to continually provide practical and cost effective solutions and recommendations for our clients.

Our reputation is built on efficient service, quality solutions and competitive fees. We pride ourselves on our practice of integrating all disciplines involved on each project. This team approach to tackling projects holds true throughout our day-to-day operations as well. We strongly believe that total co-operation among all parties involved is the key to completing projects on time and on budget. The added value to our clients is our ability to develop cost effective solutions in difficult situations or unanticipated events. This has avoided potential cost overruns in many projects for our clients.

Chimax Inc. offers a variety of engineering services including civil, structural and electrical engineering. Previous work has included the design of high voltage substations, transmission and distribution lines, switch yard design, protection and control systems, industrial buildings, overhead cranes, conveyors, mobile units for equipment transport and unique custom designs for special situations.

Services

Engineering is a key component for completing a successful project on schedule and on budget. Typical project phases include feasibility studies, conceptual design, detail design, specifications, procurement, installation supervision, commissioning and start-up.

Chimax has successfully completed over 600 projects of various sizes with our dedicated staff and partners. In addition to our practical knowledge on various regulatory (e.g. national and provincial codes, interconnection specifications, CSA, etc.) and engineering standards (e.g. IEEE, equipment specifications, etc.), our ability to put together an effective team specific to each project give us the competitive advantage in many design projects.

Completed project assignments include:

- Feasibility study, front end engineering design
- Conceptual layout design (electrical substations, switchyards, transmission and distribution lines, interconnections, industrial buildings etc)
- Detail designs including structural analysis, plan and profile, cable sag and tension review etc.
- Specifications for foundation and structure fabrication, major material procurements
- Consulting services for project owners
- Technical supports for construction contractors
- Custom engineering design for special situations
- Project management services

Chimax Inc. staffs are highly proficient in the use of the most up to date design tools (e.g., AutoCAD, PLS-CADD, PLS-Tower, PLS-Pole, STADD-PRO etc.) to facilitate the design process and detail drawings production.

All work performed by our company are covered by professional engineering liability insurance.

Experience

Chimax has completed well over 600 projects since inception. The key market segments served by Chimax include electrical power, oil and gas and mining industry. Our client list includes power utilities, major oil and gas, and mining companies as well as engineering, procurement and construction (EPC) contractors. These project engagements spanned across Ontario, Alberta and other provinces, as well as international locations such as Jamaica, St. Vincent, Bahamas, Iran, British Virgin Island, Belize etc. (see the sample list of reference projects). Chimax's engagements in these projects ranged from feasibility studies, general layouts, to detail engineering design of the civil structure for the distribution lines, substations or switch yards, to providing technical expertise or engineering support to the construction contractors.

The Government of Ontario initiative on renewable energy and "green" power accelerated many wind farm developments. Chimax Inc. is fortunate to be in the position to provide valuable experience and expertise to the success of many of these projects. As of the end of 2008, Chimax Inc. was involved in over 80% of the installed capacity.

Areas of Engineering Services

Power Station Layout and Design:
Using the client information and engineering data provided (e.g., single line diagram and available land information, layout of the equipment arrangement etc.); a typical deliverable could be a work package for construction that includes:

- Station and equipment layout,
- Detail equipment support and towers structure design,
- Detail foundations design,
- Bill of materials.

Typical engagements:

- High voltage transformer stations designs
- Distribution substations design
- Switch yards design
- Mobile high voltage equipment station design
- Retrofit and upgrade of existing stations
- Feasibility study
- Engineering consulting services
- Project management

Substation,
Greenfield Energy Centre

Transmission and Distribution Lines:

Using the proposed routing and survey information, appropriate design tools, Chimax can assist the client:

- Determine the optimal routing/right of way,
- Engineer the interface with others, liaison with contractors, suppliers, Hydro One, IESO, AESO etc,
- Provide plan and profile drawings
- Design pole/tower structures and arrangement drawings,
- Detail foundation design,
- Line bill of material,
- Sag and tension report and string chart,
- Technical support during construction.

Transmission Lines
Greenfield Energy Centre

Typical engagements:

- High voltage transmission line design
- Distribution line or collector line design
- Interconnections to transmission grid or local distribution line
- Feasibility study
- Engineering consulting services
- Project management

Old Harbour Metering Station, Jamaica

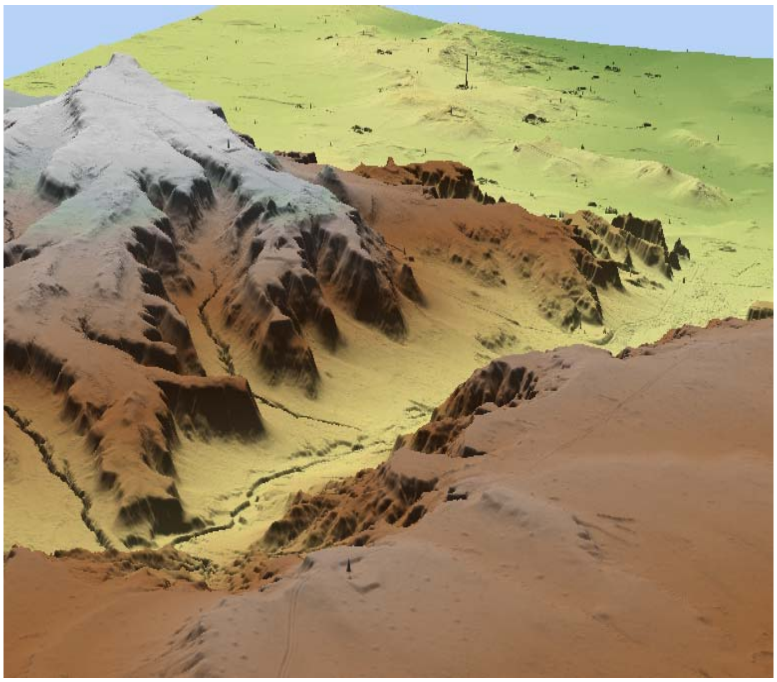
Industrial Buildings and Machinery:

Custom design for special requirements - typical engagements:

- Structure design for material handling conveyer
- Trailer design for carrying equipment or other form of mobile unit
- Modification of existing structure and building
- Structure and foundation design for light industry projects

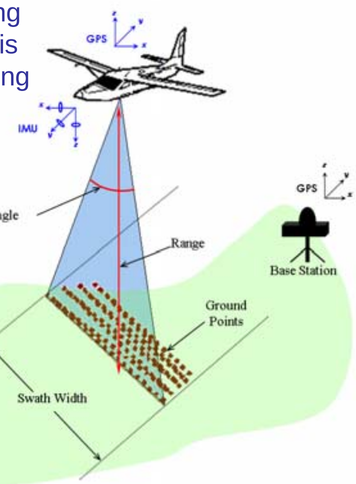
Airborne LiDAR Mapping

A Clean Harbors Company



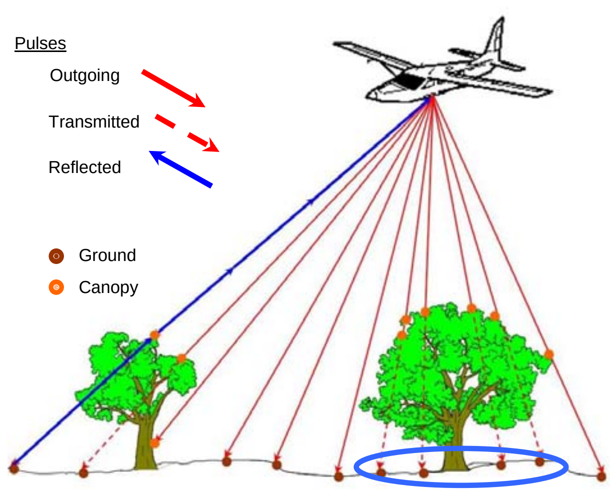
LiDAR Mapping offers:

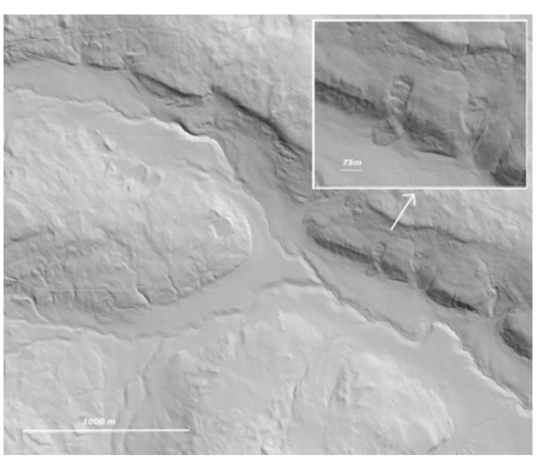
- Bare Earth and Full Feature Models
- Digital Elevation Models (DEM)
- Digital Terrain Models (DTM)
- Contours of varying intervals
- Slope Analysis and Mapping
- Planimetric Mapping
- Tree height analysis
- Cut and Fill modeling
- Orthophotography



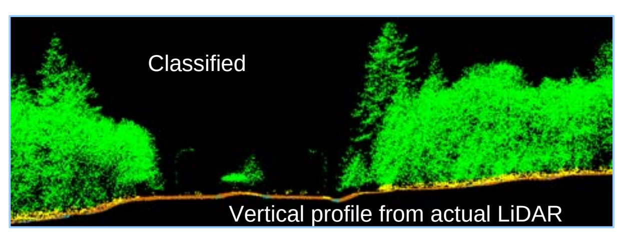
LiDAR Provides solutions for:

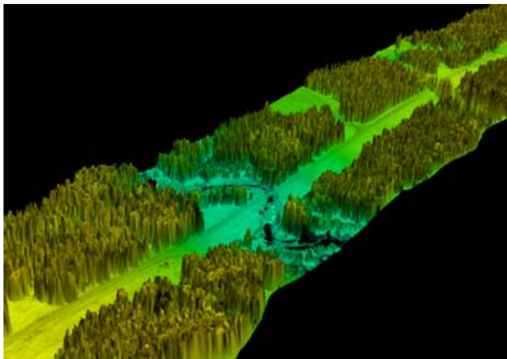
- Engineering preliminary surveys
- First Nations
- Environment
- Emergency Management
- Risk Mitigation
- Exploration and Mining
- Oil and Gas
- Renewable Energy – Wind and Solar
- Transmission Lines
- Pipelines



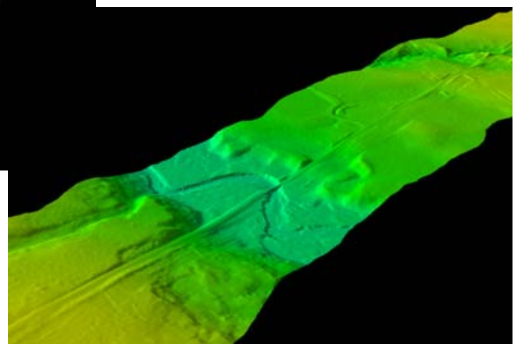


LiDAR can "see" under vegetation for Risk Mitigation in infrastructure planning





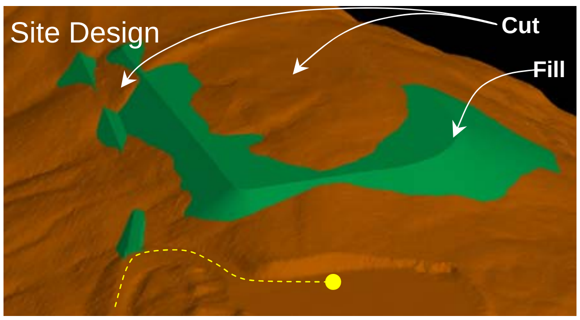
LiDAR for Corridor Mapping of Pipeline, Transmission, Road and Rail project development and planning has huge cost savings potential

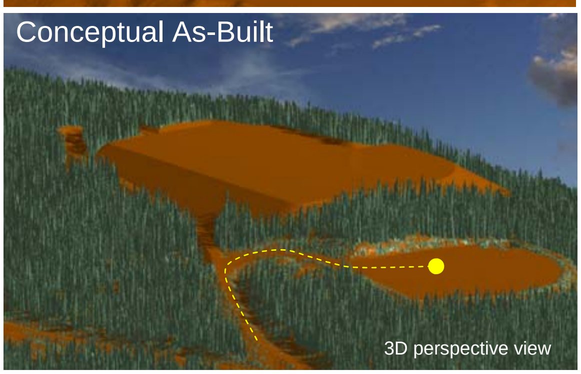


LiDAR helps understand waterway crossings, areas of steep topography and integration with existing corridors

AIRBORNE IMAGING

A Clean Harbors Company



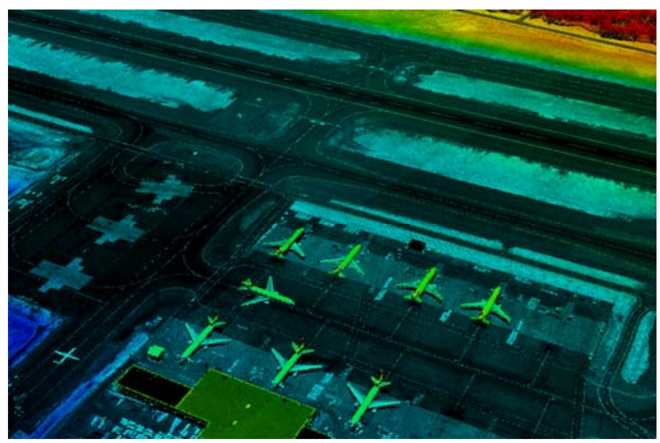


Reference line along road leading to existing pad

LiDAR is an invaluable tool when mapping open pit mines for planning, monitoring, change detection, volumes and slope stability

LiDAR deliverables include:

- Full Feature grid (format and grid spacing according to your specifications)
- Bare Earth grid
- Hill Shade Images (Geotiff format); Bare Earth and Full Feature Model
- Hill Shade Images (Geotiff format):
- Vegetation Height
- Slope map
- Elevation extractions



Airport mapping, obstacle and line of site analysis

Contact:
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APPENDIX D

TRC Engineers

Statement of Qualifications

Statement of Qualifications
TRC Engineering Services

TRC

TRC Engineers

www.trcsolutions.com

TABLE OF CONTENTS

COMPANY PROFILE

FIRM PROFILE

TRC Companies, Inc. (NYSE: TRR) is an engineering, consulting, and construction management firm that provides integrated services to the environmental, energy, infrastructure, and real estate markets. Our multidisciplinary project teams provide turnkey services to help our clients implement complex projects from initial concept to delivery and operation. A broad range of commercial, industrial, and government clients depend on us for customized and complete solutions to their toughest business challenges. Formed in 1969, and incorporated in the state of Connecticut in 1971, TRC now has more than 2100 professionals in over 75 offices located throughout the nation. Many of our professionals come from industry, so we know your business from first-hand experience. This gives us insight into your business priorities, risks, and operations. Our industry experience assures you that we will deliver and execute solutions that meet your real world needs—and add true value to your operations.

TRC ENGINEERS

TRC Engineers, the power delivery group of TRC has over 450 professionals located in more than 20 offices throughout the United States. TRC Engineers has provided full service engineering consulting services for utilities, developers, municipalities, and industry since 1999. Comprised of many experienced engineers, our project teams know how to plan, design, and install facilities that meet a client's financial, technical, and scheduling goals. TRC Engineers is unique in the power delivery industry in that we self perform a project from initial studies, through detailed design, construction management, to final commissioning.

Our goals are to make the client's job easier, be an extension of the client's staff, provide flexibility, and deliver a quality product.

TRC Engineers' capabilities include:

- Power System Studies
- Transmission
- Substations
- Protection & Controls
- EPC (Engineer, Procure, Construct) Contracts
- Distribution
- Field Services
- Nuclear Generation Services
- Generation
- Project Management
- Construction Management

AREAS OF EXPERTISE

POWER SYSTEM STUDIES

TRC offers analysis and planning of transmission, distribution and industrial power systems. Our staff of well qualified and experienced engineers understands the complex local and regional electrical grid and internal plant issues. We provide assistance and training in areas of power system relaying, conceptual design, planning and operation. Our services include:

- Merchant Plant Interconnections
- System Protection
- Switching Studies
- Transmission Planning Studies
- Feasibility Studies
- Reliability Studies
- Operational Studies
- Distributed Generation
- Short Circuit Studies
- Arc Flash Hazard Analyses

TRANSMISSION

TRC Power Delivery offers a full range of design and planning services for virtually any transmission line project. With transmission line experience including 500 kV projects completed, TRC Power Delivery is adept at handling any linear project. Our experienced team can deliver completed facilities from line extensions to major transmission additions. Our services include:

- Transmission Line Design to 500 kV
- PLS CADD
- Project Management
- Environmental Studies & Permitting
- Construction Management
- Turnkey EPC Capability
- Drafting Services
- Condition Assessment
- Fiber Optic Cable Design
- Special Studies
- Surveying
- Foundation Design
- Re-Rating
- Underground Transmission
- Submarine Cable Design

SUBSTATIONS

The TRC team has designed, constructed and commissioned hundreds of substations TRC Power Delivery can provide services from initial concept, feasibility and planning studies, complete civil, mechanical, and electrical design, land acquisition and permitting. Experienced team members can deliver completed facilities from switchyards to integrated / automated substations. TRC Power Delivery offers substation experience in:

- AIS Substations & Switchyards
- Station Expansions and Upgrades
- Traditional or Design-Build
- Site Development
- Site Civil and Geotechnical Work
- Access Roads & Fencing
- Oil Spill Containment Designs
- Ground Resistance Measurements
- Conceptual Design and Studies
- Balance of Plant Detailed Engineering
- Packaged Substations
- Capacitor Bank Additions
- Protective Relaying & Control
- Automated /Integrated Systems
- Fiber Optic Cabling
- Grounding Systems Analysis
- Communication Systems
- Communication Systems
- Insulation Coordination
- Lightning Analysis
- Lighting Survey and Analysis
- Relay Coordination Studies
- Fault Studies
- Noise and Audible Studies
- EMF Analysis
- NERC Compliance
- Security Assessment and Design

PROTECTION & CONTROLS

With extensive experience in design and commissioning of relay systems, TRC offers the range of knowledge necessary to carry out and complete your project. From conceptual design through final commissioning our engineers and designers can provide solutions to your relaying problems. We are equally at home designing retrofit upgrades or new construction with virtually any relay system. Our services include:

- Conceptual Design
- Relay Application Analysis
- Short Circuit Analysis
- CT Burden Calculations
- Settings Calculations
- Substation Automation
- Relay & Control Cabinet Design
- Detail Design Drawings
- SCADA, DFR, SER Design & Programming
- Relay Testing & Commissioning
- Outage & Fault Analysis

ENGINEER, PROCURE, CONSTRUCT (EPC) CONTRACTS

EPC (Engineer, Procure, Construct) contracts are a large percentage of TRC Power Delivery's workload. Many customers have expressed a preference for EPC contracts in recent years, and TRC has responded by delivering this full service with a high degree of success. Among our references are representatives of EPC clients for whom TRC has completed significant projects. These customers include AES Corporation, Calpine, Central Maine Power, Mitsubishi Electric Power Products, National Grid, Northeast Utilities, and Rochester Gas & Electric, to mention a few.

TRC Power Delivery is the ideal match for the client requiring experienced personnel to get the job done. Utilizing extensive design/build experience, TRC Power Delivery staff can provide the turnkey substation, transmission, and generation facilities that will meet the client's design criteria, budget, schedule, and operational requirements

Our services include:

- Full Service/Owner's Representatives
- Licensing & Permitting
- Topographic & Boundary Surveying
- Preliminary Engineering & Cost Estimating
- Develop Project Schedules
- Develop Bid Documents
- Procure & Evaluate Contractor Bids
- Bid Award & Contract Work
- Project & Construction Management
- Testing & Commissioning
- As-Builts

DISTRIBUTION

Fulfilling all of a client's distribution system engineering needs is a TRC Power Delivery specialty. TRC Power Delivery engineers are well versed in the assessment, planning, design, and construction of distribution systems up to and including 69 kV voltage. With experience from design and working within many types of systems, TRC Power Delivery has helped strengthen and improve operations as well as help assess and upgrade equipment.

While employed as utility and consulting engineers, TRC Power Delivery engineers worked with distribution systems. Each project is approached with a valuable breadth of experience, and with a creative eye toward safe and efficient future operation.

TRC Power Delivery engineers are prepared to respond quickly and professionally to a client's distribution system needs for:

- Distribution System Studies
- Conceptual Design and Cost Analysis
- Structural Design and Analysis
- Permitting and Environmental Studies
- Land Surveying, Mapping and GIS Location Services
- Route Selection
- Motor Start Analysis
- Work Plan Studies for Budget Approval
- Overhead & Underground Lines
- Conductor and Cable Design
- Generator Placement Analysis
- Power Factor Analysis
- Capacitor Bank Analysis
- Voltage Studies
- Fault Studies and Overcurrent Protection

FIELD SERVICES

Utilizing a staff of experienced engineers and test technicians, TRC Power Delivery offers comprehensive commissioning and testing services. The team approach results in a high quality product that includes well documented test results, drawings and reports. A highly experienced support staff of engineers makes TRC Power Delivery exceptionally qualified to solve complex problems, evaluate design issues and offer timely solutions. Commissioning and testing experience includes, but is not limited to:

- Programmable Logic Controllers
- SCADA systems
- Fiber Optic communication systems
- Power Line Carrier systems
- Substation protection and control systems
- Generator plant protection and control systems
- Audio tone communication systems
- High voltage rotating machines (Gen. And Motors)
- Motor controls
- Generator static exciters
- Generating plant turbine governors
- Variable speed drives
- Hydraulic and pneumatic control systems
- HMI systems
- Automation systems
- Large power transformers
- High voltage circuit breakers
- Instrument transformers
- Revenue metering

NUCLEAR GENERATION SERVICES

TRC Engineers bring all our well established engineering services and practices to the Nuclear Generation arena. TRC is unique among nuclear engineering service providers in that we also provide full range of services including design & licensing engineering, project engineering, construction management, post modification testing and commissioning services. We adapt our engineering practices to those of the client. We offer full compliance with station design control, work control and Project Management processes. This ensures seamless transition through all phases of a project from conception to closeout.

Our services include:

- Full Service/Owner's Representatives
- Preliminary Engineering & Cost Estimating
- Engineering Design Change Packages
- License & Design Basis Reviews (FSAR)
- 10 CFR 50.59 Evaluations
- Develop Project Schedules
- Develop Bid Documents
- Procure & Evaluate Contractor Bids
- Bid Award & Contract Management
- Project & Construction Management
- Testing & Commissioning
- Capacitor Bank Additions
- Protective Relaying & Control
- Automated/Integrated Systems
- Fiber Optic Cabling

GENERATION

From the initial feasibility studies for distributed generation through siting and licensing to construction and automating and commissioning of the most modern generation facilities, TRC provides a complete range of design and project management services. We are proven problem solvers in generation related projects. TRC has a hard-earned reputation for technical skill and practical knowledge on difficult interconnection issues, power generation projects, and analyzing transmission line bottlenecks. Our staff has been involved in projects in all aspects of the generation field. Our services include:

- Engineering & Design
- Distributed Generation Feasibility Through Construction
- Facility Studies and SPCC Plans
- System Studies & Modeling
- System Protection & Control Design
- Protective Relay Coordination
- Automation Controls & SCADA
- System Optimization
- Power Factor Correction
- Fault Current, Power Quality, & Harmonics Analyses

- EMF Testing & Mitigation
- Generator & Battery Systems
- Commissioning
- FERC Part 12 Inspections
- Powerhouses, Spillways & Fish Ladders
- Dam Evaluation, Design & Removal
- Rubber Dam Evaluation & Design

PROJECT MANAGEMENT

Whether you have a large complex project or a multitude of projects integrated into one program you need effective management in order to succeed. The three most important factors to consider in Project Management are scope, schedule, and controls. Utilizing our staff's vast years of experience and with the aid of the most up-to-date software TRC is able to manage any size project to a successful completion, on time and on budget.

TRC has gained experience managing large complex projects throughout New England and New York. Not only do we provide the project management, but we also offer licensing, power system studies, and design engineering services to meet all aspects of your project needs.

TRC's experience includes:

- Scheduling
- Schedule Risk Assessment (SRA)
- Earned Value Management (EVM)
- Financial Planning & Cost Controls
- Risk Management
- Communication Plan
- Quality Assurance/Quality Control
- Procurement & Material Expediting
- Performance Tracking
- Contract Management
- Staffing Plan

CONSTRUCTION MANAGEMENT

TRC Power Delivery provides a complete range of construction management services designed to assist clients in achieving business objectives. Each construction project is assigned a manager responsible for schedules, budgets, and work products for the project. TRC Power Delivery construction managers are experts in their respective fields and have demonstrated the abilities needed to complete projects on time and within budget. The manager will oversee a team tailored to meet the exact requirements of each client.
The range of services includes:

- Specification and bid package preparation
- Contractor pre-qualification
- Evaluation and solicitation of bids
- Scheduling, cost estimates and cash flow planning
- Inspection of all phases of work
- Monitoring of safety programs
- Documentation control and management

PROJECT EXPERIENCE

TRC has a unique combination of resources and experience that is ideally suited to successfully meeting this Project's needs. Our hands-on experience designing, licensing and constructing energy facilities, state and regional know-how, technical expertise, and depth of staffing resources will result in quality products, completed with efficiency, and responsive to the specific needs of each Project element. We pride ourselves on our ability to complete projects expeditiously, safely and efficiently.

Examples of projects with direct, relevant experience follow.

EPC EXPERIENCE

BARBOUR HILL SUBSTATION FOR NORTHEAST UTILITIES

TRC provided engineering, procurement and construction services to Connecticut Light & Power for the Barbour Hill Substation Modification Project. This project was divided into five (5) phases including; installation of a new 115kV substation, cut-over of six (6) each 115kV overhead lines from the existing (old) 115kV substation to the new 115kV substation, demolition and removal of the existing (old) 115kV substation, installation of a new 345kV substation, and cut-over of (into) an existing 345kV overhead line.

According to CLP's Project Manager, the Barbour Hill Substation project was their most critical substation & infrastructure upgrade project for 2007 and 2008. Not only are the upgrades significantly important to ISO-NE, CL&P and local residents, the Barbour Hill Substation also supplies power to Connecticut's (CT) Bradley International Airport, and it's Buckland Hills Mall. The substation is located in South Windsor, Connecticut, however, the project also includes coordinated work at (or between) five (5) remote substations which are located in CT and Massachusetts (MA).

WAKEFIELD JUNCTION SUBSTATION FOR MITSUBISHI ELECTRIC POWER PRODUCTS, INC (MEPPI)

As the prime consultant/contractor on the Wakefield Junction Substation project, TRC is providing engineering, procurement, and construction services for a new 345/115 kV GIS substation under the terms of an EPC contract. The project includes engineering, designing, procuring, constructing, and testing equipment to provide the owner with complete operational facilities. These facilities include an indoor 115 kV gas insulated substation, an indoor 345 kV gas insulated substation, and four (4) 345/115 kV autotransformers. Completion of this project is a critical part of various improvements to the transmission system associated with the North Shore Area Upgrades. Construction of the station shall be completed by March 1, 2009 to support cutovers and energization of equipment to be completed by June 2009.

MAGUIRE ROAD PROJECT
CENTRAL MAINE POWER

TRC, as a joint venture with E.S. Boulos, provided engineering, licensing, procurement and construction services to Central Maine Power for the Maguire Road Project. This project is designed to improve the reliability of the transmission system in Southern Maine includes the construction of a new 115 kV substation, a major expansion of a 345 kV substation, upgrades at multiple remote end substations and transmission line rebuilds and re-conductors.

This project is divided into two phases. Phase one includes the engineering, permitting and licensing of all facilities for the project and the construction of a 345 kV substation expansion that includes remote end substation upgrades.

Phase two includes the construction of a new 115 kV substation, expansion of an existing 115 kV substation, upgrades at eight remote end substation upgrades and the construction of 115 kV transmission lines.

ROCHESTER TRANSMISSION PROJECT
FOR ROCHESTER GAS & ELECTRIC

TRC, working in partnership with ES Boulos and O'Connell Electric, will complete final design, procurement and construction of the Rochester Transmission Project EPC project. The scope of work includes procurement, project management, civil and electrical construction, testing and commissioning of all facilities in this project.

The facilities in this project include approximately 38 miles of new or rebuilt 115 kV transmission lines, two new 115 kV substations, and upgrades at nine existing substations. The eleven substations included 35 kV, 115 kV and 345 kV substations.

In addition the work will also include the engineering, procurement, Construction and project management necessary to increase the thermal capacity of seven 35 kV circuits and installing additional parallel underground cables (approximately 38 circuit miles). The 35 kV work will also include installation of four additional transformers at station 42 and a capacitor bank at Station 33.

AES GRANITE RIDGE PROJECT
AES LONDONDERRY, LLC

TRC, as a joint venture with E.S. Boulos, delivered five related projects within Public Service Company of New Hampshire's (PSNH) service territory. The AES Granite Ridge Projects include the Watts Brook Substation, the National Grid U.S.A. North Litchfield Substation, the AES Granite Ridge Power site, and transmission lines at 230 kV and 115 kV connecting the facilities to the utility grids. The transmission lines, Watts Brook and North Litchfield Substations were designed and built to respective utility's standards. These projects were performed as EPC projects in support of the AES Granite Ridge power plant and were sold to the host utility upon commercial operation.

The PSNH Watts Brook substation is a 115 kV air insulated substation with a three breaker ring bus with connections to three overhead 115 kV transmission lines.

The National Grid North Litchfield substation site contains an air insulated 230 kV substation with two independent ring busses comprised of 3 breakers each. The substation accommodates connections to six overhead 230 kV transmission lines.

The AES Granite Ridge substation provides the connections to the power plant site. The substation is comprised of an air insulated 230/115 kV substation with two 230 kV and one 115 kV line terminals. Connections to the power plant were provided at the three GSU transformers (2 – 230 kV, 1 – 115 kV).

The transmission Facilities include one double circuit 230 kV transmission line from the Granite Ridge substation to the North Litchfield substation, and one single circuit 115 kV transmission line from Granite Ridge substation to the Watts Brook substation.

AMHERST SUBSTATION
PUBLIC SERVICE OF NEW HAMPSHIRE

TRC worked for Public Service of New Hampshire to provide engineering, procurement, and construction services for an expansion at the existing 345/34 kV Amherst substation facility.

The existing substation consisted of a 345 kV tap feeding a 345/34 kV 140 MVA transformer with five 34 kV circuit positions. The relay / control equipment was housed inside an existing masonry control house complete with AC/DC systems.

The TRC project scope at Amherst also included project and construction management to closely coordinate the design and construction of the substation with PSNH. This was necessary to meet the one year duration of the project which was phase oriented to maintain electrical service, while also working in close proximity to existing energized equipment.

To integrate the new equipment and operating requirements with the existing, several upgrades and removals were closely coordinated with PSNH to complete the facility.

- Supplied a completely automated protection and control design.
- Provided design, construction and testing and commissioning.
- Added a four breaker 345 kV 3,000 amp ring-bus with two new line terminals.
- A 140 MVA 345/34 kV power transformer with oil containment system.
- Two 34kV 3,000 amp low-side circuit breakers (one for the existing transformer).
- One 34 kV 2,000 amp bus-tie breaker placed within the existing configuration.
- All equipment and systems were designed to comply with NPCC Bulk Power System
- Protection Criteria operation.

APPENDIX E

Davies

Statement of Qualifications

Energy

PRACTICE PROFILE

Our Practice

Our Energy team is a cross-disciplinary group of lawyers experienced in all aspects of complex energy projects and transactions. We have developed extensive expertise in the development, financing and related aspects of projects involving electricity and natural gas transmission and distribution assets, as well as the oil, gas, nuclear, hydroelectric, wind, solar and other renewable sectors. We bring our unparalleled M&A skills to a wide range of energy transactions involving the private and public sectors. Our breadth of experience in the energy sector enables us to provide sophisticated advice and find practical solutions to achieve our clients' business objectives.

Our Clients

We act for a wide range of industry participants including domestic and international developers, purchasers, sellers, lenders and government entities. We work with all key stakeholders including regulators, transmission and distribution utilities, municipalities and community and Aboriginal groups. Our clients rely on us to organize and coordinate the teams of legal, financial, accounting and technical experts needed to successfully complete their transactions. We negotiate and structure complex transactions and navigate the regulatory environment both in Canada and abroad, advising clients on:

- Mergers & acquisitions, including public take-over bids and arrangements, share and asset purchases, major divestitures, strategic investments and restructurings;
- Financings, including private equity investments, bank-led project financings and Canadian and cross-border public offerings (including IPOs) and private placements;
- Negotiation of joint ventures and resource development agreements;
- Project development, structuring, financing and permitting;
- Public–private partnerships;
- Tax planning for project structures;
- Energy contracts and emissions trading;
- Environmental and regulatory compliance;

PRACTICE PROFILE

- *Competition Act* and *Investment Canada Act* compliance;
- Opportunities under Ontario's new *Green Energy Act*; and
- Community and Aboriginal relations.

Electricity

Davies represents some of the leading electricity generators, transmission and distribution utilities and financing entities in Canada, the U.S. and abroad. Davies also acts for small to mid-sized enterprises involved in emerging energy technologies. We are involved in several sectors of the power industry including electric and natural gas utilities and hydroelectric, nuclear and renewable energy. Our recent experience includes:

- the purchase of hydroelectric, nuclear and oil and diesel powered generating stations;
- hydroelectric development and financing and associated environmental assessment, permitting and Aboriginal risk assessment reviews;
- regulatory and civil liabilities in the purchase, operation, refurbishing and financing of nuclear facilities;
- the development, purchase, sale and financing of renewable energy projects such as wind, biofuel, biomass, solar and run-of-river; and
- Canadian and international acquisitions of small, medium and large transmission and distribution utilities.

Recognition

The firm's success in producing results for our clients has led to Davies being consistently recognized by independent rating agencies as a market leader in each of our core practice areas. *Chambers Global* recognizes Davies as a leading firm in Energy & Natural Resources and has commented that "the firm's strength lies in its significant client base, which distinguishes it in the market". Members of our energy group are consistently ranked as industry leaders by IFLR1000, Expert Guides' *The Best of the Best*, the *Lexpert®/American Lawyer Guide to the Leading 500 Lawyers in Canada* and the *PLC Which Lawyer? Yearbook.*

DAVIES

Electricity

This list is a representative selection of major transactions in which Davies Ward Phillips & Vineberg LLP's involvement is a matter of public record. Transactions are, generally, listed chronologically.

Acted for **Fortis Inc.** in its $601 million bought deal public offering of subscription receipts. The net proceeds will be used to finance a portion of the acquisition of CH Energy Group, Inc., a New York-based regulated transmission and distribution utility.

Acted for **The Manufacturers Life Insurance Company** in connection with the project financing of $167 million credit facilities intended to finance the construction of a 31MW hydroelectric project to be located on Cascade Creek north of Stewart, British Columbia.

Acted for **Fortis Inc.** in its $341-million bought deal public offering of common shares.

Acted for **AbitibiBowater Inc.** (now known as Resolute Forest Products) in connection with the sale of its 75% indirect interest in ACH Limited Partnership, which owns 8 hydroelectric generating facilities in Ontario, in a transaction valued at $640 million.

Acted for **Hydroméga Services Inc.** in connection with a bridge financing and project financing provided by Sun Life Assurance Company of Canada for the development and construction of four hydro projects on the Kapuskasing River in Ontario.

Acted for **Victoria Square Ventures Inc.**, a subsidiary of Power Corporation, in connection with the creation of Potentia Solar Inc., an independent power producer in Ontario generating electricity through solar-powered energy systems. The other shareholders of Potentia Solar Inc. are MKB Solar Rooftops Inc., an affiliate of MacKinnon, Bennett & Company Inc. and Conundrum Capital Group.

Acted for **The Manufacturers Life Insurance Company** in connection with the project financing of $87.5 million credit facilities intended to finance the construction of two hydroelectric projects in the Bear Creek region of British Columbia.

Acted for **Hydro-Québec** in connection with its $4.75-billion proposed acquisition of substantially all of the assets of New Brunswick Power and that of its affiliates, including hydroelectric, combustion and nuclear facilities.

Electricity

Acted for **Fortis Inc.** in its $250-million bought deal public offering of cumulative redeemable five-year rate reset first preference shares.

Acted for **FortisOntario Inc**., a subsidiary of Fortis Inc., in its acquisition of the Great Lakes Power electric distribution business from Brookfield Renewable Power Inc. for a purchase price of approximately $75 million.

Acted for **Fortis Inc.** in its public offering of $200 million principal amount of 6.51% senior unsecured debentures.

Acted for **Hydro-Québec** in connection with the tax planning and structuring of its $1.5-billion 1,200 MW transmission line construction and operation project connecting Québec with New Hampshire.

Acted for **FortisOntario Inc.**, a subsidiary of Fortis Inc., in connection with its acquisition of a 10% strategic ownership position in the electricity distribution business of Grimsby Power Inc.

Acted for **Fortis Inc.** in its $300-million bought deal public offering of common shares.

Acted for **Fortis Inc.** in its $230-million bought deal public offering of Series G fixed reset first preference shares.

Acted for **BMO Nesbitt Burns Inc.** in connection with its financing of the construction and operation of the run-of-the-river 23.6 MW hydroelectric facility at Umbata Falls in Ontario.

Acted for **TD Capital Group Limited** in the initial public offering and acquisition of Innergex II Income Fund by Innergex Renewable Energy Inc.

Acted for **Fortis Inc.** in its acquisition of Terasen Inc., the Canadian natural gas distribution business of Kinder Morgan, Inc., in a transaction valued at $3.7 billion, creating the largest investor-owned utility in Canada. Awarded 2007 Deal Team of the Year at the inaugural Canadian Dealmakers Gala.

Acted for **Abitibi-Consolidated Inc.** (now known as Resolute Forest Products) which with the Caisse de dépôt et placement du Québec completed a joint venture for the Company's hydroelectric generation facilities in Ontario. The joint venture, ACH Limited Partnership, was 75% owned by Abitibi-Consolidated and 25% owned by the Caisse.

Electricity

Acted for **Fortis Inc.** in its $1.15-billion bought deal public offering of subscription receipts. The net proceeds were used to finance a portion of the acquisition of Terasen Inc. from Kinder Morgan, Inc.

Acted for **Fortis Inc.** in its $150-million bought deal public offering of common shares.

Acted for **Hydro-Québec International** and **Fonds de solidarité des travailleurs du Québec** in the sale of Consorcio TransMantaro SA to Interconexíon Eléctrica SA ESP and Empresa de Energía de Bogotá SA ESP in a transaction valued at $117.5 million.

Acted for **Fortis Inc.** in its acquisition of a majority ownership position in Caribbean Utilities Company, Ltd., a TSX-listed company that is the sole provider of electricity on Grand Cayman, Cayman Islands.

Acted for **Fortis Inc.** in its $125-million bought deal public offering of first preference shares.

Acted for **Fortis Inc.** in its US$90-million acquisition of two electricity utilities which together serve 80% of the electricity customers on the Turks & Caicos Islands.

Acted for **Hydro-Québec International Inc.** and **Fonds de solidarité des travailleurs du Québec** in the sale of their indirect interest in Empresa de Generación Eléctrica Fortuna, S.A., the owner of the largest hydro electricity generating facility in Panama, to Enel Latin America LLC in a transaction valued at US$150 million.

Acted for **Caisse de dépôt et placement du Québec** in connection with its investment in ArcLight Energy Partners Fund III, L.P.

Acted for **Hydro-Québec International** in the sale of its interest in Hidroeléctrica Río Lajas SA, the owner of a hydroelectricity generating facility in Costa Rica, to Corporación de Inversiones Abonos Superior SA, its Costa Rican partner.

Acted for **Fortis Inc.** in its $130-million bought deal public offering of common shares.

Electricity

Acted for **Fortis Inc.** in its $1.5-billion acquisition of the Alberta and British Columbia electricity utilities of Aquila, Inc.

Acted for **General Electric Energy** on its proposed construction and management of an 800 MW combined-cycle project in cooperation with Hydro-Québec Production, to be built in Beauharnois, Québec (known as the Hydro-Québec Suroît project).

Acted for **Fortis Inc.** in connection with its US$45-million project financing of existing hydroelectric facilities owned by Belize Electric Company Limited.

APPENDIX F

Andrew Taylor

Statement of Qualifications

The Energy Boutique

About Andrew Taylor

Andrew Taylor started his legal career as in-house counsel with Ontario Hydro in 1997. In 2000, Andrew joined Power Budd LLP, just as the electricity industry in Ontario underwent significant changes. Andrew was actively involved in the development of Ontario's electricity market and the regulated rate regime for electricity distributors and transmitters.

In 2004, Andrew moved to Ogilvy Renault LLP where for seven years he represented electricity distributors, transmitters, and generators in respect of their regulatory obligations before the Ontario Energy Board on matters such as rates, licensing, compliance and the construction of electricity infrastructure. Andrew was a partner at Ogilvy Renault and held the positions of Co-Chair - Cleantech Practice Group and Chief Sustainability Officer (Ontario).

Commencing June 1, 2010, Andrew started his own energy regulatory practice where he continues to represent clients before the Ontario Energy Board and advise energy industry stakeholders.

Andrew Taylor is recognized by the energy industry as an expert on regulatory matters. He frequently appears as counsel before the Ontario Energy Board, and regularly gives lectures on the rate application process to electricity distributors.

Representative Work

Rate Proceedings:

- Counsel to the following electricity distributors on their 2011 cost-of-service distribution rate applications:
  - Kingston Hydro
  - St. Thomas Energy Services

- Counsel to the following electricity distributors on their 2010 cost-of-service distribution rate applications:
  - Veridian Connections
  - Essex Powerlines
  - Newmarket-Tay Power Distribution
  - Algoma Power
  - Whitby Hydro

- Counsel to the following LDCs on their 2009 cost-of-service distribution rate applications:
  - Bluewater Power Distribution
  - Canadian Niagara Power Inc. – Port Colborne
  - Canadian Niagara Power Inc. – For Erie
  - Canadian Niagara Power Inc. – Eastern Ontario Power
  - Westario Power
  - Newmarket Hydro

- Co-counsel to EnWin Utilities on its 2009 cost-of-service distribution rate application.

- Counsel to the following LDCs on their 2008 cost-of-service distribution rate applications:
  - Oshawa PUC Networks
  - Barrie Hydro Distribution

- Co-counsel to the following LDCs on their 2008 cost-of-service distribution rate applications:
  - Lakefront Utilities
  - Rideau St. Lawrence Distribution
  - Enersource Hydro Mississauga

- Co-counsel to Great Lakes Power Limited on its 2007 cost of service distribution rate application.

- Counsel to the Coalition of Large Distributors in the OEB's combined smart meter proceeding.

- Co-counsel to Great Lakes Power in its 2005 transmission rate application.

- Counsel to a coalition of LDCs who intervened in Hydro One's 2002 distribution rate application.

- Co-counsel to Great Lakes Power on its 2002 distribution and transmission rate applications.

Infrastructure Development and Construction:

- Counsel to Canadian Niagara Power in the East-West Tie Line Proceeding (EB-2011-0140) regarding the designation of a transmitter to develop a transmission line between Northeast and Northwest Ontario.

- Counsel to South Kent Wind LP (part of the Samsung group) on obtaining leave to construct a 33 km transmission line to connect a 270-MW wind farm located within the Municipality of Chatham-Kent in southwestern Ontario.

- Counsel to Greenfield Energy Centre LP on obtaining leave to construct a 4 km transmission line to connect a 1000 MW co-generation facility to the grid.

- Counsel to Erie Shores Wind Farm LP on obtaining leave to construct a 30 km transmission line to connect its wind-farm to the grid.

- Counsel to De Beers Canada and Five Nations Energy Inc. on obtaining leave to construct a 414 km transmission line in Northern Ontario.

- Co-counsel to Great Lakes Power on obtaining leave to construct a 164 km transmission line in Northern Ontario.

Policy:

- Counsel to the Ontario Waterpower Association in the Renewed Regulatory Framework for Electricity proceeding.

- Counsel to the Ontario Waterpower Association in the Transmission Project Development Planning proceeding.

- Counsel to the Ontario Waterpower Association and the Canadian Wind Energy Association in the Integrated Power System Plan proceeding.

- Counsel to the Ontario Waterpower Association and the Canadian Wind Energy Association in the Transmission Connection Cost Responsibility proceeding.

APPENDIX G

Resumés of

Management Team

FORTIS

MR. WILLIAM J. DALEY

President & Chief Executive Officer
FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/Algoma Power Inc.

EDUCATION:

1996 Rensselaer Polytechnic Institute, Troy, New York
Executive Masters Business Administration

1987 Cornell University, Buffalo, New York
Industrial Labour Relations Studies

1982 Buffalo State College, Buffalo, New York
Bachelor of Science, Industrial Technology

EMPLOYMENT HISTORY:

2003 - Present **FortisOntario Inc.**
President and Chief Executive Officer

- Approximately 30 years of direct experience in the management and operations of electrical transmission and distribution business in both US and Canada.
- Oversees a diversified electric utility holding company and manages the wholly-owned subsidiaries: Canadian Niagara Power, Cornwall Electric and Algoma Power. These utilities, located in the Niagara, Eastern and Northern regions, serve approximately 65,000 customers and meet a combined peak load of 256 MW.
- Directs the company's 10 per cent interest in Westario Power, Rideau St. Lawrence Power and Grimsby Power Inc., three regional electric distribution companies serving a combined customer base of approximately 38,000
- Manages the regulated transmission assets in the Niagara and Cornwall areas, including an international interconnection between New York State and Fort Erie, and a 5 MW natural gas cogeneration plant

2002 - 2003 FortisOntario Inc.
President-Elect

1998 - 2002 Canadian Niagara Power Company Limited
Vice President, Corporate Development

1996 - 1998 Niagara Mohawk Energy
Regional Manager for Western New York Energy Marketing Startup

1982 - 1996	Niagara Mohawk Power Corporation Regional Service Manager Manager Employee Relations Director Corporate Personnel Administration Supervisor Employee Relations Supervisor Coordination/Operation Productivity Planning Analyst
1981	National Fuel Gas Company, Buffalo Industrial Engineer Technician

BOARD MEMBERSHIPS:

- FortisOntario Inc.
- Fortis Alberta Inc.
- Canadian Niagara Power Inc.
  Chairman
- Cornwall Street Railway, Light and Power Company Limited
  Chairman
- Algoma Power Inc.
  Chairman
- Niagara Christian College
  Chairman
- Fort Erie Credit Union

FORTIS

MR. GLEN KING

Vice President – Finance & Chief Financial Officer
FortisOntario Inc./ Canadian Niagara Power Inc./Cornwall Electric/Algoma Power Inc.

EDUCATION:

1990 Chartered Accountant

1988 Memorial University of Newfoundland
Bachelor of Commerce (Co-operative)

PROFESSIONAL ASSOCIATION:

- The Institute of Chartered Accountants of Ontario

EMPLOYMENT HISTORY:

2005 - Present **FortisOntario Inc.**
Vice President, Finance & Chief Financial Officer

As Vice President, Finance & Chief Financial Officer, Mr. King has all the duties and responsibilities normally associated with the financial, customer service and regulatory staff/departments of an Ontario-based diversified and growth oriented electricity transmission and distribution company. FortisOntario is a licensed generator, transmitter and distributor of electricity in Ontario and provides distribution services to 65,000 customers.

2003 - 2005 Canadian Niagara Power Inc.
Director, Finance
Treasurer

2001 - 2003 Newfoundland Power
Director, Finance

1995 - 2001 Fortis Trust Corporation
Vice President, Finance

1988 – 1995 Deloitte & Touche Chartered Accountants
Senior Manager
Manager
Auditor
Student

BOARD MEMBERSHIPS:

Canadian Niagara Power Inc.

Cornwall Street Railway, Light and Power Company Limited

Algoma Power Inc.

United Way of Niagara Falls and Greater Fort Erie

FORTIS

MR. ANGUS S. ORFORD

Vice President, Operations
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

1990 Dalhousie University, Halifax, Nova Scotia
Master of Business Administration

1987 University of Prince Edward Island
Bachelor of Science (Physics)

1984 Technical University of Nova Scotia
Bachelor of Engineering (Civil)

1982 University of Prince Edward Island
Diploma of Engineering

PROFESSIONAL ASSOCIATION:

- The Association of Professional Engineers of Ontario

EMPLOYMENT HISTORY:

2005 - Present **FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/ Algoma Power Inc. - Vice President, Operations**

- Responsible for all duties associated with the engineering, operations and system planning services of an Ontario-based diversified and growth oriented electric utility holding company that transmits electricity and provides distribution services to approximately 65,000 customers.

Maritime Electric Company, Limited (1984 – 2005, excluding 1988-1990 academic years)

2004-2005	Manager, Transmission & Distribution
1999-2004	Manager, Customer Service & Corporate Communications
1997-1999	Manager, Marketing & Corporate Communications
1996-1997	Supervisor, Civil Engineering
1992-1996	Planning Engineer
1991-1992	Rates and Utilization Analyst
1990-1991	Manager, Western District

1987-1990 Program Coordinator, Pole Replacement

1985-1987 Supervisor, Survey Department

1984-1985 Site Engineer

TRANSMISSION RELATED WORK:

- ***Design, Plan and Project Management***

  138 kV single pole high strength steel transmission line for Hillsborough River Crossing, Charlottetown, PEI

  69 kV single pole Class 2 wood transmission lines

  - Lorne Valley switching station to Victoria Cross substation, PEI
  - Sherbrooke substation to Summerside substation, PEI
  - St. Eleanor's substation to Slemon Park substation, PEI
  - Miscouch By-Pass transmission line relocation, PEI
  - Dingwell Mills substation to Souris substation, PEI

- ***Project Management***

  69 kV single pole Class 2 wood transmission line

  - Hunter River substation to Sherbrooke substation, PEI

Board Memberships:

- Cornwall Street Railway, Light and Power Company Limited
- Utilities Standards Forum

FORTIS

Mr. R. Scott Hawkes

Vice President, Corporate Services & General Counsel
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

1987 Queen's University, Kingston, Ontario
Bachelor of Laws

1984 Queen's University, Kingston, Ontario
School of Business
Bachelor of Commerce (Honours)

PROFESSIONAL ASSOCIATIONS:

- The Law Society of England and Wales
- The Law Society of Upper Canada and Canadian Bar Association
- The Institute of Chartered Corporate Secretaries, Canada and Cayman Islands

EMPLOYMENT HISTORY:

2003 – Present **FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc. - Vice President, Corporate Services & General Counsel**

- Lead negotiator of innovative Memorandum of Understanding with Lake Huron Anishinabek First Nations to develop electricity transmission projects in Ontario.
- Responsible for regulatory and legal matters relating to the planning, development and approval of electricity transmission projects.
- Responsible for duties associated with the legal, human resources, information technology, and health, safety and environmental staff/departments of an Ontario-based diversified and growth oriented electricity transmission and distribution company.
- Responsible for duties associated with the company's Corporate Secretary position.

1990 – 2002 Company Secretary
Caribbean Utilities Company, Ltd., Grand Cayman, Cayman Islands

- Corporate secretary and in-house legal counsel reporting to the Chief Executive Officer of a publicly traded and rapidly growing electric utility, and sole supplier of power to Grand Cayman.

- Negotiated and managed long-term strategic alliances with ABB for the engineering, procurement and construction of transmission substation facilities and related transmission equipment; and MAN B&W for the engineering, procurement and construction of diesel generation expansion projects.

1989 – 1990 Lawyer
Blake Cassels & Graydon, Toronto, Canada

1988 Student-at-Law
Ontario Securities Commission, Government of Ontario

1987 – 1988 Articling Law Student
Smith Lyons Torrance Stevenson & Mayer, Toronto, Canada

BOARD MEMBERSHIPS:

- Cornwall Street Railway, Light and Power Company Limited

- Grimsby Power Inc.

MR. TIM LAVOIE, CMA

Regional Manager & Director of Northern Development
Algoma Power Inc.

EDUCATION:

2001 Society of Management Accountants of Ontario
Certified Management Accountant Professional Program

1993 Wilfrid Laurier University – Waterloo, Ontario
Honours Bachelor of Business Administration – Specialized in Corporate Finance

PROFESSIONAL ASSOCIATION:

- Society of Management Accountants of Ontario

EMPLOYMENT HISTORY:

2009 – Present **Algoma Power Inc., Sault Ste. Marie, Ontario**
Regional Manager & Director, Northern Development

- Approximately 20 years experience in the energy sector in a variety of management, operational and regulatory roles.
- Oversee and manage Algoma Power Inc., a regional distribution utility serving over 14,000 sq km area with over 11,600 customers.

2007 – 2009 **Great Lakes Power Limited – Sault Ste. Marie, Ontario**
General Manager – Transmission and Distribution

- Filed first transmission leave to construct application with the Ontario Energy Board after market opening for $85 million 230kV rebuild in Northern Ontario.
- Management, oversight and key company witness in the successful filing of 6 rates applications to the Ontario Energy Board.

2005 – 2006 Sault Hydro Operations - General Manager

2003 – 2005 Customer and Finance Manager

1999 – 2003 Accounting Manager

1995 – 1999 Management Information Coordinator

1993 – 1995 Systems Analyst/Project Co-Manager

1992 Financial Analyst

1988 – 1990 Seasonal Labourer

1991 Union Gas Limited – Chatham, Ontario
Cogeneration Financial Analyst, 1991

BOARD MEMBERSHIPS:

Algoma University Board of Governors

- Chair

Safe Communities Partnership, Sault Ste. Marie

FORTIS

MR. PIERRE J. A. DUFOUR, CD, PMP, CTECH

Manager – Major Projects
FortisBC Inc.

EDUCATION:

- Canadian Forces School of Military Engineering
  Construction/Civil Engineering Technology
  Construction Maintenance Engineering Technology

- Canadian Forces Leadership Academy
  Junior and Senior Leadership Programs

- University of Toronto
  Advanced Certificate in Project Management

- University of British Columbia, Sauder School of Business
  Certificate in Management Excellence

- Western Energy Institute
  Business Acumen Program for Emerging Leaders

PROFESSIONAL ASSOCIATIONS:

- Member of the Applied Science Technicians & Technologists of British Columbia
- Member of the Project Management Institute
- Member of the Military Engineers Association of Canada

EMPLOYMENT HISTORY:

2011 – Present **FortisBC Inc. – Manager, Major Projects**

- Accountable for providing leadership and oversight to FortisBC's Project Management Office (PMO). The PMO has a staff of project and construction managers accountable for the execution of transmission, distribution and generation major projects for FortisBC.

2006 – 2012 **Manager, Okanagan Transmission Reinforcement Project**

- Responsible for leading the Okanagan Transmission Reinforcement (OTR) Project team through all stages including planning, consultation, engineering, execution and construction, along with the regulatory approval process through the British Columbia Utility Commission (BCUC). The OTR project was approved by the BCUC in October 2008 at a cost of $141 million and was substantially completed in 2011 at a cost of $105 million.

2000–2006 **FortisBC (formerly West Kootenay Power) – Senior Project Manager**

- Provided project management services throughout all stages of project delivery (planning, engineering, construction and commissioning) for transmission and distribution capital and third party customer projects.

1994–2000 **Northwest Territories Power Corporation – Project Manager/Technologist**

- Provided project management, construction supervision and engineering services throughout all stages of project delivery for civil, mechanical, and environmental utility related projects throughout Canada's Arctic.

1976–1994 **Member of the Canadian Armed Forces (CAF) Military Engineering Branch - Military Engineer**

- Served as a Construction Engineer at various Military Units throughout Canada and Europe. Completed military career in the CAF as a Standards Warrant Officer at the Canadian Forces School of Military Engineering.

LHATC

Mr. Ross R. Assinewe

Chief Executive Officer
Lake Huron Anishinabek Transmission Company

EDUCATION:

Cambrian College of Applied Arts and Technology, Sudbury, ON
Geological Engineering Technician
Business Administration

Productivity Point International, Sudbury, ON
AutoCAD and Softdesk Certificate Program

REGISTRATIONS:

- Associate Certified Engineering Technologist, Ontario
- Canadian Council of Independent Laboratories (CCIL), Aggregate
- Canadian Standards Association (CSA), Concrete
- Certified Level I Water Treatment Plant Operator – Ontario Environmental Consortium (In Waiting)
- Certified Trainer – Confined Space Entry
- Circuit Rider Training – Ontario First Nations Technical Services Corporation

PROFESSIONAL ASSOCIATIONS:

- Associate Member Ontario Association Certified Engineering Technicians and Technologists
- Canadian Council Independent Laboratories
- Canadian Standards Association
- Level I – Water Treatment Plant Operator (Pending)
- Train the Trainer – Confined Space Entry

BOARD AFFILIATIONS:

- Sits on the M'Anishnabek Industries General Partnership Board of Directors, representing Serpent River First Nation

EMPLOYMENT HISTORY:

2011-Present **Lake Huron Anishinabek Transmission Company (LHATC)**
Chief Executive Officer

- LHATC represents 21 First Nations Communities in the Robinson Huron Treaty territory and has been established by First Nations to pursue the development of electricity transmission projects in Ontario.

2009-2010 **ANMAR Mechanical and Electrical Contractors Ltd., Project Development Coordinator, First Nations, Sudbury, Ontario**

- Responsible for coordinating the First Nation consultations and investigating potential sites for Hydro development.
- Accountable for discussions with the First Nation communities involved with Natural Resource Developments that are occurring with their territories.
- Responsible for investigating and negotiating First Nations Impact and Benefit Agreements, which provide for business opportunities.
- Involved with preparing and negotiating Joint Venture Partnership opportunities so that the First Nations can access the Set-Aside Projects associated with the developments occurring within their Territories.
- Successfully completed agreements with First Nations.

2007-2009 **Trow Associates Inc., Director, First Nation Projects, Sudbury, ON**
Director, First Nations Projects

- Liaised for the Project Team and the Aboriginal Communities and served as Aboriginal Relations Advisor in numerous engineering, environmental and municipal projects.
- Responsible for coordinating and administering the Aboriginal communication program for the assignments.
- Responsibilities included the following: Aboriginal issues analysis, social impact analysis, community/stakeholder consultation, community consultation programming and participated in the management of field and data collecting activities such as sampling, surveying and site inspection.
- Responsible for Joint Venture Partnerships, including negotiation of agreements.

2002-2007 **Sagamok Anishinabek, Director, Planning and Technical Services Unit**
Director of Planning and Technical Services Unit (P&TSU)

- Responsible with respect to services supplied by the housing department, water and sanitation department, roads department, and fire department.
- Responsible for safe operations of community buildings, new planning initiatives and delivering efficient services within a $1.8 million operating budget.
- Responsible for developing a social housing program for the Sagamok Anishinabek membership through a comprehensive community development initiative.
- The Sagamok Anishinabek has implemented the current Ontario Water Regulations and is enrolled within the provincial programs included in Ontario Regulations 459.
- Instrumental in the development of the working group committee for water treatment plant operators at the North Shore Tribal Council.

- Provided overall management and supervision within the housing department, which has accessed CMHC's social housing programs, including Section 95, HASI and RRAP.

1999-2002 **AMIK Resources, Managing Director, Sudbury, ON**
Managing Director of AMIK Resources

- Responsible for project management, municipal/environmental engineering, surveying, design, construction, inspection, supervision of industrial/municipal projects research data, information retrieval and field work co-ordination on First Nations' projects.
- Provided First Nations with housing services and acted as the prime contact for First Nation, government and other stakeholder related projects.

1998-1999 **IFNA Engineers Ltd., Sudbury, ON**
Manager

- Responsible for exploring and marking IFNA's engineering services in the Sudbury district and Northeastern Ontario.

1995 – 1998 **AGRA Earth & Environmental Ltd., Sudbury, ON**
Manager, Aboriginal Services

- Served as the main contact regarding First Nations throughout Ontario, participating on all aspects of AGRA's services, from corporate participation to project-specific fieldwork.

1994-1995 **Union of Ontario Indians, Program Manager, North Bay, ON**
Chief Executive Officer

- Reporting to the Board of Directors, Executive, and Grand Council Chief, responsible for operating within a $7 million budget and for the day-to-day administrative functions.
- Responsible for reviewing and disseminating of all material and information to the secretariat of the Union of Ontario Indians.

1992-1994 **Sagamok Anishinabek, Massey, ON**
Executive Director

- Responsible for the day-to-day administrative functions, reporting to Chief and Council of the Sagamok Anishinabek and operating within a $15 million budget.
- Reviewed and delivered all materials and information to Sagamok Anishinabek.

1991-1992 **UMA Engineering Limited, Sudbury, ON**
Civil Technologist

- Responsible for marketing UMA's municipal engineering services and participating on the project team providing the field services.
- In addition to First Nation projects, responsible for delivery of UMA's services to other non-aboriginal clients.

1987-1991 **Northland Engineering Ltd., Sudbury, ON**
Survey Party Chief

1985-1987 **D.S. Dorland Limited, Sudbury, ON**
Surveyor

- Worked with project team that included members from Ontario Hydro on the Sudbury West 230kV Hydro Transmission Line construction. Responsibilities for this assignment included the locating of the base of the Steel Lattice Towers and the Guy Wires. Verifying the R.O.W. limits was also completed.

APPENDIX H

Resumés of

Technical Team

FORTIS

MR. WILLIAM J. DALEY

President & Chief Executive Officer
FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/Algoma Power Inc.

EDUCATION:

1996 Rensselaer Polytechnic Institute, Troy, New York
Executive Masters Business Administration

1987 Cornell University, Buffalo, New York
Industrial Labour Relations Studies

1982 Buffalo State College, Buffalo, New York
Bachelor of Science, Industrial Technology

EMPLOYMENT HISTORY:

2003 - Present **FortisOntario Inc.**
President and Chief Executive Officer

- Approximately 30 years of direct experience in the management and operations of electrical transmission and distribution business in both US and Canada.
- Oversees a diversified electric utility holding company and manages the wholly-owned subsidiaries: Canadian Niagara Power, Cornwall Electric and Algoma Power. These utilities, located in the Niagara, Eastern and Northern regions, serve approximately 65,000 customers and meet a combined peak load of 256 MW.
- Directs the company's 10 per cent interest in Westario Power, Rideau St. Lawrence Power and Grimsby Power Inc., three regional electric distribution companies serving a combined customer base of approximately 38,000
- Manages the regulated transmission assets in the Niagara and Cornwall areas, including an international interconnection between New York State and Fort Erie, and a 5 MW natural gas cogeneration plant

2002 - 2003 FortisOntario Inc.
President-Elect

1998 - 2002 Canadian Niagara Power Company Limited
Vice President, Corporate Development

1996 - 1998 Niagara Mohawk Energy
Regional Manager for Western New York Energy Marketing Startup

1982 - 1996	Niagara Mohawk Power Corporation Regional Service Manager Manager Employee Relations Director Corporate Personnel Administration Supervisor Employee Relations Supervisor Coordination/Operation Productivity Planning Analyst
1981	National Fuel Gas Company, Buffalo Industrial Engineer Technician

BOARD MEMBERSHIPS:

- FortisOntario Inc.
- Fortis Alberta Inc.
- Canadian Niagara Power Inc.
  Chairman
- Cornwall Street Railway, Light and Power Company Limited
  Chairman
- Algoma Power Inc.
  Chairman
- Niagara Christian College
  Chairman
- Fort Erie Credit Union

FORTIS

Mr. R. Scott Hawkes

Vice President, Corporate Services & General Counsel
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

1987 Queen's University, Kingston, Ontario
Bachelor of Laws

1984 Queen's University, Kingston, Ontario
School of Business
Bachelor of Commerce (Honours)

PROFESSIONAL ASSOCIATIONS:

- The Law Society of England and Wales
- The Law Society of Upper Canada and Canadian Bar Association
- The Institute of Chartered Corporate Secretaries, Canada and Cayman Islands

EMPLOYMENT HISTORY:

2003 – Present **FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc. - Vice President, Corporate Services & General Counsel**

- Lead negotiator of innovative Memorandum of Understanding with Lake Huron Anishinabek First Nations to develop electricity transmission projects in Ontario.
- Responsible for regulatory and legal matters relating to the planning, development and approval of electricity transmission projects.
- Responsible for duties associated with the legal, human resources, information technology, and health, safety and environmental staff/departments of an Ontario-based diversified and growth oriented electricity transmission and distribution company.
- Responsible for duties associated with the company's Corporate Secretary position.

1990 – 2002 Company Secretary
Caribbean Utilities Company, Ltd., Grand Cayman, Cayman Islands

- Corporate secretary and in-house legal counsel reporting to the Chief Executive Officer of a publicly traded and rapidly growing electric utility, and sole supplier of power to Grand Cayman.

- Negotiated and managed long-term strategic alliances with ABB for the engineering, procurement and construction of transmission substation facilities and related transmission equipment; and MAN B&W for the engineering, procurement and construction of diesel generation expansion projects.

1989 – 1990 Lawyer
Blake Cassels & Graydon, Toronto, Canada

1988 Student-at-Law
Ontario Securities Commission, Government of Ontario

1987 – 1988 Articling Law Student
Smith Lyons Torrance Stevenson & Mayer, Toronto, Canada

BOARD MEMBERSHIPS:

- Cornwall Street Railway, Light and Power Company Limited
- Grimsby Power Inc.

FORTIS

Mr. Doyle Sam

Vice President, Engineering and Generation
FortisBC Inc.

Education:

2000 Queens University, Kingston, Ontario
Masters of Business Administration

1989 University of Alberta
Bachelor of Science (Civil Engineering)

Professional Associations:

- Association of Professional Engineers, Geoscientists of British Columbia
- Association of Professional Engineers, Geologists and Geophysicists of Alberta

Employment History:

2012-Present FortisBC Inc. – Vice President, Engineering & Generation

- Responsible for all duties associated with the system planning, engineering and project management of the organization's electric and gas transmission and distribution assets serving 160,000 electric customers and almost 1,000,000 natural gas customers.
- Responsible for the daily operations of company and third party owned hydro generating facilities.

2008-2011 FortisBC Inc. - Vice President, Engineering & Operations (electric)

- Responsible for the planning, engineering, project management and daily operations of generation, transmission and distribution.

2005-2008 FortisBC Inc. – Vice President, Transmission & Distribution

2003-2004 Aquila Networks Canada – GM (BC region) & Director Asset Management

2000-2002 TransAlta Utilities – General Manager, Wabamun Generating Station

1989-1999 TransAlta Utilities – Various Roles

- Various engineering, planning and project management roles within Transmission and Generation.

FORTIS

MR. PIERRE J. A. DUFOUR, CD, PMP, CTECH

Manager – Major Projects
FortisBC Inc.

EDUCATION:

- Canadian Forces School of Military Engineering
  Construction/Civil Engineering Technology
  Construction Maintenance Engineering Technology

- Canadian Forces Leadership Academy
  Junior and Senior Leadership Programs

- University of Toronto
  Advanced Certificate in Project Management

- University of British Columbia, Sauder School of Business
  Certificate in Management Excellence

- Western Energy Institute
  Business Acumen Program for Emerging Leaders

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- Provided project management, construction supervision and engineering services throughout all stages of project delivery for civil, mechanical, and environmental utility related projects throughout Canada's Arctic.

1976–1994 **Member of the Canadian Armed Forces (CAF) Military Engineering Branch - Military Engineer**

- Served as a Construction Engineer at various Military Units throughout Canada and Europe. Completed military career in the CAF as a Standards Warrant Officer at the Canadian Forces School of Military Engineering.

FORTIS

MR. ANGUS S. ORFORD

Vice President, Operations
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

1990 Dalhousie University, Halifax, Nova Scotia
Master of Business Administration

1987 University of Prince Edward Island
Bachelor of Science (Physics)

1984 Technical University of Nova Scotia
Bachelor of Engineering (Civil)

1982 University of Prince Edward Island
Diploma of Engineering

PROFESSIONAL ASSOCIATION:

- The Association of Professional Engineers of Ontario

EMPLOYMENT HISTORY:

2005 - Present **FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/ Algoma Power Inc. - Vice President, Operations**

- Responsible for all duties associated with the engineering, operations and system planning services of an Ontario-based diversified and growth oriented electric utility holding company that transmits electricity and provides distribution services to approximately 65,000 customers.

Maritime Electric Company, Limited (1984 – 2005, excluding 1988-1990 academic years)

2004-2005	Manager, Transmission & Distribution
1999-2004	Manager, Customer Service & Corporate Communications
1997-1999	Manager, Marketing & Corporate Communications
1996-1997	Supervisor, Civil Engineering
1992-1996	Planning Engineer
1991-1992	Rates and Utilization Analyst
1990-1991	Manager, Western District

1987-1990 Program Coordinator, Pole Replacement

1985-1987 Supervisor, Survey Department

1984-1985 Site Engineer

TRANSMISSION RELATED WORK:

- ***Design, Plan and Project Management***

  138 kV single pole high strength steel transmission line for Hillsborough River Crossing, Charlottetown, PEI

  69 kV single pole Class 2 wood transmission lines

  - Lorne Valley switching station to Victoria Cross substation, PEI
  - Sherbrooke substation to Summerside substation, PEI
  - St. Eleanor’s substation to Slemon Park substation, PEI
  - Miscouch By-Pass transmission line relocation, PEI
  - Dingwell Mills substation to Souris substation, PEI

- ***Project Management***

  69 kV single pole Class 2 wood transmission line

  - Hunter River substation to Sherbrooke substation, PEI

Board Memberships:

- Cornwall Street Railway, Light and Power Company Limited
- Utilities Standards Forum

FORTIS

MR. GLEN KING

Vice President – Finance & Chief Financial Officer
FortisOntario Inc./ Canadian Niagara Power Inc./Cornwall Electric/Algoma Power Inc.

EDUCATION:

1990 Chartered Accountant

1988 Memorial University of Newfoundland
Bachelor of Commerce (Co-operative)

PROFESSIONAL ASSOCIATION:

- The Institute of Chartered Accountants of Ontario

EMPLOYMENT HISTORY:

2005 - Present	**FortisOntario Inc.** **Vice President, Finance & Chief Financial Officer** As Vice President, Finance & Chief Financial Officer, Mr. King has all the duties and responsibilities normally associated with the financial, customer service and regulatory staff/departments of an Ontario-based diversified and growth oriented electricity transmission and distribution company. FortisOntario is a licensed generator, transmitter and distributor of electricity in Ontario and provides distribution services to 65,000 customers.
2003 - 2005	Canadian Niagara Power Inc. Director, Finance Treasurer
2001 - 2003	Newfoundland Power Director, Finance
1995 - 2001	Fortis Trust Corporation Vice President, Finance
1988 – 1995	Deloitte & Touche Chartered Accountants Senior Manager Manager Auditor Student

BOARD MEMBERSHIPS:

Canadian Niagara Power Inc.

Cornwall Street Railway, Light and Power Company Limited

Algoma Power Inc.

United Way of Niagara Falls and Greater Fort Erie

SAGAMOK ANISHNAWBEK

CHIEF PAUL ESHKAKOGAN
Sagamok Anishnawbek

EDUCATION:

1984 – 1985 Algonquin College, Ottawa, Ontario
Business & Commerce

1979 – 1983 Espanola High School, Espanola, Ontario
Secondary School Graduation Diploma

EMPLOYMENT HISTORY:

October 2005 – Present **Sagamok Anishnawbek**
Chief

- Elected as Chief of the Sagamok Anishnawbek in October of 2005. Responsibilities of the position range from being the primary spokesperson for the community to ensuring that day to day operations of the organization continue and decisions of the Council are implemented.

December 1999 – September 2005 **Sagamok Anishnawbek**
Forest Management Contractor

- Responsible for managing Forest Resource Licenses and silviculture contracts allocated from Domtar Forest Resources. Tasks include: Forest Operations Planning, Compliance Monitoring, Contract Administration and Reporting.

June 1994 – October 1999 **Sagamok Anishnawbek**
Director – Planning and Technical Services

- Responsible for the delivery of major programs including: Economic Development, Major and Minor Capital Projects, Housing, Water and Sanitation, Roads and Community Infrastructure. Duties focused on management of programs, staff supervision, financial reporting, planning, policy development and implementation.

October 1991 – May 1994 **North Shore Tribal Council**
Assistant Director – North Shore First Nations Government Program

- Responsible for assisting in the coordination of the North Shore First Nations Government Initiative/ Community Based Self-Government Negotiations. Coordination activities included providing technical/research support to member First Nations and committees. Assisted First Nations Government Coordinators in developing/implementing work plans and community consultation strategies.

January 1991 – October 1991 **Sagamok Anishnawbek**
Executive Director

- Under the direction of Chief and Council, responsible for administration and coordination of all First Nation programs and services. Tasks included financial reporting, and staff supervision. Also, responsible for providing analysis on various federal and provincial policies affecting the community.

June 1990 – December 1990 **Union of Ontario Indians**
Lands, Revenues & Trusts Coordinator

- Responsible for implementing/coordinating the Lands, Revenues & Trusts (LRT) Review Education/Consultation Process. The LRT Review was an initiative on the part on the federal government to amend the Indian Act. Developed work plans and provided information on the initiative to effectively inform the 43 member First Nations of the LRT Review and possible impacts.

October 1989 – May 1990 **Sagamok Anishnawbek**
Lands, Membership & Estates Officer

- Responsible for planning, designing and directing the maintenance of records systems in the areas of Sagamok Lands, Membership and Estates. This also involved the development of the Sagamok Membership Code.

February 1990 – May 1990 **Chiefs of Ontario**
Lands, Revenues & Trusts Coordinator

- Under contract to complete the Lands, Revenues and Trusts Review Handbook, which was a summary of the Indian and Northern Affairs LRT Review findings. The handbook was distributed to First Nations in Ontario.

LHATC

Mr. Ross R. Assinewe

Chief Executive Officer
Lake Huron Anishinabek Transmission Company

Education:

Cambrian College of Applied Arts and Technology, Sudbury, ON
Geological Engineering Technician
Business Administration

Productivity Point International, Sudbury, ON
AutoCAD and Softdesk Certificate Program

Registrations:

- Associate Certified Engineering Technologist, Ontario
- Canadian Council of Independent Laboratories (CCIL), Aggregate
- Canadian Standards Association (CSA), Concrete
- Certified Level I Water Treatment Plant Operator – Ontario Environmental Consortium (In Waiting)
- Certified Trainer – Confined Space Entry
- Circuit Rider Training – Ontario First Nations Technical Services Corporation

Professional Associations:

- Associate Member Ontario Association Certified Engineering Technicians and Technologists
- Canadian Council Independent Laboratories
- Canadian Standards Association
- Level I – Water Treatment Plant Operator (Pending)
- Train the Trainer – Confined Space Entry

Board affiliations:

- Sits on the M'Anishnabek Industries General Partnership Board of Directors, representing Serpent River First Nation

Employment History:

2011-Present **Lake Huron Anishinabek Transmission Company (LHATC)**
Chief Executive Officer

- LHATC represents 21 First Nations Communities in the Robinson Huron Treaty territory and has been established by First Nations to pursue the development of electricity transmission projects in Ontario.

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- Responsible for coordinating the First Nation consultations and investigating potential sites for Hydro development.
- Accountable for discussions with the First Nation communities involved with Natural Resource Developments that are occurring with their territories.
- Responsible for investigating and negotiating First Nations Impact and Benefit Agreements, which provide for business opportunities.
- Involved with preparing and negotiating Joint Venture Partnership opportunities so that the First Nations can access the Set-Aside Projects associated with the developments occurring within their Territories.
- Successfully completed agreements with First Nations.

2007-2009 **Trow Associates Inc., Director, First Nation Projects, Sudbury, ON**
Director, First Nations Projects

- Liaised for the Project Team and the Aboriginal Communities and served as Aboriginal Relations Advisor in numerous engineering, environmental and municipal projects.
- Responsible for coordinating and administering the Aboriginal communication program for the assignments.
- Responsibilities included the following: Aboriginal issues analysis, social impact analysis, community/stakeholder consultation, community consultation programming and participated in the management of field and data collecting activities such as sampling, surveying and site inspection.
- Responsible for Joint Venture Partnerships, including negotiation of agreements.

2002-2007 **Sagamok Anishinabek, Director, Planning and Technical Services Unit**
Director of Planning and Technical Services Unit (P&TSU)

- Responsible with respect to services supplied by the housing department, water and sanitation department, roads department, and fire department.
- Responsible for safe operations of community buildings, new planning initiatives and delivering efficient services within a $1.8 million operating budget.
- Responsible for developing a social housing program for the Sagamok Anishinabek membership through a comprehensive community development initiative.
- The Sagamok Anishinabek has implemented the current Ontario Water Regulations and is enrolled within the provincial programs included in Ontario Regulations 459.
- Instrumental in the development of the working group committee for water treatment plant operators at the North Shore Tribal Council.

- Provided overall management and supervision within the housing department, which has accessed CMHC's social housing programs, including Section 95, HASI and RRAP.

1999-2002 **AMIK Resources, Managing Director, Sudbury, ON**
Managing Director of AMIK Resources

- Responsible for project management, municipal/environmental engineering, surveying, design, construction, inspection, supervision of industrial/municipal projects research data, information retrieval and field work co-ordination on First Nations' projects.
- Provided First Nations with housing services and acted as the prime contact for First Nation, government and other stakeholder related projects.

1998-1999 **IFNA Engineers Ltd., Sudbury, ON**
Manager

- Responsible for exploring and marking IFNA's engineering services in the Sudbury district and Northeastern Ontario.

1995 – 1998 **AGRA Earth & Environmental Ltd., Sudbury, ON**
Manager, Aboriginal Services

- Served as the main contact regarding First Nations throughout Ontario, participating on all aspects of AGRA's services, from corporate participation to project-specific fieldwork.

1994-1995 **Union of Ontario Indians, Program Manager, North Bay, ON**
Chief Executive Officer

- Reporting to the Board of Directors, Executive, and Grand Council Chief, responsible for operating within a $7 million budget and for the day-to-day administrative functions.
- Responsible for reviewing and disseminating of all material and information to the secretariat of the Union of Ontario Indians.

1992-1994 **Sagamok Anishinabek, Massey, ON**
Executive Director

- Responsible for the day-to-day administrative functions, reporting to Chief and Council of the Sagamok Anishinabek and operating within a $15 million budget.
- Reviewed and delivered all materials and information to Sagamok Anishinabek.

1991-1992 **UMA Engineering Limited, Sudbury, ON**
Civil Technologist

- Responsible for marketing UMA's municipal engineering services and participating on the project team providing the field services.
- In addition to First Nation projects, responsible for delivery of UMA's services to other non-aboriginal clients.

1987-1991 **Northland Engineering Ltd., Sudbury, ON**
Survey Party Chief

1985-1987 **D.S. Dorland Limited, Sudbury, ON**
Surveyor

- Worked with project team that included members from Ontario Hydro on the Sudbury West 230kV Hydro Transmission Line construction. Responsibilities for this assignment included the locating of the base of the Steel Lattice Towers and the Guy Wires. Verifying the R.O.W. limits was also completed.

FORTIS

MR. BRUCE FALSTEAD

Manager – Aboriginal Initiatives
Fortis BC Inc.

PROFILE:

- Over 25 years of experience working with First Nations in Canada
- Extensive knowledge of First Nations' issues, protocols and history
- Strategic thinker with excellent communication, management and negotiation skills
- Experience in business development and operation of economic development corporations

EDUCATION:

- Diploma in Small & Medium Enterprise Studies, Institute of Canadian Bankers 1999 Portland State University's NW Community Development Academy Extended Studies Program 1999
- Accounting, Communications and Management 101, Saskatchewan Indian Institute of Technology 1987
- Saskatchewan Real-estate Association Real Estate Sales and Management Program; obtained Broker status 1981
- Second year student in the Certified General Accountants Association of British Columbia
- Attend numerous conferences and seminars to remain current on aboriginal issues

PROFESSIONAL ASSOCIATIONS:

- Member of the Aboriginal Community Initiatives Steering Committee, Simon Fraser University (August 2011-Present)
- Member of the Vancouver Board of Trade's Aboriginal Opportunities Committee (2010-Present)
- Member of the Board of Governors Langara College (2008-2011)
- Member of the Industry Training Authority's Aboriginal Advisory Council (2007-Present)
- Member of the Ahp-cii-uk Leadership Initiative (2007-Present)

EMPLOYMENT HISTORY:

2001–Present **FortisBC Inc.**
Manager, Aboriginal Initiatives

- Key contact for all Aboriginal issues
- Created First Nations corporate strategy
- Developed Aboriginal Relations Statement of Principles
- Responsible for consultation and advising project teams that impact First Nations:
  Natural gas transmission projects,
  Whistler Pipeline Project, Inland Pacific Connector & Kingsvale to Oliver Reinforcement Project

- Promote cultural awareness with employees
- Actively promote First Nations' employment programs and practices
- Developed Skill Builder Training program
- Mitigate and control risk and at the same time enhance long-term secure growth for the Company within Aboriginal communities

2000–2001 **Falstead Consulting, Port Alberni, B.C.**
Sole Proprietor

Representative Clients – Central Region Chiefs
Ahousaht, Hesquiaht, Tla-o-qui-aht, Toquaht and Ucluelet First Nations

- Prepared funding applications on behalf of the five First Nations for strategic economic development planning. Economic development planning was done in a partnership with Shawn Atleo of Umeek Human Resource Development Inc.

Ma-Mook Development Corporation (wholly-owned by Central Region Chiefs)
- Financial Manager of the corporation from March to September 2000. Financial officer for three subsidiary companies. Mentored affiliated companies in all aspects of operation.

Regional Aquatic Management Society
- Organized and facilitated a Selective Fisheries Harvesting practices workshop for DFO.

1997–2000 **Community Futures Development Corporation of Alberni-Clayoquot, Port Alberni, B.C.**

Business Analyst
- Responsible for management of $5 million small business loan portfolio
- Prepared and presented loan proposals for adjudication by the Board
- Assisted clients with preparation of business plans and provided ongoing business support

1993–1997 **Development Management Institute Inc. Westcoast Centre for Development Management Prince Albert, Sk. & Port Alberni, B.C.**

- DMI was a training institute for community economic development practitioners from low income and aboriginal communities, specializing in the training of development organization staff and boards in all aspects of economic development strategy and operations.

General Manager/Operations Manager
- Developed community based economic development training materials for First Nations

- Organized and marketed First Nations Economic Development workshops in conjunction with the Simon Fraser University's Community Economic Development Centre
- Coordinated the merger of the Development Management Institute Inc with the Westcoast Centre for Development Management Inc.

1992–1993 **National Indian Financial Corp. NIFC**
(wholly-owned by the Federation of Saskatchewan Indian Nations)

Manager of Financial Services

Worked for the Second Vice-Chief of the FSIN, responsible to the FSIN Economic Development Commission

- Coordinated the initial development of the National Indian Financial Corporation, assisted in the writing of its business plan. Devised and implemented the FSIN Strategic Investment Plan, directed four new business investments creating 36 new jobs
- Established offices and hired personnel for the Corporation's four locations: Regina, Saskatoon, Prince Albert and Lac La Ronge, Saskatchewan
- Assisted in the operation of four NIFC enterprises, First Nations Insurance Service, First Nations General Insurance, Cochin Conference Centre (hotel & golf course), and Clio Communications Ltd.
- Negotiated with the department of Industry Science and Technology for the transfer of the Aboriginal Business Development Program to the control of NIFC in Saskatchewan. Organized the planning and negotiated the systematic devolution of all Federal and Provincial economic programs to the Indian Economic Development Commission, bringing in $1.7 million per annum for First Nation economic activities.

1984–1991 **Lac La Ronge First Nation/Kitsaki Development Corporation**
Prince Albert, Saskatchewan

General Manager of a Subsidiary

KDC is 100% owned by the Lac La Ronge Indian Band and is responsible for the business and economic development activities of the Band

- Created and managed two business ventures for the Lac La Ronge First Nation's development corporation, First Nations Insurance Services Ltd./First Nations General Insurance located in Prince Albert & Regina, Saskatchewan
- Designed products specific to First Nations needs and negotiated with the insurance industry to provide them
- Trained First Nations personnel in the sales and service of group benefits, who are now running FNIS, which is in its 20th year.

FORTIS

MR. PAUL CHERNIKHOWSKY, P.ENG.

Director, Engineering Services
FortisBC Inc.

EDUCATION:

1994 University of British Columbia
Bachelor of Applied Science (Electrical Engineering)

PROFESSIONAL ASSOCIATION:

- Association of Professional Engineers, British Columbia
- Senior Member of the Institute of Electrical and Electronic Engineers (IEEE)

EMPLOYMENT HISTORY:

1999 – Present **FortisBC Inc. – Director, Engineering Services**

- Responsible for the overall planning, engineering and execution for the company's transmission and distribution projects

- In previous roles with the company, Paul was responsible for FortisBC's transmission network planning and prior to that for protection, control and telecommunications planning and design

1994 – 1998 **Engineering Consultant**

- Providing engineering consulting services to the mining and utility sector in BC

FORTIS

MR. MIKE JARDINE

Manager – St. John's Region
Newfoundland Power Inc.

EDUCATION:

1988 Bachelor of Engineering (Civil)
Memorial University of Newfoundland

PROFESSIONAL ASSOCIATIONS:

- Professional Engineers and Geoscientists, Newfoundland & Labrador (PEGNL)

EMPLOYMENT HISTORY:

2011-Present **Newfoundland Power, St. John's, NL**
Manager – St. John's Region

- Responsible for all aspects of customer engineering and operations for St. John's and surrounding communities, corporate responsibility for transmission, metering assets, and utility services for telecommunication providers.

2007 – 2010 Manager – Eastern Region

- Responsible for all aspects of customer engineering and operations for St. John's, Bonavista, Burin and Avalon Peninsula's; corporate responsibility for transmission and metering assets.

2005 – 2007 Manager, Western Region & Energy Supply

- Responsible for all aspects of customer engineering and operations for Western Newfoundland; corporate responsibility for generation and transmission assets.

2002 – 2004 Superintendent, Generation

- Major contributions included introduction of an asset management program for the Company's generation facilities and significant improvement in the reliability of our hydro and thermal units.

2001 – 2002 Superintendent Regional Operations, Avalon & Burin Areas

- Responsible for all aspects of Line Operations including connection of new customers and reliability of the transmission and distribution systems.

1999 – 2001 Superintendent Regional Engineering & Operations, Avalon Region

- Responsible for all aspects of engineering and line operations, including connection of new customers and reliability of the transmission and distribution systems.

1998 – 1999 Superintendent Regional Engineering, Avalon Region

- Responsible for all aspects of engineering including connection of new customers and reliability of the transmission and distribution systems.

1988 – 1997 Transmission Design Engineer

- Responsible for the introduction of transmission line computer aided design and drafting technology, development of comprehensive inspection and maintenance procedures, implementation of island wide transmission line insulator replacement program and lead design engineer for the building or rebuilding of hundreds of kilometers of transmission lines throughout the province.

MR. JIE HAN

Director – Technical Services
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

2012 University at Buffalo (SUNY), Buffalo, New York
Executive Master of Business Administration

1983 Tsing Hua University, Beijing, China
Bachelor of Electrical Engineering

PROFESSIONAL ASSOCIATION:

- The Association of Professional Engineers of Ontario

EMPLOYMENT HISTORY:

2012 – Present **FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/ Algoma Power Inc. – Director, Technical Services**

- Responsible for control room and substations, as well as continuing with responsibilities for system engineering, distribution planning and transmission.

2004 – 2012
- Responsible for the planning, engineering, and designing of all distribution system related capital projects of an Ontario-based diversified electric utility holding company that transmits electricity and provides distribution services to approximately 65,000 customers.

1990 – 2004 **Maritime Electric Company, Limited**

2001 – 2004 Supervisor, Planning and System Performance

1998 – 2001 Supervisor, Operations Planning

1997 – 1998 Supervisor, System Operations

1990 – 1997 Electrical Engineer

1983 – 1989 Electric Power Planning and Engineering Institute, Beijing, China

TRANSMISSION RELATED WORK:

- ***Transmission System Planning – Maritime Electric***

  Responsible for the system planning of Maritime Electric's 138 kV and 69 kV transmission systems. Providing technical supports for the transmission system operations.

- ***Transmission System Operation – Maritime Electric***

  Responsible for the transmission system operation at Maritime Electric.

- ***Transmission System Planning – Beijing China***

  Extensive load flow, short-circuit, and satiability analyses for various power systems (220 kV to 500 kV).

- ***Transmission Line Design and project management – Maritime Electric***

  Responsible for 138 kV transmission Line refurbishment projects. Performing Wood pole H-frame structure evaluation and line sag/tension calculations, material procurement; budgeting and budget control, project scheduling, and site supervision.

- ***Transmission substation design and project management***

  Responsible for Bedeque 138/69 kV substation upgrade project, including substation design review, equipment specifications, procurement, budgeting, project scheduling, and site supervision.

FORTIS

MR. BARRY SMITHSON

Journeyman Power Line Technician, Industrial Electrician
Director Network Operations
FortisBC Inc.

PROFESSIONAL ASSOCIATION:

- Red Seal Certification – Journeyman Power Line Technician and Industrial Electrician

EMPLOYMENT HISTORY:

FortisBC Inc. – Journeyman Power Line Technician, Industrial Electrician
Director Network Operations

- Over 30 years of utility experience, responsible for the System Control Center, which is accountable for the day-to-day operations of the FortisBC generation, transmission and distribution systems as well as the power systems for 3rd party clients.

- Experience in substation and terminal station construction, maintenance, and operations in all voltage ranges to 230 kV as well as experience in distribution and transmission facilities construction, maintenance, and operations in all voltages to 230 kV.

- Performs similar functions for FortisBC 3rd party clients who own switchyards and transmission facilities.

MR. DOUGLAS R. BRADBURY

Director, Regulatory Affairs
FortisOntario Inc./Canadian Niagara Power Inc./Algoma Power Inc.

EDUCATION:

- Memorial University of Newfoundland
  Bachelor of Engineering (Electrical)

PROFESSIONAL ASSOCIATION:

- Member in Good Standing – Professional Engineers of Ontario

EMPLOYMENT HISTORY:

Present **Director Regulatory Affairs**
Canadian Niagara Power Inc., Fort Erie

As Director of Regulatory Affairs, Mr. Bradbury is responsible for managing the regulatory relationships of Canadian Niagara Power Inc. and its affiliates with the Ontario Energy Board, intervenors and other stakeholders. This includes managing distribution and transmission rate applications and ensuring compliance with applicable rules, codes and guidelines.

1997 - 2001 **Manager Transmission and Distribution**
Canadian Niagara Power Inc., Fort Erie

As Manager of Transmission and Distribution, Mr. Bradbury was responsible for the operation of the electrical transmission and distribution systems at Canadian Niagara Power Inc.

1982 - 1997 **Newfoundland Power**

While at Newfoundland Power, a fully integrated electric utility providing service to approximately 229,000 customers in Newfoundland and Labrador, Mr. Bradbury held several managerial positions in both operations and administration.

BOARD MEMBERSHIPS:

Rideau St. Lawrence Holdings Inc. & Rideau St. Lawrence Distribution Inc.
Prescott, Ontario

FORTIS

MR. TIM LAVOIE, CMA

Regional Manager & Director of Northern Development
Algoma Power Inc.

EDUCATION:

2001 Society of Management Accountants of Ontario
Certified Management Accountant Professional Program

1993 Wilfrid Laurier University – Waterloo, Ontario
Honours Bachelor of Business Administration – Specialized in Corporate Finance

PROFESSIONAL ASSOCIATION:

- Society of Management Accountants of Ontario

EMPLOYMENT HISTORY:

2009 – Present **Algoma Power Inc., Sault Ste. Marie, Ontario**
Regional Manager & Director, Northern Development

- Approximately 20 years experience in the energy sector in a variety of management, operational and regulatory roles.
- Oversee and manage Algoma Power Inc., a regional distribution utility serving over 14,000 sq km area with over 11,600 customers.

2007 – 2009 **Great Lakes Power Limited – Sault Ste. Marie, Ontario**
General Manager – Transmission and Distribution

- Filed first transmission leave to construct application with the Ontario Energy Board after market opening for $85 million 230kV rebuild in Northern Ontario.
- Management, oversight and key company witness in the successful filing of 6 rates applications to the Ontario Energy Board.

2005 – 2006 Sault Hydro Operations - General Manager

2003 – 2005 Customer and Finance Manager

1999 – 2003 Accounting Manager

1995 – 1999 Management Information Coordinator

1993 – 1995 Systems Analyst/Project Co-Manager

1992 Financial Analyst

1988 – 1990 Seasonal Labourer

1991 Union Gas Limited – Chatham, Ontario
Cogeneration Financial Analyst, 1991

BOARD MEMBERSHIPS:

Algoma University Board of Governors

- Chair

Safe Communities Partnership, Sault Ste. Marie

FORTIS

MR. DON GILBERT

Manager - Operations
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

1984 Ontario Secondary School Honorary Graduate Diploma

PROFESSIONAL ASSOCIATION:

- Association of Electrical Utilities Safety Professionals of Ontario

EMPLOYMENT HISTORY:

2012 – Present **FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/ Algoma Power Inc. – Manager, Operations**

- Responsible for transmission and distribution line services and meter services, as well as corporate support for other projects.

2009 – 2012 **Manager – Health, Safety & Environment**

- Responsible for implementation and maintenance of the Company's integrated Health, Safety and Environment Management System ("HSEMS") consistent with OHSAS 18001 and ISO 14001 Standard.
- Provide leadership in health, safety and environmental performance based upon a commitment to continual improvement.

2007-2009 **Supervisor Line Services Canadian Niagara Power**

- Responsible for construction and maintenance of all transmission and distribution assets including:
- Supervise, administrate and liaise between departments in the efficient execution and safety of all capital and maintenance projects.
- Assist in the preparation of capital and maintenance budgets.
- Prepare tender and ensure the safe and efficient execution of projects through contractors.
- Assume the lead role in coordinating safe and efficient restoration efforts during major interruptions to service.
- Develop and implement Operational Directives and assist in the development of Occupational Control Procedures.

Niagara Falls Hydro Inc.

1999 – 2007 Leadhand – Lineman
1991 – 1999 Journeyman Lineman

	Etobicoke Hydro Electric
1988 – 1991	Journeyman Lineman
	York Hydro
1985 – 1988	Apprentice Lineman

TRANSMISSION RELATED WORK:

- All aspects of transmission system operation and maintenance including new construction, re insulating/conductor, operating system control and vegetation management

FORTIS

MS. JENNIFER ROSE

Manager – Forestry/Advisor Health, Safety & Environment
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

EDUCATION:

1996 Bachelor of Applied Science in Environmental Engineering
University of Guelph, Ontario

PROFESSIONAL ASSOCIATIONS:

- International Society of Arboriculture (ISA), Ontario Chapter
- Canadian Society of Safety Engineering
- Association of Electrical Utilities Safety Professionals of Ontario

EMPLOYMENT HISTORY:

2011 – Present **FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/ Algoma Power Inc. – Manager, Forestry/Advisor Health, Safety & Environment**

- Develop, implement and oversee Forestry programs for FortisOntario.
- Facilitate and recommend the resolution of Health, Safety and Environmental (HS&E) concerns and issues that arise within the organization through incident investigations, employee concerns, observations, inspections, audits and the Health, Safety, Environmental Management System (HSEMS) program.
- Provide support in the development of new and expanding HS&E programs by developing and/or assisting in the preparation and maintenance of HS&E policies procedures, programs, performance and providing legislative and other HS&E information to staff and others appropriate to assist in establishing corporate HS&E goals and objectives.
- Ensure legislative compliance by monitoring and keeping current on rapidly evolving HS&E legislation affecting FortisOntario.
- Provide written justifications for annual and forecasted Forestry maintenance and capital programs as it relates to all corporate rates applications.
- Oversee the management of all Algoma Power Inc. (API) forestry employees including technical planning.
- Communicate the Company's position and negotiate and resolve problems and sensitive issues with customers, suppliers and outside agencies as required.

2009 – 2010 **Right-of-Way Management Coordinator**

- Assist with distribution capital and maintenance planning ensuring environmental controls are part of the work methods.
- Develop and manage distribution and sub-transmission right-of-way and access routes cycled management plans.
- Develop and manage substation vegetation management programs.
- Develop and manage the annual off cycle right-of-way program to match the annual capital program.

- Serve as the point of contact for right-of-way related interactions between API and First Nations.
- Develop an environmental mitigation strategy to support the activities of API in the field, for example habitat stewardship, sensitive area and other environmental aspects.

2007 – 2009 **Great Lakes Power Inc. (GLP)**
Forestry Supervisor Transmission & Distribution

- Responsible for Forestry's capital and maintenance programs associated with the transmission and distribution of electricity.
- Directed the GLP Forestry crew as they conducted portions of these programs, in addition to managing a number of contractors, as well as establishing First Nation work programs.
- Supervised all projects and major maintenance work of short and long-term duration by assigning necessary labour while respecting prescribed timelines, budgets and ensured adherence to health, safety and environmental standards by both internal and external labour.

2005 – 2007 **Forestry Technician/Forestry**

- Developed annual work programs for both internal and external resources.
- Negotiated agreements with property owners on new and existing rights-of-way for various forestry activities.
- Aided in the development and up-keep of the Forestry's Notification System to manage work packages.
- Further duties included, contract management, review of project safety and environmental plans, contractor crew visits, program and budget reporting and commissioning of projects. Responsible for preparation and delivery of presentations to the public and interest groups.

2003 – 2005 **The Wilderness Group, Vegetation Management Division, Wawa, Ontario –** Project Supervisor

2000 – 2002 **Katimavik, Okanagan Valley, British Columbia/Yukon**
Project Coordinator

1999 – 2000 **Katimavik, Vancouver Island, British Columbia/Yukon –** Project Leader

1995 – 2003 **The Wilderness Group, Reforestation Division, Wawa, Ontario**
Field Manager, Crew Boss and Tree Planter (Contract Position)

BOARD MEMBERSHIPS:

- Ontario Vegetation Management Association
- Public Works Integrated Pest Management Committee
- Corridors for Life Species at Risk Management, Algoma District

FORTIS

Mrs. Kristine Carmichael

Manager – Customer Service, Human Resources, Corporate Communications
FortisOntario Inc. / Canadian Niagara Power Inc. / Cornwall Electric / Algoma Power Inc.

Education:

2012 University at Buffalo (SUNY), Buffalo, New York
Executive Master of Business Administration

2005 Brock University, St. Catharines, Ontario
Bachelor of Business Administration

2002 University of Western Ontario, London, Ontario
Bachelor of Arts

Professional Association:

Beta Sigma Gamma – Honours Academic Achievement in the study of Business

Employment History:

2008– Present **FortisOntario Inc./Canadian Niagara Power Inc./Cornwall Electric/ Algoma Power Inc. – Manager, Customer Service, Human Resources, Corporate Communications**

- Responsible for the corporate direction for all Customer Service, Human Resources and Corporate Communications of an Ontario-based diversified and growth oriented electric utility holding company that transmits electricity and provide distribution services to approximately 65,000 customers and employs approximately 200 employees.
- Management of FortisOntario's account receivables, distribution revenue, call centre and customer interaction while ensuring regulatory compliance and related reporting.
- Labour relations and negotiation of four collective agreements with three labour unions. Pension and benefit management, recruitment, and leadership development.
- Responsible for media relations, development of press releases and external marketing campaigns.

2005 - 2008 **Manager, Customer Service and Corporate Communications**

1998 - 2005 **Manager, Customer Service**

1995-1996 **Canadian Niagara Power Inc.** – Manager, Customer Service

1992-1995 **Canada Trust, Welland Ontario**
Bank Teller, Personal Banker

DONALD L. KENDALL, PE, PMP

EDUCATION
B.S., Civil Engineering, University of Kentucky, 1975

PROFESSIONAL REGISTRATIONS
Professional Engineer, Kentucky, 1979
Professional Engineer, Ohio, 1995
Project Management Professional, 2009

AREAS OF EXPERTISE
Mr. Donald L. Kendall, PE, PMP has management and technical experience in the following general areas:

- Project Management
- Transmission Engineering
- Distribution Engineering
- Transmission Line Design
- Underground Transmission
- Construction Management
- Project Estimating
- Licensing & Permitting

REPRESENTATIVE EXPERIENCE
Mr. Kendall has over 35 years of experience in the electrical utility market from engineering to project management. His qualifications include extensive hands-on planning, line design and construction, station design and construction, and projects from Kentucky, West Virginia, Ohio, Michigan, Indiana, and Texas. Mr. Kendall's background includes extensive service to both the public and private sector. He currently serves as a Senior Project Manager for the New York-Mid Atlantic Region.

TRC Engineers, Columbus, OH (Senior Project Manager: 2010-2011)

Mr. Kendall manages the Columbus Ohio office. Mr. Kendall is also involved with multiple wind farm projects in central Ohio supporting both the Ohio Power Siting Board and the PJM Feasibility Study process for the developer. Mr. Kendall is also working on station design projects for AEP in central Ohio.

AEPSC, Columbus, OH (Project Manager: 2000 – 2010)
Horizon Wind, Meadow Lake 600 MW Windfarm, Lafayette, IN
Phase 1 involved an option to build project for the developer. Phase 2 involved an AEP design. Mr. Kendall managed a design team responsible for the 345kV interconnection station and line, including design, approval of customer design, and coordination with PJM contracts, construction, billing, and schedule. (2009)

Wyandot Solar, juwi Solar, 10 MW, Wyandot County, Ohio
Mr. Kendall was project manager for improvements at North Upper Sandusky station to accommodate the generation. This was a highly visible project that was completed on a short schedule. (2009)

BP Alternative Energy, Fowler Ridge 600 MW Windfarm, Lafayette, IN
Mr. Kendall managed the 345kV station improvements, 345kV line connection, metering, SCADA, PJM contracts, construction, billing, and schedule. (2008)

Topaz Energy Gas Generation, **Laredo, Texas**
Mr. Kendall managed a design team responsible for 138kV station design, approval of customer design, coordination with the Electric Reliability Council of Texas (ERCOT), contracts, billing, construction, and schedule. (2008)

New 138kV Distribution Station, Centerburg, Ohio
Mr. Kendall served as project manager for the new 138/12kV distribution station. This project did not require siting from the Ohio Power Siting Board. This project did require multiple meetings with “The Clover Valley Concerned Citizens for Responsible Power Siting” The CVCC was purely a “not in my back yard” group. Multiple meetings were required, some concessions in landscaping and lighting were made, and the project was completed on time and on budget. (2007)

Laredo Variable Frequency Transformer, Laredo, Texas
Mr. Kendall was project manager for installation of the first commercial VFT manufactured by GE. This project included several meetings with Comision Federal de Electricidad (CFE) and ERCOT to coordinate 138kV and 230kV line ties, P&C, metering, SCADA, and schedules. This project has been featured in several publications and at trade shows and conventions. (2006 2007)

138kV Underground Service to new Datacenter, Columbus, Ohio
Mr. Kendall led the design team for the 138kV underground loop to supply a data center. The project consisted of two 138kV riser poles, parallel 138kV under-ground 2000 kcmill CU in 6 inch conduit, over site of the station design by a third party, construction, and final testing. This project was completed on a compressed schedule. (2006)

Holmes County Area Improvements, Ohio
This project involved the conversion of 40 miles of existing 34kV transmission line and associated stations to 69kV. The work was carefully coordinated around system loading. Right of way in the largely Amish county was also an issue. (2005, 2006)

Sun Coke 69kV Service, Haverhill, Ohio
Mr. Kendall served as project manager to expand an existing station and extend 69kV service to new coke ovens and the associated generation. Mr. Kendall was responsible for design and construction as well as contracts with the customer.

This project included all coordination with PJM on the new service and associated system improvements. (2005)

Davidson Dublin 138kV Underground, Hilliard and Dublin, OH
Mr. Kendall led the design team for both the station improvements and line design and construction. He also authored the siting document submitted to the Ohio Power Siting Board and served as the direct contact for the OPSB staff and Ohio EPA. This project required multiple public meetings and careful coordination with city engineers from both cities, in addition to a citizens group. The project consisted of 2000 kcmill CU, solid dielectric, xlpe cable installed in 6 inch conduit, distributed temperature fiber optic cable, and protection and control fiber optic cable. Multiple directional borings were also required. Mr. Kendall was also involved in analysis, testing, and service restoration after two splice failures that occurred on this project. (2004)

345kV breaker replacements, Donald C. Cook Nuclear, Michigan
This project involved replacement of 11 circuit breakers and the addition of one circuit breaker, with associated relays, PT, and cables. (2004-2009)

Main Street Bridge, 138kV fluid filled pipe cable relocation, Columbus, Ohio
The City was replacing the Main Street Bridge. AEP had 138kV oil filled pipe cable suspended under the bridge deck. The project included installing new pipe in trench crossing the Scioto River. The cutover included freeze pits on both sides. Mr. Kendall led the design team, construction, routing analysis with Columbus and ODOT, and coating evaluation testing. The conductor was Okonite 2500 kcmill AL compacted segmental, paper insulated. (2003)

Kentucky Power Company, Ashland, KY (Transmission Engineer: 1991 – 2000)
Mr. Kendall had responsibility as both lead engineer and project manager on multiple 138kV and 69kV projects. Several projects included responsibility for both the line and station design. In the Inez, KY area, Mr. Kendall had responsibility for routing, right of way acquisition, design, and construction of the Big Sandy Inez 138kV line. Thirty two miles of double circuit 230kV (operated at 138kV) lattice steel towers. Mr. Kendall also had construction responsibility for the Inez 138/69/12 kV UPFC Station.

Kentucky Power Company, Pikeville, KY (Distribution Engineer: 1983 – 1991)
Mr. Kendall was responsible for distribution circuit analysis, plan of service, and area load studies. He conducted coordination studies and distribution construction audits. Mr. Kendall also served as an instructor for distribution line design and was responsible for transmission relocations and rebuilds on a unit price contract.

PEH Engineers, Lexington, KY (Engineer: 1975 – 1983)
Mr. Kendall served as the lead engineer and project manager on design and construction of water distribution systems, sewerage collection, pumping stations, sanitary landfills, and land development.

EDWIN E. PEACE, PE

EDUCATION
MBA, University of Arizona, 1982
B.S., Civil Engineering, University of Arizona, 1978

PROFESSIONAL REGISTRATIONS/CERTIFICATIONS
Professional Engineer, Arizona, (#15603) 1983
Professional Engineer, California, (#37586) 1983
Professional Engineer, Nevada, (#13357) 1994

AREAS OF EXPERTISE
Mr. Edwin E. Peace, PE has technical and management experience in the following general areas:

- Engineering Management
- Project Management
- Civil/Structural Engineering
- Transmission Line Engineering

REPRESENTATIVE EXPERIENCE
Mr. Peace has over 34 years of experience in Civil Engineering and Project Management on projects for utility companies and related industries concentrating in transmission line design and construction on projects ranging from 46 kV to 500 kV.

TRC Engineers – Chief Engineer, Transmission Engineering: 2011 to Present
Mr. Peace has worked on numerous multi-discipline projects for many clients over the course of his career. Representative projects are listed below:

Southern California Edison, Tehachapi Renewable Resources 500 kV Transmission Project, Los Angeles, CA
Mr. Peace served as Project Manager and Engineer Team Supervisor for three segments of the TRTP transmission project covering over 100 miles of 500 kV and 220 kV transmission line. His team responsibilities included development of initial routes, performance of blowout studies, tower placement and studies to evaluate existing structures and alternative structures. Mr. Peace provided construction turnover packages for 100 miles of line to include: general arrangement, plan and profile, framing drawings, hardware, fiber optic, foundations and access roads.

Modesto Irrigation District, Westley to Rosemore 230 kV Transmission Project, Modesto, CA
Mr. Peace served as Project Manager for EIR preparation and design of 17-miles of 230 kV double-circuit transmission line utilizing double-bundle 954 kcmil AAC (Magnolia) conductor on tubular steel monopoles. Mr. Peace supervised EIR preparation, community information meetings, preliminary and detailed transmission and substation design, access road development, and right-of-way procurement.

Western Area Power Administration, Path-15 Los Banos to Gates 500 kV Transmission Line, Golden, CO
Mr. Peace served as Lead Engineer for the final design of 85 miles of 500 kV transmission line utilizing triple-bundle 1590 kcmil ACSR (Lapwing) conductor on lattice towers and tubular steel monopoles. Mr. Peace supervised plan and profile preparation, placement of structures, leg selection, foundation design and analysis of modifications to 500 kV lattice steel towers for helicopter erection.

Tucson Electric Power, South Loop to Gateway 345 kV Transmission Line, Tucson, AZ
Mr. Peace developed plan and profiles for both the primary (64 miles) and secondary (35 miles) routes for a double-circuit 345 kV transmission line on steel monopole structures using aerial survey data and PLS-CADD. Mr. Peace determined structure locations and heights and assisted in the development of access roads into each structure location. Mr. Peace also created Access Road drawings and supported TEP personnel in obtaining construction permit.

Arizona Public Service, Saguaro to Tortolita No. 2 500 kV Transmission Line, Phoenix, AZ
Mr. Peace served as Project Manager and Lead Engineer for a one-mile transmission connection on steel lattice towers between APS's Saguaro Switchyard and TEP's Tortolita Substation.

Arizona Public Service, Redhawk to Hassayampa No. 1 500 kV Transmission Line, Phoenix, AZ
Mr. Peace served as Project Manager for a one-mile transmission connection using tubular steel poles and lattice towers between the Redhawk Generating Station and the Hassayampa Switchyard.

Arizona Public Service, Redhawk to Hassayampa No. 2 500 kV Transmission Line, Phoenix, AZ
Mr. Peace served as Project Manager for a one-mile transmission connection using tubular steel poles and lattice towers between the Redhawk Generating Station and the Hassayampa Switchyard.

San Diego Gas & Electric, Mission to Murray 69 kV Transmission Line Upgrade, San Diego, CA
Mr. Peace produced plan and profile drawings using PLS-CADD to replace ACSR conductor with ACSS conductor to double the capacity of two seven-mile wood pole transmission lines. He created a PLS-CADD model, checked each span and modified or added structures as necessary to ensure compliance with California G.O.95 clearance requirements.

San Diego Gas & Electric, 230 kV Line Uprating Study, San Diego, CA
Mr. Peace managed project to collect LIDAR data on over 100 miles of 230 kV transmission lines on lattice steel towers and created a model of the line in PLS-CADD and used the model to determine maximum line operating temperature. Mr. Peace evaluated the line model and recommended modifications to existing line structures and conductor tensions to increase clearances to allow operation at elevated temperatures for increased capacity.

Nevada Power Company, Las Vegas, NV, (Manager, Transmission and Civil Structural Engineering: 1994 – 1998)
During his tenure at NPC, Mr. Peace led a team of 25 technical staff and worked on numerous multi-discipline projects including up to 50 individual projects concurrently. Representative projects are listed below:

Pecos 230 kV Substation Line Routing Study
Mr. Peace evaluated lines surrounding the Pecos 230/138 kV Substation to determine if the desired ultimate line configuration could be accommodated. Future need was for ten 230 kV lines and thirteen 138 kV lines to enter or pass the substation. Mr. Peace evaluated corridors for maximum capacity, reviewed planning requirements and recommended revisions to accommodate the ultimate plan.

Mead to Equestrian to Magic Way 230 kV Loop Project
Mr. Peace served as Project Manager for pre-design phase of a 50-mile twin-circuit 230 kV line to be co-owned by NPC and Colorado River Commission / Southern Nevada Water Authority. Mr. Peace assisted in negotiation of route, structure design / ownership, and contractual obligations of design team.

Pecos to Washburn 138 kV Line
Mr. Peace supervised the design of a 10-mile transmission line that required the installation of five miles of structures designed for future double circuit 230 kV line with 138 kV underbuild. Mr. Peace reviewed and approved line drawings, hardware and assembly drawings, tubular-steel structure drawings, sag charts, foundation drawings and all specifications.

Arden to Northwest 230 kV Line
Mr. Peace served as Project Manager for 30-mile transmission line project on multi-circuit tubular steel poles. Mr. Peace negotiated routing with major developers, governmental agencies and citizen groups. Mr. Peace also supervised design staff of 14 engineers and technicians. Mr. Peace approved line design and all standard drawings.

PacifiCorp, Portland, OR, (Senior Transmission Engineer: 1991 – 1994)
During his tenure at PacifiCorp, Mr. Peace worked on numerous transmission line design and upgrading projects. Representative projects are listed below:

Dixonville to Meridian 500 kV Transmission Line Repairs
Mr. Peace developed a plan for the reconstruction of a two-mile section of line that failed during severe ice storms. Mr. Peace prepared a TLCADD model of the line layout inserting additional lattice towers. Mr. Peace also developed a program to determined conductor cut lengths to be removed to provide proper sag upon insertion of additional structures.

Pomona to Wenas 115 kV Transmission Project
Mr. Peace served as Project Manager for a multi-discipline project including substation, transmission and communications for a new substation and 15-mile transmission line on tubular steel poles. Mr. Peace also performed project engineer duties for the transmission line portion of the project including line routing, budgeting, obtaining Use Permits, and designing the line using TLCADD.

Cove to Warmsprings 69 kV Transmission Line
Mr. Peace assisted in route selection and negotiation of easements with the Warmsprings Indian Tribe for a 12-mile transmission line on wood poles. Mr. Peace also developed budget estimates, designed the line using TLCADD, engineered all structures and guying, and wrote the construction specification. In addition, Mr. Peace administered the construction contract, supervised inspection, and performed field engineering.

Meridian to Lone Pine 230 kV
Mr. Peace assisted in route selection and obtaining of county Use Permit for an eight-mile transmission line on tubular steel poles. Mr. Peace managed the project, developed budget estimates, designed line layout using TLCADD and engineered the structures and foundations.

Mission Power Engineering, Irvine, CA, Aidlin Geothermal 115 kV Tap Project
Mr. Peace served as Lead Engineer, developed project estimates, developed line layout, designed all structures and guying for a three-mile wood pole tap into a geothermal plant. Mr. Peace provided all project drawings, structure and material lists and details and wrote the construction specification.

San Diego Gas & Electric, Southwest Power Link 500kV, San Diego, CA (Senior Transmission Engineer: 1993 – 1997)
Mr. Peace performed acceptance inspection, itemization of deficiencies, and reviewed/approved repairs for all steel poles. Mr. Peace also developed temporary guying system (proprietary and patented) for rapid replacement of storm damaged 500 kV structures.

SPECIALIZED TRAINING

- TLCADD
- PLS-CADD

PROFESSIONAL AFFILIATIONS

- Member ASCE

JOHN A. FULTON, PE

EDUCATION
B.S., Civil Engineering, California State University, Northridge

PROFESSIONAL REGISTRATIONS/CERTIFICATIONS
Registered Professional Engineer - California #C73181

AREAS OF EXPERTISE

- Transmission Line Design
- Project Leadership
- Civil & Structural Design
- Foundation Design

REPRESENTATIVE EXPERIENCE
Mr. Fulton specializes in Transmission Line Design and Engineering Civil/Structural Engineering with more than six years of experience providing Transmission Line Engineering and construction support. He is an experience lead project engineer that specializes in the detailed analysis of existing transmission lines as well as the detailed design of new transmission line projects ranging from 138kV to 220kV. Mr. Fulton is an organized project lead with success in client relations, technical direction, coordination, estimating and scheduling.

Mr. Fulton was responsible for the coordination, engineering, and design of numerous overhead high voltage transmission line projects. Typical projects include the preparation of preliminary and final design packages including; loading criteria, line routing, structure selection & design, plan & profile drawings, hardware & conductor selection, equipment & construction specifications, stringing tables and construction assistance through As-Builts.

<u>Transmission Line Engineering and Design</u>

Iberdrola USA – NERC Compliance Analysis
John performed analysis on multiple Iberdrola USA's transmission lines to determine and document appropriate clearance distances have been achieved based on the NERC's *Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings*. This project involves conducting the necessary survey and analysis on Iberdrola USA's transmission facilities to identify and report areas that violate National Electric Safety Code clearances based on each transmission line's design rating.

Yellowhead Area Transmission System Development
Mr. Fulton was responsible for providing technical leadership and supervision for the design team that was responsible for the design and engineering of approximately 80km of existing 138kV transmission line between the towns of Hinton and Edson in northern Alberta. The team was responsible for bringing the project from initiation to the final implementation stage. Mr. Fulton reviewed and approved all documentation produced by the transmission line design team. He prepared complete construction documentation packages, verified that design and documentation met all regulatory, environment, company and project specific requirements.

Ardenville Wind Farm Tap
Mr. Fulton led a team of Transmission Line Engineers to design and build a new single pole, single circuit, 138kV transmission line to connect the Ardenville Wind Farm to Alberta's electric grid.

Brooks Transmission Line Development and Substation Upgrade
Mr. Fulton was the lead Transmission Line Engineer for the design and construction of new single pole, single circuit, 138kV transmission line connecting the West Brooks Substation to an existing transmission line termination point.

West Edmonton Transmission Line Upgrade
Mr. Fulton was part of a team that provided the engineering to upgrade ten 220kV transmission lines in West Edmonton to improve the current carrying capacity of Alberta's aging transmission system.

Alberta Electric System Operator–220kV Backbone Tower Development
As part of a team, Mr. Fulton helped to develop a new family of 240kV lattice steel towers to be used as the backbone standard structures throughout the entire province of Alberta Canada. He performed broad based exercises including calculating conductor loads; conductor swing; and determination of tower dimensions so not to violate insulator swing air gaps. This tower family is currently being used in all new 240kV transmission lines.

Substation/Structural Engineer
Mr. Fulton developed and reviewed design concepts to drive SCE's "Special Projects" Group. Technical design included code driven design calculations; structural, stress, finite element, and failure analysis. He performed complex code driven calculations in the design of steel and reinforced concrete structures and foundations; including slabs on grade, drilled pier foundations, and miscellaneous steel supports. He also prepared detailed engineering designs, plans, drawings, specifications, and material orders as well as coordinating and supervising field construction work.

Mr. Fulton provided structural design, drafting, and construction support to the Electrical Project Group within the Infrastructure Replacement Program. Facilitated smooth execution of projects by attending regular site visits and visiting construction sites to conceptualize, identify, and resolve field problems quickly and diplomatically. He also managed structural design packages prepared by external design consultants, providing leadership and direction of multiple concurrent projects at any given time.

SPECIALIZED TRAINING

- AutoCAD and
- Microsoft Products (Excel, Word, PowerPoint, Outlook)
- PLS-Cadd, PLS-Pole, PLS Tower
- NESC, RUS, ASCE-7, IBC, CBC (USA)
- CSA, AEUC (Canada)
- AISC, ACI

PROFESSIONAL AFFILIATIONS

- American Society of Civil Engineers
- IEEE693 Working Group (June 2005 – June 2008)
- Tau Beta Pi, National Engineering Honor Society
- Order of Omega, Pi Kappa Phi Fraternity

BURNSIDE

Lyle F. Parsons, B.E.S.

Profession

Environmental Assessment, Strategic Planning and Approvals Specialist and Public Consultation Expert. Head Renewable Energy Technical Services Team

Education

B.E.S., Bachelor of Environmental Studies (Honours), University of Waterloo, 1973

Employment Record

Technical Services for Solid Waste, Environmental Planning and Assessments, Head of Agricultural and Green Team Services now Renewable Energy Services for R.J. Burnside & Associates Limited (2005-Present)

Head, Solid Waste Management, R.J. Burnside & Associates Limited (1998-2004)

Solid Waste Leader (1996-1998); Senior Project Manager (1991-1996), CH2M Gore & Storrie Limited

Project Coordinator, Halton Peel District (1985-1991); Planning Supervisor, Central Region (1984-1985); Environmental Planner, Waste Management Branch (1983-1984); Environmental Planner, Environmental Assessment Branch, Waste Management Branch and Central Region Offices (1975-1983), Ministry of Environment (MOE)

Research Assistant, McGill Sub Arctic Research Laboratory (1974-1975)

Chief Sociologist, Canada Centre for Inland Waters (1973-1974)

Citizenship

Canadian

Languages

English

Mr. Parsons is Vice President, Environment and a Senior Project Manager with R.J. Burnside and Associates Limited. He is technical head of our Renewable Energy Services group. He has over 38 years of experience in environmental assessment and planning and direct environmental management of multi-disciplinary projects in Ontario including international experience. Lyle has developed an extensive knowledge of the FIT and MicroFit Programs and its rules. He is also project manager for wind power projects in Southwestern Ontario and leads Burnside's anaerobic digestion team for renewable energy generation on farms. Lyle managed the Ontario Power Authority's (OPA) Aboriginal Renewable Energy Fund advisory service project in association with London Economics Inc. (LEI). He also worked with LEI on development of a municipal funding program for the OPA.

Mr. Parsons brings with him a wealth of experience from both the private sector and government. He has managed many projects involving approvals under the federal, provincial, and municipal statutes, often resulting in the development of unique, creative, and cost-effective solutions for private and public sector clients. He leads many strategic planning projects with the objective of finding cost effective, creative and environmentally sustainable solutions.

Lyle's has extensive experience with the Ontario Ministry of the Environment managing diverse projects while working with the Environmental Assessment Branch, Waste Management Branch, and Regional Operations. He was a member of the team that developed the Province of Ontario's "Blue Print for Waste Management in Ontario" and the "Environmental Assessment Act". Lyle's past experience while with the Ministry of the Environment (MOE) included both Head Office and Regional review functions. Lyle's experience also includes work on individual as well as Class EA's. Work included reviews of a number of Hydro One transmission line individual EA applications. He has been the key environmental advisor at well over 30 hearings held before the Environmental Assessment Board (now Environmental Review Tribunal), the Ontario Municipal Board, Ontario Energy Board, and the National Energy Board and has testified before these Boards.

Renewable Energy

Project Manager, Grand Bend Wind Farm, Class IV, 100 MW Wind Farm for Grand Bend Wind Limited c/o Northland Power, Ontario (2010-Present)

The project involves REA approvals for the project including 36 kV collector lines and a 32 kilometre 230 kV transmission line. The project also involves obtaining permits and approvals a number of associated components such as stream crossings, agricultural drains and road use from the local Conservation Authority and Municipal governments among others.

Project Manager, Over 18 First Nations Pre-feasibility Studies for Various Renewable Energy Projects Including Wind and Solar Power

The project locations were throughout Ontario with a large number located in North-western Ontario. Work programs involved determining the technical and economic feasibility of the potential project and establishing capability for connection to the Ontario electrical grid. It also included traditional knowledge and interested persons identification of issues in the study areas involved.

Project Manager, Pacific Power Renewables Inc., 10-30 MW Solar Farm Project Development, Uxbridge, Ontario

This project included Environmental Feasibility Studies.

Ontario Power Authority, Advisory Services for Aboriginal Renewable Energy Fund Development (2009-2010)

Lyle was the lead and project manager for a team of professionals who provided advisory services to the Ontario Power Authority for the development of this fund. Our team including London Economics, developed cost estimates for every type of renewable energy project as background to help develop the framework and size of the fund. We provided advisory services with respect to development of a request for statements of interest. Our team is currently providing advice on development of the rules documents for the fund. This work is now close to completion.

Ontario Power Authority, Advisory Services for Development of a Municipal Renewable Energy Program (2009-Present)

Project Manager of the Neegan Burnside Ltd. team. The Neegan Burnside team provided subcontractor services to London Economics on this project. Neegan Burnside provided advisory support in the development of a municipal renewable energy fund including cost estimates and other advisory assistance to the OPA as required.

Class II, Wind Project, Westerhout Enterprises Inc., Brucefield, Ontario (2009-Present)

Project manager for OPA, Feed in Tariff (Fit) Program application, Hydro One connection assessments and Renewable Energy studies required under the Environmental Protection Act

Class II, Wind Project, Westerhout Poultry Inc., Brucefield, Ontario (2009-Present)

Project manager for OPA, Feed in Tariff (Fit) Program application, Hydro One connection assessments and Renewable Energy studies required under the Environmental Protection Act

MV Power, Wind Turbine Manufacturer, Brucefield, Ontario (2009-Present)

Project manager for technical assistance as required to this wind turbine and tower manufacturer, work program has involved structural, electrical and noise assessment assistance.

Solid Waste Management

Strategic Planning Study for the Municipality of West Perth, Mitchell, Ontario (2007-Ongoing)

Project Manager for a strategic planning study to assist the Municipality in their long term planning for waste management and disposal. The work involved determining the current conditions of five existing landfills and the solid waste management systems approach. It included assessing requirements to continue operations and consider closure of some of the five landfills. The Strategic Plan also included review and assessment of waste to energy alternatives. Alternatives solutions were recommended which incorporate engineering controls and capture maximum capacity. The work program will result in improved solid waste system long term efficiency, identify lower cost systems. We have developed preliminary conceptual designs for the alternatives, completed detailed cost estimates for the conceptual designs considering capital, operation, closure and post closure costs. Potential environmental impacts and environmental sustainability of the systems were evaluated. Burnside is currently responsible for implementation of the results of the Strategic Plan and is in the detailed design stage.

Consulting Services for Two Landfill Sites, Municipality of Perth South, St. Pauls, Ontario (2007-2010)

Project Manager for consulting services on two landfill sites to maximize site capacity and undertake ground and surface water impact studies. Amendment to each site's operating Certificate of Approval was required including public consultations with adjacent landowners.

Development and Approval of a Solid Waste (Organics) Composting Facility, Town of Perth, Ontario (2008-2009)

Project Manager for the development and approval of a solid waste, (organics) composting facility. Work included study and determination of landfill site capacity and consultations with the Ontario Ministry of the Environment.

Numerous Solid Waste Projects, Ontario (2004-2009)

Senior Advisory Services for the following projects: Egremont Landfill Site, Wallace Landfill Site, Listowel Landfill Site and Transfer Station, Downie landfill site, Blanshard landfill site, and many more – work usually includes project lead on any public consultation, client relations.

Recycling Council of Ontario

Judge of submissions for their annual recycling awards.

Solid Waste Management Strategic Planning Study, Township of King, King City, Ontario (2004)

This study was initiated to assist the Township of King respond to the Region of York's plans to convert their waste management system into a three stream program. Burnside was retained to examine King's municipal solid waste collection programs and recommend a new program. The work included detailed cost analysis and a systems evaluation.

Solid Waste Management Strategic Planning Study, Township of North Perth, Listowel, Ontario (2003-2004)

Project Manager this planning study whose goal was to comprehensively examine existing municipal solid waste management programs and facilities and recommend new programs and facilities. The work program goals were to identify programs and facilities that are: sustainable, equitable, provide improved service to residents and are cost effective.

Landfill Operator's Training, Multiple Burnside Clients, Ontario (2000 & 2004)

Project Manager responsible for development and presentation of training seminars to municipal landfill managers and operators.

Solid Waste Management Strategic Planning Study, Township of Southgate, Dundalk, Ontario (2002-2003)

The objective of this study was to comprehensively examine existing municipal solid waste management programs and facilities and recommend new programs and facilities. The work program goals were to identify programs and facilities that are: sustainable, equitable, provide improved service to residents and reduce costs. The program has now been implemented and has successfully achieved its goals.

Annual Landfill Monitoring Reports, City of Brockville, Ontario (1994-2002)

Project Manager for landfill site annual monitoring reports from 1994 to 2002, involving preparation of waste quantity and reduction calculations, site operations, and compliance summary for landfill activities, waste management projects for future site activities, and ongoing strategic advice, for the City of Brockville, Ontario.

National Sanitary Landfill, Greenland, Barbados (1998-1999)

Project Manager, during the preliminary stage of this study, responsible for conducting a comprehensive peer of the National Sanitary Landfill, constructed by others at Greenland, Barbados. This peer review included an analysis of design and construction of the site.

Site Redesign for Steel Slag Landfill, Atlas Specialty Steels, Welland, Ontario (1998-1999)

Project Manager responsible for development of a site redesign and operations plan for a steel slag landfill, including onsite metals and refractory materials recovery operation; new applications for EPA Part V and Air Emissions, for Atlas Specialty Steels, Welland, Ontario.

Green Field Landfill Site, Town of Northeastern Manitoulin and the Islands, Manitoulin, Ontario (1998)

Project Manager for EPA and OWRA applications for a green field landfill site (Site 5A) in the Town of Northeastern Manitoulin and the Islands, Ontario. Responsible for management of the project and obtaining EPA approvals, communications with Citizens groups, testimony at an Ontario Municipal Board hearing in connection with the application.

Redesign of Biggar's Landfill, Township of Brantford, Ontario (1997)

Project Manager for the Biggar's Lane Landfill site, including redesign and MOE applications, Phases I (background and data collection) and II (conceptual site design); preparation of optimized conceptual site designs; and creation of cost analysis model to compare these designs, including design, capital, operation, and post-closure components.

Detailed Design of Humberstone Road Landfill, Welland, Ontario (1995-1996)

Project Advisor for the detailed design and contract preparation for the leachate collection, surface water management, and side-slope final cover systems, perimeter access roads, and waste relocation at the Humberstone Road Landfill site, for the Regional Municipality of Niagara, Welland, Ontario.

Quarry Road Landfill, Town of Lincoln, Ontario (1996)

Responsible for coordination of design and operations for overall site improvements, for the Town of Lincoln, Ontario.

Humberstone Landfill Site Optimization, City of Welland, Ontario (1996)

This project confirmed disposal capacity of over 20 years. The value of this capacity to our client was estimated at over $30M (Cdn.). The work included comprehensive site-assessment studies, such as hydrogeology, surface water, aquatic, noise and air emissions, visual effects, and natural resources, public opinion research and consultation, etc. The site redesign includes new operational requirements, containment systems redesign, new surface water, and leachate management facilities. The project received an EPA approval for a redesigned and improved landfill site, for the City of Welland, Ontario in December 1996.

Update the Landfill Site's Operation and Closure Plan, Town of Lincoln, Ontario (1996)

This project found an additional six years of site capacity within existing approvals. The work included new site operational requirements, site redesign, and surface water management facilities. The landfill is located in the Town of Lincoln, Ontario.

Waste Management Bylaw, City of Welland, Ontario (1996)

Development of a new waste management bylaw for the City of Welland, Ontario.

Coordination of Redesign for Humberstone Road Landfill Site, City of Welland, Ontario (1995-1996)

Responsible for site design, operations, and maintenance, including overall coordination with surface water, leachate collection, noise and air emissions, visual effects mitigation, closure cover, and after use design disciplines; design and project management liaison between other disciplines; and assistance with the overall application document/reports' preparation, for the City of Welland, Ontario.

Wainfleet / Welland Waste Management Master Plan, City of Welland, Ontario (1991-1996)

Project coordinator of the Wainfleet/Welland Waste Management Master Plan, Stage I Study, which will be subject to approval under the Environmental Assessment Act, located in the City of Welland and Township of Wainfleet, Ontario.

Alternate Landfill Operation Strategies, City of Welland, Ontario (1995/1996)

Project management activities involving development of alternate conceptual designs, including a new gatehouse, a public drop-off transfer station, and road system for the City of Welland, Ontario.

Essex / Windsor Waste Management Master Plan, Ontario (1994)

Project Manager for the study team conducting a peer review of the Essex/Windsor Waste Management Master Plan studies being conducted by others to seek approval under the EA, the EPA, and other statutes.

Landfill Site, Continued Use Project, City of Brockville, Ontario (1992-1994)

This project included a mandatory hearing under the EPA and testimony before the Environmental Assessment Board. All work was successfully completed and project approval granted for expansion of the landfill site in the City of Brockville, Ontario.

Landfill Emergency Certificate of Approval, City of Brockville, Ontario (1992)

Project Manager who successfully obtained an Emergency Certificate of Approval, under the EPA, Part V, for a landfill site in the City of Brockville, Ontario.

Landfill Environmental Audit, City of Welland, Ontario (1992)

Project Manager responsible for environmental audits of landfill sites operated by the City of Welland and the Township of Wainfleet, Ontario. Later work entailed development of a database compliance monitoring system to track site operations.

NEEGAN BURNSIDE

Profession

Environmental Engineer

Education

Honours B.Sc. (Eng.) Environmental Engineering, Co-op Education Program, University of Guelph, 2001

Certificates

Ecological Land Classification for Southern Ontario, 2006 (MNR)

Professional Societies

Professional Engineers Ontario

Employment Record

Environmental Engineer, R.J. Burnside & Associates Limited (2006-Present)

Project Assistant, R.J. Burnside & Associates Limited (2000-2005)

Environmental Projects Research Assistant, Polycon Industries (1999)

ISO14001 Coordinator, Plydex, Division of Magna International (1998)

Citizenship

Canadian

Languages

English

Jennifer Vandermeer, P.Eng.

Ms. Vandermeer has a wide range of project experience servicing the needs of both Canadian and global clients. Jennifer provides an environmental engineering perspective to environmental and social impact assessment projects undertaken at both federal and provincial levels in Canada. Jennifer has completed several Class Environmental Assessments for transportation, transit, bridge and water / wastewater projects and has been involved with wind power development projects for the private sector. Internationally, she served as a project coordinator for the social and environmental assessment of a large hydropower facility situated on the Victoria Nile in Uganda and has also worked on projects in Egypt, Oman, Brazil, Barbados, St. Lucia and Trinidad. Jennifer is currently working on the Environmental Impact Assessment for the expansion of the Mangrove Pond Landfill in Barbados. Ms. Vandermeer demonstrates excellent communication and organizational skills, and is able to converse easily within multi-disciplinary environments.

Jennifer has five years of project experience in the solid waste management sector. She has successfully completed projects for conventional municipal solid waste landfills and bioreactor landfills at conceptual design, tender and construction phases as well as landfill liability assessments, landfill operation and maintenance plans and site closure projects in Canada and overseas.

Environmental Assessments

Municipal Class Environmental Assessment, Schedule B for the Gore Road Widening (Patterson Sideroad to Highway 9), Region of Peel, Ontario (2011-Ongoing)

EA Coordinator responsible for managing EA efforts including preparation of public consultation materials, liaison with Region staff and review agencies and coordination of studies by environmental sub consultants.

GO Transit Class Environmental Assessment, Group B for the Proposed Rail Expansion from Hamilton to Niagara Region, GO Transit, Ontario (2009-2010)

EA Coordinator responsible for managing EA efforts including public consultation, liaison with municipalities, inventories of the existing natural, social and economic environmental conditions within the study area, and studies by environmental sub consultants. Primary author and coordinator of the Environmental Study Report (ESR) for this project.

Environmental Impact Assessment for Mangrove Pond Landfill Cell 4, Northern Depot and Leachate Treatment Plant, Government of Barbados, Sanitation Service Authority, Barbados (2009-2010)

EIA Coordinator for facilities to be constructed at the Mangrove Pond Landfill and the Waste Management Centre at Vaucluse. Project is in support of development of additional site capacity (Cell 4), a maintenance and administration facility for waste collection vehicles (the Northern Depot), and a 350 m3/d leachate treatment facility (preliminary size).

Canadian Environmental Assessment Act Screening Assessment for New School, Chippewas of Nawash Unceded First Nation, Ontario (2010)

EA Coordinator responsible for review and update of screening report, coordination of environmental fieldwork and liaison with INAC Environmental Officer.

Canadian Environmental Assessment Act Screening Assessment for New Community Recreation Centre, Moose Deer Point First Nation, Ontario (2010)

EA Coordinator responsible for review of existing environmental conditions of site, background document review and preparation of screening report.

Municipal Class Environmental Assessment, Schedule B for the Creemore Sewage Treatment Plant Equalization Tank, Clearview Township, Ontario (2009-2010)

EA Coordinator responsible for managing public consultation program, facilitating communications with the study team, and coordination of sub-consultants. Primary author and coordinator of the Project File Report (PFR) for this project.

GO Transit Class Environmental Assessment, Group B for the Proposed Rail Expansion from Georgetown to Kitchener, GO Transit, Ontario (2008-2010)

EA Coordinator responsible for managing EA efforts including two sets of public information centres, coordinating inventory of the existing natural, social and economic environmental conditions within the study area, and coordination with environmental sub consultants. Primary author and coordinator of the Environmental Study Report (ESR) for this project.

Municipal Class Environmental Assessment, Schedule B for Grey Road 3 Bridge, Grey County, Ontario (2009)

EA Coordinator responsible for facilitating communications with the study team, client and coordination of sub-consultants. Completed desktop inventory of natural, social and economic environmental conditions within the study area. Primary author and coordinator of the Project File Report (PFR).

Municipal Class Environmental Assessment, Schedule B for Concession Road 7 Bridge, Township of Adjala-Tosorontio, Ontario (2008-2009)

EA Coordinator responsible for facilitating communications with the study team, client and coordination of sub-consultants. Completed desktop inventory of natural, social and economic environmental conditions within the study area. Primary author and coordinator of the Project File Report (PFR).

Municipal Class Environmental Assessment, Schedule C for the Sideroad 10 Reconstruction and Widening, Town of Bradford West Gwillimbury, Ontario (2008-2009)

EA Coordinator responsible for coordinating the public consultation program, which included facilitation of notices, preparation and attendance at a public information centre, responses to stakeholder comments. Assisted in the writing, review and preparation of the ESR.

Municipal Class Environmental Assessment, Schedule B for the Septage Receiving Station Installation, Regional Municipality of Peel, Brampton, Ontario (2007-2009)

EA Coordinator responsible for coordinating public consultation efforts and completing an inventory of the existing natural, social and economic environmental conditions within the study area. Providing assistance in the writing, review and preparation of the PFR.

Municipal Class Environmental Assessment, Schedule B for the Herridge North Reservoir, Region of Peel, Mississauga, Ontario (2008)

EA Coordinator responsible for coordinating consultation efforts, which included public and agency notification and a public information centre. Facilitated communications with the study team, and Region of Peel and City of Mississauga staff relating to the EA. Primary author and coordinator of the Project File Report (PFR) for this project.

Municipal Class Environmental Assessment, Schedule B for the Professor Day Drive Widening, Town of Bradford West Gwillimbury, Ontario (2008)

Responsible for facilitating public and review agency consultation for the EA as well as co-writing, reviewing and preparation of the PFR and it's submission for public review.

Municipal Class Environmental Assessment, Schedule C for the Sixth Line Widening, Town of Bradford West Gwillimbury, Ontario (2007-2008)

EA Coordinator responsible for coordinating the public consultation program, which included facilitation of notices, preparation and attendance at a public information centre, responses to public and agency comments. Facilitated writing, review and preparation of the ESR.

Municipal Class Environmental Assessment, Schedule B for the Melbourne Drive Widening, Town of Bradford West Gwillimbury, Ontario (2007-2008)

Responsible for coordinating final public consultation efforts and the writing, reviewing and preparation of the PFR and it's submission for public review.

Environmental Assessment for the Proposed Sewer and Water Service Extension for a Commercial and Retail Development, Town of Midland, Ontario (2006-2008)

EA Coordinator responsible for liaising with client and stakeholders as well as writing, reviewing and preparing an environmental assessment report for an extension of municipal services (sanitary sewer and potable water) for commercial and retail development. A harmonized documentation approach was taken incorporating the requirements of the Municipal Engineers Association (MEA) Municipal Class Environmental Assessment and the Canadian Environmental Assessment Act.

Social and Environmental Assessments for the Bujagali Hydropower and Interconnection Projects, Bujagali Energy Limited, Uganda (2006-2008)

Project Coordinator and Assistant Project Manager responsible for facilitating the preparation of a multi-volume suite of documents for submission to Ugandan regulators and six International Financial Institutions (IFIs). Coordinated many project efforts completed by the multi-discipline international consulting team and liaised with client and IFI representatives during the course of this complex assignment. Determined applicable regulatory requirements for the SEAs including Ugandan requirements and IFI policies. Helped to write and review numerous components of the SEA documentation. Lead various project management aspects of this $1.2 M project including project invoicing and sub-consultant contracting. Currently assisting consultant team with client support activities leading up to project approval. Support activities include preparation of social and environmental actions plans, liaison with regulators and lending agency representatives, public consultation, and preparation of SEA update reports.

Unexploded Ordnance (UWO) Environmental and Cultural Resource Investigation at the Former Camp Ipperwash – Environmental Awareness Training, X-Tech Explosive Decontamination Inc., Forest, Ontario (2007)

Responsible for the preparation of a pamphlet to assist UWO technical staff in the identification of rare species and vegetation communities that will be encountered during field work.

Preliminary Environmental Constraints Analysis for the a Proposed Wind Power Project, Geilectic Inc., Sowerby, Ontario (2007)

Study coordinator responsible for the conducting a preliminary constraints analysis which enabled decisions to be made relating to location of proposed wind generation equipment. The analysis involved research and documentation of all regulatory requirements at federal, provincial and municipal levels of government. The work also required documentation and mapping of land use designations, natural heritage features and mining rights within the study area.

Preliminary Environmental Constraints Analysis for the South River Wind Power Project, Geilectric Inc., South River, Ontario (2007)

Study assistant responsible for researching and documenting local planning policies, MNR Crown Land Use policies, and breeding bird data for the four candidate project areas.

Induced Development Assessment Related to the Mackenzie Gas Project, Indian and Northern Affairs Canada (INAC), Northwest Territories (2007)

Project Engineer responsible for researching baseline conditions of the valued socio-economic components in the regions impacted by induced development. Facilitated report writing and preparation of mapping for the project.

GHG Emissions and Reduction Studies and GHG Utilization

Project Design Document for the Development of a Green Energy Complex, Mangrove Pond Landfill, Canada's Clean Development Mechanism (CDM) and Joint Implementation (JI) Office, Barbados, West Indies (2004)

Assistant Project Manager responsible for coordination of project efforts with Canadian and Barbadian partners. Prepared a detailed project design document in accordance with United Nation Framework Convention on Climate Change (UNFCCC) rules for small-scale CDM projects.

Landfill Gas Baseline Studies, St. Lucia and Trinidad and Tobago, Canada's CDM and JI Office, West Indies (2004)

Assistant Project Manager responsible for coordination of project efforts with Canadian, St. Lucian and Trinidadian partners. Conducted visual audits of the closed Ciceron Landfill site in St. Lucia and the active Beetham Landfill Site in Trinidad. Assisted with field measurements of gas concentrations and flows and prepared baseline study reports for both sites. Facilitated follow-up discussions with representatives from each country.

National Greenhouse Gas Inventory & Emission Reduction Strategies Project, Canadian International Development Agency (CIDA), Egypt (2001-2004)

Assistant Project Manager responsible for facilitating the Cairo 2003 workshop and coordinating project efforts with the Canadian and Egyptian project partners. Completed quarterly status reports for technical and financial aspects of the project.

GHG Abatement Project for the Canabrava Landfill Site, Industry Canada, Salvador, Brazil (2002-2003)

Project Assistant responsible for completing design calculations and drawings for demonstration cell LFG extraction and collection system, the development of engineering reports, and coordinating communication with project partners.

Landfill Site Design/Redesign

Closure and Transfer Station Design, Curve Lake First Nation Landfill, Ontario (2006)

Project Engineer responsible for providing a cost estimate for closure and post-closure care of the existing landfill and construction of a new transfer station. Undertook review of options for waste collection, transfer, and disposal alternatives for the First Nation. Provided technical input for the conceptual design drawings and design report.

Detailed Fast-Tracked Design and Construction of Cell 1, National Sanitary Landfill, Sanitation Service Authority, Barbados, West Indies (2005)

Project Assistant responsible for numerous detailed design assignments for the development of a new 714,000 m^3 waste containment cell at the National Sanitary Landfill. Wrote the detail design report for this project and also assisted with site layout considerations and the preparation of the detailed design drawings and tender documents. Project is now in construction phase.

Infrastructure Facilities and Scalehouse Design and Tender, Vaucluse Solid Waste Management Centre, Solid Waste Project Unit, Barbados, West Indies (2005)

Project Assistant responsible for overall site infrastructure and detailed design plans including scalehouse and front-end area works. Also provided assistance with the design of the surface water management facilities.

Sohar Solid Waste Management, Scheme, Implementation Phase, Wadi Haybi Landfill, Dr. Ahmed Abdel Warith and Partners, Llc. Sultinate of Oman (2005)

Project Assistant responsible for the detailed design of a fully serviced 2-hectare windrow composting facility at the Wadi Haybi Landfill. Assisted with detailed design of a gravity sewer, scale house facility, maintenance building and fuel storage area for this landfill site.

Conceptual Design for Phase 3B Cell Development, Mangrove Pond Landfill Site, Sanitation Service Authority, Barbados, West Indies (2004)

Project Assistant responsible for developing conceptual design plans for a new waste containment cell located on a 4.1-hectare land area adjacent to the active waste cell (Phase 3). Wrote the conceptual design brief and prepared conceptual design drawings for this project.

NEEGAN BURNSIDE

Tricia Radburn, M.Sc.(Pl), MCIP, RPP

Profession

Environmental Planner,
Ecological Restoration Specialist

Education

M.Sc. (Pl), University of Guelph, 2010

Diploma, Ecosystem Restoration, Niagara College, 2001

B.Sc. (Env.), University of Guelph, 2000

Certificates

Ontario Wetland Evaluation for Southern Ontario, 2006

Ecological Land Classification, 2004

Low Complexity Prescribed Burn Workers Course, 2004

Electrofishing, 2001

BioMAP, 2000

Employment Record

Environmental Planner, R.J. Burnside & Associates Limited (2006-Present)

Generic Regulations Assistant, Upper Thames River Conservation Authority (2005-2006)

Stewardship Assistant, Ontario Ministry of Natural Resources (2003-2004)

Surface Water Monitoring Officer, Ontario Ministry of Natural Resources (2002-2003)

Eco-Tourism Consultant, CIDA/ Cerro Blanco Protected Forest, Ecuador (2001)

Citizenship

Canadian

Languages

English

Tricia is experienced in assessing and analyzing development impacts on environmental and natural heritage features. Certified in Ecological Land Classification and Wetland Evaluation, Tricia has conducted field studies and analyzed environmental conditions for Environmental Impact Studies under the *Planning Act*, Greenbelt Plan, Oak Ridges Moraine Conservation Plan, Niagara Escarpment Plan and a variety of class environmental assessment processes. She is knowledgeable of a wide variety of permitting processes and has experience with approvals under the *Public Lands Act*, *Endangered Species Act*, *Species at Risk Act*, *Fisheries Act* and Conservation Authority regulations. Prior to working at Burnside, Tricia worked for the Upper Thames River Conservation Authority where she helped to incorporate *Ontario Regulation 97/04 – Development, Interference with Wetlands and Alterations to Shorelines and Watercourses* into UTRCA policies and guidelines.

She recently completed a Masters degree in First Nation Energy Planning under Ontario's new Green Energy Act, Renewable Energy Approval Regulation and various incentive programs.

Energy Projects and Renewable Energy Approvals

Grand Bend Wind Farm 100 MW Renewable Energy Approval, Northland Power Inc., Grand Bend, Ontario (2011-Ongoing)

Coordinated all fieldwork and prepared documentation for all components of the Natural Heritage Assessment portion of the Renewable Energy Approval as well as Endangered Species Act permitting. Worked closely with the Ministry of Natural Resources and coordinated changes in the work program to correspond with ongoing updates and amendments to the provincial guidelines as the project progressed. Attended Public Information Centres to answer questions about the project and its potential impacts on the environment with local landowners.

Uxbridge Goodwood 20 MW Solar Farm Renewable Energy Approval, Pacific Power Inc., Uxbridge, Ontario (2011-Ongoing)

Coordinated fieldwork associated with the Natural Heritage Assessment and identified preliminary environmental constraints which could affect the feasibility of the project.

Aboriginal Renewable Energy Fund Pre-Feasibility Studies for Various First Nation Communities, Ontario (2011-Ongoing)

Assisted in coordinating funding applications. Prepared a questionnaire for communities to address Aboriginal Traditional Knowledge and Interested Person portions of the pre-feasibility studies. Provided QA/QC for the pre-feasibility reports.

Festival Hydro Transformer Station Class Environmental Assessment for Minor Transmission Facilities, Stratford, Ontario (2010-2011)

Prepared a Class EA for a new transformer station in the City of Stratford. Conducted all required public notifications and assessments potential impacts associated with noise, construction and operation of the facility.

Westerhout Class 2 Wind Facilities Renewable Energy Approval Applications, Huron County, Ontario (2009-2010)

Consulted with agencies to confirm approval application requirements under the new Renewable Energy Approval Regulation, O. Reg. 359/09 for two wind facilities. In particular, discussions were held regarding the need for archaeological assessments. Different agencies interpreted the new regulations in different ways. Ensured that a consensus was achieved and all parties agreed to the same conclusion. Ensured that all consultation requirements with agencies and stakeholders were completed.

Elgin Grovlea Class 2 Wind Facility Renewable Energy Approval Application, Elgin County, Ontario (2010)

Prepared a Renewable Energy Approval Application under O. Reg. 359/09 for a Class 2 wind facility. Considered how the construction and operation of turbines could impact adjacent natural heritage features. Ensured that all neighbours, stakeholders and agencies were consulted as required under the regulation.

Preliminary Wind Farm Planning, Wabaseemoong and Ginoogaming First Nations, Whitedog and Longlac, Ontario (2009-Present)

Conducted a preliminary assessment of environmental constraints associated with proposed wind farms in the Ginoogaming and Wabaseemoong First Nations. Conducted initial interviews with community leaders to identify concerns, resources and areas of importance within the communities that will require additional study and discussion as the projects progress.

South River Wind Farms Environmental and Regulatory Constraints Screening, Nipissing and Parry Sound Districts, Ontario (2007)

Four proposed wind farm sites were assessed for environmental and regulatory constraints that could limit energy development. Sites spanned organized and unorganized municipalities which included Crown and private lands. Results allowed the client to make an informed decision about whether to proceed with wind farm development on the sites.

Honeywood Wind Power Constraints Analysis and Environmental Assessment, Mulmur Township, Ontario (2006-2008)

The first stage of this project was to prepare preliminary environmental constraints analysis, including a compilation of all relevant municipal, provincial and federal policies in effect in the study area. A search of background data sources was conducted to identify potential environmental constraints and list all the necessary approvals required for the project. Based on this review, the project moved forward into the Environmental Assessment process. Conducted fieldwork and data reviews to document natural heritage features to support the EA and requirements of the Niagara Escarpment Commission.

East Garafraxa and Marsville Wind Farm Environmental and Regulatory Constraints Screening, East Garafraxa, Ontario (2006-2007)

Environmental and regulatory constraints were assessed for two potential wind farm sites. Natural heritage features were identified through a desktop review and consultation with applicable agencies. The report was used by the client to assist in making a decision about whether to proceed with the project.

Captus Energy Wind Farm Environmental Assessment, Huron County, Ontario (2006)

Initiated preparation of a natural heritage report to supplement the Environmental Assessment. Identified natural heritage features and described preliminary protection measures to minimize impacts. Project did not move forward due to constraints in transmission line capacity.

Advisory Services

Peer Review of the Duntroon Quarry Natural Environment Report, Clearview Township, Ontario (2006-Present)

Reviewed the Natural Environment Report prepared in support of the proposed Duntroon Quarry expansion on behalf of the Township of Clearview. Consulted the PPS, Township of Clearview, County of Simcoe and Niagara Escarpment Plan to determine if a proposed quarry expansion conformed to all applicable natural heritage and aggregate resources policies. Advised the Township on how to proceed with the application and requirements for additional information and detailed studies.

Peer Review of the Sargeant-Waverley Pits #1 and 2 Natural Environment Report, Tiny Township, Ontario (2006)

Reviewed the Natural Environment Report relative to the policies of the PPS, Aggregate Resources Act, Township of Tiny and County of Simcoe Official Plans to determine if two new proposed aggregate extraction pits, one involving below water table extraction, met natural heritage and aggregate resource policies.

Peer Review of Amaranth Estates Environmental Impact Assessment, Amaranth Township, Ontario (2006)

Provided advisory services to the Township of Amaranth with respect to an Environmental Impact Assessment for a proposed subdivision. Recommended an approach to appropriately resolve concerns with a wetland on the property that had inadvertently been left off Greenlands mapping in a recent update to the Township's Official Plan.

First Nations Planning and Advisory Services

Sheshatshiu Innu Community Commercial Zoning and CEAA Screening, North West River, Labrador (2010-Ongoing)

The community is interested in designating a portion of its reserve lands for leasing to non-First Nation commercial development. I prepared materials for, and assisted in organizing and facilitating a community workshop to help the community identify where commercial development should be located. The workshop was used to help community members consider types of existing development are compatible or incompatible with the proposed commercial development. Reviewed Indian and Northern Affairs Canada's land use policies to understand the process for designating reserve lands and writing a Head Lease to allow reserve lands to be leased to non-First Nation developers and business owners. Coordinated with land surveyors and land appraisers and staff associated with a Phase 1 Environmental Site Assessment.

Cape Croker Recreational and Cultural Master Plan, Chippewas of Nawash Unceded First Nation, ON (2010-2012)

Undertook consultation with the community to identify a "wish list" for improvements to community recreational and cultural facilities. Lead focus groups with representative sample of community groups an segments, including youth, Elders, parents, participants in cultural arts and recreation programs. Managed a local youth who was hired to assist with community consultation. Summarized findings from focus groups, comment cards and long questionnaires. Identified community priorities and recommended measures for implementation.

Territorial Planning Concepts, Grand Council Treaty #3, Kenora, Ontario (2010).

The overall goal of the project was to initiate discussions that may eventually lead to a consultation agreement between the Grand Council Treaty #3 ("GCT3"), Ministry of Natural Resources and Ministry of Northern Development, Mines and Forests that will clarify how the GCT3 wishes to be consulted on land use and resource management applications and how the GCT3 may use consultation opportunities to create new economic partnerships and economic development opportunities. Summarized legislation associated with land use and resource management in Northern Ontario. Identified policies in the Public Lands Act, Mining Act, Crown Forest Sustainability Act that allow for participation of the Grand Council Treaty #3 ("GCT3") and its member communities in land use planning decisions. The Proposed Growth Plan for Northern Ontario was also reviewed for strategies and objectives that could provide new economic opportunities for the GCT3. Surveyed member communities by phone to understand community concerns with their relationship with the MNR and MNDMF. Prepared materials for, organized and assisted in delivering a presentation and community workshop to further understand the GCT3's interests in land use planning. Suggestions were made to resolve misunderstandings and challenges that were limiting the current relationship between all parties.

Land Use Planning Guide for Northern Ontario for the Métis Nation of Ontario (2010)

Created a planning guide for the Métis Nation of Ontario ("MNO"). The guide included summaries of planning legislation and policies including the Planning Act, Public Lands Act and Crown Forests Sustainability Act among others. Particular attention was paid to new ore recently updated legislation such as the Mining Act, Proposed Growth Plan for Northern Ontario and Bill 191, draft Far North Act. Recommendations were then made to increase the MNO's involvement in planning and resource management in Northern Ontario.

Review of Amendments to the Township of Pelee Official Plan on behalf of the Walpole Island First Nation (2010)

Reviewed draft updates to the Township of Pelee Official Plan. Identified which were relevant to the rights and interests of the Walpole Island First Nation ("WIFN"), including policies for the identification and protection of natural and cultural resources. It was found that the Official Plan did not appropriately identify the WIFN's existing land claim to portions of the Township or known WIFN archaeological sites on Pelee Island. Recommended appropriate responses for the WIFN to ensure that their rights and interests are considered and incorporated.

Review of Amendments to the Bruce County Official Plan on behalf of the Saugeen Ojibway First Nations, Wiarton, Ontario (2009-Present)

Reviewed major amendments proposed to the Bruce County Official Plan. Identified which were relevant to the rights and interests of the Saugeen Ojibway First Nation ("SON"), including policies for the identification and protection of cultural resources, policies for shoreline areas with the potential to affect water quality and fisheries resources as well as polices for large scale wind power developments and boundary mapping of significant natural heritage features. Recommended appropriate responses for the SON to ensure that their rights and interests are considered and incorporated into planning documents.

Review of Coast Guard Proposal to Store Dredged Material from the St. Clair River at the Walpole Island High Banks Pit Site, Walpole Island First Nation, Ontario (2007)

Provided review and analysis of existing documentation, inventories and previous studies documenting the significance and sensitivity of natural heritage features on, and adjacent to, the Walpole Island High Banks lands. Prepared a community questionnaire to identify the cultural uses of plants, recreational opportunities and cultural significance of the property. Assisted with organization of a Public Information Centre to provide information and collect community opinion on the project. Provided advise to the community regarding the suitability of the borrow pit to store the dredged material. Identify the permitting requirements needed to proceed with the project ie. Environmental Assessment, Fisheries Act authorization and Species at Risk Act permits.

Matawa First Nation Winter Road Realignment Preliminary Environmental Assessment (2007)

Prepared a preliminary INAC CEAA Screening to identify opportunities and constraints related to the realignment and potential upgrading to all-season roads for the winter road system servicing five First Nation communities in northern Ontario.

Species at Risk Surveys and Permitting

Species at Risk Project Biologist, XTEC, Former Camp Ipperwash, Ipperwash, Ontario (2007-2009)

Worked in conjunction with the unexploded ordnance clearing team and the Stony and Kettle Point First Nation on the Former Camp Ipperwash, Military Training Center. Ensured adherence to the Canadian Wildlife Services ("CWS") Species at Risk Permit required for vegetation clearing. Worked with the local community for several months over two field seasons to identify and avoid Federal and Provincial Species at Risk and culturally important species and sites during site operations. Attended an Aboriginal Cultural Awareness Training sessions presented by the Stony and Kettle Point First Nation.

Detroit River International Crossing Individual Environmental Assessment and Endangered Species Act Permit Review, Windsor, Ontario (2008-Present)

Reviewed Natural Heritage background reports, Environmental Assessment documents, *Endangered Species Act* permits and Management Plans for Rare Species on behalf of the Walpole Island First Nation ("WIFN") to determine if Aboriginal interests and rights associated with traditional use of the area were appropriately addressed. WIFN's primary interests related to rare tallgrass prairie habitat and species, given the presence of similar habitats on Walpole Island.

Species at Risk Act and Endangered Species Act Permitting, Moose Deer Point First Nation, Mactier, Ontario (2009)

Prepared and coordinated permit applications under provincial and federal species at risk legislation in association with construction of a new water treatment and distribution system in proximity to the habitat of several protected reptiles and amphibians. Developed mitigation and monitoring plans to ensure potential impacts were minimized.

Environmental Impact Studies

Winifred Woods Trail Environmental Impact Study, City of Kitchener, Ontario (2011-2012)

Coordinated Ecological Land Classification, breeding bird surveys and wetland delineations for an Environmental Impact Study of a proposed trail joining the Pioneer Park subdivision with the Walter Bean Trail through the Winifred Woods Environmentally

Sensitive Policy Area. The trail traversed lands owned by the City of Kitchener and Grand River Conservation Authority ("GRCA") and included a number of Significant Wildlife Habitats and natural hazard lands. Various trail routes and trail designs were assessed. Undertook negotiations with the GRCA regarding portions of the trail on their lands.

Lake Simcoe Aeropark Environmental Impact Study, Oro-Medonte, Ontario (2008-Present)

Identified impacts to natural heritage features associated with a proposed industrial subdivision located adjacent to the Lake Simcoe Regional Airport. Work involved staking boundaries of natural features with the local Conservation Authority and coordinating a number of sub consultants to conduct detailed vegetation and wildlife inventories, including a study of bird hazards to aviation safety at the airport in relation to habitat areas on the subject lands.

Preliminary Environmental Constraints Analysis of the Proposed YMCA Cedar Glen Camp Expansion and Redevelopment, King Township, Ontario (2010- Ongoing)

The YMCA was interested in preparing a Master Plan for the Cedar Glen camp to plan future expansion and redevelopment of the site. Met with the client to clarify their needs and the scope of work required. Identified all applicable natural heritage policies and identified potential development constraints associated with the Natural Heritage System of the Greenbelt Plan and Natural Linkage policies of the Oak Ridges Moraine Conservation Plan. Identified and recommended future study and work requirements in order to move the development forward.

Environmental Impact Study of the Balzer Creek Trail, Kitchener, Ontario (2009-2010)

An Environmental Impact Study was prepared at the request of the Grand River Conservation Authority ("GRCA") because the proposed trail was located within the GRCA's regulation limit. The EIS considered how the trail would be constructed, where it was to be located and how it would be used in order to assess potential impacts on the adjacent Balzer Creek. During the EIS several Butternut trees, and endangered species, were identified in close proximity to the trail. Discussions were held with the Ministry of Natural Resources to determine how to proceed, including the process under the Endangered Species Act. Negotiations were successful in avoiding the need for a permit based on trail routing.

Humber College Orangeville Campus Environmental Impact Study, Town of Orangeville, Ontario (2006-2008)

Identified natural heritage features, analyzed potential impacts and recommended mitigation measures for the proposed Humber College Orangeville Campus in the Town of Orangeville. Field studies including Ecological Land Classification and amphibian monitoring were conducted in order to determine the significance and sensitivity of environmental features. The analysis included implications of the development on wildlife corridors, valleylands, wetlands and a coldwater stream.

Veteran's Way Residential Subdivision Environmental Impact Study, Town of Orangeville, Ontario (2006-2008)

Identified natural heritage features, analyzed potential impacts and recommended mitigation measures for a proposed residential subdivision and commercial development in the Town of Orangeville. Field studies including Ecological Land Classification and amphibian monitoring were conducted in order to determine the significance and sensitivity of environmental features. The analysis included implications of the development and stormwater management proposal.

Secondary and Master Servicing Plans

Community of Colgan Master Servicing Plan, Township of Adjala-Tosorontio, County of Simcoe, Ontario (2008-Present)

Identified land use and natural heritage policies of relevance to infrastructure planning and recommended measures to incorporate natural heritage protection into the Master Servicing Plan.

Churchville Planning and Heritage Study, City of Brampton, Ontario (2007)

Inventoried existing natural heritage and natural hazard conditions and reviewed land use policies in the City and Regional Official Plans, PPS, Secondary Plan and Subwatershed Study. Developed comprehensive land use guidelines for the Churchville planning area to protect natural heritage features and provide clarity with respect to natural hazard lands.

North West Fergus Secondary Plan Environmental Impact Assessment, Fergus, Ontario (2007)

Identified all natural heritage and hazard land constraints, recommended lands for protection, recreation and trail development as part of the West Fergus Secondary Plan.

Environmental Assessments

Rumble Pond Stormwater Management Pond Retrofits, Schedule B Municipal Class Environmental Assessment, Town of Richmond Hill, Ontario (2010-2011)

Completed an Environmental Assessment to evaluate a number of alternatives associated with upgrades to a stormwater management pond. The preferred alternative included measures to improve passage for Redside Dace, an Endangered species which are known to be present in the area.

Creemore Drainage Project File Report, Schedule B Municipal Class Environmental Assessment, Clearview Township, Ontario (2009-2010)

Prepared an Environmental Assessment to identify and assess alternative solutions to improve drainage and resolve ongoing flooding issues in the Creemore Village Core as well as on lands designated for future development. The preferred solution was identified based on environmental impacts, effectiveness in managing flooding, economics and its consistency with the Official Plan.

GO Transit Hamilton to Niagara Rail Expansion Environmental Assessment, Ontario (2009-Ongoing)

Reviewed Official Plan policies for all municipalities along the proposed rail line route. Identified environmental and land use constraints in areas proposed for new GO transit rail stations as part of the Environmental Assessment for the proposed expansion.

Detroit River International Crossing Individual Environmental Assessment Review, Windsor, Ontario (2008-Ongoing)

Reviewed Natural Heritage background reports and Environmental Assessment documents on behalf of the Walpole Island First Nation ("WIFN") to determine if their interests and rights associated with traditional use of the area were appropriately addressed.

Dissette Street Schedule C Municipal Class Environmental Assessment, Bradford-West Gwillimbury, Ontario (2008-2010)

Reviewed Official Plan policies and Conservation Authority policies with respect to their impact on wetland, floodplain and woodlots being affected by the proposed road widening of 8th Line and Dissette Street, Bradford. Consulted with the Conservation Authority and proposed a compensation strategy to deal with features lost, partially or entirely during construction. Attended a Public Information Centre, summarized public comments associated with land acquisitions, encroachment into a natural area and increased traffic and noise.

GO Transit Georgetown to Kitchener Rail Expansion Environmental Assessment, Ontario (2008-2009)

Reviewed Official Plan policies for all municipalities along the proposed rail line route. Identified environmental and land use constraints in areas proposed for new GO transit train stations and layover sites.

Policy Planning and Strategy Development

Comprehensive Review and Overhaul of Barbados' Groundwater Protection Zoning Policy and System, Barbados (2007-Present)

Reviewed zoning bylaws, land use restrictions and incentive programs designed to protect groundwater resources in four jurisdictions including the Regional Municipality of Waterloo; Miami-Dade County, Florida; the US Virgin Islands; and the State of Western Australia. Analyzed policies for their relevance and applicability to environmental, economic and social conditions in Barbados. Recommended policies, including legal and incentive-based instruments that could be used by Barbados to protect groundwater resources.

Development, Interference with Wetlands and Alterations to Shorelines and Watercourses Regulation Development, London, Ontario (2005-2006)

Assisted with the incorporation of *Ontario Regulation 97/04 – Development, Interference with Wetlands and Alterations to Shorelines and Watercourses* into Upper Thames River Conservation Authority policies and guidelines. Included preparation of a submission for approval of the regulation by the Province of Ontario, public information documents and public consultation materials.

Review and Updates to Ontario’s Low Water Response Program, Peterborough, Ontario (2002-2003)

Coordinated and facilitated a workshop to evaluate the success and challenges associated with the first version of Ontario’s Low Water Response Program. Updated the program document to reflect new policies and clarify protocols. Coordinated posting of the program changes on Ontario’s Environmental Bill of Rights Registry.

Eco-Tourism and Park Planning Strategy, Cerro Blanco Protected Forest, Guayaquil, Ecuador (2001)

Developed a park planning strategy to increase tourism potential for a 6000 ha protected forest while protecting significant natural features and rare species. Identified locations for a new trail systems, butterfly garden, aviary and tourist accommodations as well as areas requiring environmental protection, restoration and enhancement.

NEEGAN BURNSIDE

Profession

Aquatic Resource Specialist

Education

Terrain and Water Resources Technologist, Sir Sandford Fleming College, School of Natural Resources, 1996

Certificates

CISEC-Certified Inspector for Sediment and Erosion Control, Aug 2011

MNR/TRCA Ontario Stream Assessment Protocol (OSAP), June 2010.

OBBN-Ontario Benthos Biomonitoring Network Certification, June 2010

DFO, Ontario Freshwater Mussel Identification Course, 2007

MTO/DFO/MNR Fisheries Protocol, Fisheries Assessment Specialist, Fisheries Contract Specialist (RAQs Certified), 2006

MNR Class 1 Electrofishing Certification and Trainer, 2006

ROM, Ontario Freshwater Fishes Identification Course, 2005

Professional Societies

Ontario Association of Certified Engineering Technicians and Technologists (OACETT)

Employment Record

Aquatic Resource Specialist, R.J. Burnside & Associates Limited (2007-Present)

Aquatic Resources Technologist, AMEC Earth and Environmental, Mississauga, Ontario (2003-2006)

Environmental Technologist, AMEC Earth and Environmental, Vancouver, British Columbia (1998-2003)

Citizenship

Canadian

Languages

English

Christopher Pfohl, C.E.T.

Christopher has a broad range of experience in Canada and internationally, with 13 years of professional experience in Aquatic Resources including environmental assessment, existing condition studies, habitat restoration, environmental monitoring and protection, determination of fish habitat, Species at Risk, hydrology, hydrogeology and contaminated sites. He has extensive knowledge of the *Fisheries Act*, as it pertains to the protection of fish and fish habitat. Christopher is responsible for obtaining permits from various government agencies, environmental impact assessment, environmental and construction monitoring, developing and conducting sampling programs for fisheries and aquatic habitat inventories, and the preparation of technical reports based on project requirements. He has coordinated and conducted numerous sampling programs for fish, amphibians, invertebrates and sediment, surface and ground water. He is responsible for liaison with government agencies, First Nations, large corporations, and stakeholders.

Christopher has undertaken projects for a wide range of clients throughout the energy, development, transportation and mining sectors in local and remote areas of Canada and overseas. This requires the development and coordination of extensive aquatic investigations and includes the management of logistics, field staff and sub-consultants, data analysis, report and proposal preparation.

Christopher is also a former member of the Canadian Fly Fishing Team (2007 to 2010) and has competed in numerous events across North America and internationally.

Biological Resources

Coves ESA Master Plan and Rehabilitation of the East Pond, City of London, London, Ontario (2011-Ongoing)

Mr. Pfohl was subcontracted by North South Environmental to provide aquatic support for development of the Coves ESA Master Plan located in an urban environment. He was responsible for background review, confirmation of existing conditions and input to rehabilitation of the Coves ponds and watercourses as it pertains to aquatic resources. A rehabilitation matrix was developed by Mr. Pfohl to determine the best options for improvements to the aquatic conditions in the Coves ponds and watercourses. A rehabilitation concept and plan has been provided for funding approval.

Bronte Creek Rehabilitation and Natural Channel Design, Trout Unlimited, Lowville, Ontario (2011)

Aquatic Resources Specialist responsible for natural channel design options and prescriptions for areas that have been impacted by erosion, heavy pedestrian use, and areas of channel widening. Christopher conducted spawning surveys for rainbow trout (steelhead) and Chinook salmon to determine critical habitat areas to be protected during construction. Habitat prescriptions included spawning areas, riffle sections, boulder clusters, large woody debris, pool creation, juvenile habitat and retrofit of existing riffle structures. He conducted swim-up counts for steelhead fry and determination of prescription success based on the contractor's rehabilitation works. Trout Unlimited has been overwhelmed with the positive feedback on the construction and design.

Barrier Mitigation for Redside Dace, Don Head West, Town of Richmond Hill, Ontario (2011-Ongoing)

Aquatic Resource Specialist responsible for collection of Endangered Species (Redside dace) based on the conditions of the Endangered Species Act (ESA) permit. Mr. Pfohl provided support during the application for the ESA permit along with the appropriate animal care protocols. He was required to salvage all aquatic life from a work area planned for barrier mitigation under the conditions set-out in the ESA permit. A "rocky ramp" was constructed to mitigate the impassable barrier for fish movement. A Scientific Collectors Report has been submitted to MNR on behalf of the client and the conditions of the ESA permit. Ongoing monitoring for habitat success is required during 2012.

Siloam Pond Natural Channel Design, Mill Run Golf and Country Club, Uxbridge, Ontario (2010-Ongoing)

Mr. Pfohl provided aquatic resource input into the final design of more than 350m of brook trout habitat in Uxbridge, Ontario. The Siloam Pond was taken off-line to reduce thermal impacts to a cold water fishery and provide a constant water source for the golf club. Christopher provided suitable habitat designs for large woody debris, riffle sections and over-wintering habitat in strategic locations along the channel and as part of the compensation required for the DFO Authorization. He was also responsible for obtaining the Scientific Collectors Permit from MNR, fish salvage, construction monitoring, and submission of fish collection records as part of the condition of the MNR permit. Mr. Pfohl will be monitoring the new channel for habitat use, substrate movement and naturalization of the riparian corridor as part of the permit conditions provided in the DFO Authorization.

Colgan Well, Determination of Surface Water Impacts, Township of Adjala-Tosorontio, Colgan, Ontario (2011-Ongoing)

Aquatic Resources Specialist responsible for determination of groundwater areas that may be impacted from a production well located in Colgan, Ontario. Groundwater upwelling and seepage areas were documented to determine potential impacts to receiving watercourses from groundwater extraction and potential effects to the fishery.

Endangered Species Act Approval, King Street Reconstruction, Region of Peel, Bolton, Ontario (2011)

Mr. Pfohl was responsible for acquiring approval from MNR for an outlet to Cold Creek, a tributary of the Humber River. Cold Creek is designated as potential Redside dace habitat and a Letter of Advice (LOA) was obtained from MNR for the construction works associated with an outlet structure to the watercourse. The LOA was provided by MNR based using approved Best Management Practices and Mitigation measures associated with the construction works.

Erosion and Aquatic Assessment, Upper Rouge River and Beaver Creek, Town of Richmond Hill, Ontario (2010-2011)

Aquatic Resources Specialist responsible for erosion and aquatic conditions assessment for 18km of the Upper Rouge River, and Beaver Creek, a tributary of the Rouge River, Richmond Hill. Required to identify areas of erosion that may cause impacts to municipal infrastructure, public and private land. Aquatic conditions were assessed in conjunction with erosion areas that may be improved during future works. Collected information was used to determine a level of potential hazard.

GO Transit Class Environmental Assessment, Group B for the Proposed Rail Expansion from Toronto to Milton, GO Transit, Ontario (2011-Ongoing)

Aquatic Resource Specialist responsible for coordinating existing conditions surveys for all watercourse crossings from Union west to Milton Station. Efforts included site visits to watercourses to document existing and critical fish habitat and determination for potential Fisheries Act Authorizations. Responsible for reporting information under the requirements for Municipal Class Environmental Assessment Projects for the preparation of the Environmental Study Report (ESR).

Environmental Monitoring, Richmond Hill Community Environmental Center, Region of Peel, Richmond Hill, Ontario (2010-2011)

Environmental Monitor responsible for inspecting erosion and sediment controls required for the construction of the Richmond Hill Community Environmental Center. Receiving waters from the site connect to protect Redside dace habitat that is highly sensitive. Stringent monitoring was required during construction along with weekly reporting.

Species at Risk Monitor, Water Treatment and Distribution System, Moose Deer Point First Nations Reserve, MacTier, Ontario (2009-2011)

Species at Risk and Environmental monitor for construction of a water treatment and distribution system along the eastern shore of Georgian Bay. Protected Species at Risk include endangered and threatened turtles and snakes. Required to facilitate and conduct Species at Risk training for First Nations and construction workers based on mandatory requirements from the Environment Canada, Species at Risk permit.

GO Transit Class Environmental Assessment, Group B for the Proposed Rail Expansion from Hamilton to Niagara Falls, GO Transit, Ontario (2010)

Aquatic Resource Specialist responsible for coordinating existing conditions surveys for all watercourse crossings in the Hamilton to Niagara region. Efforts included site visits to watercourses to document existing and critical fish habitat and determination for potential Fisheries Act Authorizations. Responsible for reporting information under the requirements for Municipal Class Environmental Assessment Projects for the preparation of the Environmental Study Report (ESR).

Erosion and Aquatic Assessment, German Mills Creek, Town of Richmond Hill, Ontario (2009-2010)

Aquatic Resources Specialist responsible for erosion and aquatic conditions assessment for 10km of German Mills Creek, a tributary of the East Don River, Richmond Hill. Required to identify areas of erosion that may cause impacts to municipal infrastructure, public and private land. Aquatic conditions were assessed in conjunction with erosion areas that may be improved during future works. Collected information was used to determine a level of potential hazard.

Stream Realignment, Upper Nottawasaga River, Township of Mono, Ontario (2009-2010)

Project Coordinator responsible for stream realignment of 105 linear metres of coldwater habitat in the Upper Nottawasaga River watershed. Project required coordination of contractors, reporting to the Township of Mono and Nottawasaga Valley Conservation Authority and liaison with landowners. Realignment involved creation of suitable habitat for coldwater species (brook trout and migratory rainbow trout) including riffle structures, large woody debris placement, native substrate loading, vegetative mats for undercuts and riparian plantings. Responsible for salvage efforts and compliance with the Department of Fisheries and Oceans (DFO) authorization for the “Harmful alteration, disruption or destruction” (HADD) of fish habitat and future monitoring requirements.

Ribb Dam Supplemental EA, World Bank, Ethiopia (2008-2009)

Project Coordinator/Aquatic Resource Specialist on a World Bank funded project to undertake a series of studies to update the existing EA in compliance with World Bank guidelines. Assisted in the development of Habitat Suitability Curves for Physical Habitat Simulation (PHABSIM) model to determine potential impacts to habitat for African barbs, Nile tilapia, and African catfish of the Ribb River. Studies focused primarily on aquatic and wetland baseline information, potential hydrological effects, and impacts and mitigation measures related to the construction of a large water supply dam.

GO Transit Class Environmental Assessment, Group B for the Proposed Rail Expansion from Georgetown to Kitchener, GO Transit, Ontario (2008-2009)

Aquatic Resource Specialist responsible for coordinating existing conditions surveys for over 50 watercourse crossings in the Credit Valley and Grand River watersheds. Efforts included site visits to watercourses to document existing and critical fish habitat and determination for potential Fisheries Act Authorizations. Responsible for reporting information under the requirements for Municipal Class Environmental Assessment Projects for the preparation of the Environmental Study Report (ESR).

Unexploded Ordnance Clearing, Species at Risk Biologist, XTEC, Former Camp Ipperwash, Ipperwash, Ontario (2007-2009)

Biologist Team member responsible for adherence to the Environment Canada (EC) Species at Risk Permit required for vegetation clearing on the Former Camp Ipperwash, Military Training Center. EC issued a permit under the Species at Risk Act to protect threatened and endangered species known to exist on site based on previous observations during biological inventories required under the Canadian Environmental Assessment Act. Vegetation clearing was required to conduct electromagnetic (EM) surveys to determine unexploded ordnance locations. The Biologist Team was responsible for identification and avoidance of Federal and Provincial Species at Risk during site operations.

Fixed Link Project CEAA Screening, Chippewas of Georgina Island First Nation, Sutton West, Ontario (2007-2008)

Responsible for the preparation of an aquatic existing conditions report for the study area and made recommendations on a preferred alternative route based on potential effects to the aquatic environment. Information prepared was included in the Preliminary Evaluation of Engineering and Environmental Alternatives Study and CEAA Screening Report for the proposed Fixed Link. The proposed Fixed Link is to be a reliable all-weather transportation (vehicle and passenger) link from Georgina Island to the mainland.

Water Intake Repair, CEAA Screening, Six Nations, Ontario (2007-2008)

Preparation of a Letter of Intent (LOI) to the Department of Fisheries and Oceans (DFO) for work within hazard lands to repair a communal water intake structure. The intake structure, which is built into the bank of the Grand River, is experiencing erosion around the sheet pile facing walls, as well as movement of the sheet pile walls. The repair must alleviate the sheet pile movement, and erosion around the structure.

Natural Gas Pipeline Construction, Senior Environmental Monitor, Union Gas, Strathroy, Ontario (2007)

Lead Environmental Monitor reporting to Union Gas for the construction of an 18km, 48" Natural Gas pipeline loop from Strathroy to Lobo Station. Responsible for all environmental aspects of the project including; protection of Cultural resource sites, fish and wildlife, sediment and erosion control, spill clean-up, and selection of discharge sites for dewatering applications. Also responsible for maintaining adherence to Water Take Permits (MOE), Protection of Fish and Fish Habitat (DFO), Flood/Fill Regulation for St. Clair Regional Conservation Authority (SCRCA), and the reporting requirements based on the conditions of each permit. A total of seven watercourse crossings were completed in the dry, following proper mitigation measures required for sediment and erosion control and fish and wildlife salvage. Also responsible for bank stabilization, riparian area planting, and pipeline cover project on the adjacent 28" pipeline, including associated meetings with DFO and SCRCA.

Peer Review of MAQ Quarry Natural Environment Report, Township of Grey Highlands, Ontario (June 2008-Ongoing)

Mr. Pfohl provided a peer review of aquatic existing conditions report to determine if potential impacts to aquatic life was determined and appropriately addressed. He provided a review of the field program for suitable sampling methods and determination of fish habitat. Significant environmental resources were present on, and adjacent to, the proposed below- water table quarry, including a provincially significant wetland, habitat of endangered species and other provincially-rare species. Proponents challenged the identification of Significant Wildlife Habitat and Significant Woodlands on the site. The proposal also created debate over the protection of environmental resources and whether the provision of a supply of aggregate material close to markets should take precedence. Proponents have yet to address outstanding comments.

Fish Habitat Assessments, Road Crossings, Various Clients across Ontario (2007-Ongoing)

Responsible for collecting and mapping fish habitat information for over 70 various road crossing and highway twinning projects in Ontario. Habitat Assessments (MTO Protocol 2006) were completed as part of the information requirements based on the Environmental Assessment Act. Information has been presented at Public Information Centers, in Environmental Study Reports and various Environmental Assessment documents for regulatory review.

Municipal Class Environmental Assessment, Schedule C for the Dissette Street Widening, Town of Bradford West Gwillimbury, Ontario (2007-2010)

Aquatic Resource Specialist responsible for coordinating the aquatic existing conditions survey to determine potential for fish habitat as defined under the Fisheries Act for future road widening. Consultation with the Lake Simcoe Region Conservation Authority (LSRCA) to develop a program which included sampling of local watercourses, habitat mapping (MTO Protocol 2006) and background review for reporting EA requirements. Submission of a Letter of Intent (LOI) to LSRCA to provide watercourse improvements in conjunction with mitigation and monitoring efforts to avoid a HADD to fish habitat was facilitated.

Municipal Class Environmental Assessment, Brook Trout Spawning Surveys, Credit River, Orangeville Waste Water Treatment Plant Expansion, Town of Orangeville, Ontario (2007-Ongoing)

Aquatic Resources Specialist responsible for conducting Brook trout spawning surveys with the Credit Valley Conservation Authority (CVC) on the upper Credit River. Spawning Surveys were required to determine presence/absence of critical habitat for Brook trout in sections of the Credit River downstream from the Orangeville Waste Water Treatment Plant. Concerns from CVC on the proposed expansion of the plant triggered more intense investigations of the Credit River immediately downstream of the outfall.

Various Wind Energy Projects, Amphibian Monitoring, Confidential Clients, Southern Ontario (2007-Ongoing)

Responsible for developing and conducting Amphibian Monitoring programs for spring breeding surveys. Breeding surveys were developed based on the Marsh Monitoring program for Ontario. Survey results were reported for each study area and included in the Provincial and Federal Environmental Assessment documents.

Victor Diamond EIA/Baseline Study, Annual Fisheries Surveys, DeBeers Canada, Attawapiskat, Ontario (2004-2006)

Field project manager responsible for baseline studies and annual fisheries surveys to quantify Whitefish and Brook trout abundance in potential groundwater drawdown areas for a proposed diamond mine in northern Ontario. Required to obtain

Fish and Wildlife Act "Scientific Collection Permits" and Public Lands Act "Work Permits" from Ministry of Natural Resources (MNR) to conduct annual surveys. Construction of a full span fish fence to determine fall migratory species and abundance in the Nayshkootayow River. Trained First Nations field staff to monitor water quality and fish abundance in potential groundwater drawdown areas. Obtained "Permit to Take Water" from MOE for waterway crossings and provided environmental monitoring during construction. Collection of tissue samples analyzed for the "Sportfish Eating Guide of Ontario" and future reference for Brook trout DNA. Collection of aging structures (otilith and scale) for Lake whitefish, Lake ciscoe and Brook trout. Initiated the first round of benthic collections and water sampling for the Environmental Effects Monitoring (EEM) program based on specific discharge locations. Information collected from baseline studies was included in the EIA and the Comprehensive Study Report for Government Agencies, Public, and First Nations review.

Aquatic Baseline Study, Howell's River, Lab Mag Services, Schefferville, Quebec (2006)

Field project manager responsible for baseline aquatic studies pertaining to the construction of an iron ore mine in northern Labrador. Responsible for locating last remaining stocks of *Ounaniche* (land locked Atlantic salmon) on the Howell's River system for a satellite based telemetry program. Conducted morphometrics, anaesthesia and surgical placement of transmitters in adult *Ounaniche*. Responsible for field crew logistics, aquatic data collection, health and safety in remote locations, and client liaison.

Redhill Creek By-Pass, Environmental Monitor, UMA and Dufferin Construction, City of Hamilton, Ontario (2006)

Environmental Monitor responsible for compliance to the Environmental Protection and Sediment and Erosion Control Plan related to highway construction works. Required to submit daily environmental monitoring reports to determine non-compliance issues related to contractor performance. Protection of significant habitat adjacent to project construction limits. MTO project number.

Goreway Road Expansion, Fisheries Assessment, Brampton, Ontario (2006)

Responsible for collecting field data for fish habitat assessments of approximately 7 water crossings along the proposed ROW using the new MTO/DFO/MNR protocol for future expansion of Goreway Road.

Lakes and Rivers Improvement Act (LRIA), Permit Application for Dam Construction, Confidential Client, Uxbridge Township, Ontario (2006)

Project coordinator responsible for the submission of a LRIA permit application to construct a dam on a tributary of Duffins creek. Required to coordinate and fulfill the information requirements set out in the LRIA guidelines for MNR permit applications.

Hwy 410 Extension, Fisheries Assessment, Brampton, Ontario (2005)

Responsible for conducting fish habitat assessments and fish inventories for a section of Etobicoke Creek for the Hwy 410 extension. The aquatic ecosystems inventory and assessment was carried out to meet the established criteria set forth by the Ontario Ministry of Transportation (MTO), "*Environmental Reference for Highway Design*", November 2002 (ERD).

Hwy 5 West of Hwy 6 and East of Hwy 8, Preliminary Design, Hamilton, Ontario (2005)

Aquatic ecosystem and existing conditions assessment for watercourses along Hwy 5, West of Hwy 6 and East of Hwy 8. The aquatic ecosystems inventory and assessment was carried out to meet the established criteria set forth by the Ontario Ministry of Transportation (MTO), "Environmental Reference for Highway Design", November 2002 (ERD).

GO Transit Rail Line Expansion, URS Corporation, Hamilton to Burlington, Ontario (2005)

Responsible for determining all waterway crossings and potential impacts to fish habitat associated with the expansion of an existing rail line from Hamilton to Burlington.

Parry Sound Power Generation, Seguin River Water Management Plan, Fisheries Impacts Associated with Historical Dam Manipulation, Parry Sound, Ontario (2005)

Responsible for determining potential fisheries habitat impacts for the Seguin River System based on historical information on dam manipulation provided by Parry Sound Power Generation.

Environmental/Construction Monitoring, Montcalm Mine, Falcon Bridge, Timmins, Ontario (2005)

Environmental monitor responsible for environmental and construction monitoring for the installation of a pipeline diffuser in the Groundhog river, Timmins, ON. Responsible for contractor supervision, fish and wildlife monitoring, water quality monitoring and the implementation of the Sediment and Erosion Control Plan.

Walleye Spawning Survey, Parry Sound Power Generation, Parry Sound, Ontario (2005)

Responsible for enumeration of spawning Walleye *(Sander vitreus vitreus)* in the Seguin River downstream of the Parry Sound Power Generation, Hydroelectric Dam in Parry Sound. Information collected was presented to stakeholders and public interest groups in conjunction with the Ministry of Natural Resources (MNR) and Department of Fisheries and Oceans (DFO).

Habitat Suitability for Walleye, Three Nations Lake, Pamour Mine Expansion Project, Porcupine Joint Venture, Timmins, Ontario (2004)

Conducted an extensive literature review of Suitable Habitat for Walleye *(Sander vitreus vitreus)*. The information was used to determine suitable habitat, substrate, depths, and spawning shoal design for a compensation plan for Three Nations Lake. The lake was dyked to provide access to subsurface gold deposits and a new section of the lake was flooded to provide a “no net loss” of fish habitat.

Site Reconnaissance of the Pembina Pipeline Oil Spill, Pine River, District of Chetwynd, British Columbia (2000-2003)

Field project manager responsible for coordinating and conducting the 2000-2002 site reconnaissance of the Pine River Oil Spill, the largest oil spill to a fresh water environment in North America which occurred on August 1, 2000. Responsible for coordinating and conducting a fingerprinting program with BC Research to determine the original source of hydrocarbons present in the Pine River. Accessed depositional areas along the river using a canoe, and video documented sampling locations for future legal evidence. Reviewed analytical data for report preparation and submission to regulatory agencies. Information regarding observations, sampling techniques, and analytical data were presented to the District council members, residents of Chetwynd, and Government Officials at public information sessions.

Kokanee Stranding Assessment, BC Hydro, Duncan River, Nelson, British Columbia (2003)

Field team member responsible for a Kokanee stranding assessment during a reduction in water flows at a BC Hydro generating dam on the Duncan River in Nelson, BC. Stranded fish were captured using electro-fishing methods for identification and enumeration. Data collected will be used to determine effects on fish during future flow reductions.

Environmental Monitoring and Fish Salvage, Stanley Park Seawall Undermining Repair, Vancouver Board of Parks and Recreation, Vancouver, British Columbia (2003)

Environmental monitor required to inspect construction activities including shotcrete applications in a marine environment for the Stanley Park Seawall. Responsible for obtaining specific fish collection permits and approval of work permit extensions from the DFO on behalf of the client. Selected tidal pools were bailed and marine life collected and transported to the Burrard Inlet for release prior to the preparation of undermined locations. An environmental monitoring report including fish collection details was submitted to the DFO for review.

Environmental Protection Plan, Stanley Park Seawall Undermining Repair, Vancouver Board of Parks and Recreation, Vancouver, British Columbia (2003)

Responsible for the preparation of an Environmental Protection Plan that was reviewed by DFO prior to gaining approval for the repair works along the Stanley Park Seawall.

Environmental Monitoring, BC Hydro Substation Construction, Alltec Corporation, Langley, British Columbia (2003)

Environmental monitor responsible for environmental and construction monitoring for a BC Hydro Substation adjacent to a Restrictive Covenant zone. Responsible for water quality testing and sampling, client liaison, and reporting any infractions to the provincial regulations. A final monitoring report was sent to the Ministry of Water Land and Air Protection, Habitat Protection Branch for final review.

Fisheries Habitat Overview, Aurora South, Syncrude, Fort MacMurray, Alberta (2003)

Responsible for conducting a reach break analysis for the Regional Study Area (RSA) selected for future Oil Sands mining in north-eastern Alberta. Potential fisheries and wildlife values have been determined and documented using background information and an aerial photography of the RSA. Information gathered was used for the Environmental Impact Assessment (EIA) for future development.

Natural Gas Well Feasibility Study, Rosetta Exploration, Hudson’s Hope, British Columbia (2002)

Project manager and coordinator required to determine the feasibility of an exploration well for natural gas. Site investigations were conducted in a remote location in north-eastern BC to determine if previous occupants have impacted an area used for previous oil and gas exploration. Information collected was used to determine future impacts on the local ecology. Information presented to the client was reviewed by the Oil and Gas Commission prior to gaining permits for future exploration.

Environmental Effects Monitoring, Equity Mine, Placer Dome, Houston, British Columbia (2002)

Responsible for conducting and coordinating fieldwork and an Environmental Effects Monitoring (EEM) program for Silver mine in northern BC. A release of tailings effluent into the local watershed from previous spring runoff was investigated using biological indicators and water and sediment quality. Installation of periphyton blocks and invertebrate baskets used were used to monitor downstream conditions. A sediment-sampling program in a lake near the mine was also incorporated into the effects monitoring program to determine concentrations and toxicity to invertebrates from possible metals contamination.

Environmental Protection Plan/Environmental Monitoring for a Culvert Removal and Habitat Restoration, Innovative Housing, Surrey, British Columbia (2002)

Responsible for final submission of the Environmental Protection Plan to the Ministry of Water Land and Air Protection, Habitat Protection Section, for review and approval for “Working in and about a stream”. Christopher was the on-site Environmental monitor for the construction work related to the removal of a culvert to daylight an existing creek and substrate placement to provide habitat restoration. Responsible for documenting construction activities, water quality monitoring, client liaison and final reporting required by Ministry of Water Land and Air Protection.

2000 Follow-up Studies to the Stewart Creek Oil Spill, Confidential Client, Stewart Creek, British Columbia (2000)

Responsible for conducting sediment and benthic invertebrate sampling program at seven sites in the fall of 2000, five years after a crude oil spill in the Stewart Creek watershed. The project involved comparisons of the hydrocarbon and benthic invertebrate data collected in 1995, 1997, and 2000.

Fish Collection and Sediment Sampling, Translink, Richmond, British Columbia (2000)

Conducted fish collection and sediment sampling to determine and compare Polycyclic Aromatic Hydrocarbons (PAHs) in fish tissue and sediment samples. Analytical results of the sediment were compared to the fish tissue and the consumption levels presented in the “Guide to Eating Sportfish, 2001”, Ministry of Environment, Ontario.

Biological Inventory

Christopher has been certified by MNR/TRCA under the Ontario Stream Assessment Protocol (OSAP) with addition certification by the Ontario Benthos Biomonitoring Network (OBBN). He has completed the Ontario Fishes Identification Course presented by the Royal Ontario Museum, and is certified by MNR as a Class 1 Electrofishing Crew Leader and trainer. Christopher has been certified under the MTO/DFO/MNR Fisheries Protocol, Fisheries Assessment Specialist, Fisheries Contract Specialist presented by MTO/DFO/MNR in November 2006, and is RAQS certified by MTO. Christopher has completed the Ontario Freshwater Mussel Identification Workshop (DFO), the Marsh Monitoring protocol for Amphibian Breeding surveys and egg mass surveys for breeding salamanders (Species at Risk). He has conducted numerous aquatic inventories in Ontario, Labrador and British Columbia, in local watersheds to very remote areas in northern climates.

Health and Safety

Christopher has been a Health and Safety Committee member and employee representative for the last 6 years and has completed numerous Health and Safety Plans for a variety of projects.

NEEGAN BURNSIDE

Profession

Chief Executive Officer

Education

Civil Engineering, Queen's University, 1971

Professional Societies

Association of Professional Engineers of Ontario

Member of the Wahta Mohawk Territory

Miziwe Biik Development Corporation – Volunteer Member of the Board of Directors

Employment Record

Chief Executive Officer, Neegan Burnside Ltd. (2004-Present)

Vice-President Aboriginal Business Development, Neegan Burnside Ltd. (2003-2004)

President, Canadian Aboriginal Science and Engineering Association (1993-Present)

Special Projects Officer, Canada Executive Interchange to Assembly to First Nations & Chiefs of Ontario (1994-1997)

Senior Executive Director Technical Services, INAC (1974-1997), Senior Engineer Rideau Canal (1973); Project Development (1969-1973) Government of Canada

Citizenship

Canadian

Languages

English

Mervin J. Dewasha, P.Eng.

Mervin Dewasha, P. Eng., is the Chief Executive Officer and majority owner of Neegan Burnside Ltd. He is also a major shareholder in R.J. Burnside & Associates Limited and Senior V.P. Aboriginal Market Sector for Burnside.

Merv is a member of the Wahta Mohawk First Nation and has served with Indian and Northern Affairs Canada in various capacities including Director of Engineering and Architecture and Contracts in two Regions. Merv worked on the Executive Interchange to the Assembly of First Nations and Chiefs of Ontario. His involvement included accessing capital for First Nation housing and infrastructure and financing for Aboriginal business development.

He has over 35 years experience working with First Nations in project management, operations and maintenance and senior management. He has been a driving force in improving the quality of services, capacity building and transferring technical services to First Nation control. He has also been a leader encouraging Aboriginal youth to pursue careers in science and engineering and incorporating an Aboriginal Employment Strategy within the company.

Merv has developed positive working relationships in Federal Government, Aboriginal Organizations and the Private Sector. He has contributed to finding creative solutions to barriers and implementing change. Merv has also been a leader in native human resources, capacity development and careers in technical areas. In addition, he has excellent skills in public consultation and presentations and the ability to explain technical matters for understanding by the general public.

Mervin has received widespread recognition, including numerous awards due to his exceptional contribution to Aboriginal education in science and engineering and Canada. He was recognized in March 2009 as a recipient for the National Aboriginal Achievement Award. His companies are leaders in demonstrating success of the Federal Government Policy Strategy on Aboriginal Procurement (PSAB).

Neegan Burnside and its sister company, Burnside, have been working with First Nations since 1970. Neegan Burnside continues to grow under the leadership of Merv, who became CEO of Neegan Burnside Ltd. in 2005. The aboriginal business has had an annual growth rate of 16% during this period. Neegan Burnside has conducted over 1,200 projects across all provinces and territories and served over 200 First Nation communities during the past 10 years. Projects have varied in range from $ 5,000 to over $ 2.5 million. The firm has worked for clients such as Independent First Nations, INAC, and private sector industry. Merv is also Director of Nuna Burnside Engineering & Environmental Ltd., which provides engineering and environmental services to Nunavut, and has overall responsibility for projects totalling over $7 million.

Founder and President, Canadian Aboriginal Science and Engineering Association (CASEA), Toronto, Ontario (1994-Ongoing)

Mr. Dewasha is founder and President of the Canadian Aboriginal Science and Engineering Association (CASEA). CASEA is a non-profit organization, which seeks to significantly increase the number of Aboriginal scientists and engineers in Canada and to develop technologically informed leaders within the Aboriginal communities. The primary event is the National Aboriginal Career Symposium.

The objective of CASEA is to increase the opportunities for Aboriginal youth to participate and excel in science and engineering careers through an Aboriginal Role Model Program, Science Camps, Shad Valley Program, Pre-University Science Camps, Teachers Instruction Programs, Career Fairs, College Chapters and Employment Opportunity Programs.

Participant, Professional Engineers of Ontario, Equity and Diversity Committee (2004)

PEO has established an Equity and Diversity Committee (EDC) to “recommend an action plan to integrate equity and diversity values and principles into the general policy and business operations of Professional Engineers Ontario (PEO)”.

Corporate Services and Facility Management Program of Health Canada – Transfer to First Nation Control, Ontario Chiefs in Assembly to the First Nation, Toronto and Ottawa, Ontario (1997-2002)

Appointed by the Ontario Chiefs in Assembly to the First Nation team, Merv developed and negotiated the transfer to First Nation control of the Corporate Services and Facility Management Program of Health Canada, Ontario Region, a five-year agreement worth approximately $38 Million. The agreement included capacity building and employment for 42 positions to be filled by aboriginal people. The program was terminated by Health Canada during the Treasury Board approval stage.

There are three major components to his career: Government of Canada, First Nation Organizations and Aboriginal Community Service.

Executive Interchange, Assembly of First Nations and Chiefs of Ontario, Toronto, Ontario (1992-1997)

As Executive Interchange to the Assembly of First Nations and Chiefs of Ontario, Merv used his extensive experience with capital programs and Aboriginal communities to create innovative change. His main involvement and initiatives are, National Aboriginal Housing Task Force, National Aboriginal Financing Study providing Access to Capital for Housing and Infrastructure for First Nations, Financing and Construction of the Kasabonika Lake First Nation School, Financing for Aboriginal Business Development, and First Nation funding agreements.

First Nation Team, Corporate Services and Facility Management Program of Health Canada, Ontario Region – Transfer to First Nation Control, Ottawa and Toronto, Ontario (1996)

Mr. Dewasha was appointed by the Chiefs in Assembly to the First Nation Team to develop and negotiate the transfer to First Nation control of the Corporate Services and Facility Management Program of Health Canada, Ontario Region. This program was approximately $38 Million over five years. The transfer includes the capacity building of 42 positions to be filled by Natives over the next three years. The program was terminated by Health Canada during the Treasury Board approval.

Participant, United Nations Conference on Human Settlements, Habitat II, Istanbul, Turkey (1996)

Honourable Diane Marleau, Minister of Public Works and Government Services extended an invitation to Mr. Dewasha to participate in the United Nations Conference on Human Settlements, Habitat II, as part of the Canadian Delegation. He successfully negotiated Indigenous clauses into the Conference Declaration.

Special Project Officer to Gordon Peters, Ontario Regional Chief, Assembly of First Nations, Toronto, Ontario (1994)

Mr. Dewasha’s secondment agreement was renewed and he became a special project officer to Gordon Peters, Ontario Regional Chief. Mr. Dewasha worked with the Kasabonika Lake First Nation Project Team to develop a $6M financing agreement and constructed the community school six years ahead of the planned schedule. This loan was the first loan developed by a First Nation in Canada without a government guarantee.

Assembly of First Nations, Toronto and Ottawa, Ontario (1992)

Mr. Dewasha was requested by the Chief of Staff of the Assembly of First Nations to accept a secondment to the AFN. During this time, he was asked to review the lack of economic impact on First Nations by the large capital program. This resulted in two initiatives: the formation of the Canadian Aboriginal Science and Engineering Association and a concept paper for the First Nation Bank of Canada.

Indian and Inuit Recruitment Development Program, Government of Canada, Ottawa, Ontario (1969-1984)

Mervin J. Dewasha began his career as one of the first aboriginal students in the Indian, Inuit Recruitment Development program in 1969. He began in project planning and project management and had 15 years in Senior Management. Mr. Dewasha played a significant role in devolution of programs to First Nation organizations. He contributed to change by: developing the first guidelines to transfer capital projects to First Nation control; developed the tribal Council Technical Services concept; developed the Native Advisory Council to the Regional Director Ontario Region Indian Affairs' recruited and hired native students and graduates; worked with the Ontario Indian Housing Council to develop the first Indian Housing Building Code and the training of native housing inspectors; was involved with the development and implementation of the "Technology Transfer Strategy to First Nations".

AWARDS

2010 CCAB Aboriginal Business Hall of Fame Award (ABHF) in recognition and celebration of his accomplishments as an individual business leader and for his contributions to sustainable economic development for Aboriginal communities.

2009 Ontario Medal for Good Citizenship, Mervin Dewasha for his tireless work advocating Native access to education.

2009 National Aboriginal Achievement Awards, Technology & Trades, in recognition of career achievement as an Aboriginal professional and building self-esteem and pride as well as providing a valuable role model for Aboriginal youth.

2006 Professional Engineers Ontario "Citizenship Award" for his dedication in "issues of native access to the engineering profession and tireless work within the aboriginal community to promote engineering and science as career choices".

2002 Indian and Northern Affairs Canada, Deputy Ministers Award "Circle of Excellence Award" in recognition of his management and dedication for the success of the October 2001 National Aboriginal Career Symposium.

2001 Bill Hanson Award (2001) - IANE, Interprovincial Association on Native Employment; for his "outstanding contribution to the employment of Aboriginal Peoples".

1995 Deputy Minister's Public Works Government Services Canada, Award of Commendation in recognition of his work with Aboriginal youth and communities in the field of science.

1993 Canada 125th Anniversary Medal for his work and assistance to Aboriginal communities and his continued support to Aboriginal communities through volunteer projects.

Joy Rutherford, B.E.S., P.Geo., QP_{ESA}

Profession

Hydrogeologist

Education

Bachelor of Environmental Studies, University of Waterloo 1983

Professional Societies

Association of Professional Geoscientist of Ontario

International Association of Hydrogeologist

Employment Record

Hydrogeologist, R.J. Burnside & Associates Limited (2006-Present)

Partner and Senior Hydrogeologist, Duncan & Rutherford Environmental (1994-2006)

Dairy Herd Management, Fairlaine Farms (1989-1994)

Progressing from Field Technician to Project Manager, Morrison Beatty Limited (1982-1989)

Assistant Hydrogeologist, Co-op workterms at Ontario Ministry of Environment and North Grey Region Conservation Authority (1980-1982)

Citizenship

Canadian

Languages

English

Ms. Rutherford is a professional geoscientist who has specialized in hydrogeology for over 20 years. She has worked with both public and private clients in groundwater assessment, management and protection. Clients have included municipalities, builders and developers, school boards, conservation authorities, contractors, farmers, crop advisors, and aggregate producers.

Throughout her career, Joy has completed a variety of geological and hydrogeological investigations. In recent years she has been involved in projects relating to landfill assessments and monitoring, rural and urban development, water supply and on-site sewage disposal, wetland impact evaluations, aggregate resources and peer review.

Joy has worked on all aspects of consulting projects, from the field to project management. She has been responsible for project scheduling and budgeting, field program design and completion, contractor selection and supervision, liaison with regulatory agencies, public meetings and open houses.

Landfill Hydrogeology

Joy has been involved in numerous municipal and private landfill projects over the years, including assessing site geology and hydrogeology; designing site instrumentation, monitoring programs and contingency plans; providing hydrogeological support for engineering designs; and investigating off-site impacts.

Off-Site Contamination Investigation and Monitoring, Municipality of Central Huron, Huron County, Ontario (2008-Ongoing)

Assessed extent of a chloride plume from old tannery waste. Investigation included evaluating groundwater to surface water interaction in a wetland and potential impacts to the wetland and an adjacent Municipal Drain.

Off-Site Contamination Contingency Plan Implementation, Township of Ashfield-Colborne-Wawanosh, Huron County, Ontario (2009-Ongoing)

Monitoring of small rural landfill indicated movement of chloride off-site below a large wetland. Work with Township and MOE to find resolution of Reasonable Use exceedance.

Hydrogeological Assessment and Monitoring Program Design, Blanshard and Downie Landfills, Township of Perth South, Perth County, Ontario (2007-Ongoing)

Completed initial hydrogeological assessment for two municipal landfills not previously monitored. Designed monitoring program and installed instrumentation at the sites. Provided groundwater impact input into Strategic Waste Planning and, based on the outcome of the planning, provided input into a Design and Operations Plan for the Blanshard Landfill and a closure plan for the Downie Landfill.

Hydrogeological Assessment, Morris Landfill, Municipality of Morris-Turnberry, Huron County, Ontario (2009-2011)

Completed a two phase hydrogeological assessment. The first phase was to support an application to MOE to temporarily close the exiting fill area and move to a new fill area on the site. The second assessment was used to determine how much of the site could be safely developed in the future using natural attenuation. The project included presentations to council and incorporating input from council.

Hydrogeological Input for D&O Plan, Salford Landfill, Oxford County, Ontario (2011)

Reviewed current geological and hydrogeological conceptual site model, current site monitoring program and contingency plans for a new Design and Operations Plan for an existing municipal landfill.

Hydrogeological Assessment, Ashfield Landfill, Township of Ashfield-Colborne-Wawanosh, Huron County, Ontario (2010)

Hydrogeological assessment to support a new Design and Operations Plan for an existing landfill. The new plan allowed for the use of the full theoretical site capacity. The hydrogeology study was required to show that the new plan would not cause unacceptable impacts on groundwater and surface water. The project included public consultation through local open house presentations.

Peer Review, Mohawks of the Bay of Quinte, Greater Napanee, Lennox and Addington County, Ontario (2010)

Reviewed the Site Conceptual Model for the existing Richmond Landfill and reported findings to client. Participate in a group presentation to the Minister of the Environment and senior ministry staff.

Groundwater Investigation, Six Nations Active Landfill, Six Nations of the Grand River, Brant County, Ontario (2009-2010)

Hydrogeological study for an existing landfill: design and install monitoring network, assess site attenuation and develop long term monitoring program.

Landfill Monitoring and MOE Compliance Reporting

Joy is currently responsible for the compliance monitoring and annual reporting for ten landfill sites in Southern Ontario. Reports are completed to the Ontario Ministry of the Environment 2010 Monitoring and Reporting Technical Guidelines.

Landfill Monitoring, Ashfield, West Wawanosh and Old Ashfield Landfills, Township of Ashfield-Colborne-Wawanosh, Huron County, Ontario (2008-Ongoing)

Monitoring and annual reporting for three municipal landfills.

Landfill Monitoring, Wingham and East Wawanosh Landfills, Township of North Huron, Huron County, Ontario (2008-Ongoing)

Monitoring and annual reporting for two municipal landfills.

Landfill Monitoring, Howick Landfill, Township of Howick, Huron County, Ontario (2008-Ongoing)

Monitoring and annual reporting for a municipal landfill.

Landfill Monitoring, Blyth-Hullett Landfill, Municipality of Central Huron, Huron County, Ontario (2008-Ongoing)

Monitoring and annual reporting for a municipal landfill.

Landfill Monitoring, Morris Landfill, Municipality of Morris-Turnberry, Huron County, Ontario (2008-Ongoing)

Monitoring and annual reporting for a municipal landfill.

Landfill Monitoring, Blanshard and Downie Landfill, Township of South Perth, Perth County, Ontario (2007-Ongoing)

Monitoring and annual reporting for two municipal landfills.

Monitoring Instrumentation, Various Landfills in Bruce and Huron Counties, Ontario (2004-2006)

Supervised installation of monitoring wells and gas probes at municipal landfills including; Wingham, East Wawanosh, Ashfield, West Wawanosh, Morris, Howick, Blyth-Hullett, Huron, and Kinloss.

Landfill Monitoring, Mid-Huron Landfill, Goderich Township, Ontario (1998-2000)

Groundwater and surface water monitoring at a municipal landfill near Holmesville.

Landfill Monitoring, Various Municipal Landfills, Ontario (1995-1996)

Groundwater and surface water monitoring at landfills in Port Elgin, Markdale, Mono Township, Melancthon Township, and East Wawanosh Township.

Landfill Instrumentation and Monitoring, Various Municipal and Private Landfills, Ontario (1982-1989)

Groundwater and surface water compliance monitoring at numerous landfills including Warwick, West Nissouri, Markdale, Port Elgin, Mississauga (flyash), East Wawanosh Township, Sturgeon Falls, and Niagara Falls.

Rural Development

Presentation to the Huron-Perth Association of Realtors, Stratford, Ontario (2011)

Presenter at the Burnside "Environmental Issues and Real Estate Transactions" Course. Topics covered included

Nitrate Impact Assessment, Grafton Heights Subdivision, Township of Alnwick/Haldimand, Northumberland County, Ontario (2012)

Nitrate impact assessment to determine maximum number of lots for a proposed residential development with on-site sewage treatment.

Nitrate Impact Assessment, Mary Street, Municipality of Morris-Turnberry, Huron County, Ontario (2011)

Nitrate impact assessment to determine nitrate concentration at lot line for a three lot severance in Plan 410.

Geology and Hydrogeology Evaluation, Capital Planning Assessment, Eabametoong First Nation, Ontario (2011)

Review field investigation data provided by others to assess suitability of soil, depth to bedrock and depth to water table for a proposed residential development area.

Preliminary Nitrate Impact Assessment, Port Albert, Township of Ashfield-Colborne-Wawanosh, Huron County, Ontario (2011)

Preliminary nitrate impact assessment to determine maximum number of lots that could be developed for residences with on-site sewage treatment.

Nitrate Assessment, West Street, Plan 410, Municipality of Morris-Turnberry, Huron County, Ontario (2009 & 2011)

Nitrate impact assessment to determine nitrate concentration at lot line for a proposed rural residence.

Soil and Nitrate Assessment, Grainger Development, Municipality of Bluewater, Huron County, Ontario (2007-2008)

Assessment of the nitrate impact on local groundwater for a proposed 15 lot rural residential development. Also identified soils for preliminary on-site sewage bed design to assess lot sizing.

Nitrate Impact Assessment, J. Moffat, Township of North Huron, Huron County, Ontario (2007-2008)

Assessment of the nitrate impact from a proposed lot severance with a new on-site sewage system on local groundwater and surface water.

Impact Assessment, Ancaster Agricultural Society, Hamilton, Ontario (2007)

Assessment of phosphorous and nitrate impact of a proposed on-site sewage system on a surface water channel.

Sewage Disposal Suitability Assessment, Soaring Eagle Enterprises, Municipality of Kincardine, Bruce County, Ontario (2007)

Assessment of the nitrate impact on local groundwater for a proposed 12 lot rural residential development. Identified soils for on-site sewage bed design.

Nitrate Impact Assessment, D. Campbell, Township of Morris-Turnberry, Huron County, Ontario (2007)

Assessment of the nitrate impact from a proposed on-site sewage system in Plan 410 (Lower Town).

Nitrate Impact Assessment, Driftwood Beach Park, Howick Township, Huron County, Ontario (2006)

.Assessment of the nitrate impact of a new on-site sewage system on local groundwater supplies and adjacent in-land lake (Lakelet). New system to service campground expansion.

Jurisdictional Review, MOE Procedure D-5-4, Ministry of the Environment (2006)

Conducted review of alternative procedures for assessing the impact of nitrates from residential developments serviced by on-site sewage systems. Reviewed procedures primarily in Canada and the United States.

Nitrate Impact Assessment, Woodland Links Golf Course, Municipality of Central Huron, Ontario (1999-2002)

Completed a reasonable use assessment for the clubhouse on-site sewage system. Conducted the nitrate monitoring program.

Nitrate Impact and Sewage Disposal Assessment, J. Dennis, Township of Turnberry, Huron County, Ontario (1998-1999)

Assessed soils for on-site sewage systems and conducted a groundwater quality impact study for a proposed 5 lot residential subdivision in Plan 410 (Lower Town).

Nitrate Impact and Sewage Disposal Assessment, J. Beldman, Township of East Wawanosh, Huron County, Ontario (1997-1999)

Assessed soils for on-site sewage systems and conducted a groundwater quality impact study for a proposed ten lot residential subdivision.

Groundwater Resources

Joy has been involved in numerous studies to evaluate existing groundwater resources. These projects have consisted of baseline groundwater inventories and mapping, rural water well surveys, and groundwater availability studies. The studies were done for municipal water supplies, private residential systems and industrial uses.

Permit to Take Water, Belgrave Water Supply System, Municipality of Morris-Turnberry, Huron County, Ontario (2012)

Renewal of ten year permit for a municipal water system with two source wells.

Hydrogeological Study, Trussler Road and Bleams Road, Kitchener, Ontario (2011)

Geological and hydrogeological field investigation at a licensed gravel pit. Installation of monitoring wells to collect data for water balance study. Property was potential subject of an OMB hearing.

Source Water Protection, Bayfield-Ausable/Maitland Valley Source Protection Area, Ontario (2008-2010)

Participated in the Wingham working group formed to supply local input to the source protection planning process.

Hydrogeological Study, Clinton Municipal Water Supply, Municipality of Central Huron, Ontario (2006-2007)

Completed hydrogeological study for three municipal wells to obtain a new permit to take water for the grandfathered system.

Permit to Take Water, Blackhorse Golf & Country Resort, Township of Huron-Kinloss, Ontario (2007)

Worked with golf course operator and MOE to obtain renewal permit.

Hydrogeological Study, Wingham & Blyth Water Supplies, Township of North Huron, Ontario (2002)

Testing of municipal wells to determine hydrogeologic setting, assess well condition, and evaluate source water quality (GUDI).

Groundwater Management Study, Town of Exeter, Ontario (2000-2001)

Completed monitoring well installation and geologic interpretation for four municipal supply wells.

Groundwater Supply Study, J. Beldman, Township of East Wawanosh, Huron County, Ontario (2000)

Groundwater availability assessment for a proposed ten-lot rural residential development at Hutton Heights.

Municipal Water Supply Study, Beatty Franz & Assoc./Hensall PUC, Huron County, Ontario (1996-1997)

Assessment of nitrate contamination in a shallow aquifer in the Village of Hensall. Two existing municipal water supply wells in the aquifer experienced high nitrate levels. Supervised construction and testing of a new municipal well.

Best Management Practices: Water Wells, Beatty Franz & Assoc./Ontario Ministry of Agriculture, Food and Rural Affairs (1996)

Co-authored a forty-eight page booklet providing groundwater and water well information to farmers and other rural landowners. The Water Wells booklet was part of OMAFRA/Agriculture Canada Best Management Practices series.

Aggregate Extraction

Site Plan Amendment, McKague Pit, Township of South Bruce, Bruce County, Ontario (2012)

Obtained an amendment of the licensed boundary for an operating gravel pit. Amendment required to allow the construction of a sewage treatment plant on the Township property.

Hydrogeological Study, Jacklin Pit, Hanna & Hamilton Const., Municipality of Huron East, Ontario (2004-2007)

Determined hydrogeological conditions at an existing gravel pit. Assessed the impact on the local groundwater and water supply wells of changing license to extract below water table.

Water Table / Gravel Quantity Assessment, McLean Pit, Municipality of Huron-Kinloss, Bruce County, Ontario (2006)

Determined depth to water table, and assess depth and extent of granular material at a proposed gravel pit expansion.

Hydrogeological Impact Assessment, Golder Associates, Township of Greenock, Bruce County (1995)

Completed aquifer testing to assess the impact on local water supplies and stream baseflow of dewatering at a proposed limestone quarry.

On-site Sewage Disposal Systems

Joy has been involved in several field studies to evaluate the condition of existing on-site sewage systems. In some cases, the assessment was to determine life expectancy or OBC compliance. In other cases the assessment was done to locate the cause of bed failure.

Certificate of Approval Limits Evaluation, Wellington Catholic District School Board (St. John Brebeuf), Erin, Ontario (2011-2012)

Review historical treatment plant effluent quality, groundwater levels and flow mapping, and groundwater quality monitoring to evaluate C of A limits. In conjunction with engineer and plant operator, recommend revised effluent limits to MOE.

Tile Bed Assessment, Avon Maitland District School Board (Elma), Town of North Perth, Perth County, Ontario (2011)

Assessed condition of 40 year old on-site subsurface sewage system to determine remaining life expectancy.

Tile Bed Assessment and Site Evaluation, Avon Maitland District School Board (Holmesville), Mun. of Central Huron, Huron County, Ontario (2011)

Assessed condition of existing on-site subsurface sewage system for cause of failure. Conducted site evaluation for a proposed new tile bed for a public school.

Tile Bed Assessment and Site Evaluation, Avon Maitland District School Board (East Wawanosh), Twp of North Huron, Huron County, Ontario (2009)

Assessed condition of existing on-site subsurface sewage system for cause of failure. Conducted site evaluation for a proposed new tile bed for a public school.

On-Site System Assessments, Avon Maitland District School Board, Huron County, Ontario (2009)

Desk top assessment of several on-site systems serving rural elementary schools. Assessment for capacity, operating condition and OBC compliance. Assessment used to prepare an operating manual for the systems.

Site Monitoring, Brampton Fairgrounds, Brampton Ontario (2008-2009)

Design and implement monitoring program Tile Bed Assessment and Site Evaluation, Dalewood Golf Course, Port Hope, Ontario (2007)

Assessed an existing on-site subsurface sewage disposal system for cause of failure. Conducted site evaluation for a proposed new tile bed for the golf course clubhouse.

Tile Bed Assessment and Site Evaluation, Kettleby Valley Camp and Outdoor Centre, Township of King, Ontario (2006)

Assessed two existing on-site subsurface sewage disposal systems for life expectancy and expansion potential. Conducted site evaluation for a proposed new tile bed for children's camp facility expansion.

Tile Bed Assessment and Site Evaluation, Avon Maitland District School Board, Huron-Perth Counties, Ontario (2006)

Assessed existing on-site subsurface sewage disposal systems for life expectancy and failure causes at three public schools (Grey Central, Mornington, Sprucedale). Conducted a site evaluation for a proposed new tile bed at Grey Central.

Site Evaluations for On-site Sewage System Design

Since 1998, Joy has had considerable involvement in projects to evaluate soils, assess percolation times, determine water table depth and identified drainage problems for proposed on-site sewage systems.

Site Evaluations for On-site Sewage System Designs, Over 600 Individual Building Sites, Ontario (1998-Ongoing)

Completed Ontario Building Code: Part 8 Site Evaluations at more than 600 sites in Huron, Perth, Bruce, Grey, and Middlesex counties. Evaluations include assessment of soil percolation times and water table depth. Assessments completed for single residential lots, severances, and subdivision proposals.

Site Evaluation and Site Monitoring, Ancaster Agricultural Society, Hamilton, Ontario (2007-2009)

Assessed soil percolation time and water table depth for a large on-site system at a proposed fairground development. Design and implement monitoring program

Site Evaluation, Camp Hermosa, Township of Ashfield-Colbourne-Wawanosh, Huron County, Ontario (2006)

Assessed soil percolation time and water table depth for large on-site tile bed at a children's summer camp.

Soil and Water Table Assessment, R.J. Burnside/Howick Homes, Howick Township, Huron County, Ontario (2005)

Identified soils and water table conditions for a proposed eight-lot rural residential development in the Village of Wroxeter.

Soil Assessment, R.J. Burnside/PKS Holdco, Township of Ashfield-Colborne-Wawanosh, Ontario (2004-2005)

Identified soils and water table conditions for a proposed twenty-lot rural residential development.

Soil Assessment, G.D. D'Arcey Construction, Howick Township, Huron County, Ontario (2000)

Identified soils and water table conditions for a proposed six-lot rural residential development in the Village of Fordwich.

Soils and Water Table Assessments

Soil and Water Table Assessment, Bayfield Mini Storage, Municipality of Bluewater, Huron County, Ontario (2007)

Determined soil characteristics and water table depth for an on-site stormwater infiltration system at a proposed commercial building in Bayfield.

Site Characterization for Liquid Manure Storage Facilities, Various Sites, Ontario (2002-2006)

Completed fourteen site characterization studies to determine soil texture and structure, water table depth, and aquifer depth as required by the Nutrient Management Act and municipal by-laws.

Hydraulic Conductivity Assessment, R.J. Burnside/Cornerstone Const., Municipality of Bluewater, Ontario (2003)

Determined soil hydraulic conductivity and water table depth for on-site stormwater disposal at a proposed residential development on Eugene Street in Bayfield.

Soil Assessment, L. Epworth & Sons, Howick Township, Huron County, Ontario (2000)

Assessed soils and water table conditions at an existing septage disposal site.

Contaminated Sites and Environmental Site Assessments

Throughout her career, Joy has been involved in many projects dealing with soil and groundwater contamination. She has worked on industrial sites to map contaminant spread, verify site clean up, and set up ongoing monitoring programs. In recent years, this work has been primarily Phase I and Phase II Environmental Site Assessments.

Phase I and Phase II ESA, Wingham & District Hospital, Township of North Huron, Huron County, Ontario (2011-2012)

Coordinated the Phase I ESA with a geotechnical investigation and an archaeological study. The three studies were required by the Ministry of Health for an addition to the hospital. Conducted Phase II ESA on an UST identified in the Phase I.

Peer Review of Phase I and Phase II ESAs, Township of East Luther Grand Valley, Dufferin County, Ontario (2010)

Peer review of Phase I and Phase II reports of explosives storage and distribution facility located in a rural agricultural area.

Soil Sampling for Hydrocarbons, Former Culross Township, South Bruce, Bruce County, Ontario (2010)

Located site of a previously removed underground fuel storage tank, conducted test dig, submitted soil samples for testing, and completed report.

Tank Removal, Wingham United Church, Township of North Huron, Huron County, Ontario (2008)

Documented removal of underground fuel oil tank, submitted soil samples for testing and completed report.

Phase I, Phase II ESA and Record of Site Condition, Stever Development, Town of Minto, Wellington County, Ontario (2007-2008)

Completed ESA and filed RSC for former sawmill site in the Village of Clifford. Site slated for redevelopment to residential lots.

Phase I ESA, Goderich Sunset Golf Club, Township of Ashfield-Colborne-Wawanosh, Huron County, Ontario (2007)

Completed ESA for existing golf course property.

Soil Testing, Gregory Drain, Township of Morris-Turnberry, Huron County, Ontario (2006)

Determined level of soil contamination on a former railway bed adjacent to a proposed municipal drain realignment .

Phase I ESA, Brian Huber Holdings Ltd. Stratford, Ontario (2006)

Completed ESA at the site of a former United Co-operatives of Ontario storage facility on Linton Street. The operation handled bulk pesticides, fuels, and liquid and granular fertilizers.

Soil Testing, 1st Street Reconstruction, Collingwood, Ontario (2006)

Determined level of soil contamination from hydrocarbons below 1st Street prior to reconstruction and widening of the street.

Phase I ESA, Listowel Memorial Hospital, Listowel, Ontario (2006)

Completed ESA at the site of a former feed mill and agricultural retail outlet.

Groundwater Monitoring, Wescast Industries, Township of North Huron, Huron County (2005-2008)

Collected routine groundwater samples for monitoring downgradient of an automotive manufacturing plant.

Phase I and Phase II ESA, Former Railway Bed, Tow of Minto, Wellington County, Ontario (2005)

Completed site inspection and soil testing along a former railway bed in the Village of Clifford.

Phase I and Phase II ESA, Terraprobe, Township of North Huron, Huron County, Ontario (2005)

Completed site inspection and historical information research for a former landfill area in the Town of Wingham. Conducted test pit program to map extent of till.

Phase I ESA, Terraprobe, Municipality of Morris-Turnberry, Huron County, Ontario (2005)

Completed site inspection and historical research for a working abattoir in Lower Town.

Phase I and Phase II ESA, R. Buckle, Village of Teeswater, Bruce County, Ontario (2000)

Completed soil sampling along a former railway bed prior to rezoning to residential use.

Phase I and Phase II ESA, Township of Howick, Village of Gorrie, Huron County, Ontario (1999)

Carried out historical research and soil sampling at a municipally owned former railway yard.

Phase I and Phase II ESA, Township of Howick, Village of Fordwich, Huron County Ontario (1999)

Carried out historical research and soil sampling at a municipally owned former railway yard.

Phase I ESA, J. Dennis, Township of Turnberry, Huron County, Ontario (1999)

Completed historical research on site usage at a former car oiling facility in Lower Town.

Phase I and Phase II ESA, Maitland Engineering, Town of Wingham, Huron County, Ontario (1995)

Carried out historical research and soil sampling at the site of a former furniture factory.

Agricultural Drainage and Large Livestock Barns

Hydrogeologic Study, Hessel Drain Project, Township of North Huron, Huron County, Ontario (2010)

Assessed the impact of agricultural drain construction (including open channel excavation) on the water levels in an existing wetland.

Hydrogeologic Study, Parson Pond, Township of Melancthon, Dufferin County, Ontario (2007)

Assessed the impact of the redevelopment of a former off-line pond on local groundwater and surface water in the Nottawasaga Watershed.

Well Testing and Water Sample Collection, H&L Koelen Farms, Municipality of Kincardine, Bruce County, Ontario (2002)

Performance tested water supply well for proposed large livestock (farrowing) barn. Identified and sampled local water wells. Searched for unused water wells on farm properties.

Hydrogeological Study, Geene Farms, Township of Huron-Kinloss, Bruce County, Ontario (2001-2002)

Assessed groundwater vulnerability to contamination at a proposed large livestock (hog) barn. Identified and sampled adjacent water supply wells. Submitted monitoring program to municipality.

Hydrogeological Study, BarnHem Farms, Municipality of South Bruce, Ontario (2001-2002)

Assessed the groundwater vulnerability to contamination from a proposed large livestock (hog) barn. Identified and sampled adjacent water supply wells.

Hydrogeologic Impact Study, McKauge-Weishar, Municipality of Morris-Turnberry, Ontario (2001)

Assessed the effect of a proposed agricultural severance on water quality in an adjoining hamlet of Belmore.

Profession

Civil Engineer

Education

Bachelor of Science (Civil Engineering), University of Waterloo, 1988

Professional Societies

Professional Engineers Ontario

Employment Record

Senior Vice President, R.J. Burnside & Associates Limited (2005-Present)

Vice President, R.J. Burnside & Associates Limited (2000-2005)

Branch Manager, R.J. Burnside & Associates Limited (1993-2000)

Project Manager, R.J. Burnside & Associates Limited (1988-1993)

Citizenship

Canadian

Languages

English

Ian Drever, P.Eng.

As a Senior Vice President at R.J. Burnside & Associates Limited, Mr. Drever has been involved in a wide variety of public and private sector projects. Mr. Drever has acted in the role of both project manager and project director/liaison, depending on the scope of the project and the needs of the client.

On public sector projects, Mr. Drever's focus has been in the area of Environmental Assessment and Master Servicing Plans. Ian's overall technical background and his knowledge of both agency approval requirements and the Class Environmental Assessment process allow him to be an effective contributor to or manager of any project team.

Mr. Drever's private sector development experience is extensive. His background planning knowledge and technical experience combine to form an excellent base from which development management/ project management services are provided. Ian has completed design and/or provided management direction on commercial, industrial and residential site plans and subdivisions. Mr. Drever has assisted many clients in the preliminary assessment of sites during the due diligence phase prior to land purchase. He has completed or participated in the completion of Functional Servicing Reports, Master Servicing Studies, Stormwater Management Reports and Floodline Analyses. Mr. Drever has participated on Ontario Municipal Board files, successfully settling servicing issues prior to the Hearing. With this wide background, Mr. Drever provides clients with effective and timely advice.

Private Sector Development

Seaton, Mattamy Homes, City of Pickering, Ontario (2010-Present)

Project Director and Lead Engineer for Neighbourhood 19 Functional Servicing and Stormwater Report encompassing some 2000 acres in the Community of Seaton. Provide direction of the preliminary engineering and detailed design of three residential subdivisions comprising some 220 units on 200 acres of developable area, completion of support engineering documents (Functional Servicing Report), agency liaison to secure approvals, etc.

Nigus Holdings, Sorbara Group, Township of Centre Wellington, Ontario (2007-Present)

Project Manager for a 220 acre residential development in northwest Fergus.

Woodbine Live! Woodbine Live GP Inc., City of Toronto, Ontario (2006-Present)

Project director of the civil works for the redevelopment and revitalization of the Woodbine Raceway. The project encompasses an entertainment district, mid-town office district, retail district and residential district. Over 2,000,000 square feet of commercial/office space and 2000 residential condominium units on 80 hectares of land are proposed. Services provided include grading, storm, sanitary and water servicing, as well as master planning of civil works.

Bonaire Highlands, Bonaire Highlands Limited, Town of Fergus, Ontario (2006-Present)

Project Manager through preliminary engineering and design phase of a 220-unit residential subdivision. Project was subject of a successful Ontario Municipal Board appeal.

Block 40-3, Great Gulf Homes, City of Brampton, Ontario (2003-Present)

Project Manager and Block Engineer for Block 40-3 of the Bram West Secondary Planning Area, comprising approximately 1000 acres. Responsible for preliminary servicing, spine servicing, completion of support engineering documents (Environmental implementation Report and Functional Servicing Report) agency liaison to secure approvals, cost share etc.

Goreway Station, Sithe Energies, City of Brampton, Ontario (2010)

Project Manager of the civil works portion of an 800 MW natural gas fired generating station and overhead transmission line on a 50-acre site. Services provided include, site servicing and grading, stormwater management design, securing of approvals for a 2 km overhead transmission line, crossing permits for Highway 407 and appearance at an Ontario Energy Board Hearing.

Countryside Villages, Metrus Properties, City of Brampton, Ontario (2009)

Project manager for an Infrastructure Servicing Study for 1600 acres of land in North Brampton. The focus of the study is to assess water and sanitary sewer capacity and routing for the secondary planning area.

Southdown Station, Sithe Energies, City of Mississauga, Ontario (2000-2008)

Project manager of the civil works portion of an 800 MW natural gas fired generating station and buried transmission line on a 35-acre site. Services provided included, site servicing and grading, stormwater management design, and securing of approvals for a 1 km buried transmission line.

Confidential Client, Land Acquisition Analysis, Several Properties (2008)

Project manager for an assessment of servicing constraints in support of a due diligence analysis covering some 1500 acres on several properties in multiple municipalities. Provided a detailed review of servicing and water collection/distribution and treatment capacity, identified potential solutions to constraints, costed servicing options and reported to client.

Red Leaves Lodge/Minett Landing, Ken Fowler Enterprises, Township of Muskoka Lakes, Ontario (2001-2006)

Project manager of the civil works for the redevelopment of the former Lake Rosseau Beach Resort and Wallace Marina, as well as the development of The Rock Golf Course. First phase of development approved permits over 300,000 sq. ft. of commercial/resort type development. Services provided include grading, storm, sanitary and water servicing, as well as master planning of civil works.

Municipal Engineering

Doon Valley Golf Course, City of Kitchener, Ontario (2010)

Project Manager for the engineering approvals component of the expansion of this municipally operated course. Services provided included design of an integrated stormwater management facility to serve as an aesthetic feature for the course while providing servicing to the adjacent residential development. Additionally cut/fill analysis and floodplain modelling was necessary to support a Fill Permit application.

Preliminary Infrastructure Servicing Report, City of Brampton, Ontario (2002)

Project Manager for the completion of a preliminary master servicing report focused on developing sanitary and water servicing alternatives for the Northwest Brampton planning area of the City of Brampton. The study analyzed alternative servicing scenarios for an area in the order of 6,000-acres.

Bolton South Hill Master Drainage Facilities, Town of Caledon, Ontario (1997)

Project Director for the design of two master stormwater detention facilities in the Bolton South Hill Area. Provided periodic input into the design and approvals process and cost share associated with the same. The project included wet ponds/extended detention facilities.

Steeles Avenue East Environmental Management Plan, City of Toronto, Ontario (1995)

Project Director as a subconsultant to LGL Limited for the preparation of an Environmental Management Plan for the widening of Steeles Avenue from McCowan Road to Pickering Townline in the City of Toronto. Environmental engineering support was provided to LGL Limited in the preparation of the Environmental Management Plan, which was prepared as a guideline for use by the proponent, contractor and public to mitigate the environmental impacts of the road widening during the design and construction stage.

10^{th} Line Road Reconstruction, Town of Halton Hills, Ontario (1995)

Project Manager for the 10th Line Road Reconstruction, Town of Halton Hills. This project involved proceeding through the Class Environmental Assessment process for roads. Included in this process were several points of public contact and regular meetings with a Public Liaison Committee to assist in completing the assessment process.

Lorena Anne Niemi, P.Eng.

Profession

Civil Engineer

Education

B.Sc.Eng., University of Guelph, Water Resources Engineering, 1999

Professional Societies

Professional Engineers Ontario

Employment Record

Leader – Development, Design and Approvals, R.J. Burnside & Associates Limited (2009-Present)

Project Engineer, R.J. Burnside & Associates Limited (1999-2009)

Junior Technical Assistant, Arlat Technologies Inc. (1999)

Citizenship

Canadian and British

Languages

English

As an engineer and Technical Sector Leader, Lorena is involved in the completion and co-ordination of the design of a variety of land development projects for residential, commercial, industrial and golf course clients covering infrastructure, grading and stormwater management works. In addition, Lorena has been involved in the design of municipal services under various land development projects. Lorena maintains effective interaction with both clients and approval agencies to obtain the necessary approvals. She is familiar with development and design regulations in Ontario and a number of municipalities and governing agencies.

Development

Mattamy Homes, Seaton Development, Pickering, Ontario (2009-Present)

On-going works involving the co-ordination and completion of preliminary engineering assessment and design of three residential subdivisions, totalling over 2000 units, within the Seaton Planning area. Works include grading/earthworks, drainage and servicing design for preliminary costing purposes as well as review of MESP stormwater management pond alternatives.

Woodbine Live!, City of Toronto, Toronto, Ontario (2006-Present)

On-going works including Project Management, preliminary engineering and detailed infrastructure design including sanitary, storm and water services, for an 84ha mixed use, entertainment, commercial, retail and residential development on the existing Woodbine property. The project includes a mix of both private and public infrastructure design.

Sithe Southdown Station, City of Mississauga. Mississauga, Ontario (2000-2009)

Involved in the securement of approvals and permits for the development of an 800MW power generation facility, similar to the Goreway Station. Works include the site grading and servicing design along with the detailed design of a stormwater management facility and involvement in the cable routing construction/design brief as well as assessment of transmission line routing and the securement of approvals therein.

Woodbine Entertainment Group, Mohawk Revitalization Project, Town of Milton, Campbellville, Ontario (2002-2007)

Completion of the preliminary engineering work and Project Management required for securement of required zoning and official plan approval for the revitalization of the existing Mohawk Property to include an 18 hole golf course, hotel and conference center. Works also included assessment of the existing floodlines, surface and groundwater interaction through out the property and available and required infrastructure to service the proposed works.

Sithe Goreway Station, City of Brampton, Brampton, Ontario (2000-2005)

Involved in the securement of approvals and permits for the development of an 800

MW power generation facility. Works included the design of a stormwater management facility, a sewage pumping station and watermain, as well as, floodline impact analysis of Mimico Creek.

Menkes Development Goreway Drive, City of Brampton, Brampton, Ontario (2003-2004)

On-going works including a cut and fill analysis for the proposed industrial development and the design of an external sanitary sewer to provide services to the Menkes Development along with adjacent landowners.

Menkes Development Intermodal Drive, City of Brampton, Brampton, Ontario (2003)

Completed a channel realignment design on a tributary to Mimico Creek encompassing the naturalization of the channel, flood control and stormwater management to allow for the development of adjacent lands. Also completed the site grading and servicing design for the industrial development adjacent to the channel.

Permits

Menkes External Sanitary Sewer, Menkes Industrial Holdings Inc., Brampton, Ontario (2004)

Secured the required fill permit.

Wildwinds Golf Course, Shawn P. Watters and Associates Ltd., Center Wellington, Ontario (2002)

Secured the required fill permit.

Sithe Southdown Station, Sithe Canadian Energies Ltd., Mississauga, Ontario (2002)

Secured the required rail-crossing permit.

Sithe Goreway Station, Sithe Canadian Energies Ltd., Brampton, Ontario (2001)

Secured the required fill permit and associated updates and extensions.

Royal Ontario Golf Club, Kaneff, Milton, Ontario (2001)

Secured the required fill permit.

Sithe Goreway Station, Sithe Canadian Energies Ltd., Brampton, Ontario (2001)

Secured the required rail-crossing permit.

Computer Literacy

Lorena has extensive working knowledge of a number of hydrologic and hydraulic computer modeling programs including QUALHYMO, SWMHYMO, OTTHYMO, GAWSER, HEC2, HEC-RAS,, FlowMaster and CulvertMaster. Lorena also has broad experience with AutoCAD and desktop design models including SoftDesk, LD3 and LDD.

James R. Walls, B.Sc., P.Geo., QP$_{ESA}$

Profession

Geoscientist

Education

B.Sc., University of Toronto, 1983

Professional Societies

Professional Geoscientist, Assoc. of Professional Geoscientists of Ontario (APGO), Manitoba (APEGM)

Association of Professional Engineers, Geologists, and Geophysicists of the Northwest Territories and Nunavut (NAPEG)

Employment Record

Geoscientist, R. J. Burnside & Associates Limited (1996-Present)

Environmental Geologist, Dames & Moore, Canada (1991-1996)

Environmental Geologist, Morrison Beatty Ltd. (1990-1991)

Project Geologist, International Platinum Corporation (1987-1990)

Geologist, Borealis Exploration Ltd. (1986)

Mine Geologist, McAdam Resources Inc. (1985)

Geologist, Urangesellschaft Canada Ltd. (1985)

Mine Geologist, Consolidated Professor Mines Ltd. (1984)

Geologist, J. C. Stephen Exploration Ltd. (1984)

Geologist, Kerr Addison Mines Ltd. (1983)

Citizenship

Canadian

Languages

English

James Walls is a Senior Project Manager and Geoscientist (APGO, APEGM , NAPEG) with over 20 year's of geological and environmental experience. Mr. Walls gained a wide range of experience in bedrock geology, surficial geology, and physiography while working in the mining and exploration industry.

Mr. Walls is experienced at conducting environmental site assessment and remediation projects (Phase I, II, and III) at a variety of sites involving contaminated soil and groundwater. His projects have involved the delineation of contamination, the analysis of remedial options, the development and oversight of remediation strategies and post-remedial assessments. His experience includes industrial sites contaminated with fuels, oils, chlorinated organics, PCBs, and DNAPL chemicals. His projects have been conducted in urban and remote areas of northern Canada, South America and the Caribbean. Mr. Walls has over 12 years of experience working with landfills, including environmental assessment, siting, design, rehabilitation, and closure. Mr. Walls has worked on projects throughout northern Canada including over 50 First Nation communities and 12 arctic Hamlets.

Mr. Walls is a Qualified Person (QP) as per O.Reg. 153/04 and National Instrument 43-101. He has been an expert witness for litigation and hearings.

Environmental Reviews

Hydrogeological Review, Richmond Landfill Site, Mohawks of the Bay of Quinte, Ontario (2010)

Conducted a hydrogeological review of a large landfill on traditional territory, and assessed potential impacts to water supply and the environment.

Environmental Assessment of First Nation Landfill Sites, INAC, Manitoba Region (2009-2010)

Provided senior technical oversight of desktop and field investigations of all active, closed, and abandoned solid waste sites on all First Nations in Manitoba. Recommendations for action, NCSCS screening, and potential cost liability assessments.

Environmental Review, Depot Harbour, Wasauksing First Nation, Parry Sound, Ontario (2007-2009)

Project Manager responsible for project management and implementation QA/QC, budget control and client liaison. Conducted a review of historical environmental documents of a former explosives manufacturing facility on lands to be returned to the First Nation. Identification of environmental issues and remedial action plans for future development of the lands.

Phase I Environmental Site Assessments

Phase I Environmental Site Assessment – Henvey Inlet First Nation, Henvey Inlet First Nation, Pickerel, Ontario (2006-2007)

Project Manager responsible for conducting a Phase I Environmental Site Assessment of Henvey Inlet First Nation Lands. The Phase I ESA was conducted in anticipation of the transfer of responsibility for First Nation lands and resources from the Government of Canada to the First Nation pursuant to the First Nation Land Management Agreement (FNLMA).

San Leasing Ltd. and Piruqsaijit Ltd., Rankin Inlet and Arviat, Nunavut (2006)

Conducted Phase I ESA's of 30 commercial, institutional, and residential properties.

Meno-Ya-Win Health Center, Sioux Lookout District Hospital, Sioux Lookout, Ontario (2004-2005)

Phase I Environmental Site Assessment and Designated Substances Inventory of a regional hospital. Quantification of asbestos containing materials and abatement options analysis.

Conducted Phase I ESA's of entire First Nation communities as part of the First Nation Land Management Agreement, as well as specific sites being developed for new land uses.

Phase I ESA, Whitefish Lake First Nation, Ontario (2003)

Conducted a Phase I ESA of all First Nation Lands and surrounding areas including mines and landfills to document environmental liabilities as part of the First Nation Land Management Self Government Agreement process.

Phase I ESA, Hiawatha First Nation, Ontario (2002)

A detailed Phase I ESA of all First Nation lands and buildings was conducted to establish environmental conditions prior to the transfer of First Nation lands from the Government of Canada pursuant to the Anishnaabe Self Government Agreement.

Phase I ESA, Curve Lake First Nation, Curve Lake, Ontario (1999-2001)

Conducted an environmental assessment of all First Nation lands, to identify environmental issues prior to the transfer of lands through a self government agreement. Conducted environmental assessments of new land acquisitions.

Phase II ESA's and Environmental Issues Inventories

Experience includes Phase II ESA's and Phase III Environmental Issues Inventories, which involve the investigation and assessment of contaminated sites. Projects often involved a remedial options analysis to address issues, Canadian Environmental Assessment Act (CEAA) screening, and National Classification for Contaminated Sites (NCCS) evaluations. Recent projects include:

Phase II ESA, Remedial Options Analysis, Cooper Site, City of Stratford, Ontario (1996-Ongoing)

Conducted Phase II ESA and remedial options analysis on a 7 ha former locomotive manufacturing facility, with soil and groundwater contamination. Site parcels have been evaluated, and remedial action conducted in support of redevelopment for various landuses.

Phase II ESA Parklands, Town of Newmarket, Ontario (2008-2010)

Conducted Phase II ESA studies and environmental characterization to support a Risk Assessment of former orchard lands impacted with arsenic, lead, and pesticides. Drilling and sampling programs, public and agency consultation, and remedial options analysis and costing.

Phase II ESA and Water Quality Assessment, Constance Lake First Nation, Calstock, Ontario (2000-2002)

Concerns with the community's surface water supply prompted an environmental assessment of an active sawmill operation both on and adjacent to First Nation lands. The quality of water, fish, and benthic organisms in Constance Lake was assessed to determine the impact of the industrial land use. A Phase II Environmental Site Assessment was conducted over the entire sawmill site.

Phase I and II Assessments, City of Stratford, Stratford, Ontario (1997-Present)

Phase I and II assessments of a large former locomotive manufacturing facility with metals, hydrocarbons, and PAH contamination. Remediation of parts of the site. Remedial options assessments. Evaluation of asbestos and emergency response following a large fire.

Akulivik Soil Remediation, Natural Resources Canada (NRCan), Akulivik, Quebec (2008-2009)

Project Manager responsible for conducing a soil remediation program at a former prospecting/survey camp located approximately 70 km northeast of Akulivik, Quebec. The project involved delineation and removal of hydrocarbon impacted soil, which was shipped to a licensed facility in the south. Responsible for project management, QA/QC, budget control, and client liaison.

Preliminary Environmental Investigation of Hydrocarbon Seepage into a Creek, Chippewas of Nawash Unceded First Nation, Wiarton, Ontario (2007-2009)

Project Manager, responsible for project management, QA/QC, budget control, and client liaison. The purpose of this study was to determine the source of hydrocarbon contamination, suspected of being gasoline, entering a creek 20 m south of the cemetery. Provided technical support for investigative studies and remedial action including a pump and treat system.

Phase II EA, Festival Hydro Inc., Stratford, Ontario (2000-2008)

Phase II Environmental Assessment of a former coal gasification facility impacted with coal tar and petroleum hydrocarbons. Installation of monitoring wells on and off site. Delineation of contamination and remedial options analysis.

Remedial options analysis, cost benefit analysis, and technical advice regarding site redevelopment.

Phase II ESA and Remedial Options Analysis – Former Lumber Mill, Couchiching First Nation, Ontario (2002-2003)

A 6 ha site previously used for a lumber mill and other industrial operations was assessed to determine the amounts and types of waste materials and degree of contamination in groundwater, surface water, and soil. The assessment was followed by a remedial options analysis to determine the most effective method for redeveloping the site.

Landfills and Waste Management

Project Manager, responsible for hydrogeological studies, well installation, annual monitoring programs, site inspections and hydrogeological reports for over 70 landfill sites. Experience includes the location of new sites, assessment of operating sites, and site closure. Experience includes industrial hazardous waste landfills, municipal landfills, First Nation landfills, and international projects. Recent First Nation projects include:

Elma, Listowel, and Wallace Landfill Sites, Municipality of North Perth, Ontario (2002-2010)

Conducted hydrogeological assessments of three landfill sites and conducted ongoing monitoring programs. Conducted assessments of leachate impacts and assisted with the design and installation of a leachate collection system at the Listowel site. Provided recommendations for closure of the Wallace site. Conducted hydrogeological assessments as part of the redevelopment and expansion of the Elma site.

Calculated buffer zones and contaminant attenuation zones. Participated in agency and public consultation.

Waste Management Plan and Landfill Site Location Study, Couchiching First Nation, Fort Frances, Ontario (2002-2004)

Evaluation of waste management options and recycling. Evaluation of the existing landfill and selection of a new on Reserve landfill site.

Hamlet of Arviat, Nunavut (2009-2010)

Conducted landfill site selection study to locate a new solid waste site and access road. Conducted community consultation, field studies, and preliminary designs. Detailed design of a selected site completed and community consultation continues. Evaluations of existing solid waste, contaminated soil, and bulky metals sites. Prepared submissions for a new water license including O&M plans, annual reports, and supporting reports. Liaison with regulatory agencies and conducted public consultation.

Asubpeeschoseewagong Netum Anishnabek First Nation, Grassy Narrows, Ontario (2001-2005)

Conducted a waste management planning study to evaluate waste management options. Conducted a landfill site selection study to locate a new on-Reserve landfill site. Conducted an environmental assessment of the existing landfill.

Landfill Site Design and Closure, Weenusk First Nation, Peawanuck, Ontario (2002-2004)

Evaluation of existing landfill site and proposed new landfill site. Preparation of a design for the new site and closure of old site.

Example of First Nation Projects

The following projects are examples of the range of work conducted for First Nation communities and organizations:

- Pays Plat First Nation – Septic system impact and water quality study
- Six Nations of the Grand River – Landfill site management practices and procedures
- Weenusk First Nation – satellite imagery mapping of traditional territory
- Saugeen First Nation – Evaluated existing and closed landfills, and options for a new site
- Kaskechewan First Nation – Waste management profile and assessment of new landfill sites
- Serpent River First Nation – Quarry assessment and feasibility study
- North Caribou Lake First Nation – Waste management and new landfill layout and operations plan development
- Six Nations of the Grand River – uncontrolled waste disposal and materials storage study
- Constance Lake First Nation – Sewage spill assessment and remediation
- Toronto Council Fire – Fuel oil leak assessment
- Stanjikoming First Nation – new landfill site permitting
- Attawapiskat First Nation – technical review and advice regarding the environmental impacts of the Victor Pipe diamond mine development
- Wasbaseemoong Independent Nations – Landfill site selection study.

Example of Arctic Projects

Hamlet of Kugluktuk, Nunavut (2008)

Water supply intake assessment and development of a conceptual design for a new river intake. Assessment of geological survey data.

Waste Disposal Facility, NWB Water Licence Application, Hamlet of Whale Cove, Nunavut (2007-2008)

One project to assess the existing waste disposal facility and one project to prepare NWB water license application. Included evaluation of hydrocarbon impacted soil and landfarm.

Aggregate Resources Inventory, Hamlets of Kugluktuk, Gjoa Haven, Kugarruk, and Taloyoak, Nunavut (2006-2008)

Aggregate resources inventory for four communities in the Kitikmeot.

Geological Mapping and Field Assessment, Hamlet of Kugluktuk, Nunavut (2005-2008)

Geological mapping and field assessment for the development of a new sewage treatment facility and solid waste management facility. Impact assessment and report preparation.

Landfill and Waste Disposal Practices, Municipality of Qikiqtarjuaq, Nunavut (2005-2007)

Conducted an evaluation of the existing landfill and waste disposal practices. Assessed contaminated soil stockpile and designed a biotreatment cell. Developed options for a new site and long term water disposal in a permafrost environment.

Hamlet of Repulse Bay, Nunavut (2006)

Evaluated the existing landfill site and compared as-built to design. Conducted landfill staff training.

Environmental Assessments, San Leasing Ltd. and Piruqsaijit Ltd., Nunavut (2006)

Conducted environmental assessments of 30 commercial and residential properties in Rankin Inlet and Arviat.

Uranium Exploration Programs, Urangesellschaft Canada Ltd., Baker Lake, Nunavut (1985)

Conducted Uranium exploration programs including geophysical surveys, geological mapping, and drilling programs near the Kiggavik uranium deposit west of Baker Lake.

Industrial Sites

Dupont Canada Inc., Kingston, Ontario (1996-2001)

A long term project at a nylon and chemical manufacturing facility included:

- Environmental studies of contaminated soil and groundwater in active production areas and areas of historic activity
- Decommissioning of an industrial wastewater lagoon
- Assessment and remediation of soils, sludges, and liquids
- Assessment and remediation of chemical and fuel spills.

Union Carbide Bakelite Facility, Belleville, Ontario (1993-1996)

This long-term project at a chemical manufacturing facility involved:

- Location, excavation, removal and disposal of hundreds of buried drums of hazardous chemicals
- Decommissioning of several PCB contaminated settling basins and large sludge lagoons, including segregation and disposal of PCB waste
- Assessment and remediation of an industrial waste disposal area in a marshland containing thousands of buried drums
- Investigation and assessment of PCB impacted marshlands
- Numerous studies involving the delineation, assessment and remediation of contaminated soils, groundwater and industrial wastes.

Uniroyal Chemicals, Elmira, Ontario (1990-1993)

This long term project at an active chemical producing facility included:

- hydrogeological investigations of contaminated soil and groundwater
- installation of monitoring wells and sampling for various contaminants including DNAPL and LNAPL chemicals
- investigation of buried drums, waste disposal areas, sludge lagoons and tar pits.

Aggregate Resources

Aggregate Resources Inventories, Government of Nunavut (2007-2008)

Aggregate resources inventories for the Hamlets of Gjoa Haven, Taloyoak, Kugarruk, and Kugluktuk.

Expert Testimony and Peer Review

Provided peer review and testimony for litigation and hearings. Accepted as an expert witness for submissions at hearings and in support of applications and litigation.

Township of East Luther-Grand Valley, Dricia Mediation (2009-2010)

Environmental document review, consultation, and statement of agreed upon facts.

City of Stratford, Expropriation of Industrial Lands (2008-2010)

Provided advice and technical assessments including remedial options, environmental liabilities, and costs related to the expropriation of a large industrial site in the downtown.

Mineral Exploration

Projects related to mineral exploration, include:

- Platinum Group metals and gold exploration projects throughout Canada, including remote locations in Ontario, Quebec, Northwest Territories, Yukon Territory, British Columbia, Saskatchewan, Newfoundland and Labrador
- Uranium exploration projects at remote locations in Saskatchewan and the Northwest Territories
- Base metals exploration projects throughout Canada
- Project management on various sized projects from grass roots exploration and prospecting to advanced drilling projects
- Mine geologist at Spud Valley Mine, Zeballos, BC and Duport Mine, Shoal Lake, Ontario.

Assessment Reports, Big Trout Lake, Platinex Inc., Aurora, Ontario (2000-2009)

Prepared assessment reports incorporating geological, geochemical, geophysical, and satellite remote sensing data. Prepared qualifying reports as per National Instrument 43-101 under the Securities Act.

Gold Mine, Mi'kmaq Rights Initiative, Nova Scotia (2009)

Conducted a review of environmental documentation submitted as part of the development application for a gold mine on traditional territory. Provided recommendations for an Impact Benefits Agreement.

Remote Sensing

- Using geophysics to map impacts to groundwater resources from leachate
- Mineral exploration using RADARSAT, Landsat, and other satellite imagery
- Mineral exploration using airborne hyperspectral sensors
- Environmental impact assessments using satellite and airborne optical, hyperspectral, and geophysical data.

Health and Safety Experience

Responsible for establishing health and safety protocols, ensuring regulatory compliance, preparing site specific health and safety plans, and conducting employee training. Experienced in developing Health and Safety protocols including:

- Level "B" hazardous site conditions
- Confined space entry
- Toxic and explosive atmospheres
- Handling and sampling chlorinated organics, PCBs, asbestos and other hazardous contaminants.

Training Provider

Landfill Operators Training, Several Sessions for Municipal Staff in Southern Ontario (2002, 2004, 2009)

Conducted multi-day training programs for landfill operators and public works managers for rural municipalities in southern Ontario.

Landfill Site Training, Organization of Eastern Caribbean States, St. Lucia (2003)

Developed and implemented a training program for landfill site operators and waste management staff for a number of Caribbean countries. Included leading site visits and providing classroom instruction.

Publications

Walls, J.R. and Kalinauskas, A.K., The Delineation of Groundwater Resources in Bedrock Aquifers using RADARSAT, Proceedings of the Fourteenth International Conference on Applied Geologic Remote Sensing, 2000.

Kalinauskas A.R., Walls J.R., and Godin E., (2001) "Airborne Geochemistry Using Hyperspectral Imaging", Presented at the Canadian Exploration Geophysicist Symposium, Toronto, Canada.

Kalinauskas A.R., Rubinstein I, Walls J.R., (1998) "Vegetation Correction Model Using RADARSAT, JERS and LANDSAT TM", poster paper - GIS (1995), Toronto, Canada.

NEEGAN BURNSIDE

Profession

Electrical Engineer-in-training

Education

Arc Flash Analysis Certification for Power Quality System Evaluation and Safety Compliance, 2009

B.A.Sc. (Eng), University of Windsor, Electrical Engineering, 2008.

Professional Societies

Professional Engineers Ontario

Employment Record

Engineer in Training, R.J. Burnside & Associates Limited (2007-Present)

Citizenship

Canadian, American

Languages

English, French and Arabic

Sammy Elias, B.A.Sc. (Eng), E.I.T.

Sammy Elias is an Electrical Engineer-in-training with R.J. Burnside & Associates Limited and provides technical assistance to both public and private clients. The majority of Sammy's experience has been in the field of building services for utility services, pump station design for water and wastewater control, electrical design and layout for medical centers, emergency/standby generator systems, indoor & outdoor lighting, fire alarm design/upgrades, building assessments, cost analysis and tender specifications preparation. Presently Sammy has been focused on North America's first Renewable Energy Feed-in Tariff (FIT) Program in Ontario which includes delivery of FIT consultations, contracts, developing the scope of renewable projects, and technical designs.

Building Design Services

Grassy Narrows Arena Upgrades, Asubpeeschoseewagong Netum Anishnabek First-Nation, Ontario (2009-Present)

This design build project included design specifications, detailed single line diagram for power distribution, ESA plan review and interconnection with third party supplied refrigeration equipment. Hydro One coordination included upgrades to an existing single phase overhead service to a new three phase service. Further design considerations were undertaken to interconnect many surrounding facilities to the newly available three phase power.

Moose Deer Point Gymnasium, Moose Deer Point First-Nation, Ontario (2009-2011)

Electrical detail design for this Greenfield site included normal power and a propane powered generator for emergency power distribution, energy efficient lighting and lighting control design. Design considerations were taken to accommodate the use of this facility as an emergency shelter.

Sanofi Pasteur, North York, Ontario (2009-2010)

Design for fuel monitoring and anti-spill monitoring system for two underground tanks, and one above ground tank. Detail design included interconnection between all new equipment with existing Siemens Building Automation System.

Collingwood Public Works, Collingwood, Ontario (2009-2010)

Design for electrical services for the normal and emergency power distribution for this existing facility. Interior and exterior energy efficient lighting design, with custom lighting for all wash-bay, public works, and administrative areas. Emergency power interconnections included interconnection to an existing sewage lift station adjacent to the property.

Orangeville Christian Fellowship, Orangeville, Ontario (2009-2010)

Design for electrical services pertaining to coordination with Orangeville Hydro and power distribution for the entire facility. Interior and exterior energy efficient lighting design, with operational cost reducing lighting controls. Custom lighting requirements were met to accommodate the dual use of this facility as community centre and a Church.

Meno-Ya-Win Health Centre, Town of Sioux Lookout, Ontario (2007-2009)

This project involved designing all electrical building services for a new 60 bed acute care hospital, the design scope included an onsite electrical substation with two backup diesel-generator sets. Involvement included assisting in the design of the fire alarm system, short-circuit calculations, security system, audio visual nurse call system, lighting, lighting control equipment, lightning protection, GPS controlled clock system, data and communications wiring systems for this remote northern Ontario community.

Ontario Fire Academy, Town of Orangeville, Ontario (2009)

New electrical design and equipment specifications for a new addressable fire alarm system for code compliance. The system was designed to provide adequate capacity for future building expansion.

River Valley Poultry farm, Newburgh, Ontario (2008)

Power distribution design for new expansion, including electrical detail design and complete construction ready drawing set.

Collingwood Legion, Town of Collingwood, Ontario (2007)

For this heritage location the preliminary design included investigation of the existing fire alarm system, electrical design and equipment specifications for the new fire alarm system redesign for code compliance while using existing wiring to lower labour and component costs.

Custom Home, Confidential Client, Caledon, Ontario (2007)

Designed electrical services pertaining to the entire custom home property, circuiting for all exterior and interior lighting, lighting control, pool pumps, pump controls, car wash and hydraulic hoist. Responsibilities included electrical site visits and coordination between the client and contractors.

Renewal and Alternative Energy

Feed-In Tariff, Ontario (2009-Ongoing)

Completed Feed-In Tariff (FIT) applications, along with Local Distribution Company interconnection (LDC) details. Burnside assisted various clients with: Initial Feed-In Tariff consultations, pre-FIT LDC meetings, preliminary & detailed electrical design including single line diagram preparation for suitable interconnection methods required by local jurisdictions having authority. Burnside also completed Connection Impact Assessments required by the LDCs. This approach provided our clients with a turn-key approach to all Feed-In Tariff Projects.

Wind projects:

Westerhout Enterprises Inc.: Three 16kW wind turbines for a total generating nameplate capacity of 48kW.

Westerhout Poultry Inc.: Two 16kW wind turbines for a total generating nameplate capacity of 32kW.

Elgin Grovlea Farms Inc.: Two 16kW wind turbines for a total generating nameplate capacity of 32kW.

Solar projects:

MSC Solar, Orangeville, Ontario: Burnside assisted this new solar development firm with pre-feasibility studies for various rooftop solar applications throughout the GTA region.

Whitefish Bay Hydro Feasibility studies, Naotkamamegwaning First-Nation, Ontario (2010-Present)

Detail feasibility for the development of a 355 kW run-of-river Hydro-generation project. Detail review, includes pa-back calculations, over-head distribution routing, and equipment specifications.

Two 10 Megawatt Fixed axis Photovoltaic Solar Farms, Port Dover, Ontario (2010-2011)

Medium & low voltage detail design, grounding & bonding design, fiber-optic inverter interface, ground-resistivity studies, ground-grid and step & touch potential designs, Hydro coordination & approvals, ESA submission & approvals, and substation commissioning. With over 140,000 panels, and 30 inverters, these projects spanned over a combined total of 120 acres. These projects also involved coordination and liaison with embedded utilities prior to generation approvals. Both projects were initially approved under the Renewable Energy Standard Offer program (RESOP) and were later grandfathered into the Feed-In Tariff (FIT) program.

5 Megawatt Fixed axis Photovoltaic Solar Farm, Alderville First-Nation, Ontario (2010)

Electrical detail review & submission of the Connection Impact Assessment form and interconnection single line diagram required by Hydro One for contract approval.

Aboriginal Renewable Energy Fund (AREF), Ontario Power Authority, Ontario (2010)

Assisted in the development of detailed electrical design costs, and approval procedures for the approximation of various renewable energy project types. This was then implemented in Ontario's Aboriginal Renewable Energy Fund (AREF), which assists with some of the initial development costs associated with First Nation and Métis community renewable energy projects.

MV Power Wind turbines – Jamco Trailer, London, Ontario, (2009)

Hydro One Micro-generation forms and single line production for Net-metering and Feed-in-tariff applications for various gride-tied commercial wind turbine installations.

Solar Farm – Confidential Client, Oxford County, Ontario, (2009)

Hydro One Connection Impact Assessments for a 64 Mega-watt Utility Scale Solar farm. This included inverter selection and single line diagram production.

Municipal Wastewater Treatment and Pumping Stations

Tavistock Sewer Reconfiguration & Sewage Pumping Station, County of Oxford, Ontario (2010)

Complete design of a Greenfield Sewage Pumping Station Detailed design and tendered drawings.

Drayton Waste Water Services, Mapleton Township, Ontario (2009)

Preliminary design investigation, electrical design and equipment specifications.

Plattsville Waste Water Services, Village of Plattsville, Ontario (2007-2009)

Site investigations, electrical site services, electrical design/specifications, communication system design/specifications, standby generator, instrumentation and controls design tendering. PLC equipment operations, requirements for system and system alarming including the automation of a new sand filter station and positive displacement blower buildings.

Golf Courses, Recreational and Entertainment Facilities

Scarborough Golf and Country Club, Scarborough, Ontario (2010-Present)

Electrical detail design, Hydro liaison, and tendering for underground and overhead power services. Electrical Services for Golf Club New Irrigation Pump house.

Thornhill Golf and Country Club, Thornhill, Ontario (2009)

Electrical detail design and tendering for primary underground and overhead power services. Electrical Services for Golf Club New Irrigation Pump house.

Lambton Golf and Country Club, York, Ontario (2009)

Electrical detail design and tendering for primary underground power services. Electrical Services for Golf Club New Irrigation Pump house and surrounding residential services.

Toronto Golf Club, Mississauga, Ontario (2008-2009)

Electrical detail design, and tendering. Electrical Services for Golf Club (including primary duct bank, pad mount transformer, communications), underground electrical service to existing maintenance building to replace existing overhead service, coordination with Enersource Utility and specifications development.

Building Condition and Assessments Building Design Services

Georgina Civic Centre Building Assessment, Toronto, Ontario (2009)

Review of code compliances and deficiencies related to electrical servicing for this Heritage facility. This included a report with pricing for any foreseeable upgrades to the electrical system within the next 10 years.

Biggin Court Residential Buildings Assessment, Toronto, Ontario (2009)

Review and reporting of code compliances and deficiencies related to electrical servicing for five residential buildings with over 300 dwelling units.

Hamilton Ambulatory Dispatch Centre Building Automation System Assessment, Hamilton, Ontario (2009)

Review and reporting of existing normal and standby power distribution services for interconnection with a new proposed Building Automation System.

Ontario Provincial Police Station – CB Richard Ellis, Niagara Falls, Ontario (2009)

Review of existing design drawings and specifications, including drawings for any electrical renovations, upgrades or additions which may have occurred during the life of the building. Recommendations were made to ensure that the electrical systems of the building are in state-of-the-art operating condition, and in compliance with current standards.

Ray Twinney Centre, Newmarket, Ontario (2009-2010)

Conducted a full lighting assessment for two Class III multi-purpose skating arena's for the Ray Tweeny Centre. This included light level calculations, energy efficiency assessment, lighting controls assessment, and possible replacements with increased energy efficiency.

St. Catharine's Court House – CB Richard Ellis, St. Catharine's, Ontario (2009)

Report for reduced energy usage through lighting retrofit programs to achieve lower kilo-watt hours and ultimately operating costs. Various lighting retrofit solutions were suggested and implemented depending on location and usage.

Schools Building Performance Audit, Canada Green Building Council & LEED® Canada Initiative, Ontario (2008)

Two schools were audited for building efficiency. Thorough documentation of all existing electrical and mechanical equipment (including light level calculations, power quality analysis of building electrical systems, power factor study, and electrical services pertaining to all mechanical equipment)

Site Services & Street Lighting

Richmond Hill Community Environmental Centre, York Region, Ontario (2009-2010)

Electrical detail design for this Greenfield site included energy efficient site lighting for all waste disposal stations, and truck weight stations. Detail design included coordination with Local Utility Corporation, power distribution and fibre optic communications throughout the entire site, specifications and drawings.

St. Catharine's Court House Parking Lot– CB Richard Ellis, St. Catharine's, Ontario (2009-2010)

Design for electrical services for an existing high security parking lot. Electrical design included coordination with Local Hydro Utility, site services, parking lot gates, and wireless integration with existing court house security and card entry systems.

William Street Lighting Assessment, Orangeville, Ontario (2009-2010)

Review of existing lighting conditions, proposed new light standards, prepared lighting layout and various suitable light level calculations.

Toscanini Road Reconstruction, Town of Richmond Hill, Ontario (2007)

Preformed lighting measurements and assessment for the Town of Richmond Hill for this collector, residential street while in full compliance with the Town's standards, and design criteria.

Utility Services

Georgian Manor Drive, Collus Power Corporation, Collingwood, Ontario (2007)

Design and preparation of loading calculations for sizing pole mounted transformers, secondary distribution bus sizes, and AutoCAD drawing layouts for new overhead power lines. All existing primary lines were then reconnected into the newly installed lines.

First Street Pole line Relocation, Collus Power Corporation, Collingwood, Ontario (2007)

Field surveying to appropriately position poles to be re-located. Preliminary design and AutoCAD drawing layouts.

Solid Waste Management

Blyth Hullet Landfill Gas detector – Municipality of Central Huron, Ontario, (2009)

Member of Design Build Team and responsible for the design of an off-grid solar powered gas emergency notification system. System characteristics included autonomy for a minimum of seven days, ability to withstand extreme temperatures cold and lightning protection. Performed instrumentation detailed design and tender specifications.

Raw Sewage Digester and Blower Upgrades, Department of National Defence Base Canadian Forces Base Borden, Borden, Ontario (2009)

Site investigations, electrical site services, ventilation control for mechanical HVAC equipment, and AutoCAD drawing layouts in accordance with DND standards.

NEEGAN BURNSIDE

Carl Lankinen, B.A.Sc., M.A.Sc., P. Eng.

Profession

Structural Engineer

Education

M.A.Sc. Civil Engineering, University of Waterloo, 2003

B.A.Sc., Civil Engineering, University of Waterloo, 1996

Professional Societies

Professional Engineers Ontario

Assoc. of Professional Engineers and Geoscientists of New Brunswick and Newfoundland Labrador.

Assoc. of Professional Engineers of Nova Scotia

Assoc. of Professional Engineers, Geologists and Geophysicists of Alberta

American Society of Civil Engineers

Structural Engineering Institute

Employment Record

Structural Engineer, R.J. Burnside & Associates Limited, (1996-Present)

Consumer's Gas, Ontario (1995)

Giffels, Toronto, Ontario (1995)

Region of Hamilton Wentworth, Ontario (1994)

Ministry of Transportation, Ontario (1993)

Citizenship

Canadian

Languages

English

Carl has built 15 years of structural engineering experience since starting his career at R.J. Burnside & Associates Limited. He has leveraged his proven engineering abilities on over 1800 projects ranging from small residential to large industrial, commercial and institutional. Carl is the Technical Leader of Structural Engineering at Burnside. In his role, he has spearheaded the acquisition and implementation of Robot Structural Analysis, MathCAD and Revit Structure. He is responsible for quality control and assurance of the structural group at Burnside and maintenance of the quality standards library for the structural group.

Carl seeks challenges and has worked on a number of unusual projects such as wind turbines & foundations, solar trackers, solar farms, strawbale buildings, water standpipes, zip-lines, smoke stacks, industrial bridges, air supported structures, air inflated structures and even a yurt. During this experience, he has designed cast-in-place concrete, precast concrete, prestressed concrete, hot rolled steel, cold-formed steel, wood, timber, masonry, aluminum and glass components. He has also worked on reinforcing a concrete girder bridge with fibre reinforced polymer reinforcement.

Carl has completed a number of peer reviews of drawings, calculations, reports, buildings and components. These include opining on the collapse mechanism(s) of failed structures. He has reported on structures involved in litigation, insurance claims and dispute resolution. To this end, he has qualified as an expert witness while testifying at a Professional Engineers of Ontario tribunal.

Mr. Lankinen is considered the firm's foremost expert in computer modeling and analysis of structures. His design background is varied and involves a number of tools such as MathCAD, Maple, Excel, AutoCAD, Revit Structure and Robot Structural Analysis.

Structural Design Services

Alternative Energy

Two 50 Acre Solar Farms - 7.5MW and 8.5MW, EHV, Simcoe, Ontario (2010)

Structural design and drawings for steel framing of tables and masts supporting the solar arrays. Design of the concrete foundations for equipment pads.

Roof Mounted Solar Trackers, University of Toronto, Toronto, Ontario (2010)

Structural analysis of the wind loads on the rooftop mounted arrays. Drawings depicting arrays and reactions for roof designer.

Ground Mounted Solar Tracker Foundations, DEGERenergie, Various Location, Ontario (2010)

Structural design and drawings for the concrete foundations supporting ground mounted solar trackers for a variety of tracker types and locations in Ontario.

Industrial Roof Review for Rooftop Solar Arrays – 100kW, Endura Energy, Oakville, Ontario (2010)

Structural analysis of existing steel roof system for additional loads associated with solar arrays.

Residential and Agricultural Roof Reviews for Rooftop Top Solar Arrays, Various Clients, Various Locations, Ontario (2010)

Structural analysis of existing wood framed roof systems to support additional loads imposed by proposed solar array installation. Provided design and drawings for the truss reinforcement.

Preliminary Design - Wind Turbine Foundations, 10MW, Geilectric Inc., Township of Mulmur, Ontario (2009)

Structural design and drawings for the concrete foundations supporting 2MW wind turbines.

Wind Turbine Foundations and Tower Reviews, WAMM Energy, Southwestern Ontario (2004-2006)

Structural design services for wind turbine foundations in southwestern Ontario. Services included design of tower extensions to increase wind exposure of the wind turbine.

Wind Turbine Foundation, New World Generation Inc., Owen Sound, Ontario (2005)

Structural engineering services for the design of a concrete foundation for a pilot project in southwestern Ontario.

Anaerobic Digester Tank Design, Beef Facility, Lucan, Ontario (2005)

Structural design review of 4,000 m^3 anaerobic digester manufactured in Germany for installation on a private beef facility in Lucan. Preliminary structural design was completed on several framing options for a proposed 6,000 m^3 anaerobic digester.

Stunts

300-Foot Zip Line, Virgin Wireless, Toronto, Ontario (2005)

Consulted with rigging crew and completed analysis for a 300-foot long zip line from the top of the Eaton's Centre in Toronto. Analysis included determination of sag in the line and calculating the landing point.

Residential

Homes and Components, Various Clients, Various Locations, Ontario (2003-2010)

Structural design, drawings and reports for a variety of residential projects ranging from simple house beams to complete house designs including foundation underpinning.

Straw Bale Homes, Various Clients, Ontario & Alberta (2004-2010)

Provided structural wood design, steel, concrete design along with building science consulting services for the construction of straw bale homes in Ontario and Alberta. Most of the projects were new construction with one project involving the renovation of a turn of the century home.

Design of Homes in Flood Prone Areas, Various Clients, Various Locations, Ontario (2000-2010)

Provided structural designs and consultation for a number of residential construction projects that required wet and/or dry flood proofing. Analysis included the design of walls and foundations for hydrostatic and hydrodynamic pressures associated with the river course.

Timber Framed Homes, Various Clients, Various Locations, Ontario (2004-2010)

Provided structural design of heavy timber framed residences, with some integrating straw bale wall systems. Some of the framing utilized conventional steel connections with others used traditional wood dowelled connections.

Concrete Dome Residences, Great Lakes Dome Company, Various Locations, Ontario (2004-2009)

Provided structural design of residences constructed of concrete domes. Services included the design of the dome, foundation and construction reviews.

House Underpinning, Jacques Whitford, Scugog, Ontario (2009)

Structural design and drawings for underpinning of an entire residential foundation to facilitate the removal of oil contaminated soils.

Eby Village, Fryett Architect, Kitchener, Ontario (2003-2004)

Provided structural design for a four-storey apartment complex. The building consisted of wood framed roof and walls with precast concrete floors.

Structural Steel Design and Building Science Consulting for Renovations, Hilborn House, Mr. Jonathan Spaetzel, Cambridge, Ontario (2003-2004)

Provided structural steel design and building science consulting services for the renovation of a 5,000 square foot heritage home.

Concrete Dome Residence, Cushnie, Southampton, Ontario (2003)

Provided structural concrete design of a concrete dome residence.

Underground Parking Facility, Whispering Pines, Kitchener, Ontario (2003)

Provided structural concrete design of an underground parking facility for a four-storey residential apartment complex.

Interior Concrete Floor, Middlesex Concrete, Middlesex, Ontario (1998)

Provided structural concrete design of a 30 foot x 30 foot clear span suspended concrete floor.

Exterior Concrete Deck, Krista Nauss, Park Hill, Ontario (1998)

Provided structural concrete design of a 2,000 square foot exterior concrete deck surrounding the rear and sides of the home. The design of concrete circular stairs was also completed.

Interior Concrete Garage Floor, Krista Nauss, Park Hill, Ontario (1998)

Provided structural concrete design of a 2,300 square foot interior concrete suspended floor supporting six vehicles.

Commercial

Traxxside Additions, Traxxside, Guelph, Ontario (2009-2010)

Provided structural design for an addition to an existing storage facility, extensions to bin frames and extensions to a railway spur. Design services included the concrete foundation and framing design.

Sanimax Additions, Sanimax, Guelph, Ontario (2004-2008)

Provided structural design for an addition to an existing storage facility, extensions to bin frames and extensions to a railway spur. Design services included the concrete foundation and framing design.

Concrete Dome Kiosk, Great Lakes Dome Company, Toronto, Ontario (2005)

Provided structural design of a concrete dome security kiosk for a condominium. Services included the design of the dome, foundation and construction reviews.

Joist Review for Roof Top Units, Kings Buffet, Guelph, Ontario (2005)

Completed structural review of roof framing for support of several roof top units. Conducted snow shadow modeling and joist reinforcement layout drawings.

Romeo Street Business Park, Ritz Architect, Stratford, Ontario (1997)

Provided structural design of a second storey addition to an existing single storey band office.

Industrial/Manufacturing

Structural Design, Goodyear Plant Expansion (6000sqft), Napanee, Ontario (2010)

Structural design and drawings for a two storey addition for tire testing.

Structural Design, Mars Canada, Newmarket, Ontario (2010)

Structural design of mezzanines supporting equipment.

Equipment Platforms and Conveyor Systems, Various Locations, Effem, Bolton, Ontario (2010)

Structural design for various projects for equipment platforms and conveyor systems.

Five Large Frames for the Manufacture of Roofing Materials, IKO, Europe (2010)

Reviewed drawings provided by client and analysed frames supported equipment and processes for the manufacture of roofing materials. Prepared calculation report.

Equipment Installation at Various Industrial Facilities, Various Clients, Various Locations, Ontario (2010)

Working with various millwrights on a number of projects at industrial facilities for the installation of equipment.

Nuclear Power Plant Retrofitting, AECL, New Brunswick (2009)

Completed finite element analysis of a variety of components to be used to retrofit a nuclear power plant in New Brunswick. Prepared reports complete with calculations for peer review.

Building Code Review, JEA Masonry & Construction, Guelph, Ontario (2006)

Completed structural design review and life safety review for the renovation of an industrial facility. Services included liaising with Building Officials and Fire Marshals to determine fire hazard from stored materials.

Foundation Design, Greatario Engineered Storage, Innerkip, Ontario (2003-2006)

Provided structural engineering services for the design of numerous concrete foundations supporting water storage tanks across the eastern provinces and in Ontario.

Steel Frame & Foundation Design, We Cover Buildings, Elmira, Ontario (2001-2006)

Provided structural engineering services for the design of several rigid steel framed structures for construction across North America. Provided designs for various types of concrete foundations to support the steel structures.

Foundation Design, Cover-All Buildings, Various Locations, Ontario (2003-2006)

Provided structural engineering services for the design of foundations for steel truss framed structures.

Design of Precast Concrete Plant, Syricon Corp., Princeton, Ontario (2002)

Provided structural design review to relocate an existing rigid frame steel structure to Princeton. Designed the concrete foundations for the structure.

Csa Precast Concrete Plant Certification, Syricon Corp., Princeton, Ontario (2002)

Provided structural engineering services for the design of precast concrete floor panels and wall panels. Conducted plant certification reviews to ensure plant compliance with CSA regulations.

Plant Extension, Stackpole Ltd, Stratford, Ontario (2001)

Provided structural design services for a 100,000 square foot plant extension. Engineering services included steel frame and concrete foundation design.

Energy Recovery Facility, Toromont Energy, Waterloo, Ontario (1999)

Provided structural design services for a new energy recovery facility located on an existing landfill site.

Bioconversion Facility, Thermo-Tech Ltd, Hamilton, Ontario (1997)

Provided structural design services for a bioconversion facility. Engineering services included the design of the foundations and construction reviews of the steel frame.

Structural Tasks, Cooper Standard, Stratford, Ontario (1996-2002)

Provided structural design services for a variety of plant requirements including mezzanines, equipment relocations and additions.

Assembly

Orangeville Christian Fellowship Church, Orangeville, Ontario (2010)

Structural design and drawings for steel structural, main floor and foundations.

Schmidtzville Restaurant Addition, Schmidtzville, Ontario (2010)

Structural design and drawings for a two storey restaurant addition.

Structural Design and Drawings, Caledon Hospice, Caledon, Ontario (2009)

Structural design and drawings for steel structure, concrete foundations, precast main floor and timber grand entrance way.

Circus Tent Review, Ftl Design Studio, Toronto & Montreal, Canada (2003)

Conducted a structural review of the largest circus tent in North America for erection in Toronto and in Montreal. Performed construction reviews of tent and prepared report detailing snow removal procedures in Montreal.

Change of Use Structural Audit, St James Anglican Church, St Mary's, Ontario (2002)

Conducted a structural audit of various structural concerns involving the change of use of the deacon's residence to a commercial occupancy.

Structural Audit, St James Anglican Church, Stratford, Ontario (2002)

Conducted a structural audit of various structural concerns raised by owner. Review included the timber framed balcony, floor and rubble foundation walls.

Truss Review, Nancy Campbell Collegiate Institute, Stratford, Ontario (1999)

Conducted a structural review of a cracked timber truss spanning the auditorium. Prepared a repair detail for the cracked truss.

Innerkip Golf Course Clubhouse, Wilson Architect, Innerkip, Ontario (1999)

Provided structural design for clubhouse. Clubhouse was constructed of glulaminated rafters, steel walls, steel & wood floors and concrete foundations. Several architectural features presented unique design challenges, such as cantilevered floor systems.

Service Facilities/Automotive Dealerships

Entryway, Olympic Honda, Guelph, Ontario (2003)

Provided the structural design for an entryway into an existing dealership. The addition involved reviewing and reinforcing existing open web steel roof joists and construction of a new concrete foundation at the front of the building.

Aeroplane Hanger, Flightline Service Inc, Breslau, Ontario (1999)

Provided the structural design of an aeroplane hanger with refuelling facility, offices and retail components. The structure was steel framed with concrete foundations.

Paint Room, Milverton Millwrights, Milverton, Ontario (1998)

Provided the structural design for an addition to the existing building. The addition was for painting various structural components. The addition was steel framed with concrete foundations.

Structural Assessments/Expert Witnessing

Damaged Concrete Floor Slab on Grade, Forbes Chochla LLP, Kitchener, Ontario (2010)

Review of background documentation and analysed the concrete slab on grade by modelling the slab on a bed of springs using finite element analysis. Prepared a report outlining the findings.

Fertilizer Storage Bin, Cargill Aghorizons, Shetland, Ontario (2010)

Attended the site to observe the fertilizer storage bin. Prepared a report outlining observations, recommendations and steel reinforcement for the bin.

Site Measure, Cover-All Building, University of Guelph, Guelph, Ontario (2010)

Site measure of existing building. Prepared a report outlining the analysis of frame and a review of reinforcement options.

Renovated Residence, Ritchie Ketcheson Hart LLP, Toronto, Ontario (2008)

Visited the site to observe conditions. Identified critical issues relating to life safety dealing with building science and proper use of the home. Prepared a preliminary report of our findings.

Residential Foundation Wall Deterioration, Ritchie Ketcheson Hart LLP, Toronto, Ontario (2007)

Attended the site to observe the current condition of the existing foundation wall. Completed a structural assessment of the walls through calculations and field testing. Prepared a preliminary report of findings.

Residential Underpinning, Mr. Ken Kosow, Guelph, Ontario (2007)

Completed site observations, design and drawings for construction staging required to excavate a basement beneath an existing single storey residence. The design and drawings included underpinning staging.

Commercial Floor Assessment, Halton Place, Toronto, Ontario (2007)

Calculated the load carrying capacity of an existing 50 year old commercial structure. Completed the design and drawings for steel reinforcement to bring the load capacity to 100 psf (4.8 kPa).

Residential Underpinning, Madorin, Snyder LLP, Guelph, Ontario (2007)

Completed site observations, design and drawings for underpinning required to lower a residential basement by 12”. Design and drawings included underpinning staging.

Cracked Foundation Reviews, Various Contractors, Guelph, Ontario (2004-2006)

Conduct reviews of cracked foundations for various homebuilders in the Guelph area. Reviews include a description of the cracking mechanism and a repair strategy.

Steel Truss Frame Review, Client, Ottawa, Ontario (2005)

Completed a structural analysis of a steel truss framed building to address owner’s concerns. Prepared a summary of the analysis.

Cottage Construction Dispute, Client, Muskoka, Ontario (2005)

Completed a peer review of a structural engineering report of a cottage in the Muskokas that raised concerns with the framing. Provided a structural engineering report of our findings complete with an opinion of costs.

Collapsed Concrete Pit Wall, Dairy Barn, Client, Location, Ontario (2005)

Completed a peer review of a structural engineering report regarding the collapse of an interior concrete pit wall. Provided a structural engineering report of our findings.

Animal Research Facility Review, Pfizer, Michigan, USA (2004)

Conducted a review of the layout of the facility in order to identify any concerns or issues with regard to animal comfort and handling. Prepared a report highlighting areas of concern.

Expert Witness at a Tribunal, Toronto, Ontario (2003)

Conducted a detailed structural review of an existing suspended concrete floor slab. The strength of the floor slab was under dispute. Reviewed two opposing expert witness reports and conducted a site review of the floor. Prepared a detailed report countering other expert claims and presented findings at a tribunal. Qualified as an expert witness at the tribunal.

CN Railway Trestle Bridge Damage Review, Ritchie Ketcheson Hart LLP, Toronto, Ontario (2003)

Review expert reports regarding a CN Rail train derailment caused by a improperly secured piece of construction equipment. Conducted testing of the rigging/securement of the equipment. Prepared a report outlining our findings suitable for litigation.

Barn Collapse, West Wawanosh Insurance, Dungannon, Ontario (2002)

Conducted a detailed structural review describing site observations and the collapse mechanism of a barn. Wrote a report describing the review and detailing the collapse mechanism for the purpose of an insurance claim.

Foundation Wall Collapse, Township of Zorra, Ontario (2002)

Conducted a detailed structural review describing site observations and the collapse mechanism of a pit wall in a barn under construction. Wrote a report describing the review, detailing the collapse mechanism and a repair recommendation.

Pier Review of Arena Audit, Town of Newmarket, Ontario (2002)

Conducted a detailed structural pier review of a structural audit prepared by another structural engineering company. Wrote a report describing our findings.

Bin Wall Collapse, Agribrands Purina, Woodstock, Ontario (2000)

Conducted a detailed structural review of a 10,000 ton bin that had a wall collapse. Prepared a report describing the collapse mechanism and a repair/maintenance strategy.

Riding Arena, Krista Nauss, Park Hill, Ontario (1999)

Conducted a detailed structural and fire safety review of an existing house riding arena and stables. Wrote a report describing the review and areas of concern suitable for litigation.

Recreational/Hospitality

Sports Domes, Various Clients, Ontario, British Columbia, New Brunswick (2003-2010)

Design of air supported structures for a wide variety of uses including driving ranges, tennis, soccer and basketball.

Arden Park Hotel, Milverton Millwrights Ltd, Stratford, Ontario (1999)

Provided structural design of an eight-foot deep heavy steel truss spanning 60 feet supporting three floors of the hotel over the ballroom.

Log Picnic Pavilion, True North Log Homes, Montreal, Quebec (1998)

Provided structural design of a heavy timber frame and trusses for a picnic shelter with cooking facilities and seating.

Grain/Fertilizer

Grain Bin Wall Panel Removal, TVT Millwrights, Princeton, Ontario (2010)

Attended the site to measure and make observations. Completed an analysis of the bin with select panels removed and prepared a report outlining findings and recommendations.

Grain Shipping Terminal, James Richardson International, Hamilton, Ontario (1997)

Provided structural design of a new grain shipping terminal in Hamilton Harbour. Structural concrete design included truck unloading, truck load out, truck scale, grain dryer, system of concrete tunnels beneath bins for conveyor system and steel towers for conveyors to transport grain into bins and into ships.

Industrial/Agricultural

Drive Sheds, Equestrian and Dairy Facilities, Various Clients, Various Locations, Ontario (2003-2010)

Completed structural designs and drawings for a large number of agricultural projects across Ontario. The projects ranged from small additions, manure storage tanks, grain silos and complete barns.

Beef Research Facility, University of Guelph, Elmira, Ontario (2003-2004)

Provided design/build services for project. We were later retained to provide structural engineering services and drawings.

Various Structural Tasks, Agribrands Purina, Woodstock, Ontario (1997-2001)

Provided structural design services for a variety of projects involving cutting openings in floors and installing new grain bins.

Government/Municipal

Guelph Transit Hub, City of Guelph, Guelph, Ontario (2010)

Design of bus shelters and retaining wall supporting railway.

Potable Water Standpipes and Pedestals, Various Clients, Various Locations, (2003-2010)

Structural design and drawings for concrete foundations and pedestal designs supporting potable water storage tanks in a variety of Provinces including; Ontario, Quebec, Newfoundland, Prince Edward Island, Nova Scotia and New Brunswick.

Second Story Addition to Band Office, Naicatchewenin Band Office, Fort Francis, Ontario (1999)

Provided structural design of a second storey addition to an existing single storey band office.

Romeo Street Water Reservoir, City Of Stratford, Ontario (1997)

Provided structural concrete design of a large underground drinking water storage tank (7,500 m^3).

NEEGAN BURNSIDE

Mark Sheedy

Profession

Project Manager and Construction Contracts Manager

Education

Diploma, Civil Engineering Technology, Ryerson Polytechnical Institute, 1985

Employment Record

Vice-President, Field Services, R.J. Burnside & Associates Limited (2008-Present)

Project Manager and Construction Contracts Manager, R.J. Burnside & Associates Limited (1994-2008)

Contracts Administrator, R.J. Burnside & Associates Limited (1990-1994)

Construction Inspector/ Supervisor and Branch Office Manager, Paul Theil Associates Ltd. (1985-1990)

Citizenship

Canadian

Languages

English

As Vice President, Field Services, Mark Sheedy heads up the Field Services Team throughout the company and is responsible for Quality/Control for that group. During his 25 years of consulting experience, Mr. Sheedy has been involved in an extensive number of projects for a wide variety of significant clients.

As a Project Manager Mr. Sheedy is involved with variety of projects and clients. This includes many private residential developments, commercial site plans, numerous municipal infrastructure projects as well as energy projects and First Nation projects. He prepares or assists with proposals as well as managing projects through design, approvals and construction. Budget control is amongst his duties as well as staff coordination and communication with agencies, governments and clients.

Private Development Construction

Project Management on various commercial site plans including Tim Hortons, Sobeys, A&W and various industrial developments or renovations as well as numerous residential developments in Southern Ontario.

Project Manager, Mattamy Homes, Bracebridge-Clearbrook Development, Bracebridge, Ontario (2007-2010)

Coordinate design team, approvals and tendering & construction for multi-phase 500 lot development including four SWM ponds, rock excavation, intersection signalization & groundwater control requirements.

Civil Construction Manager, Sithe Energy Goreway Station Power Generating Station, Brampton, Ontario (2007-2009)

Coordinated Owners engineering team for civil services and transmission line construction for 880MW gas fired power station in Brampton, Ontario. Prepare civil contracts for water supply, transmission line design build and construct including interconnection to Hydro One power grid.

Project Manager, Sobeys at Chinguacousy & Queen, Sobeys Ontario, City of Brampton, Ontario (2003)

Managed the site servicing and grading design and approvals as well as construction inspection and coordination for the Sobeys site plan at Chinguacousy and Queen Street in Brampton. Prepared proposal and managed budget control for our services. Project included final preparation of turn lane design and entrance configuration from Chinguacousy including temporary conditions layout during extended utility re-locates.

Project Manager, Broadway Plaza Expansion at Broadway/Townline, Beacon Group, Town of Orangeville, Ontario (2002)

Project Management of site plan design, approvals and construction for plaza expansion to add Tim Hortons and A&W restaurants as well as an expansion to the existing building. Project included new entrances on to Broadway, underground site services as well as design considerations given to re-construction of parking area within in the flood plain of Mill Creek.

Project Manager, Brymar Developments, Nirod Investments, Alliston, Ontario (2002-2003)

Project Management of a three-phase residential Development in Alliston in the Town of New Techumseth. Included acquiring final design approvals and managing the project through three phases of site servicing work including earthworks, pond construction, dewatering, external roads and sewers and internal sewer, watermain and road construction. Included liaison with the Town, County, Owner and Builder.

Project Manager, Sobeys at Mayfield Road & Highway 10, Ventawood Management, Brampton, Ontario (2001)

Project Management of design, approvals and construction of site plan for second phase of site plan development, which included new entrances, site services and parking lot expansion. Also included was turn lane and lane widening and lane extensions design along Mayfield Road east through intersection with Colonel Bertram Road for cost share calculations and entrance detailing purposes.

Project Manager, Various Projects for Rice Group, Innisfil and Simcoe County, Ontario (1999-2002)

Project Management for Rice Group client with various retirement community reconstruction projects, residential projects and commercial site plans. Includes the Forest Valley Estate lot Development at Innisfil Beach Road and Highway 400. Private road reconstruction program at Sandy Cove Acres retirement community as well as storm pond design and construction for flood relief.

Contracts Manager, Princeton Heights, Roseburn Developments, Bolton, Ontario (1998)

Contracts Manager through tendering and construction for Princeton Heights in Bolton. This residential subdivision in Bolton included constructing the municipal services including a stormwater management pond for 87 lots.

Contracts Manager, Southridge Estates, Harbourview Investments, Bolton, Ontario (1995-2002)

Contracts Manager through tendering and construction for the South Ridge Estates residential development project in Bolton. This multi-phase project spanned approximately eight years and included general grading, storm water management, underground servicing and road building for some 600 homes.

Contracts Administrator, Edgewood Valley Subdivision, First Professional Development, Orangeville, Ontario (1991)

Contracts Administrator for Edgewood Valley Subdivision in Orangeville for First Professional Developments. This project consisted of 205 lots with a construction value of approximately $2.0 M and included an external sanitary trunk sewer and three storm/quality ponds.

Municipal Construction

Project Manager – Construction, Trunk Sanitary Sewer Rehabilitation, Peel Region, Brampton, Ontario (2006)

Coordinate final design approvals, tendering and construction including replacement and bypass under the Credit river at numerous locations of a 1050mm to 1200mm dia trunk sanitary sewer main. Included significant in stream works, including river fordings, coffer daming and temporary bridge crossings.

Contracts Administrator, George Bolton Parkway, Corporation of the Town of Caledon-JV, Bolton, Ontario (2002)

Contracts Administrator for construction of the George Bolton parkway link from Coloraine Drive to Regional Road No. 50 in Bolton in the Town of Caledon, Region of Peel. Project included road construction, sewer and watermain installations and construction of three storm water management ponds. Watermain construction required a bored and jacked crossing of Regional Road No. 50. The storm sewer work included installation of outlet piping and manholes within the southbound lanes of Regional Road No.50.

Contracts Administrator, Brampton Pedestrian Bridges, City of Brampton, Ontario (1998)

Contracts Administration for the construction of pedestrian bridges and pathways in Valleybrook Park and Kalimba/Camden Park as well as on underpass at Bovaird Drive for the City of Brampton.

Contracts Administrator, Elizabeth St. Reconstruction, Town of Listowel, Ontario (1991)

Contracts Administrator for reconstruction of services and roads for Elizabeth Street for the Town of Listowel. This project included preparation of the tender as well as coordinating the construction inspection, administering the contract and liaison with the Municipality and Contractor.

Contracts Supervisor, Road and Infrastructure Reconstructions, Corporation of The Town of Aurora, Ontario (1988-1990)

Contracts Supervisor for complete reconstruction of a number of streets for the Town of Aurora. This included replacement of underground services and liaison with the public and the municipality.

Contracts Administrator, Flood Relief Project, Town of Richmond Hill, Ontario (1987)

Contracts Administrator for reconstruction of services and roads for Zelda Road and Bluegrass Street for the Town of Richmond Hill. This project included installation of a large diameter storm for basement flood relief.

First Nation Infrastructure Construction

Project Manager, Pic River First Nation, High Falls and Manitoulin Falls, Ontario (2010)

Coordinate engineering team to act as the Owner's review engineer for two hydro-electric development sites in the Thunder Bay general region.

Contracts Administrator, Grassy Narrows Community Infrastructure, Grassy Narrows First Nations, Kenora, Ontario (1993-1995)

Contracts Administrator for infrastructure expansion for the Grassy Narrows Community near Kenora. Project value was approximately $6.0 M and included a new water plant with lake intake, water standpipe and 8 km water distribution main. Also included was a package sewage plant, as well as distribution and collection systems with extensive trench rock excavation. This involved site visits over a two-year period and liaison with the First Nation and Federal Government Authorities.

Contracts Administrator, Water Supply and Distribution, Chippewas of the Thames First Nation, Muncey, Ontario (1992)

Contracts Administrator for a water supply and distribution project for Chippewas of the Thames Community near London, Ontario. The project included installation of production wells, water plant, water tower and an extensive 21 km distribution network.

Contracts Administrator, Site Servicing, Alderville First Nation, Alderville, Ontario (1992)

Contracts Administrator for a rural subdivision project for the Alderville Community near Peterborough. The project included construction of roads and ditches for an estate lot type subdivision for this First Nation Community within their lands.

NEEGAN BURNSIDE

Arunas R. Kalinauskas, B.Sc.

Profession

Geomatics Specialist

Education

B.Sc., University of Toronto, Physical & Environmental Geography, 1981

M.Sc., course work, York University, Experimental Space Science, 1986

Professional Societies

Ontario Association of Remote Sensing

Employment Record

Manager, Geomatics Group, Neegan Burnside Ltd. (2006-Present)

Manager, Geomatics Group, R.J. Burnside & Associates Limited (1996-2006)

President, Remote Sensing and GIS Consultant, ARK Enterprises (1991-1996)

Instructor ARCView GIS Course, Humber College (2000)

Manager, Remote Sensing Applications, Moniteq Ltd. (1990-1991)

Project Manager, Remote Sensing Applications, Moniteq Ltd. (1986-1990)

Hyperspectral Remote Sensing Research Assistant, York University (1982-1986)

Remote Sensing Research and Teaching Assistant, University of Toronto (1980-1982)

Citizenship

Canadian

Languages

English, Lithuanian

Arunas Kalinauskas, Manager, Geomatics Group, has over 25 years of remote sensing and GIS experience. He has undertaken many diverse remote sensing and GIS application projects. Arunas has lead the development of many new applications and models using a variety of geomatics sensors and platforms.

Arunas has focused his work on applications and commercialization of remote sensing and GIS technology. One of the key areas where he has focused his commercialization efforts has been in the design and implementation of local government GIS applications modules. As well, he has worked on Municipal GIS software products to provide cutting-edge industry-specific solutions.

Recently, Arunas has lead Burnside developers, and strategic partners in the development of effective asset management and capital planning tools. In this role, Arunas has been formulating solutions that combine client expectations with engineering expertise gathered from Burnside's engineering staff.

Geographic Information Systems

Project Manager, Development and Delivery of Burnside Asset Manager, Canada (2008-Present)

Design and development of Burnside Asset Manager software solution. The system was developed and delivered to 12 Municipalities. This application is also integrated with Direct IT's Work Manager solution making the combined asset management system a complete end to end asset and maintenance management solution. This solution is now being sold across Canada and into the USA.

Technical Manager, Feasibility Study on a Municipal Asset Information System, Saskatchewan Municipal Affairs (2008-2010)

Undertook a feasibility study on a Municipal Asset Information System (MAIS) for the Province of Saskatchewan which included identifying their information technology system needs and analysed possible solutions. The project defined a system that was simple in design and maintenance, flexible to accommodate diverse capabilities of local governments. The project had three phases, composed of client consultation, technical strategy development, and final recommendations. The Province received the recommendations well and has been formulating their next steps to move forward.

Project Manager, Public Sector Accounting Board (PSAB) Capital Asset Policy and Inventory for Municipalities (2008-2010)

Working with many Municipalities to assist in the development of PSAB policy and the collection and inventory of their capital assets. This satisfies the first stage of the change in financial reporting for Municipalities.

Technical Manager, City of Kingston Asset Management Plan for City Parks, (2008-2010)

Developed the design for the Information Technology part of the Asset Management Plan of the City Parks Department. The project included the consultation of the asset data collection and maintenance to ensure that this data is the sole data repository for Parks assets. The Plan included the use of the City's current GIS and IT infrastructure, which would enable the City to expand it's use to all of the other City departments. The resulting plan included the Recreation/Leisure/Parks, Engineering, Public Works, IT/GIS, Finance, Booking and Call Centre in the delivered Asset Management Plan. This project is being used as an example for other City Departments to move towards a corporate Asset Management Plan.

Project Manager, Development and Delivery of Burnside Mobile GIS Systems – Route Patrol Manager, Winter Patrol Manager, Sidewalk/Trail Maintenance Manager, Fleet Manager, Canada, USA (2002-2009)

Working on the design and development of the Burnside mobile GIS solutions. Once developed the systems were sold and installed in over 30 Southern Ontario Municipalities. This product line is now being promoted across Canada and into the USA.

Project Manager, Web GIS System for the County of Perth, Ontario (2008)

Partnering with ORION Technologies Inc. a web GIS solution was delivered to Perth County and the four local municipalities. Each group is able to view their municipal parcel fabric and associated land owners as well as other GIS mapped layers.

Project Manager, GIS Needs Project, Perth County and Local Municipalities, Ontario (2006)

Through meetings with Municipal staff and data review a comprehensive GIS Needs study was developed and presented for the County of Perth and the Local Municipalities. This project has lead to many more implementation projects of Burnside GIS Solutions to the County and Local Municipalities.

Group Leader, Multi-Criteria Analysis for Platinum Exploration, Plantinex Inc., Aurora, Ontario, (2004)

Client data was integrated into a GIS system and processed to identify the highest probability locations for further exploration drilling. This project included working with the client geologists and implementing.

Project Manager, New Zoning Bylaw GIS Mapping, Township of Adjala-Tosorontio, Alliston, Ontario (2003)

Working with client municipal planners, and old zoning information, a new zoning by-law was generated and mapped. Old zoning mapping was converted from

AutoCad drawings into a full ArcGIS Geodatabase. This provided for the Township easy access to new zoning information through their GIS.

Project Manager, GIS Strategic Plan for the Saginaw Chippewa First Nation (SCIT), Michigan, USA (2003)

Through on site meetings and discussions Burnside gathered information about various department workflow and data. This then was translated into a SCIT GIS Strategic Plan. The plan/report was presented to SCIT department managers.

Group Leader, Municipal GIS Roads Module, Township of Mulmur, Lisle, Ontario (2002-2003)

Customization of municipal GIS module, which includes specialized GUI and script function keys to assist municipal staff operators. GPS data collection of the town road network was also included. The GPS information is then integrated with other road inventory data to create a linked complete road database and map. Prioritization schedules for road upgrades and maintenance are computed using the GIS system. Installation and training of staff is also completed. Support of the installed GIS module is continuing.

Group Leader, Municipal Groundwater Protection Study 10 Municipalities, Orangeville, Shelburne, Mono, Amaranth, East Garafraxa, Minto, East Luther, Grand Valley, Mulmur, Wellington North, Ontario (2001)

All data collected and maps will be integrated into a GIS system for more efficient and effective computation of groundwater resources for 10 municipalities. Data will be geophysically displayed and reported.

Project Manager, Aerial Photography and Mapping for Saginaw Chippewa First Nation, Michigan, USA (2001)

Ortho rectified aerial photography was collected over the Saginaw Chippewa First Nation (SC). Both spatial and vertical mapping of SC physical assets were created and delivered.

Project Coordinator, Municipal Roads Needs Study Using GIS, Tiny Township, Perkinsfield, Ontario (2001)

Integration of all Municipal road segment make-up and quality inventory was linked to existing Municipal assessment parcel maps and database. The GIS system was also used to compute a prioritized road maintenance and road upgrades schedule.

Project Manager, Application of GIS Technology for a Municipality, Town of Mono, Orangeville, Ontario (2000)

Completed the clean-up and geometric rectification of the Town maps and then linked the maps to the Town's assessment database in a GIS system. The project team then created a user interface that enables Town staff to access information, perform queries, and create notification mailings at their fingertips more cost effectively.

Project Manager, Municipal GIS Notification and Land Use Modules Customization Installation, Training and Support Service, Town of Mono, Orangeville, Ontario (1999)

Installed customized GIS system for the Town of Mono. Wrote and implemented specialized GUI and GIS scripts. Performed verification of the GIS system functionality and database links. Finally, successfully trained staff with respect to the use of the customized GIS system. Ongoing service and support of the installed GIS system is continuing.

Airborne Remote Sensing

Project Manager, Diamond Exploration, using hyperspectral remote sensing in Greenland, Hudson Resources, Greenland (2003)

Processed data of airborne hyperspectral data collected over Greenland. Analyzed the data spectral signatures for diamond barring kimberlite potential. This project provided the client with maps of high potential mineralized areas. Verified results in field surveys. Further work is being carried out on this property by the client.

Project Manager, Design and Implementation of an Airborne Hyperspectral Profiling System, Nevada, USA (2002)

Designed and built a new hyperspectral profiling system. Installed and tested the system in a survey air plane, over a site in Nevada. The data was processed and showed good correlation with ground field data. This system identified surface materials via spectral characteristics. This project was in conjunction with the Canadian Space Agency (CSA), and the USA, National Aeronautics and Space Administration (NASA).

Project Manager, Implementation and Operation of Airborne Hyperspectral Imaging Surveys, USA and Canada (2001)

Survey sales, planning, implementation and operation of the TRWIS III hyperspectral imaging spectrometer. Conducted several projects in the collection of airborne hyperspectral data. Coordination of field surveys as well as planning around weather conditions resulted in successful data capture missions. Data delivery to clients with follow-up to ensure data quality was provided.

Project Manager, Development and Implementation of Water Quality Software for Hyperspectral Data, Ariel Geomatics Inc., Halifax, Nova Scotia (1994)

Radiative transfer model development and modification for commercialization was completed and then integrated into a software package that utilizes airborne hyperspectral data. Test data from Chile was processed.

Project Manager, Land-Use Classification Using Hyperspectral Remote Sensing and GIS System, Hungarian Department of Environment and Agriculture, Hungary (1989)

Processing and analysis of hyperspectral data collected over Hungary. This project utilized the high spectral resolution information to identify different crops, tree types and soils. It also was processed and used as a baseline environmental data set. Information was integrated together using a simple GIS system.

Project Manager, Hyperspectral Remote Sensing for Inland Lake Water Quality, Ontario Ministry of the Environment, Ontario (1989)

Application of developed hyperspectral water quality models for chlorophyll monitoring. This project demonstrated to a government client the hyperspectral sensor and its potential to mapping physical water quality parameters across inland lakes.

Project Manager, Hyperspectral Remote Sensing for Inland Lake Water Quality, Ontario Ministry of the Environment, Ontario (1989)

Application of developed hyperspectral water quality models for chlorophyll monitoring. This project demonstrated to a government client the hyperspectral sensor and its potential to mapping physical water quality parameters across inland lakes.

Project Scientist, Atmospheric Correction Models Development and Writing of a Software Program for Hyperspectral Data Correction, Canada Centre for Remote Sensing, Ottawa, Ontario (1988)

Tested different radiative transfer models for atmospheric connection and wrote a software program that can be applied to hyperspectral imagery data. The results of this program produces surface reflectance spectra.

Project Specialist, Municipal Coastline Base Mapping, Metro Toronto Region Conservation Authority, Metropolitan Toronto, Ontario (1988)

Processed hyperspectral airborne digital imagery for sewage treatment outfall plume location and circulation patterns along municipal costal zone. In addition, enhanced the data and used it to update the municipal basemaps.

Project Scientist, Hyperspectral Remote Sensing for Geobotanical Anomaly Identification, Canada Centre for Remote Sensing, Ottawa, Ontario (1988)

Vegetation stress and red edge shift were identified using airborne hyperspectral data over a known gold deposit. The models and software developed was verified using ground-based surveys.

Project Scientist, Development of Bathymetric and Water Quality Models for Commercial Mapping Using Hyperspectral Remote Sensing, Canada Centre for Remote Sensing, Ottawa, Ontario (1987)

This project was commercial implementation of Mr. Kalinauskas graduate studies research. The hyperspectral models were implemented in a software program and tested over a coastal inland lake. Bathymetric accuracies of sub 1/4 metre were identified.

Project Scientist, Hyperspectral Remote Sensing for Coastal Zone Mapping and Feature Classification, United States Marines, USA (1987)

Mapping of a coastal region using hyperspectral signatures to separate and identify different sub-water surface bottom types, coastal soils and rock types as well as vegetation types.

Satellite Remote Sensing

Project Manager, IKONOS Satellite Data Acquisition Over Mining Site for Royal Nickel Corp. (2008 and 2010)

Definition of the data required for the client and interaction with the satellite data provider to ensure the proper data was collected processed and delivered to the client. This project required many attempts to data capture as the weather was not favourable for data collection.

Project Manager, Satellite Remote Sensing Study of the Geological Structure of the Big Trout Intrusion, Platinex Inc., Aurora, Ontario (2002)

Combined RADARSAT and IKONOS satellite imagery with other satellite imagery, airborne geophysics, ground based geology and a number of other data sets into a Geographical Information System (GIS) database. The project interpreted the structure and defined new platinum group metals (PGM) targets within the Big Trout ultramafix intrusion.

Project Manager, The delineation of Groundwater Resources in Bedrock Aquifers for the Cochabamba Municipality using RADARSAT, Prefectura of Cochabamba, Bolivia (2002)

An interpretation of the bedrock structure of the Cochabamba area was conducted using RADARSAT, Landsat, SPOT and other satellite data, which was combined into a GIS database with geological mapping and other geological and geophysical datasets. The data was processed and interpreted to provide a regional and local understanding of the structurally hosted groundwater resources. Ground truthing included detailed mapping and geophysical surveying to identify drill targets.

Project Manager, IKONOS Satellite Data Orthorectification for Municipalities, Town of Mono, Town of Orangeville, Town of Shelburne, Township of Mulmur, Lisle, Ontario (2001)

IKONOS 1m colour satellite data was ordered and processed. The orthorectification processing of the data was completed by Burnside and delivered to clients. This data was then installed on the Municipal servers and accessed via Municipal GIS or CAD systems.

Project Manager, IKONOS Satellite Data for the Municipality of Kenora and Wauzhushk Onigum First Nation Base Map, Wauzhushk Onigum First Nation, Kenora, Ontario (2001)

IKONOS satellite image geometric rectification and image enhancement was completed for the areas of the Town of Kenora and the neighbouring Wauzhushk Onigum First Nation. This one metre resolution base map was then to be used in a capital works building project.

Project Manager, Integration of RADARSAT Data with Other Data Sets for Mineral Exploration, Erapuca Project, Intrepid Minerals Corporation, Honduras, (1999)

The project team acquired satellite imagery and conducted a regional structure interpretation to assist Interpid Minerals Corporation in developing exploration targets over large inaccessible concessions. This data was combined in a GIS database with airborne geophysics, geochemical and geological data. Multi-criteria analysis was used to identify high priority exploration targets for further gold exploration.

Project Manager, Interpretation of a RADARSAT Image of Northern Honduras after Hurricane Mitch, CARE Canada and CIDA (1998)

RADARSAT satellite imagery provided by the Canadian Space Agency was processed and interpreted to determine impacts to infrastructure such as roads, pipelines, bridges, etc., as well as impacts to crops, drainage systems and potential landslide areas.

Project Manager, Integration of Satellite and Airborne Data for Exploration in Eastern Bolivia, American Barrick Corporation, Bolivia (1998)

Landsat, JERS and RADARSAT satellite data was combined with airborne geophysical data sets as geological mapping in a pilot project to identify exploration targets based on the clients mineralization models.

Project Manager, Development of a Vegetation Compensation Model (VCM), Centre for Research in Earth and Space Technology (CRESTech), Ontario (1998)

RADARSAT, JERS, and Landsat data were utilized in the development of a model to eliminate the vegetative cover of the Amazonian forest. The VCM model has demonstrated the ability to expose the surface structural features below the Amazonian forest canopy.

Project Manager, Instruction of Hyperspectral Training Course, Hungarian Department of Environment and Agriculture, Budapest, Hungary (1988)

Instructed and trained top ranking Hungarian government staff in hyperspectral technology and data processing. This program covered hyperspectral sensor, hardware, calibration, and spectral feature identification selection of other related projects.

Project Manager, Training and Instruction of Theory and Application of Remote Sensing for Water Quality and Bathymetric, Thailand National Research Council, Bangkok, Thailand, (1988)

Provided a one-week training course for the National Research Council in Thailand, on remote sensing for water quality and bathymetry. This course made use of hands on software demonstration and training. This project was in conjunction with a CIDA technology transfer program.

Project Scientist, Satellite Monitoring of Desertification, People's Republic of China (1982)

Landsat data and historical information was integrated together to map how desert regions in China were growing. This project included a field verification survey, during which instruction of methods used was formally taught at the Chinese Academy of Sciences, Bejing University and the Desert Land Institute. The survey confirmed very high accuracy of satellite remote sensing methodology.

Publications

Kalinauskas A. R., Walls J. R., and Godin E. 2001. “Airborne Geochemistry Using Hyperspectral Imaging”, Presented at the Canadian Exploration Geophysicist Symposium, Toronto, Ontario, Canada.

Walls J. R. and Kalinauskas A. R. 2000. “The Delineation of Groundwater Resources in Bedrock Aquifers Using RADARSAT”, Proceedings of the Fourteenth International Conference of Applied Geologic Remote Sensing, Las Vegas, Nevada, USA.

Kalinauskas A. R., Rubinstein I., Walls J. R. 1998. “Vegetation Correction Model Using RADARSAT, JERS, and LANDSAT TM”, Poster Paper - GIS/98, April, Toronto, Canada.

Buxton R.A.H., Kalinauskas A. R., Markovic M., Levesque S., and Ripley H. T. 1996. "Development of water quality software for CASI imaging spectrometry", Proceedings - Oceanology International Conference 96, March, Brighton, UK.

Kalinauskas A. R., Hutchinson N., and Neary B. 1990. "Use of past, present, and future satellites for monitoring chlorophyll in lakes", Proceedings of the Ministry of the Environment Technology Transfer Conference, November, Toronto, Ontario.

Kalinauskas, A.R. 1989. "Use of high spectral and spatial resolution airborne digital sensors for marine applications - Case studies". Oceans 1989. Seattle, Washington.

Kalinauskas, A.R., N. Hutchinson, and B. Neary. 1988. "Remote Sensing for Chlorophyll, Case study - Lake of the Woods, Ontario". Presented at the 31st International Association for Great Lakes Research, Hamilton, Ontario.

O'Neill, N.T., A.R. Kalinauskas, and J.R. Miller. 1987. "Passive optical bathymetry: Status review and perceived development methodologies in operational hydrography". Proceedings of the 11th Canadian Symposium on Remote Sensing, Waterloo, Ontario.

O'Neill, N.T., A.R. Kalinauskas, G.A. Borstad, H. Edel, J.F. Gower, and H. Van der Piepen. 1987. "Imaging spectrometry for water applications". Proceedings of the 31st Annual International Technical Symposium on Optical and Optoelectronic Applied Science and Engineering - Imaging Spectroscopy II, San Diego, California, SPIE Proceedings V. 83.

Teillet, P.M., N.T. O'Neill, A.R. Kalinauskas, D.R. Sturgeon, and G. Fedosejevs. 1987. "A dynamic regression algorithm for incorporating atmospheric models into image correction procedures". Proceedings of the International Geoscience and Remote Sensing Symposium.

O'Neil, N.T., A.R. Kalinauskas, J.D. Dunlop, A.B. Hollinger, H. Edel, M. Casey, and J. Gibson. 1986. "Bathymetric analysis of geometrically corrected imagery data collected using a two dimensional imager". Proceedings of the Society of Photo-Optical Instrumentation Engineers.

Dick, Kenneth, Arunas Kalinauskas, John Miller, and S.C. Jain. 1984. "Shallow water model evaluation for passive remote sensing of water depths". Proceedings of the ninth Canadian Symposium on Remote Sensing, p. 177-182.

Miller, John, Kenneth Dick, and Arunas Kalinauskas. 1984. "Water depth mapping by passive remote sensing", Final Technical Report - PRAI Project #P-8105, p. 116.

Luk, Shiu-Hung, and Arunas Kalinauskas. 1982. "Satellite Monitoring of recent decertification in the Yulin Region, the People's Republic of China". Proceedings of the first thematic mapping conference - Remote Sensing of Arid and Semi-Arid Lands, Cairo, Egypt.

NEEGAN BURNSIDE

Paul M. Stubbert, B.A.

Profession

GIS Specialist

Education

Post Graduate Certificate in GIS, Niagara College of Applied Arts and Design, 2001

B.A., Major in Geography St. Mary's University, 1994

Primer for GIS (Correspondence) College of Geographic Sciences, 1999

Imagery Analysis (Correspondence) United States Army Professional Development Program, 1995

Canadian Forces School of Intelligence and Security, 1993

Employment Record

GIS Specialist, R.J. Burnside & Associates Limited (2001-Present)

Teacher, GEOS Corporation of Japan (1997-2000)

Intelligence Officer, Canadian Forces Intelligence Branch (1990-1996)

Citizenship

Canadian

Languages

English, Basic Japanese

Paul has been employed at Burnside since 2001 and has logged over 15,000 hours on the ArcGIS suite of software. Paul's primary project focus has been divided between municipal infrastructure and information, hydrogeology, and hydrotechnical services

Paul has worked on municipal infrastructure and information projects for dozens of municipalities primarily throughout Ontario, but also including Africa and the Caribbean. Since 2002, he has been supporting hydrogeological and hydrotechnical related projects that have covered over 100,000 km^2 of area.

Paul is recognized as an authority within Burnside on spatial database design, employment, and cartography. He has contributed to the design of the Burnside Asset Management Data Model in use by several municipalities and Burnside business partners. He has also developed standard database models for internal Burnside use and project support. These models have increased Burnsides ability to serve its clients by allowing efficient transfer and integration of information between different projects, increasing quality control for data, and enabling the rapid production of high quality cartographic products.

Paul's training with the Canadian Forces focused on supporting senior operations and planning staffs of a multi-disciplined organization through the coordination, collection, processing and dissemination of information. This included the development of situational awareness through the use of ground, airborne, and spaceborne reconnaissance assets, geomatics products, and information collection from various sources and agencies.

He has been employed as an instructor over a period of 10 years of involvement with Canada's Cadets and Military. He has also passed several junior leadership courses and was commissioned an officer in 1992.

Groundwater and Source Water Protection Projects

Country of Barbados, Lakehead Region Conservation Authority (City of Thunder Bay), Mattagami Conservation Authority (City of Timmins), Region of Peel, Grey and Bruce Counties, City of Sault. Ste. Marie, Towns of Shelburne, Orangeville and Mono, Townships of Amaranth, Adjala-Tosorontio, East-Garafraxa, East-Luther Grand Valley, Mapleton, Guelph/Eramosa, Melancthon, and Mulmur, Six Nations of The Grand River (2002-Present)

Responsible for modeling hydrogeologic and geologic surfaces from well database, geologic and topographic data. This included integrating various government and municipal geospatial and database datasets with remote sensing and GPS field data, locating contaminated sources via imagery and geocoded data, creating queries in MOE well database to extract data for modeling, and creating cartographic output and cross sections for reports. Created front-end and back-end databases to assist project team in data entry and evaluation.

Hydrology and Hydraulic Analysis

Highway Reconstruction Projects, County of Simcoe, Midhurst, Ontario (2009)

Responsible for the processing of detailed terrain models and the evaluation of catchment areas for culverts; pre and post construction environments.

Floodplain Mapping, Municipality of Kincardine, Ontario (2007)

Responsible for extraction of model data via Hec-GeoRas, including defining of hydrographic surface environment with ArcHydro, management of data models, and cartographic production.

Solid Waste Management

Topographic Map Production, Landfill Facilities and Areas, Barbados (2006-Present)

Responsible for topographic map production and updates to landfill facilities and areas. Provision of data to sub-consultants for air modeling. Creation for 3D movies demonstrating the evolution of landfill facility over its lifetime.

Solid Waste Routing Pick Up Options, Townships of Southgate, Dundalk, Ontario (2004)

Responsible for creating routing scenarios to assess solid waste pickup options. Also created solid waste pickup routing for waste trucks. The work included customizing MS Access database for recording the delivery of waste carts and evolved database to meet the needs of daily administration of the waste management system, interpolating hydrogeologic surfaces to evaluate contamination susceptibility for areas around landfills, and providing cartographic products to support all phases of project implementation.

Municipal Planning

Towns of Mono and Shelburne, Townships of East-Garafraxa, Amaranth, Mulmur, Clearview, East-Luther Grand Valley, Ontario (2001-Present)

Responsible for creating and maintaining municipal planning data to include parcel fabric, official plan and zoning. In addition, created infrastructure data to include roads, bridges, culverts, emergency numbers, etc. Also performed image processing and orthorectification of Ikonos satellite imagery.

Municipal Infrastructure & Transportation Projects

Towns of Mono, Shelburne and Zora, Townships of East-Garafraxa, Amaranth, Mulmur, Clearview, East-Luther Grand Valley, Guelph/Eramosa, Mapleton, Six Nations of the Grand River, Ogemawahj Tribal Council, and Mattawa Tribal Council, Rep of Mozambique (2003-Present)

Responsible for database design and field data collection. Post-processing and QA/QC of data. Query and calculation development to evaluate asset conditions. Cartography. Processing of satellite imagery.

Mineral Exploration

Mineral Search, Platinex Inc., Markham, Ontario (2003)

Responsible for conducting multi-criteria analysis of magnetic, chemistry and geological data in the search for platinum deposits. In addition, created cartographic output and cross sections for reports, integrated datasets from over 6 agencies, and provided

Environmental Assessment

GO Transit Niagara Expansion, GO Transit, Niagara Area, Ontario (2010)

Responsible for the integration of data from various sources and agencies for public information centers.

Bujagali Hydropower Project, Sithe Canadian, Uganda (2006)

Responsible satellite image processing, analysis, and mapping of environmental restrictions. Assisting Engineers in the routing of new transmission corridors through urban areas.

Resume of Experience and Qualifications
Bruce E. Clarida, P. Eng. FEC
Civil Engineer and Project Director

Bruce E. Clarida, P. Eng. FEC
Civil Engineer and Project Director

Profile

Thirty one (32), years of progressive experience in planning, design and project management of large Civil infrastructure projects in Hydroelectric Generation and Transmission facilities, Wind and Solar PV Energy, Dams and Reservoirs ;
VP Engineering and Development, Clarida Green Energy, completed 190 MW of Wind energy and 66 MW of ground mount Solar PV;
Business Development Manager for Peter Kiewit Infrastructure Co., a large North American contractor;
Director, Major Projects for Brookfield Power, an independent power producer, responsible for a program of power facility construction and expansion projects including large Earth fill dams and composite Spill control facilities, Concrete gravity dams, Hydroelectric generation facilities, Wind Generation facilities and 115 and 230 kV Transmission Lines and Substations;
Professional Engineer, (Civil) registered in Ontario, (PEO);
Twenty five (25), years of service to PEO in elected positions of Regional Councillor and Councillor-at-Large;
Inducted as an Officer in PEO Order of Honour in April, 2007,
Inducted as a Fellow of Engineers Canada, November, 2009

Education

Advanced Certificate in Project Management, 2004, University of Toronto
Bachelor of Engineering (Civil), 1980, Lakehead University

Project and Employment History

Clarida Green Energy **2011 to Present**

Responsible for Project Development and Engineering oversight for the construction of 60 Mw of Solar PV in Sault Ste. Marie, ON. The project developer and Owner, Starwood Energy, retained Clarida Green Energy as the site Civil Contractor for the development of its initial 10 Mw blocks. Clarida was retained as the EPC Contractor for the final 10 Mw block.

PowerTel Utilities Contractors **Contract 2012**
Project Manager

Contractor to PowerTel Utilities Contractors through my consulting firm, B.E. Clarida & Associates INC, serving as Project Manager for the fabrication, construction and erection of 230 kV lattice structures and the construction of three 230 kV Substations, a Disconnect Switchyard and intertie to the Hydro One 230 kV transmission line, forming part of the Lower Mattagami River Project;

Peter Kiewit Infrastructure Co. **2006 to 2011**
Business Development Manager
Responsible for Business Development which included the preparation of P3, (Public Private Partnership), and Design Build proposals for large infrastructure projects, (Windsor Essex Parkway; Windsor Detroit International Crossing), ensuring that the Owners requirements and performance expectations are met while identifying and developing opportunities for innovation and cost efficiency.

Brookfield Power Corporation **2004 to 2006**
Director, Major Projects
Major Projects include those with capital cost of $10 million or greater or of strategic importance to the Corporation. The Director is responsible for the successful delivery of the Major Projects program including;

- Permitting and regulatory approvals,
- Preparing preliminary conceptual designs,
- Establishing the contracting and implementation methodology,
- Contract negotiations, planning and scheduling,
- Managing the construction of the project including the implementation of Safety and Work Management systems, Quality Control, Environmental Management and Risk identification and mitigation programs, the communications plan and the testing and commissioning of the works,
- Completion of the project with post mortem reviews, compiling the lessons learned and the hand over of the project to the Business unit operating entity.
- Planning and implementation of surveillance and maintenance programs to ensure the protection and safe operation of the assets

The hand-over of the project to the Operations Team included a training program for the key personnel and having Operations Staff on site as part of the commissioning acceptance program.

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176 Henry St. Rockwood, ON, N0B 2K0
Cell- 905 802 9669; Res- 519 856 0601

Director, Major Projects (cont'd)

Major projects completed include;

- **Shikwamkwa Replacement Dam Project**; a $100 million replacement of an aging zoned earth fill dam approximately 1500 m crest length, complete with a plastic concrete cut off wall excavated up to 80 m in depth through a slurry trench, the placement of 1.5 million cubic meters of zoned earth fill and the breaching and abandonment of the existing dam; project completed in December 2005

- **Weldon G.S., Frequency Conversion** for Great Lakes Hydro America, Millinocket Maine; a $14 million US, overhaul and rebuild of 2 Kaplan type units and 2 Propeller type units, stator rewinds and powerhouse upgrade for frequency conversion to 60 cycles, construction of temporary substation to supply 50 cycle power to major customer and construction of a new 60 cycle substation for interconnection to Bangor Hydro at Bangor Me.; project completed in October 2005,

- **Rapide des Cedres G.S**; installation of two, S type units in and existing concrete flow control structure, total output of 8.9 MW; the $ 24 million Design-Build Contract included acquisition of all permits from regulatory authorities, construction of powerhouse and intake monolithic with the existing structure, tailrace extension and transmission interconnection; completed December 2005 and placed in service

- **230 kV Transmission Reinforcement Project**; replacement of 150 km of two 115 kV transmission lines with a single 230 kV transmission circuit for a capital cost of $37 million, completed in October 2005; Construction of 230 kV transmission substation and the integration into the existing operating system, at a capital cost of $21 million; placed in service in May, 2006.

- **Prince Wind Energy Development**; Prince Twp, Sault Ste. Marie, includes two phases of construction;

  Phase 1: included 66, 1.5 Mw SLE, GE wind turbines, 35 Km of roads, four major water crossings, a 34.5/230 kV transformer substation; 34.5 kV buried cable collection system, 11.5 km of 230 kV transmission system and a interconnection to a 230kV transmission line, total capital cost of $200 million

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Phase 2: consisting of 60, 1.5mW SLE, GE wind turbines, 25 km of roads, two major water crossings; a 34.5 kV buried cable collection system and a 34.5/230 kV transformation substation for interconnection to the 230 kV transmission line, total capital cost of $192 million.

Completed the Class EA and negotiated terms and conditions to proceed with the work; negotiated a Memorandum of Understanding with Batchawana First Nation for protection of their heritage and cultural resources, negotiated land lease agreements, completed the Plan of Development for OMNR approval to proceed, negotiated EPC construction contracts with the major contractors; formed construction implementation teams of site managers, job superintendents, inspectors and engineers and monitored progress through regular monthly and weekly meetings.

Great Lakes Power Limited **1992 to 2004**
Project Manager and Senior Civil Engineer

Program and Project Manager for the operation, maintenance, condition assessment and improvement of the Hydroelectric Generation and Transmission assets of Great Lakes Power Limited, a wholly owned subsidiary of Brookfield Power. Typical annual budgets for these programs ranged from $300,000 to $1.5 million in capital and major maintenance expenditures.

Planned and implemented the following programs;

- The Dam Safety Management, Effluent Management and Safety Management programs,
- Asset Condition Assessments and monitoring programs,
- Prioritised work programs for the repair and improvement of civil assets including earthen and concrete composite dams and spillway facilities,
- Prepare, negotiate and manage construction programs for new generation and transmission assets, manage Consultant assignments and construction budgets.
- Asset evaluation of energy facilities and businesses as part of the Assessment Team evaluating the assets for acquisition.

Project Manager for the R. A. Dunford G.S.; The Project included the construction of a new dam and spillways, a power canal and intake, a new powerhouse with 2, 22.5 Mw Kaplan units a 34.5 generation substation and transmission interconnection to an existing T.S., and the demolition and removal of the existing High Falls operating site following commissioning of the new project.

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Project Manager and Senior Civil Engineer (cont'd)

The major tasks included:

- Managing Consultant assignments for Preliminary Design Concept and to establish the scope of the works and construction budgets,
- Contractor prequalification process and the selection of tenderers to the project,
- Negotiate the Water to Wire Equipment Supply and Installation (WWESI) subcontract and the Design-Build, (DB) contracts,
- Obtain all permits and approvals including agreements with the Michipicoten First Nation
- The evaluation of tenders, the selection of the Design-Build Contract team, and the negotiation of the final DB Contract,
- The development and implementation of the project Safety Management and Environmental Protection plan,
- Negotiate agreements with the Township officials to facilitate their review and approval role in the works,
- The selection and negotiation of an agreement with an Owner's Representative for the day to day construction administration, and,
- The management of the Owner's review and monitoring of all aspects of equipment supply and construction.

- Program Manager for the planning, preparation and implementation of the GLP Dam Safety program to comply with the Canadian Dam Association guidelines and Provincial regulatory requirements including consultant assignments, facilities assessments, review with regulatory agencies, and implementation of the program,

- Program Manager for a five year, $12.0 million program of condition assessment and prioritized work plans to upgrade and improve the monitoring equipment and capabilities at all dams and hydraulic structures pursuant to the Dam Safety program,

- Project Manager for the $1.5 million interim stabilization of the Shikwamkwa Dam, including the installation of an automated piezometric monitoring and data acquisition system, the subsurface geotechnical and geophysical investigations of the embankment and the installation of graded filter blankets and weighting berms,

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Totten, Sims, Hubiki Limited, (AECOM) **1988 to 1992**
Senior Project Engineer

Responsibilities

Provide Engineering Design and Project Management services for the planning, design, and Environmental Assessment, of Civil engineering works for Clients throughout Northern Ontario; Supervise multi-discipline project teams of up to 20 scientific, engineering and technical staff. TSH and Kresin Engineering and Planning Limited, now AECOM, provides Consulting Engineering services to clients including the Provincial Municipal agencies, and companies in Ontario.

The following are some of the projects and roles;

- Conducted a Class Environmental Study of alternatives to provide a municipal water supply to the Town of Markstay, Ontario, and secured a commitment of $1.6 million in Provincial Government funding to extend the RM of Sudbury water supply system to Markstay.

- Project Manager for the Environmental Assessment of alternatives for the $2.1 million expansion of Second Line in the City of Sault Ste. Marie. The project included preparation and public review of alternatives, negotiations with the Mayor and Council and Engineering and Public Works officials of the City of Sault Ste. Marie,

National Energy Board **1980 to 1988**
Division Chief, Pipelines Branch

Provide engineering advice to the Board and Board Panels on the condition and capacity of oil and gas pipeline and storage facilities in Canada, including Board Hearing Panels and Counsel reviewing facilities applications for proposed interprovincial oil and gas pipelines construction projects, (i.e. the Norman Wells pipeline, Trans Canada Pipeline facilities expansion projects),

Performed accident investigations and assisted Board Hearing Panels in the inquiry of probable causes and recommended measures for prevention and improved performance of facilities,

Represented the Board on National, Provincial and Industry Standards and Code committees regarding pipeline design, construction, operation and maintenance practices.

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Professional Associations and Affiliations

- Registered Professional Engineer in Ontario (PEO), since 1982
- Officer, PEO Order of Honour, April 2007
- Fellow, Engineers Canada, November 2009
- PEO Regional Councillor, Northern Region (PEO), 1998 to 2003 and Councillor at Large 2003 to 2006 and 2008 to 2011
- Member, Professional Practice Committee, PEO, September 1997 to 2003
- Member, Discipline Committee, PEO, 1998 to present
- Member, Design Build Institute of America, (DBIA), 2000 to 2006
- Member, Project Management Institute, (PMI), 2000 to present
- Member, Canadian Dam Association, (CDA), 1992 to 2007
- Member Canadian Wind Energy Association, (CanWEA), 2005 to present
- Member Canadian Solar Energy Association, (CanSIA) 2010 - present

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Training, Seminars and Conferences

Canadian Dam Association

- Introduction to Decision Support Systems
- Applications of DAMBRK models
- Rip Rap Design and Repair
- Data Processing Systems in Dam Safety
- Embankment Dams Filters, Erosion Protection and Fuse Plugs
- Use of Geophysical Methods to Detect Anomalies in Embankment Dams
- Swelling of Concrete in Dams
- Emergency Preparedness Planning and Response for Dam Owners
- Practical Approaches to Dam Risk Management

Acres International Geotechnical Seminars

- Pressure Tunnel Liners and Surface Penstocks
- The Assessment and Rehabilitation of Hydroelectric Facilities

University of Wisconsin, Milwaukee

- Design of Transmission Lines

The Canadian Institute

- Expedite a Successful Environmental Assessment

University of Toronto – Professional Development Centre

- Professional Project Management
- Advanced Certificate in Project Management

Federal Energy Regulatory Commission

- Emergency Acton Plan Exercises

Canadian Construction Association

- Design – Build Stipulated Price Contracts

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Publications

CLARIDA, B.E., DONNELLY, C.R., MacTAVISH, B., 1999. The Unconventional Application of Conventional Materials, Proceedings of the First CDA Annual Conference, Sudbury, Ontario.

CLARIDA, B.E., MacTAVISH, B., 1998, Wood Stave Penstock Life Extension by Installation of a Plywood, Proceedings of CEA Conference, Toronto, Ontario.

CLARIDA, B.E., STEAD, R., 1997, Owner Improves Method for Releasing Stop logs, Hydro Review, Vol. 16, n.1, pp. 66

CLARIDA, B.E., et al, 1998, Expandable Gates Can be Used in Various Water Passages, Hydro Review

CLARIDA, B.E., DONNELLY, C.R., ERZINCLIOGLU, A.R., MacTAVISH, B., RIGBEY, S.J., WALSH, H.B., 2000, A Phased Approach to the Rehabilitation of an Aging Northern Dam, Proceedings of Hydrovision 2000, Charlotte, N.C.

CLARIDA, B.E., DONNELLY, C.R., HOOTEN, D., ROGERS, C.A., An Assessment of the Effectiveness of Blast Furnace Slag in Counteracting the Effects of Alkali-Silica Reaction, Proceedings of the 11th International Conference on Alkali-Aggregate Reaction in Concrete, Quebec City, P.Q.

Hobbies and Interests

Bluegrass Music – Playing the five-string banjo and singing lead and harmony vocals

Barbershop Harmony Music – Singing the “Lead” part with Barbershop Quartets and choruses,

Golf

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DAVID R. HARDY

B.A. (Hons.), M.E.S., M.C.I.P, R.P.P.

David Hardy is a Principal of Hardy Stevenson and Associates Limited, ("HSAL"). HSAL specializes in land use planning, project development and management, socio-economic and environmental impact assessment, public consultation, and strategic planning. Dave is a Registered Professional Planner and trained facilitator and has extensive experience in all of these areas. Dave has participated in over 75 environmental assessments. He has also facilitated close to 1000 strategic planning meetings and public consultation plans for public and private clients; conducted multi-stakeholder consultation and mediation in numerous sectors; and completed environmental planning assignments for a variety of nuclear waste management projects.

He has extensive experience in facilitating the public approvals process for housing, water and waste water, transportation and energy infrastructure projects. Dave has also led project development activities (conception, design, finance, pre-feasibility studies, feasibility studies) for a variety of energy, housing and infrastructure projects. He has completed numerous socio-economic impact studies related to plans, policies and infrastructure. Dave has facilitated Ontario Energy Board hearings and provided expert advice at the: Ontario Energy Board, Ontario Court of Appeal (Discovery Hearing), Ontario Municipal Board, Ontario Environmental Assessment Board, Consolidated Joint Board and the Federal CEAA and EARP Panels.

Education

Master of Environmental Studies, York University, 1978

B.A. (Hons), Sociology-Urban Studies, York University, 1975

Partial completion, Dipl. Public Administration, University of Toronto

Professional Affiliations

Full Member of OPPI and CIP

International Association of Public Participation

Founding Member, International Association for Impact Assessment

Member, International Association of Business Communicators

Past President, Conservation Council of Ontario

Past President, Scarborough North Rotary Club

Past Vice-Chair, Canadian Standards Association, Technical Committee on Environmental Assessment

Employment

Principal, 1990 – Present
Hardy Stevenson and Associates Limited, Toronto, ON

Director, 2002 – Present
Economic Growth Solutions Limited, Toronto, ON

CFO, 2008 – Present
Everbrite Solar Limited and Gander Energy Limited

Director, Guyana Hydropower Limited, 2005 - Present

Senior Planner - Long Range, 1989 - 1990
Town of Aurora, ON

Coordinator - President's/Chairman's Office, 1986 - 1989
Ontario Hydro, Toronto, ON

Senior Community Studies Planner, 1984 - 1986
Ontario Hydro, Toronto, ON

Community Studies Planner, 1978 - 1984
Ontario Hydro, Toronto, ON

Community Relations Officer, 1977 - 1978
Ontario Hydro, Toronto, ON

Select Project Experience

Central Pickering Development Plan Regional Services EA, 2010 and ongoing – Project Director for communications and consultation activities. Responsible for developing a communications plan and stakeholder sensitivity analysis. Facilitated the Project's Technical Advisory Committee and Community Stakeholder Committee. Client: Region of Durham.

Community Well-Being Research Paper, 2009 to 2010. Lead Researcher and Project Director. Conducted research for case studies and developed community well being indicators for the siting of a nuclear waste management facility. Also presented findings at a workshop. Client: NWMO.

Durham Region, Long Term Transit Strategy, 2009/ 2010 – Extensive consultation and communications program to develop a long term transit strategy.

Vancouver 2010 Winter Olympic and Paralympic Games Bid – With REWERX, designed and implemented the public consultation process and completed the preliminary socio-economic impact study for submission to the International Olympic Committee in support of the Games going to Vancouver.

Ostrander Point Wind Energy Farm, 2008 – Directed the socio-economic impact assessment of 20 MW wind energy project proposal in Prince Edward County. Client: Stantec for Gilead Power Corp.

Niagara-on-the-Lake Servicing Improvements, 2008 – Undertaking socio-economic impact assessment of the NOTL Wastewater Treatment Plant for a Municipal Class EA. Client: Hatch Mott MacDonald for Region of Niagara.

North Bolton Elevated Tank Class EA, 2008 – Undertaking socio-economic impact assessment of the Bolton Elevated Tank, Reservoir and Feedermain (Peel Region) for a Municipal Class EA. Client: UMA Engineering for Region of Peel.

Benefits Blueprint, Saint John, New Brunswick – For the Province of New Brunswick Energy Hub, Dave directed the development of a strategic growth action plan that is putting Saint John, NB on the map as planning in advance of economic and community growth. Dave directed the development of population, employment and housing forecasts and through business case development, designed specific programs to best-position the in infrastructure, housing, economy and business, workforce development, community interests, arts and culture, and education and training.

Economic Impact Study of Airport Closures, GTAA – Developed and implemented a survey of tenants, local business, and off-site airport related businesses associated with Buttonville, Oshawa and Markham Airports. Undertook an analysis of survey results and developed re-development scenarios of the affected airports.

Bathurst Street and Langstaff Road – Social profile as the front end of a social impact and land-use analysis for a sewage pipeline extension Class Environmental Assessment along Bathurst Street and Langstaff Road in York Region for KMK Engineers and Landscape Architects

Morningside Heights – Socio-economic and land-use analysis of Morningside Heights transportation route alignment in Scarborough/ Markham.

Rockfort Quarry – Social impact peer review Rockfort Quarry application Town of Caledon.

Five W Farms Quarry – Social impact assessment, Five W Farms quarry expansion application, OMB appearance.

Centreville Quarry – socio-economic impact assessment peer review, Camden East Township, for Lafarge Canada Limited, appeared and gave expert evidence before the OMB.

GUJARAT State Highway's Project, India – Advised lead consultant on a potential social impact approach for improving the performance of the road transportation network regarding the GUJARAT State Highway's Project in India.

Hotel Dieu Hospital, Kingston – Analysis of social impacts of Health Services Restructuring Commission recommendations pertaining to Hotel Dieu.

Crematorium and Columbary, Vaughan – examination of social impacts of siting a crematorium and columbary in Vaughan, Ontario.

Vector Pipeline – completion of socio-economic analysis and public consultation strategy for final link of the Chicago to New York 48" natural gas pipeline.

Millennium Pipeline – Analysis of the economic benefits of the $160 million dollar Millennium (Dawn to Lake Erie) pipeline in SW Ontario.

Durham West Corridor Water Pipeline – Land-use and socio-economic study for York Region and Consumers Utilities

Dawn Compressor Station to Lake Erie - 36" natural gas pipeline, with Ecological Services for Planning and Ecoplans for Union Gas and TransCanada Pipelines

Balm Beach, Perkinsfield and Wyevale, Tiny Township – XHP 4" natural gas pipeline socio-economic impact assessment with Ecological Services for Planning. Client: Consumers Gas.

Carp 4" Pipeline Socio-Economic Study – with Ecological Services for Planning for Consumers Gas for proposed natural gas pipeline, with Ecological Services for Planning.

Dufferin County, Site U4 landfill analysis and Waste Generation and 3Rs review – for Harrington and Hoyle, East Luthur Grand Valley Township.

ITER Research Facility – Socio-economic impact site assessments, for Canadian Fusion Fuels Technology Centre.

Community Impact Agreements – Research in relation to Taro Quarry Landfill on for Turkstra, Garrod, Hodgson.

Line Nine project – Socio-economic and cultural impact assessment study, for InterProvincial Pipelines Limited. With Ecological Services for Planning.

Supply to Village of Chalk River and Chalk River Nuclear Labs – Socio-economic and cultural impact assessment study for Consumers Gas for a proposed 4" natural gas pipeline. With Ecological Services for Planning.

Supply to Tweed, Ontario and IKO to Marmora, Ontario – Socio-economic and cultural impact assessment study of proposed 4" natural gas pipeline. For Centra Gas Limited.

Dufferin Simcoe Reinforcement study – Socio-economic and cultural impact assessment study of proposed 12" natural gas pipeline (work in progress). For Consumers Gas Limited.

Terms of Good Neighbour Policy – Peer Review Laidlaw Environmental Inc. hazardous waste landfill Compensation and Terms of Good Neighbour Policy -- Laidlaw Environmental and WOHICA.

North Simcoe Landfill – Preparation of Evidence and Expert Testimony for North Simcoe Landfill, Terms, Conditions and Compensation, on behalf of Wye Citizens.

Natural Gas Transmission Pipeline, Ancaster, ON – Peer review of social impact assessment and public consultation program for a proposed 12 inch natural gas transmission pipeline for the Town of Ancaster, Ontario. Expert evidence at Ontario Energy Board.

MNR Timber Harvesting Policy – Supervised socio-economic impact study of timber harvesting policy options for Ontario Ministry of Natural Resource.

Taro Aggregates East Quarry – Peer Review of Taro Aggregates East Quarry Landfill proposal social impact assessment; preparation of proposed socio-economic Conditions of Approval.

Rotary (PCB) Kiln, Sarnia – Peer Review of Social Impact Assessment of Laidlaw Inc. Rotary (PCB) Kiln, Sarnia. Retained by Citizen's Environmental Action Group through Willms and Shier.

Steetley Quarry Products Hamilton-Wentworth – Social Impact Assessment and Public Consultation Review of Steetley Quarry Products Hamilton-Wentworth landfill site environmental assessment documents. Environmental Assessment Board expert witness on behalf of Greensville Citizens Against Serious Pollution and the Calvin Christian School.

MOE 3R's Strategies, GTA – Social Impact Assessment of 3R's Strategies in the Greater Toronto Area, for the Ministry of Environment. Reviewing demographic factors related to efficacy of 3R's programs. Joint project with RIS Ltd., Future Urban Research and Dillon Consultants Ltd.

Little Jackfish River Hydro-electric Development – Socio-Economic Impact Review of Little Jackfish River Hydro-electric Development. Review of Ministry of the Environment's Blue Review for the Armstrong Resource Development Corporation.

Tenaska Energy (Omaha, Nebraska) and Campbell's Soup Co-generation project – Socio-economic Analysis of Tenaska Energy (Omaha, Nebraska) and Campbell's Soup Co-generation project. Project management, social and economic impact analysis of 100 MW proposed co-generation facility in South Etobicoke. Joint project with Chait and Associates and Jonathan Kauffman and Associates.

World Bank, Energy Division – World Bank, Senior staff presentation, Energy Division, regarding socio-economic strategic considerations in reactor operation, decommissioning and spent fuel management in CIS countries and Eastern Europe, Washington, D.C. in cooperation with ESTI Ltd.

Research and witness preparation – Prepared witnesses and conducted research to support Ontario Hydro social impact assessment team testifying at the Environmental Assessment Board Demand/Supply Plan Hearings.

Wesleyville Candu – Coordinated the socio-economic impact assessment for Ontario Hydro's 2800MW Wesleyville Candu A project environmental assessment. Assembled and managed the SIA consulting team, designed the assessment, defined the study area, and supervised sub-consultants.

North Channel Generating Station – Researched potential socio-economic impacts associated with the siting of a future North Channel Generating Station, and assisted in the completion of the North Channel Social Evaluation of Sites: Support Document.

Hamner to Mississauga Transmission line – Assumed lead responsibility for the study design, research, assessment of associated impacts and preparation of the Social Environmental Assessment for the Hamner to Mississauga Transmission line approved by the Ministry of the Environment.

Ontario Hydro – Developed and completed many of Ontario Hydro's early socio-economic impact assessment studies. Work included scoping, researching and writing the Elliot Lake T.S. to Quirke Lake T.S. transmission line socio-economic impact assessment, one of the first Ontario Hydro projects to receive approval under the Environmental Assessment Act.

Algoma TS to Elliott Lake TS – Researched and wrote the Algoma TS to Elliott Lake TS Social Impact Assessment Study.

South-West Ontario transmission expansion and Supply to Ottawa – Responsible for the Scoping of the social impact assessment component of the South-West Ontario transmission expansion and the Supply to Ottawa. (Approved by the Consolidated Hearings Board).

Atikokan Generating Station community impact agreement – Conducted (with research support) the community impact monitoring program for the Atikokan Generating Station community impact agreement. As a member of a project team, researched and supervised the production of annual community impact monitoring reports.

Population and Employment Influx Model – Assumed lead responsibility for developing the Population and Employment Influx Model, a pre-Lotus program for determining population and employment impacts. In association with research conducted for the Nuclear Fuel Waste Management Centre and with support from computer scientists.

The Interim Waste Authority's Step 5 Approach and Criteria – Joint author of the response to The Interim Waste Authority's Step 5 Approach and Criteria, Social impact analysis, site examination, structured interviews regarding impact of M6 Town of Markham proposed landfill site.

IWA Short List Analysis, South York Quarry Lands – Project management of comparative evaluation process and social impact analysis of rank of South York Quarry lands against other

York Region short list sites. Joint project with Dames and Moore, Canada, Hemson Consultants Ltd., and Robert Lehman Planning Consultants.

IWA Sites C34B and C48, Peel Region – Field survey research and social impact analysis. Public and Council presentations. Report prepared for the Town of Caledon regarding 2 proposed landfill sites. Joint project with Lawrence Environmental, Gore and Storrie, Ecologistics.

Parry Sound Waste Management Master Plan – Development of Landfill Site Search Social Criteria and Evaluation Methodology and Local Economy and Tourism/Recreation Criteria and Methodology, Parry Sound Waste Management Master Plan. Criteria prepared for Cave Engineering.

Federal Hazardous Waste Transportation – Report prepared for Atomic Energy of Canada Ltd Case Study Analysis of Hazardous Waste Transportation in Canada. Report prepared for Atomic Energy of Canada Ltd.

Waste Facility Siting Social Criteria – Analyzed Waste Facility Siting Social Criteria prepared by the Provincial Interim Waste Authority for Superior Crawford Sand & Gravel Ltd.

L.B. Pearson Airside Development – Reviewed Social Impact Assessment of L.B. Pearson Airside Development for the City of Etobicoke. Expert testimony at FEARO Hearing.

L.B. Pearson International Airport – Reviewed social impact support material submitted to FEARO by Transport Canada regarding the proposed expansion of the L.B. Pearson International Airport (As sub-consultant to Concord Environmental Consultants, for the City of Etobicoke).

Green Lane Landfill, Southwold Township – Conducted a social impact assessment study and the public involvement program of the proposed expansion of the Green Lane Landfill site in Southwold Township as sub-consultant to Conestoga Rovers, for St. Thomas Sanitary Collection Services Limited.

Greater Toronto Area Solid Waste Interim Steering Committee – Developed Social Impact Assessment Site Selection Criteria and SIA work plan for the Greater Toronto Area Solid Waste Interim Steering Committee (As sub-consultant to the LURA Group).

Parkway Belt West Plan Review, Ontario Realty Corporation – Conducted site visits, analyzed applicable policies, and provided recommendations on real estate transactions for provincial land holdings within the Parkway Belt West Plan in Halton and Peel Regions. Also provided advice to the ORC for their response to the Ministry of Municipal Affairs and Housing on the proposed review of the Parkway Belt West Plan.

Review and Recommendations Related to the Proposed City of Burlington Official Plan, Ontario Realty Corporation – Completed an assessment of the impact of Burlington's Official Plan review on provincially owned lands, including property-specific constraints and opportunities, and recommended changes to the amendments that reflect current and proposed future uses of provincially owned lands.

GTA Road segment analysis – Land-use analysis and social profile of road segments in the Towns of Pickering, Markham and Whitchurch-Stouffville for an environmental assessment related to the selection of a large water pipeline route for Cole Sherman and the Inter-Regional Consultants Group

Warwick Landfill Expansion – Peer review of Canadian Waste Services, Warwick Landfill Expansion for Warwick Watford Public Advisory Committee.

Richmond Landfill Expansion – Peer review of Canadian Waste Services, Richmond Landfill Expansion for Richmond Public Advisory Committee and Environmental Advisory Committee.

Petang State, Malaysia – Conducted Preliminary Environmental Assessment of the location of an aluminium diecasting manufacturing facility in Petang State, Malaysia.

Cellular Tower Planning – Monitored and reviewed planning applications pertaining to Cellular Tower locations of telecommunications company (Microcell).

By-law variance – 853 Bathurst St Analysis and report on planning considerations involved with By-law variance, 853 Bathurst St. Toronto; OMB Hearing.

'Home work' By-law review – Review of 'Home Work' By-law, City of Toronto for Deer Park Ratepayers' Group Inc., fall 1996.

Caledon subdivision review – Review of new townhouse subdivision plan, Caledon, Winter 1996.

King severance application – Review of DeBuono property severance application for Mr. & Mrs. Watt, King Township before Committee of Adjustment review, summer 1996.

'Environment-first' policies – Reviewed application of 'environment-first' policies within Town of Richmond Hill, Ontario Official Plan (OPA 129) for Oak Ridges Lake Wilcox Resident Association. Expert evidence at Ontario Municipal Board hearing.

OPPI – Appointed by Ontario Professional Planners Institute as representative to Ontario Municipal Network Project.

Rotary Seniors Village – Developed proposal for 3,000 unit community. Managed team of consultants.

Oro Township Pit expansion and Gravel Haul route – Planning analysis and socio-economic impact assessment associated with Pit expansion and Gravel Haul route in Oro Township. Expert testimony at O.M.B. Hearing under Aggregate Resources Act and Planning Act.

Oak Ridges Moraine policy integration – Assisted Markborough Properties with Oak Ridges Moraine environmental planning strategy associated with the development of a Regional Mall in York Region.

Official Plan Review studies – Assumed primary responsibility for completing, and supervising consultants conducting Official Plan Review studies satisfying the requirements of the Planning Act. Wrote the terms of reference, supervised the awarding of contracts and managed studies of the land use, housing, culture and recreation, commercial and retail and transportation aspects of the Official Plan Review. Developed draft environmental policies. Chaired, Transportation Policy Committee; Member of Culture and Recreation Master Plan Committee. (Senior Planner, Town of Aurora). Participated as Aurora planner representative on York Region Community Services Council.

Servicing, population and employment projections – Completed water and sewer servicing, population, demographic and employment projections, prepared planning reports, commented on O.P.A.s and Secondary Plan Applications and maintained liaison with Regional and Provincial representatives (Senior Planner, Town of Aurora).

OPA Public Consultation Funding Plan, Scarborough – Prepared work plan and approach for funding, public consultation, preparing for zoning and Official Plan amendment for a non-profit housing development (Holy Trinity [Guildwood], Scarborough).

North Toronto Community Centre Re-zoning – Completed a zoning analysis of the proposed North Toronto Community Centre and expert testimony re: Ontario Court of Appeal.

Land use and socio-impact planning, Town of Atikokan – Assigned as Planner by Ontario Hydro to assist Town of Atikokan in addressing socio-economic and land-use impacts associated with generating station construction. Negotiated agreements.

Region of Peel Official Plan – Facilitating stakeholder workshops and leading public consultation on a variety of Official Plan components as part of the 5-year Official Plan review process.

Sutton WPCP Expansion – Facilitating Stakeholder Adviosry Group meetings as part of the Class EA for expansion of the Sutton WPCP servicing Sutton and Jackson's Point.

Saint John Parking and Snow Removal Study – For the Saint John Parking Commission, conducted the consultation and facilitation for the parking and snow removal study in the City of Saint John, NB.

9th Line Expansion – Facilitated Community Workshop for the design of expansion of 9th Line between Markham and Whitchurch Stouffville.

Ontario Energy Board OH Servco and Transco – Facilitation and mediation of Ontario Energy Board rate application hearings for OH Servco and Transco application and managing facilitation of new electricity licences (20 sessions).

Biosoilds and Residual Waste, Toronto – Facilitated 8 meetings of Toronto Beneficial Use of Biosoilds Multi-Stakeholder Advisory Committee and developed public consultation strategy.

Ontario Nuclear strategy – Retained to facilitate 2 Workshops leading to revision of Ontario Nuclear strategy for decommissioning Ontario's nuclear reactors.

Pickering Working Group – Facilitated series of workshops for the Pickering Working Group for Ontario Hydro Nuclear.

MNR Lands For Life – Facilitated workshops for the Ministry of Natural Resources in Northern Ontario for the Lands For Life land-use planning initiative.

Consumers Utilities - Water Supply Pipeline – Facilitated series of workshops in York and Durham Region for Consumers Utilities - Water Supply Pipeline and Interregional Consultants Group.

Caledon East Water Supply Study – Peel Region, Caledon East Water Supply Study, Facilitation of Public Meetings and Workshops.

Diocese of Toronto – Facilitated 1999-2001 Budget development process and organizational restructuring for a major faith group. Also retained to complete 2000-2001 budget process.

Natural Resources Canada CANMET – AETE program, Facilitation of Final Integration Report Workshop.

Ontario Hydro Facilitation, Pickering – Facilitated an action plan with Pickering residents and staff to address Ontario Hydro's emissions of copper, brass, lead and zinc into Lake Ontario.

Government of the Yukon – Planned and facilitated Workshop on socio-economic impact assessment.

Bronte 230kV transmission line – Facilitation of Criteria and Factors Ranking Workshop, Supply to Bronte 230kV transmission line project, Town of Oakville, Ontario Hydro.

Canadian Model Forest Network – Public Consultation Training and Facilitation for Model Forest Managers and staff. Two day Ottawa Workshop for Canadian Model Forest Network.

Energy Mediation – Mediation of outstanding issues of interest to Ontario Hydro, Municipal Electric Association and Association of Major Power Consumers (GM, INCO, Ford Motors, Stelco).

High Occupancy Vehicle Lanes – Facilitated Public Involvement Activities associated with proposed High Occupancy Vehicle Lanes for Metro Transportation. Provided media and communications advice. Strategic briefing of politicians and senior staff.

Strategic Planning and Facilitation for **Kortright Centre workshop on** education and tourism.

High Level Nuclear Waste Disposal, France – Reviewed and Reported on Public Consultation Programs associated with High Level Nuclear Waste Disposal for NUSYS, Paris, France.

MNR Forest Values Project – Planned, organized and facilitated a two day workshop for Ontario Ministry of Natural Resources, Forest Values Project. To seek advice on forest revenue options from 75 stakeholders (110 participants) from First Nations, environmental interests and the forest industry. Prepared report.

Steetley Quarries – Review and analysis of Public Consultation conducted by Steetley Quarries, South Quarry Landfill Site. Expert Witness at EAB Hearing.

Ontario Hydro Multi-Stakeholder Consultation – Facilitated 5 Workshops on Rates and Non-Utility Generation before 1994 Ontario Energy Board Hearing.

MNR Timber Production Policy – Designed, organized and facilitated a three day Workshop for Ministry of Natural Resources Timber Production Policy. Prepared report representing views of variety of sectors and stakeholders (90 participants).

HARDY STEVENSON AND ASSOCIATES

ANDRZEJ SCHREYER
B.A. (Hons.), M.A.

Andrzej is senior planner with Hardy Stevenson and Associates Limited and a provisional member of the Ontario Professional Planners Institute and the Canadian Institute of Planners. His experience includes developing public consultation and communications plans, preparing social impact assessment and land use planning studies in support of major infrastructure projects in the GTA, preparing community-based strategic plans, and helping private sector clients with the planning approvals process.

Prior to working at Hardy Stevenson and Associates, Andrzej was Senior Planner at Office for Urbanism (now Dialog) where he played a key role during the City of Mississauga Official Plan review process. He was also the Inaugural Town Planner and Conservation Agent for the Town of Swampscott, Massachusetts where he established the Town's development review process protocols and initiated the successful review of the Township Zoning By-law and the Planning and Conservation Department's Site Plan Review Guidelines.

Andrzej's approach to planning recognizes that: (i) no urban environment exists in isolation; socio-economic, behavioral, cultural, political, physical and historical particularities have to be considered when developing strategies in view of creating environments that enrich the lives of its users; (ii) collaborative approaches free of pre-determined notions are critical to high-quality results; and, (iii) a delicate balance exists between individual and community aspirations, quality of life and economic affluence and the natural and built environment.

His work can be distinguished by his balanced and comprehensive approach, creative energy and, devotion to the achievable and the imagined. He has held positions in the private and public sectors, both in Canada and the U.S. in areas including urban planning, economic development, environmental conservation and policy analysis.

Education	**Master of Arts**, **Geography**, The University of Western Ontario, 2004
	Bachelor of Arts (Hons.), **Environmental Geography**, Nipissing University, 2001
Professional Affiliations	Provisional Member of the Ontario Professional Planners Institute (OPPI) Provisional Member of the Canadian Institute of Planners (CIP)
Employment	**Senior Planner**, **Hardy Stevenson and Associates**, 2009 - Toronto, ON, Canada
	Senior Planner, Office for Urbanism, 2008 – 2009 Toronto, ON, Canada
	Town Planner/Conservation Agent, 2006 – 2007 Swampscott, MA, U.S.A
	Environmental Policy Analyst, 2004 – 2006 Jamestown, RI, U.S.A
	Economic Development Officer, 2001 - 2002 North Bay, ON, Canada

Additional Training

Managing Multiple Projects Seminar, Skillpath, Toronto, ON, 2010

Public Issues and Conflict Management, National Oceanic and Atmospheric Association Coastal Training Program, Boston, MA, 2007

Fundamentals for Conservation Commissioners, Massachusetts Association of Conservation Commissions, Wakefield, MA, 2007

Introduction to GIS and Mapping, Metropolitan Area Planning Council, Boston, MA, 2007

Project Experience

Ashbridges Bay Treatment Plant M&T Upgrade Municipal Class EA
Project planner. Assisted with the preparation of a rationale for the appropriate approval schedule for changes to the existing and proposed facilities under the Municipal Class Environmental Assessment process. Currently preparing a Socio-economic impact assessment of the proposed facility upgrades and sewer-works related construction activity.
Client: City of Toronto

Sagatay Transmission Line Corridor Study, 2012
Project planner and co-author of transmission line corridor study for the construction of a 230 Kv line in north-western Ontario.
Client: Private

Niagara-on-the-Lake Community Vision, 2012
Project Manager of the Niagara-on-on-the-Lake Community Vision Study. Designed the public consultation and engagement process visioning process, facilitated focus group sessions and Community Advisory Committee meetings. Lead author of the Community Vision Document.
Client: Town of Niagara-on-the-Lake

Portlands Energy Centre Ecological Sustainability Strategy, 2012
Preparation of strategic plan, best practices research, workshop design.
Client: Portlands Energy Centre

Keswick Water Pollution Control Plant Effluent Outfall Expansion Project Class EA, 2011
Project planner and author of socio-economic impact assessment study.
Client: Regional Municipality of York

Township of Woolwich Economic Development Plan, 2010
Project planner and author of communications and public consultation plan. Designed public consultation approach and associated materials for Public Information Centres, youth workshop and Older Order Mennonite focus group.
Client: Township of Woolwich

Niagara-on-the-Lake Waste Water Servicing Class EA, 2010
Developed a workshop to discuss/confirm an appropriate evaluation and ranking methodology and process pertaining to Waste Water Treatment Plant alternatives.
Client: Regional Municipality of Niagara

West Vaughan Sewer Servicing Class EA, 2010
Project planner and author of communications and public consultation plan, Stakeholder Sensitivity Analysis. Land use planning support.
Client: Regional Municipality of York

West Whitby Development Area Water Supply and Sanitary Sewage Servicing, 2010
Project planner and author of communications and public consultation plan.
Client: Regional Municipality of Durham

West Richmond Hill Pumping Station and Watermain, 2010
Project planner and author of stakeholder sensitivity analysis, communications and public consultation plan and socio-economic impact assessment study.
Client: Regional Municipality of York

Solar Farm Land Assessment/ Feasibility, 2010
Project manager/planner and author of ground-mounted solar farm land assessment and feasibility studies. Assembled and managed project teams to meet the requirements of the Renewable Energy Approval (REA) process as per the requirements of the Green Energy Act (GEA) for the development of ground-mounted solar farms.

Caledon Water Supply and New Reservoir, 2010
Project planner and author of policy implications report pertaining to water servicing provisions and well locations. Also authored preliminary socio-economic impact assessment study for alternative water servicing routes and well locations.
Client: Regional Municipality of Peel

William Osler Health System Vision and Cluster Analysis, 2010
Project planner and co-author of cluster analysis report; assisted in the development of a Vision for the Peel Memorial Center for Integrated Health and Wellness; compiled and analyzed data; undertook a literature review of cluster analysis techniques and the economic implications of clusters; conducted research on clusters located in the GTA.
Client: William Osler Health System

Town of Caledon Community-Based Strategic Plan, 2010
Project planner and principal author of Community-Based Strategic Plan; carried out policy research; developed and implemented community workshops; assisted in writing Current Situation Report.
Client: Town of Caledon

Facilitation, Hess Village Community Liaison Committee, 2010
Project planner and principal author of quality of life assessment and monitoring framework; carried out land use analysis of Hess Village and adjacent neighbourhoods; designed group workshops and acted in a supporting role to the lead facilitator.
Client: City of Hamilton

Lornewood Creek Sanitary Sewer, 2009
Project lead and author of social impact assessment study for alternative sanitary sewer improvement methods and access points for construction crews for Municipal Class EA; carried out community profile inventory.
Client: Regional Municipality of Peel

Mid-Halton Waste-Water Treatment Plant EA, Stages IV & V, 2009
Project lead and author of socio-economic impact assessment study for alternative shaft site locations for Municipal Class EA.
Client: Regional Municipality of Halton

City of Mississauga Official Plan Update, 2009
Project planner responsible for the development and update of Official Plan policies; assisted in the development and implementation of public consultation events.
Client: City of Mississauga

Hurontario and Main Street Study, 2009
Project planner responsible for development of urban design guidelines for the Hurontario Corridor to facilitate higher-order transit.
Client: City of Mississauga and City of Brampton

Metrolinx Regional Transportation Plan Leadership Engagement, 2008
Project planner responsible for the development of a workshop for key professionals in the fields of urban planning, urban design, architecture and industrial design to infuse multidisciplinary thinking surrounding the development of Mobility Hubs and transit vehicles.
Client: Metrolinx

Swampscott Zoning Bylaw Review, 2007
Project lead responsible for updating and reviewing Town of Swampscott Zoning Bylaw policies; acted as ex-officio member of the Zoning Bylaw Review Committee.

Swampscott Planning Board Rules and Regulations Update, 2006
Project lead and principal author of Planning Board Rules and Regulations.

Swampscott Conservation Commission Rules and Regulations Update, 2006
Project lead and principal author of Conservation Commission Rules and Regulations.

Town of Swampscott, GIS Implementation, 2006
Project lead: implementation of Town GIS

Light Manufacturing Competitive Analysis Study, 200
Co-author of Light Manufacturing Competitive Analysis Report for the City of North Bay Department of Economic Development.

Publications

Journal Publications:

Schreyer, Andrzej. *Planning for Sex in the City*. Municipal World. Volume 122, Number 7, July, 2012 (featured as Cover Story).

ePublications:

Schreyer, Andrzej. *What Makes a Resilient City?* Sustainable Cities Collective. Aug. 19, 2011: http://sustainablecitiescollective.com/brynajones/28388/what-makes-resilient-city.

Schreyer, Andrzej. *Public Consultation with Web 2.0*. Sustainable Cities Collective. Sept. 8, 2011: http://sustainablecitiescollective.com/hardystevenson/28933/public-consultation-web-20.

Schreyer, Andrzej. *Construction Stakeholder Management*. Sustainable Cities Collective. Nov. 12,2011: http://sustainablecitiescollective.com/hardystevenson/31367/construction-stakeholder-management.

HARDY STEVENSON AND ASSOCIATES

YURI HUMINILOWYCZ

B.A. (Urban Planning), R.P.P.

Yuri is a Vice President at Hardy Stevenson and Associates Limited. He has 35 years of work experience including 25 years in the electric utility business. He has worked as an urban planner, environmental assessment specialist, real estate asset manager, finance analyst, business development specialist and corporate strategic planner. Most recently he has become involved in mediation and conflict resolution.

Education

Bachelor of Applied Arts (Urban Planning), Ryerson University, 1974

Professional Affiliations

Full Member of OPPI and CIP

Employment

Vice President, April 2005 to Present
Hardy Stevenson and Associates Limited, Toronto, ON

Director Real Estate, April 2003 to December 2004
Hydro One Networks Inc., Toronto, ON

Director of Business Development, May 2000 to March 2003
Hydro One Telecom Inc., Toronto, ON

Business Manager – Wires Operations, April 1999 to April 2000
Ontario Hydro Services Company, Toronto, ON

Senior Advisor to the Chief Financial Officer, October 1998 to March 1999
Ontario Hydro, Toronto, ON

Business Manager – Commercial Analysis & Venture Development, March 1997 to Sept 1998
Ontario Hydro, Toronto, ON

Managing Partner – Corporate Strategic Planning, March 1996 to February 1997,
Ontario Hydro, Toronto, ON

Director – Corporate Real Estate, 1989 – 1996
Ontario Hydro, Toronto, ON

Various Positions in Real Estate and Environmental Planning, 1977 – 1996
Ontario Hydro, Toronto, ON

Planner, 1974 – 1977
City of North York, ON

Additional Training

Certificate in Dispute Resolution, York University, 2005

Selected HSAL Project Experience

City of Burlington Official Plan Review, 2005 – Managed a review of Provincial land holdings in Burlington to determine the impact of the City's new Official Plan. Made recommendations to client on property disposition and retention strategies. Client: Ontario Realty Corporation.

Land Use Planning of Provincial Land, 2006 - 09 - Determined highest and best land uses and development potential for several provincial land parcels across Southern Ontario all of which were deemed surplus to government needs. Managed partner consultants engaged to provide engineering, servicing and land valuation advice. Client: Ontario Realty Corporation.

Lornewood Creek Sanitary Sewer Improvements Class EA, 2007- 2008 – Participated in socio-economic impact assessment for upgrades to the sanitary sewer located in the Lornewood Creek, Mississauga. Client: Associated Engineering for Region of Peel.

Invenergy Generating Station OMB Appeal, 2006 – Acted as expert witness at OMB hearing appealing Committee of Adjustment approval of the generating Station. Client: John Monger, Solicitor for the Power Workers Union.

Wesleyville Generating Station Site property tax assessment appeal, 2006 – 2007 – Assisted Port Hope staff and their solicitor in negotiations with Ontario Power Generation and Hydro One. Developed strategy for the assessment appeal. Client: Town of Port Hope.

Integrated Power System Plan Strategic EA, 2007 – 2008 – Participated in the review of Ontario Power Authority's Integrated Power System Plan and the completion of a high lever environmental assessment of approximately 13 proposed transmission line projects and other energy projects. Client: Ontario Power Authority.

Turtruba Hydroelectric Dam Project, 2005 – 2010 – Participated in the advancement of this project including meetings with Guyanese Government Prime Minister and Cabinet members. Participated in marketing meetings with Trinidadian Board of Trade. Client: Guyana Hydro Power.

Hydro One Corridor Lands Study, 2009 – Conducted a review of transit related uses of Hydro One Corridor Lands. Developed a comprehensive data set of the current state of projects and made recommendations regarding methods of better managing this process. Client: Ontario Realty Corporation.

Peel Memorial Hospital, 2010 – Completed a detailed land use analysis of development options for the former Peel Memorial Hospital site in Brampton as part of a lager Business and Economic Opportunity Study completed jointly with HDR Corporation. Client: William Osler Health System.

York Region 2011 – Completed comprehensive population projections for the portion of the City of Vaughan planned to be serviced by the proposed West Vaughan Sewage Servicing Project. These projections were used to develop sewage capacity engineering modeling. Client: Hatch Mott MacDonald.

Other Project Experience

As Director of Real Estate for Ontario Hydro, accountable for the acquisition, management and disposal of all lands and buildings. In the mid-1990's this comprised a real estate portfolio of $4 billion book value and about 2 million square feet of office space. Completed a real estate and accommodation rationalization review, which resulted in the sale of close to $10 million of surplus real estate assets, a reduction of close to one million square feet of office space and a reduction of over $1 million in annual property taxes.

In the early 1990's, managed a major right of way acquisition program for Ontario Hydro involving new transmission lines from London to Nanticoke, London to Bruce and Ottawa to Cornwall involving over 1000 impacted property owners.

In early 1999, the Ontario Government decided to split Ontario Hydro into three new companies. The three new entities were Ontario Power Generation (the electricity generation business), the Independent Electricity Market Operator (the system operations business) and the Ontario Hydro Services Company (the transmission and distribution business). Seconded by the Chief Financial Officer of Ontario Hydro to assist with the activities required to implement this demerger. Specific assignments included the allocation of real estate and other assets, the equitable distribution of the pension fund and the establishment of a nuclear decommissioning fund and governance structure.

For almost two years in the late 1990's, acted as Business Manager for Ontario Hydro's Commercial Analysis and Venture Development group. This involved identifying, assessing and prioritizing business opportunities (investments, mergers, acquisitions, alliances and dispositions) considered essential to the Corporation's long-term competitive position. One of the notable opportunities assessed was the creation of a telecom subsidiary for Ontario Hydro. The company's analog microwave based teleprotection and control system was antiquated and failing and Yuri developed a business case for replacing it with fibre optic cabling. The business case was approved and Hydro One Telecom Inc. was created I March, 2000. Yuri was named the Director of Business Development for this new subsidiary and served in this position until March 2003.

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George Hamilton McKibbon, RPP, MCIP, AICP
Certified Environmental Planner

McKibbon Wakefield Inc. provides environmental planning services. *Our mission is to help organizations and individuals conduct planning processes and studies to meet a variety of regulatory and policy requirements and to plan for sustainable development.* We implement this mission by providing tailored services to meet design and approval requirements and work with respected and qualified collaborators in teams that include the scientific, technical and design professions. I am committed to developing healthy communities that address the challenges we face in adapting to and mitigating the impacts of climate change.

George McKibbon formed McKibbon Wakefield Inc. in 1996. Previously he was Senior Consultant: Land Use Planning with Ecologistics Limited (1987 to 1996), planner and senior planner with the Niagara Escarpment Commission (1978 to 1987) and Conservation Planner with the Hamilton Region Conservation Authority (1974 to 1978). During Mr. McKibbon's service with the Niagara Escarpment Commission, he helped draft the Niagara Escarpment Plan that was subsequently approved in 1985.

Present and former clients include corporations (e.g., Hanson Brick, Archer Daniels Midland, and Maple Leaf Foods), First Nations (e.g., Nishnawbe-Aski Nation, Windigo First Nations Council, and Bearskin Lake First Nation), and government ministries, agencies and municipalities (e.g., Environment Canada, Ministry of Natural Resources, Nuclear Waster Management Organization and City of Hamilton).

George has over 35 years of planning experience and is a graduate of the University of Guelph (M.Sc., Rural Planning and Development) and York University (Masters in Environmental Studies). He is a Registered Professional Planner in Ontario and a member of the American Institute of Certified Planners in the United States. In July 2012, he obtained advanced credential: AICP CEP, Certified Environmental Planner.

He was the Director of Policy Development, Ontario Professional Planners Institute (2007 to 2010), and Canadian Representative, Upstate New York Chapter Board of the American Planning Association (2003 to 2008), and is a member, Canadian Institute of Planners Healthy Communities Committee, where he contributes to the development of Heart and Stroke Canada's Healthy Canada by Design Project.

He has received member service awards from the Ontario Professional Planners Institute and the American Planning Association. Over the last 5 years, he has spoken on active healthy communities many times to planning and public health audiences in the United States and Canada including participating in an Ontario Municipal Board educational session on healthy communities. In the winter semester, 2011, he was Planner-In-Residence in the School of Environmental Design and Rural Development at the University of Guelph where he has a graduate faculty appointment.

EDUCATION

- M.Sc, Rural Planning and Development, 1985; University of Guelph
- Certificate Course: Urban Systems Innovations, 1977; MIT
- Masters in Environmental Studies, 1974; York University
- Honours B. A. (Geography), 1971; Brock University

MEMBERSHIPS

- Canadian Institute of Planners
- Ontario Professional Planners Institute
- American Institute of Certified Planners
- Charter Member, American Planning Association

EMPLOYMENT

October 1, 1996 to Present — **McKibbon Wakefield Inc. – Environmental Planner and Principal**
Hamilton and Burlington, Ontario

McKibbon Wakefield Inc. designs and implements environmental studies in support of land use planning activities. Our office is situated in Burlington in premises also occupied by Planners, Ken Dakin and Donald May and G. O'Connor Consultants Inc., Landscape Architects.

1987 to 1996 — **Senior Consultant – Land Use Planning**
Ecologistics Limited, Hamilton, Ontario

Mr. McKibbon was responsible for land use and environmental planning projects in Canada, a shareholder and Secretary of the Board of Directors (1994-1996).

1978 to 1987 — **Planner and Senior Planner, Niagara Escarpment Commission**
Georgetown, Ontario

Mr. McKibbon helped draft the Niagara Escarpment Plan which was approved in 1985.

1974 to 1978 — **Conservation Planner, Hamilton Region Conservation Authority**
Ancaster, Ontario

Mr. McKibbon reviewed municipal plans and planning applications, helped prepare park master plans, water management studies, and environmentally sensitive area studies, and administered the "fill and construction" regulations under the Conservation Authorities Act.

Awards
Mr. McKibbon received awards as the planner in a design team, from the Western Section of the Upstate New York Chapter of the American Planning Association, June 2011, and the Upstate Chapter of the American Planning Association, September 2011, for the Confederation Park Master Plan Review and Update. The Awards were for Planning Excellence and Innovation in Sustaining Places.

Mr. McKibbon was scholar in residence at the University of Guelph's School of Environmental Design and Rural Development in the winters semester, 2011, where he developed and taught a course on First Nations planning and consultation to graduate students. He also participated in advanced planning and environmental assessments courses as a resource and presented an open lecture to the University School on the review of the Provincial Policy Statement.

Mr. McKibbon received an *OPPI Member Service Award* for serving as Director of Policy Development between November 2007 and October 2010. During this team he helped develop OPPI's Healthy Communities Initiative and he developed responses on Provincial legislative and policy initiatives. He also spoke 12 times to planning and public health audiences in the United States and Ontario on OPPI's Health Communities initiative.

Mr. McKibbon received an American Planning Association recognition award for serving as New York State Chapter Canadian Officer between the years of 2003 and 2008 on the New York State Chapter Board at the Upstate Conference in October 2008.

Mr. McKibbon received an *OPPI Member Service Award* at the Institute's Conference in October 2007 for his contributions to the Policy Committee, helping draft "*Healthy Communities, Sustainable Communities*" and serving as Canadian representative on the Upstate New York Chapter of the American Planning Association.

Mr. McKibbon participated in a design team lead by G. O'Connor Consultants Inc., Landscape Architects, which produced the *Hamilton Recreational Trails Master Plan, 2006*. The Master Plan received a C.S.L.A. and A.A.P.C. Regional Merit Award in March 2007. He provided planning advice on the development of a multi-use, off-road recreational trail system that incorporates measures to address emerging health concerns such as obesity and lifestyle issues as well as providing alternatives to the automobile in support of municipal transportation and land use planning objectives.

Mr. McKibbon was a planning advisor to the study team that produced the award winning report *"Visions of the Future, Land Use Development Scenarios for the Rideau Canal Shoreline"* for Environment Canada and the Canadian Park Service, Ontario Region. He provided planning and regulatory advice on the alternative development scenarios to ensure these reflected current planning practice. The report received the C.S.L.A. Citation, the C.S.L.A. Regional Honour Award and the CIP J. Wilson Award for Planning Excellence in 1993.

Publications
In alphabetical order: Hazel Christy, David Harrision, George McKibbon, Alice Miro and Olimpia Pantelimon, Members of the Healthy Communities Committee, 2012, Planning

Notes from Home and Abroad: Creating Healthier Communities; Part 2, Plan Canada, Summer.

D. Hunter, N. Sahni, G. McKibbon. 2012, “Ontario’s Public Lands Act: What Miners Need to Know, securitiesmininglaw.com

D. Hunter, N. Sahni, G. McKibbon. 2012, “A New Paradigm for Aboriginal Consultation in Ontario: What Miners Need to Know”, securitiesmininglaw.com and GLOBE-Net, The business of the environment online.

D. Hunter, N. Sahni, G. McKibbon. 2012, “Canada’s New Environmental Assessment and Aboriginal Consultation Regime: What Miners Need to Know”, securitiesmininglaw.com and GLOBE-Net, The business of the environment online.

D. Hunter, N. Sahni, G. McKibbon. 2012, “Canada’s New Environmental Assessment Regime: What Miners Need to Know”, securitiesmininglaw.com and Ontario Mineral Exploration Review and GLOBE-Net, The business of the environment online.

In alphabetical order: Hazel Christy, David Harrison, George McKibbon, Alice Miro and Olimpia Pantelimon, members of the Healthy Communities Committee, and Ann McKibbon, PhD., Clinical Epidemiology and Biostatistics, McMaster University, 2012, “*Our 21st Century Challenge: Healthier Communities*”, Plan Canada, Spring.

D. Hunter, N. Sahni, G. McKibbon. 2012, “*The Drummond Report: What Miners Need to Know”*, securitiesmininglaw.com

D. Hunter, N. Sahni, G. McKibbon. 2012, “*MNDM Releases Draft Mining Class Environmental Assessment for Comment”*, securitiesmininglaw.com

P. General, G. McKibbon, L. Whyte. 2011. “*Creating Peace, Respect and Friendship, The Power of Consultations*” in Ontario Planning Journal, Vol. 26, No. 6., November/December.

G. McKibbon. 2010. *Grey Bruce Health Unit’s Healthy Communities Conference”*, in OPPI Members Update and News, Volume 7, Issue 6 June 1.

G. McKibbon. 2010. “*Looking for a Cure for Solastalgia*”, in Ontario Planning Journal, Vol. 25, No. 2, March/April.

G. McKibbon. 2009. “*Healthy Communities as a Way of Life: OPPI Partnership with MAH*.” In Ontario Planning Journal, Vol. 24, No. 6, November/December.

G. McKibbon. 2009. “*The importance of Children”*, in Ontario Planning Journal, Vol. 24, No. 2, March/April.

S. Rowe, G. McKibbon, P. Whyte, and S. Tousaw. 2009. *“Bill 150, An Act to enact the Green Energy Act 2009”*. In OPPI Members Update and News, Volume 6, Issue 3, March 3.

G. McKibbon. 2008. *"Built Environments for Active Living Abroad"* in OPPI Members Update and News, Volume 5, Issue 6, June 2.

G. McKibbon. 2008. *"Clean Air Hamilton's Climate Change and Public Health Conference: Looking Forward, Imagine a Future and then Create It!*" in OPPI Member Update and News Volume 5, Issue 4, April.

G. McKibbon. 2008. *"A Social Vision for Climate Change"* In Municipal World, February.

G. McKibbon. 2008. "*Effective Things that You can do to help implement the Policy Paper*." In OPPI Member Update and News, Volume 5 Issue 2, February 1.

G. McKibbon. 2008. *"Setting the Tone: Implementing OPPI's Call to Action",* in OPPI Member Update and News Volume 5 Issue 1, January 2.

In alphabetical order, Melanie Horton, George McKibbon, Lesley Pavan, Nick Poulous, Alex Taranu and Dan Leeming. 2007. *"Healthy Communities, Sustainable Communities"*, Ontario Professional Planners Institute, released on World Town Planning Day, November 8, 2007.

G. McKibbon. 2006. *"Sustainable Communities and a personal reflection on 9/11, Hurricane Katrina and planning practice."* in OPPI Member Update and News Volume 3 Issue 11, November.

G. McKibbon and members of the Natural Resources Working Group. 2006. "*First Nations and Planning*", in OPPI Members Update & News, Volume 3, Issue 9, October.

G, McKibbon. 2006. "*The Changing Field of Ethical Enquiry: Reflections on Current Thinking.*" in the Ontario Planning Journal, Volume 21, No. 5, September/October.

G. McKibbon. 2006. "*Border Dispute: Understanding Canadian Licensing Requirements*", in The New York State APA "The Upstate Planner", Volume 21, Issue 3, August.

G. McKibbon and members of the Natural Resources Working Group. 2006. *"Climate Change Implications for Planners"*, in OPPI Members Update & News, Volume 5, Issue 5, May 1.

G. McKibbon and members of the Natural Resources Working Group. 2005. *"The Ministry of the Environment Land Use Compatibility Guidelines (D1 through D6)"* in OPPI Members Update & News, Volume 2, Issue 12, December 1.

R. Holt, G. McKibbon. 2000. *"Negotiating a Pit Expansion"*, in Intervenor, published by the Canadian Environmental Law Association, Volume 25, No. 3 and 4, July-December.

G. McKibbon. 1999. *"Term and Condition 77: Origins, Implementation and Future Prospects"*, in the Economic Renewal Forum Report on Partnership Trends: Aboriginal

Business and the Forest Sector, Economic Renewal Secretariat, presented in Sault Ste. Marie, Ontario, December 8 and 9.

G. McKibbon. 1992. *"A Background to Resource Planning for Native Communities in Northern Ontario"*, in Doing Business with First Nations proceedings from the Canadian Institute Conference, April 23 and 24.

F. McKay, G. McKibbon. 1992. Presentation on *"Negotiations"* at a conference entitled "*Sharing the Land*", convened by the Canadian Environmental Law Association, January 25 and 26.

D. Hunter, G. McKibbon, and N. Kleer. 1989. *"Rural Development: Environmental and Planning Issues"*, in From the Barnyard to the Boardroom: Issues in Rural Practice, proceedings from a Continuing Legal Education Workshop, Canadian Bar Association – Ontario, June 6.

G. McKibbon, C. Lewis and F. Shaw. 1987. *"Protecting the Niagara Escarpment"* in the Journal of Soil and Water Conservation, Volume 42, Number 2, March/April.

G. McKibbon. 1987. *"The Role of Land Use Change in the Management of the Niagara Escarpment"*, in Lands Directorate, Environment Canada, Monitoring for Change: Workshop Proceedings, Land Use in Canada Series Volume 28.

G. McKibbon. 1986. *"A Review of Class Environmental Assessment Experience in Ontario"*, a background paper prepared for the Canadian Environmental Law Research Foundation. Findings reported in Environmental Assessment in Ontario, R. Gibson and B. Savan, Canadian Environmental Law Research Foundation, December.

G. McKibbon. 1981. *"Ecosystem Stability and Biophysical Land Classification Techniques"*, Occasional paper No. 7. Department of Urban and Regional Planning, Ryerson Polytechnical Institute, Toronto.

Presentations

G. McKibbon, 2012, "New Resources for Planning Healthy Communities", presentation at a Federation of Canadian Municipalities and Heart and Stroke Foundation Webinar entitled "The Health Case for Active Transportation and Smart Growth, September 11.

G. McKibbon, 2012, "New Resources for Planning Healthy Communities", presentation to Clean Air Hamilton, September 10.

G. McKibbon, 2012, "New Resources for Planning Healthy Communities" presentation at the Shaping Healthy Communities: A Prescription for Change "Lunch and Learn" session May 25.

G. McKibbon, 2011, "Paradigm Shift: Evidence Based Planning and Pedestrian Mobility" presentation at the Western Lake Ontario District "Lunch and Learn" session, November 24.

G. McKibbon, 2011, "Effective Planning and Design for Healthy Communities" presentation at the Sustainable Housing and Communities Working Group, National Housing Research Committee, Ottawa, November 8.

G. McKibbon, 2011, "Effective Planning and Design for Healthy Communities" presentation at the Ontario Professional Planners Institute Conference, Ottawa, October13.

G. McKibbon with David Harrison, 2011, "Effective Planning and Design for Healthy Communities" at the Eco Cities World Summit Conference, Montreal, August 22.

G. McKibbon, 2011, "Planning for Healthy Communities", a presentation by the Canadian Institute of Planners, at the Healthy Communities by Design Workshop, 2nd Canadian National Obesity Summit, April 28 to May 1.

G. McKibbon, 2011, "Open Lecture to the University of Guelph School of Environmental Design and Rural Development on the review of the Provincial policy Statement 2005, March.

G, McKibbon, 2009. *"Planning by Design: The Healthy Communities Guide"* at the Go for Health: Government Sector Forum, Essex County, November.

G. McKibbon with Sue Cuming, Thelma Gee and Lynne Peterson, 2009. *"Planning by Design: The Healthy Communities Guide"* at the Canadian Institute of Planners/Ontario Professional Planners Institute Conference, "*Building a Better World*", October.

G. McKibbon. 2008. *"Built Environments for Active Living Abroad: Canada"* presentation at the American Planning Association Upstate New York Conference in Rochester, New York State. October.

G. McKibbon. 2008. "*Built Environments for Active Living Abroad: Canada*" presentation at the American Planning Association Conference in Las Vegas Nevada, April and May.

G. McKibbon. 2008. Moderated a Session entitled *"On How Bill 51 is being Implemented"* at an Insight Ontario Planning Forum: Land and Economic Development, March 31st and April 1st.

G. McKibbon, Melanie Horton, Alex Taranu and Nick Poulous. 2007. "*OPPI Moves forward with Healthy Communities Initiative: We are gaining ground in creating and fostering healthy communities*" presentation at the OPPI Lifestyles Conference in the Town of Blue Mountain, October.

G. McKibbon. 2007. Presentation on Northern and Aboriginal and Public Health and Land Use Issues at conference sponsored by the Association of Local Public Health Associations (ALPHA) in Toronto, February.

H. Evens, J. Ferguson and G. McKibbon. 2006. Presentation on Ontario's Growth Plan at the Joint Annual Conference of the New York Upstate Chapters of the American

Planning Association and the American Society of Landscape Architects and the NYS Geographic Information System Association in Auburn, New York State, September.

G. McKibbon. 2004. Presentation on natural resource policy within a larger presentation by the OPPI Policy Committee entitled *"Land Use Planning in Ontario: A Buff-and-Tone Approach or Major Surgery?"* of the OPPI, Canadian Institute Planners Conference, July.

G. McKibbon. 1999. Presentation of *"Term and Condition 77: Origins, Implementation and Future Prospects"*, at a conference on Partnership Trends: Aboriginal Business and the Forest Sector, Economic Renewal Secretariat, presented in Sault Ste. Marie, Ontario, December 8 and 9.

T. Waboose, G. McKibbon. 1996. Presentation to a workshop addressing mining environmental concerns at a conference entitled *"First Nations Environment Conference, Strengthening Mother Earth – the Environmental Challenge"*, London, Ontario, December 10, 11 and 12.

G. McKibbon. 1992. Presentation of *"A Background to Resource Planning for Native Communities in Northern Ontario"*, at the Doing Business with First Nations, Canadian Institute Conference, April 23 and 24.

F. McKay, G. McKibbon. 1992. Presentation on *"Negotiations"* at a conference entitled "*Sharing the Land*", convened by the Canadian Environmental Law Association, January 25 and 26.

D. Hunter, G. McKibbon, and N. Kleer. 1989. Presentation of *"Rural Development: Environmental and Planning Issues"*, at the From the Barnyard to the Boardroom: Issues in Rural Practice Continuing Legal Education Workshop, Canadian Bar Association – Ontario, June 6.

G. McKibbon. 1987. Presentation of the paper *"The Role of Land Use Change in the Management of the Niagara Escarpment"*, at the Lands Directorate, Environment Canada, Monitoring for Change: Workshop.

Advisor

Stakeholder Dialogue: Promoting Healthy Weights using Population-based Interventions in Canada, McMaster Health Forum, September 17 2012.

Membership in an advisory committee providing input into the Residential Preference Survey reported in *"City and Regional Residential Preference Survey Results for Toronto and Vancouver: A CLASP Final Report"* by Dr, Larry Frank et al., March 7 2012.

Membership in a Heart and Stroke Canada review committee that helped review and provide input into the development into three *"Planning Healthy Communities Fact Sheets"* entitled *"Active Transportation, Health and Community Design: What is the Canadian Evidence Saying?" "Active Living, Children and Youth: What is the Canadian evidence saying?"* and *"Health Equity and Community Design: What is the Canadian evidence saying*?" March 2012.

Membership in the Canadian Institute of Planners Healthy Communities Committee who helped review and provide input into the *"Healthy Communities Practice Guide"* prepared by HB Lanarc Golder, March 2012.

Membership in an advisory team who worked with the National Collaborating Centre for Environmental Health to develop an online: "*Inventory of Built Environment Resources"* 2012.

One of several key informants to the Healthy Living issue Group of the Pan-Canadian Public Health Network in the preparation of the "*Bringing Health to the Planning Table: A Profile of Promising Practices in Canada and Abroad."*

Participant in the Heart and Stroke Foundation/Canadian Obesity Network "*Listening for Direction Workshop on Barriers and Enablers to Financing Smart Growth in Canada: Role and Opportunity for the Canadian Obesity Network*", 2007, in Edmonton on September 25^{th}.

Advisor on land us planning matters to Evergreen in the production of *"Keeping it Green: A Citizen's Guide to Urban Land Protection in Canada"*, 2005.

Professional and Community Activities

OPPI representative on the Conference Planning Steering Committee which planned the 9^{th} and 4^{th} Annual A. D. Latornel Conservation Symposium, "Conservation in Action: Crossing Boundaries and Connecting Communities" and "Conservation in Communities, Sustaining Ecology, Culture and Economy", October 1997 and November 2001 in Alliston, Ontario.

Member of Region of Hamilton-Wentworth Vision 2020 Progress Team which is evaluating the implementation of the Region's (now City of Hamilton) Vision 2020 – The Sustainable Region" policy. The Team reported to Regional Environmental Services Committee and Regional Council in December 1998. The Progress Team report and recommendations entitled "Strategies for a Sustainable Community, was adopted by Regional Council in 1998.

Member of the Upwind Downwind Conference Planning Committee of Clean Air Hamilton, June 1998 to the present and member of Clean Air Hamilton Coordinating Committee 2010 to the present. Specifically, he helped organize the 3^{rd}, 4^{th}, 5^{th} and 6^{th} Upwind Downwind Conferences held on February 2012 (Unlikely Partners), February 2010 (Air Knows no Boundaries), February 2008 (Climate Change and Healthy Communities), February 2006 (Cities Air and Health) and March 2004 (a practical conference on improving air quality). In 2010, he joined the Clean Air Hamilton coordinating Committee as a volunteer planning adviser.

Both Vision 2020 and Clean Air Hamilton have won international recognition as model municipal sustainable development efforts.

Director of Policy of the Ontario Professional Planners Institute and chair of the Policy Committee 2007 to the 2010. In addition he was a member of the Public Policy Committee's Environment and Resources Working Groups, 1997 to 2010. From 2002 to 2006, he was Chair of the Natural Resources Working Group. During his tenure as

Chair, he participated in the preparation of Institute comments on several Provincial legislation and policy initiatives including the preservation of Oak Ridges Moraine, revisions to the Provincial Policy Statement, amendments to the Planning Act and drafts of the Greenbelt and Growth Plans and supporting legislation. From 2006 through 2007, he chaired the Sustainable Communities Working Group where he helped develop OPPI's healthy community initiative.

Canadian Representative, Upstate New York American Chapter Planning Association Board from 2003 to 2008. The Chapter Board and OPPI appointed Mr. McKibbon to keep both organizations informed on items of mutual interest and to participate in Board business.

Chair 2000 to 2003, Ecumenical Downtown Ministries Steering Committee (EDM). EDM represented several City of Hamilton downtown churches. It developed projects which helped fill the gaps. These include a concert by "la Chorale de l'Accuel Bonneau" (The Montreal Homeless Men's Choir) in support of the Housing Emergency Loan Program, the Stone Mason's "free" clothing outlet which served up to 9,000 users each year and helped organize the ongoing Social Justice Stations of the Cross Good Friday observance.

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PROFILE

Rob is co-founder and principal of Northern Bioscience, an ecological consulting firm offering professional consulting services supporting ecosystem management, planning, and research. Dr. Robert F. Foster: Dr. Foster brings 20 years of research and work experience in boreal and tropical (Mali, Tanzania) ecosystems to Northern Bioscience. Dr. Foster has excellent analytical capabilities and has expertise in the development of digital databases and the use of geographic information systems (ArcView, ArcGIS) for natural resource management and protected areas planning. He has been the lead investigator for the gap analysis and related studies supporting the National Marine Conservation Area initiative on Lake Superior. Dr. Foster played a lead role in the analysis and development of the ecosite and wetland ecosystem classifications for northwestern Ontario. He has also conducted data analysis and interpretation for a variety of projects on boreal forest ecology, wildlife habitat, and fisheries. Dr. Foster has a very strong background in the design and implementation of field studies involving vegetation inventory, invertebrate and wildlife monitoring and wetland evaluation and mapping. He has excellent written and oral communication skills, having authored or co-authored numerous popular, technical and scientific reports.

EDUCATION

D. Phil. Zoology	1993	University of Oxford, Oxford, England
H.B.Sc. Biology	1989	Lakehead University, Thunder Bay, Ontario

MAJOR SCHOLARSHIPS AND AWARDS

Rhodes Scholar
Natural Science and Engineering Research Council of Canada Centennial Scholarship

LANGUAGES

English (fluent), French (working), Swahili (working)

CONSULTING EXPERIENCE

Principal, Northern Bioscience 1996 - present
Carried out over 100 projects for government, industry, First Nations, and non-government organizations in Canada and the United States. Main areas of focus (and sample projects) have included:

Biological Inventory and Monitoring

- Canadian Lake Superior co-lead for the assessment of water level management impacts on wetlands and nearshore fish habitat for the International Joint Commission / Environment Canada (2009-present)
- Conducted field surveys for avian and plant species at risk at Ontario Power Generation lands at Kakabeka Falls GS (2009)
- Conducted aerial surveys for woodland caribou and wolverine on 1.8 million ha of the Taa Shi Key Win land use study area for the Mishkeegogamang and Eabametoong first nations (2009), and supported summer caribou calving surveys.
- Rare plant and bird survey for Rainy River First Nation traditional territories on Lake of the Woods (2007)
- Completed detailed life science inventories for 17 parks and conservation reserves in Northwestern Ontario (2000-2007)
- Completed reconnaissance level earth and life science reconnaissance-level surveys for over 50 parks and conservation reserves in northwestern Ontario (2001-2007)
- Conducted life science inventory of Rainy Lake area for Rainy Lake Conservancy (2001-2003)
- Conducted rare and invasive plant surveys for Voyageurs National Park (MN)(2002-2004), Lake Nipigon area (2004), and Atikokan (1997)
- Conducted herpetofaunal surveys Lake Superior Basin (2003), Lake Nipigon area (2004), Schreiber-White Lake area (2005)
- Conduct prairie vegetation, rare plant and invertebrate monitoring at Kay-Nah-Chi-Wah-Nung (Manitou Mounds)(2001, 2004) for Rainy River First Nation.
- Conducted bird migration monitoring at the proposed Lake of the Woods Sand Spit Archipelago Important Bird Area (IBA)(2001)

Environmental Assessment / Environmental Impact Statements

Hydropower / Dam Removal

- Led terrestrial, wetland, and aquatic components for environmental assessment for hydropower development on the Namewaminikan River (2006-present)
- Conducted terrestrial and aquatic baseline environmental surveys for potential hydroelectric development on Matawin, Roaring, and Shebandowan rivers (2007-present).
- Conducted baseline terrestrial/riparian environmental surveys for Little Jackfish hydroelectric development EA (2007-present)
- Conducted fisheries and fish habitat assessment on the Aguasabon River below the Long Lake Control Dam (2006-2009)
- Conducted fisheries and fish habitat assessment and nursery habitat rehabilitation at the Wawatay Generating Station on the Black River (2007-2009)
- Conducted odonate surveys for proposed hydroelectric developments on the Kabinakagami and Kapuskasing Rivers (2007, 2009)
- Conducted rare plant survey for proposed hydroelectric development on the Namakan River (2007, 2009)
- Conducted rare plant, herptile, benthic invertebrate, and mollusc surveys for proposed hydroelectric development on the Aguasabon River (2008)
- Led post dam removal sediment and vegetation monitoring for Onion Lake Dam removal EA on Current River (2008-2009), as well as pre-removal wetlands assessment

Wind Power

- Conducted breeding migration monitoring, waterfowl and raptor surveys for Greenwich Lake wind farm (wetland inventories in northwestern Ontario (2007-2009)
- Conducted breeding bird surveys and migration monitoring at Lakehead Wind Farm.

Mining / Aggregate

- Conducted a baseline terrestrial environmental assessment for the Marathon PGM study area including forest bird monitoring, aerial surveys for peregrine falcons and woodland caribou, terrestrial habitat mapping, and species at risk surveys (2009)
- Conducted fish community and fish habitat assessment of containment cell and adjacent watercourses on Rubicon properties near Red Lake, Ontario (2009)
- Conducted desktop and field assessment of terrestrial species at risk at the Rubicon Red lake property (2009-2010)
- Prepared desktop terrestrial baseline environmental conditions review for Canada Chrome Corporation's "Big Daddy" Deposit in the Ring of Fire (2010)
- Conducted technical/scientific review of Level 1 aggregate reports 2008, 2009 for TBT Engineering (2009)
- Collected field samples for sediments, benthic invertebrate, and fish communities for baseline aquatic EEM for NAP Shebandowan West project (2008)
- Conducted desktop review of baseline aquatic and terrestrial environment for background conditions for North American Palladium's Shebandowan West advanced mineral exploration project (2007)
- Conducted small fish assessment for Environmental Effects Monitoring for Lac des Iles Mine (2006, 2007)
- Conducted rare plant survey for proposed MTO quarry near Morson, Ontario (2007)
- Conducted assessment of small fish growth and fecundity for Environmental Effects Monitoring for North American Palladium's Lac des Iles mine (2006)
- Assessed wetlands in Ecosidstrict 3W-2 for protected area representative value and conducted inventory for plant and animal species at risk for 10 wetlands proposed for peat mining (2006)
- Conducted rapid assessment technique to determine the probability of provincial significance for 59 wetlands (> 100 ha in size) on the English River forest near Ignace (2006)

Utility/Transportation Corridors

- Pre-construction bird nesting survey for Hwy 11-17 Hodder Avenue bypass (2010)
- Conducted terrestrial/aquatic baseline surveys for Little Jackfish hydroline corridor (2010)
- Conducted assessment of potential hydroline corridor between Pickle Lake and Kama Pt on woodland caribou and other natural values, including aerial surveys (2008-present)
- Conducted baseline terrestrial assessment for potential hydroline from Red Lake to Pikangikum (2010 to present)
- Conducted rare plant and other significant features survey for proposed winter road near Shesheeb Bay, Black Bay Peninsula (2007).
- Assessed fisheries impacts for Municipal Class EA for Lakeshore Drive resurfacing (2005)
- Fish habitat assessment of Savanne River bridge (2004)
- Conducted assessment of potential boat launch sites on Black Bay (2003)
- Conducted pre-operations surveys for rare plants along gas pipeline right of way (2001)

Residential / Cottage / Industrial / Urban Development

- Conducted terrestrial and aquatic baseline surveys for Marina Park development EA and design support for habitat restoration/creation (2009-present)
- Conducted terrestrial and fish habitat surveys and EIS for proposed cottage development on Lerome and Plateau lakes near Atikokan (2008-2009)
- Conducted field assessment and prepared environmental impact statement (EIS) for five separate Thunder Bay residential lots with respect to provincially significant wetlands (2002-2010)

- Prepared environmental impact statement of proposed commercial development on great blue heronry near Red Lake, Ontario (2008).
- Conducted field assessment and prepared environmental impact statement of proposed cottage development on bald eagles on Anglican Island, Lake of the Woods (2008).
- Conducted environmental risk assessment for several The Nature Conservancy properties on Lake Superior.
- Conducted environmental assessment of fencing at 2 grain elevators on the Thunder Bay waterfront (2006)
- Prepared environment impact statement for development on Cloud Bay, Lake Superior (2000-2001)
- Conducted environment impact statement for Thunder Bay Regional Hospital site (1999)

Fisheries

- Conducted drift-netting for larval lake sturgeon on the Kaministiquia River below the Kakabeka Falls generating station (2006, 2007, 2010).
- Conducted netting for lake sturgeon movement study on the Ashweig River above Long Dog Lake for Wawakapewin First Nation (2009).
- Review of non-target impacts of sea lamprey control methods for OMNR (2009)
- Conducted coldwater fisheries assessment of Camp 14 Lake and stream near Marathon for potential permit to take water (2008).
- Review and analysis of potential impacts of removal of Black Sturgeon Dam on non-walleye species (2007).
- Review and analysis of potential impacts of removal of Black Sturgeon Dam on walleye ().
- Conducted fisheries and fish habitat assessment at the McKenzie Forest Products Hudson mill site (2007)
- Analysed potential fisheries impacts of Onion Lake dam removal, including fall-walleye index netting, electro-fishing, and beach-seining (2005)
- Assessed hundreds of water crossings for fish habitat impacts during forest audits (1999-2005)
- Co-author of Black Bay walleye rehabilitation plan (2001)
- Co-author of fisheries management plan for Vermilions Lake system (2000-2001)
- Analysed Lac Seul muskellunge data and developed management recommendations (1999)
- Compiled northern pike and smallmouth bass databases for northwestern Ontario (2002, 2004)

Forest Auditing / Forest Resource Management and Science

- Served as biologist on five Independent Forest Audits in Ontario (1999-2006)
- Served as ecologist on Forest Stewardship Council (FSC) certification audit and annual compliance audit using Boreal and draft Great Lakes St. Lawrence standards for 3 Ontario SFLs (2004, 2006, 2008)
- Served as biologist for Sustainable Forestry Initiative (SFI) audit of Kenogami Forest (2004)
- Field-tested draft Boreal Standards for Forest Stewardship Council of Canada (2003)
- Collected field data and performed analysis of vegetation management techniques for field trials near Sioux Lookout, Atikokan, Thunder Bay, and Espanola.
- Conducted pre-harvest surveys for rare plants in Fort Frances MNR District (2000, 2007)
- Conducted FEC data analysis on young and under-represented forest stands and V-types and undertook field verification of ecosites (1996, 2000)
- Prepared technical report on use of grazing animals for forest vegetation management (1997)

Protected Areas Management and Conservation

- Prepared review and assessment of significance of fish and wildlife in Pimachiowin-Aki, proposed UNESCO World Heritage Site on the Manitoba/Ontario border (2009-present)
- Helped develop ecological component for OMNR's Great Lakes Heritage Coast Strategy (2003)
- Conducted gap, human use, and trends analyses; undertook field inventory; and provided scientific and GIS support to Parks Canada for proposed National Marine Conservation Area on Lake Superior (1997-2006)
- Conducted technical and scientific reviews of Important Bird Area (IBA) community conservation plans from across Canada (2000).

Recreation Development

- Provided ecological input and GIS support for City of Dryden Trail Enhancement and Development Project (2003), Rushing River / Eagle-Dogtooth Trail Strategy (2003), and Atikokan Recreation Corridor Master Plan (2004).

Species at Risk Assessments / Recovery Strategies

- Coauthored COSEWIC status reports for Rapids Clubtail (*Gomphus quadricolor*), Northern Barrens Tiger Beetle (*Cicindela patruela*), Laura's Clubtail (*Stylurus laurae*), Drooping Trillium (*Trillium flexipes*), Bogbean Buckmoth (*Hemileuca* sp.), and Bluehearts (*Buchnera americana*)(2006-2010)
- Prepared national recovery strategies for Flooded Jellyskin (*Leptogium rivulare*) lichen and False Rue-anemone (*Enemion biternatum*)(2007) for Canadian Wildlife Service
- Prepared provincial recovery strategy for small-flowered lipocarpha (*Lipocarpha micrantha*) (2003)
- Prepared national recovery strategy for western silvery aster (*Symphytotrichum sericeum*) (2004)

Wetland Evaluation, Inventory, and Monitoring

- Conducted wetland evaluations using the Northern Ontario Wetland Evaluation Manual at for over 15 wetland in northern Ontario (1996-present)
- Conducted wetland inventories in northwestern Ontario (1997-2007)
- Conducted assessment of historical change in Black Bay Peninsula peatlands using aerial photography (2006
- Conducting 5-year wetland inventory and monitoring of effects of water level management on Rainy Lake basin (2001-2005)
- Conducted analysis and field verification of peatlands in Ignace area to develop preliminary wetland evaluation scores (2003-2004)
- Collected field data for 100 wetland ecosystem classification plots in northeastern Ontario (1997)

Wildlife Habitat

- Developed spatial predictive model for peregrine falcon nesting habitat in Ontario (2003-2006)
- Analysed marten habitat availability on the Lakehead Forest based on remote-sensed data and trapper surveys (2000)
- Reviewed the Status of the Habitat in the Lake Superior Basin for the Lakewide Management Plan (LaMP)(2002, 2003)
- Conducted mark-recapture studies of small mammals to examine impact of herbicides and vegetation management on small mammals (1996, 1997, 2003)

- Identified moose aquatic feeding areas (MAFAs) from aerial photographs for Black Sturgeon Forest (2003).
- Revised the Aulneau Peninsula Enhanced Management Area wildlife management plan (2000) and undertook pre-harvest values surveys (2003).

OTHER PROFESSIONAL EXPERIENCE

Landscape classification biologist Ontario Ministry of Natural Resources, 1995-1996
- conducted data synthesis and analysis of wetland vegetation and environmental data
- assisted with development of ecosite and wetland ecosystem classifications, including field testing of keys
- assisted in writing/editing of ecosite, wetland classification and wetland plant field guides

Small mammal biologist Ontario Forest Research Institute, 1995
- coordinated field research on the effects of vegetation management techniques (herbicide applications, brushsaws, etc.) on small mammal population dynamics
- was responsible for field logistics, data quality and supervision of eight-person field crew
- conducted small mammal trapping, identification, handling and tagging

Natural heritage biologist Nature Conservancy of Canada, 1995
- collected data from government, academic and other sources on the status and distribution of rare, threatened and endangered plants, animals and communities in NW Ontario
- compiled digital catalogue of sources for use by the Natural Heritage Information Centre

Ecological consultant Canadian Forest Service, 1994-1995
- conducted multivariate analyses of forest ecosystem classification (FEC) plot data to compare fire origin and anthropogenic stands of varying ages and species composition
- compiled silvicultural history records for FEC plots and conducted field plot locating.

Field crew leader Ontario Ministry of Natural Resources, 1994
- identified and estimated percent cover of vascular and non-vascular plant species in various physiognomic strata on sample plots; collected other vegetation data
- dug soil pits, identified horizons by texture, structure, colour etc., and described site-specific pedology and characteristics
- collected basic mensurational data including tree heights, diameters and ages

Doctoral student University of Oxford, 1989-1993.
- conducted ecosystem-based research in the Serengeti of Tanzania on the role of dung beetles and termites in nutrient cycling
- collected ecological data on vegetation, soils, weather, insect and ungulate populations
- established and maintained research camp in remote location over 2 1/2-year period
- analysed data with uni- and multivariate statistics

Interpretive naturalist Pukaskwa National Park, 1989.
- researched and presented educational programs and guided hikes on natural history
- coordinated the preparation and distribution of all park programming promotion
- contributed to the park entomological and photographic collections

Research assistant Biology Department, Lakehead University, May-Aug. 1987-1988.
- worked on research project examining the effect of acid rain on trembling aspen genetics;

acquired root cuttings, propagated seedlings, and conducted electrophoretic analyses

- assisted with field work for jack pine and larch genetics projects, including site location and field reconnaissance, soil sampling and tissue collection
- carried out tiger beetle (*Cicindela* spp.) genetics project, including specimen collection, electrophoretic analysis, data analysis and summary
- dissected tropical carabid beetles and derived preliminary phylogenetic relationships

Timber cruiser Borealis Forestry Consultants, 1986.

- timber cruised as part of a two-person forest resource inventory crew
- duties included tree identification and basic mensuration, navigation, map-reading, aerial photo interpretation, use of small boats and outboard motors

ADDITIONAL TRAINING

- Ontario Bat Monitoring Workshop for Wind Power Projects — June 2010
  Ontario Ministry of Natural Resources / University of Western Ontario
- Canadian Red Cross First Aid and CPR — May 2010
- University of New Brunswick Backpack Electrofishing Course — July 2009
- Identification of Ontario Fishes Workshop — April 2008
  Royal Ontario Museum, Toronto
- Screenings under Canadian Environmental Assessment Act — Feb 2006
  Canadian Environmental Assessment Agency, Ottawa
- Lead Assessor training for Forest Stewardship Council (FSC) auditing — June 2001
  Smartwood, Timmins
- Forest Landscape Analysis Workshop, OMNR, Thunder Bay — Jan 2000

RELATED ACTIVITIES

- member of the Ecological Society of America, American Fisheries Society, Society for Conservation Biology, Federation of Ontario Naturalists
- Thunder Bay Field Naturalists (TBFN),
  - member (1995-present)
  - Director (2009-present)
  - Executive, Thunder Cape Bird Observatory (1997-1999)
- participant in OMNR / Bird Studies Canada
  - Ontario Odonata Atlas (2000-present)
  - Ontario Herpetological Survey (1997-present)
  - Ontario Nocturnal Owl Survey (1996-present)
  - Ontario Bird Atlas (2001-2005)
  - Forest Bird Monitoring Program (1994-1998)

SELECTED PUBLICATIONS 2000-2008

2008

Harris, A.G. and R.F. Foster. 2008. Western Lake Superior Biodiversity Assessment 2007 Update Report. Unpublished report prepared for Nature Conservancy of Canada.

Foster, R.F. and A.G. Harris. 2008. COSEWIC assessment and update status report on the Drooping Trillium *Trillium flexipes* in Canada. Committee on the Status of Endangered Wildlife in Canada. Ottawa.

Harris, A.G. and R.F. Foster. 2008. Matawin River Aquatic and Terrestrial Inventory Existing Conditions - Background Report. Unpublished report prepared for McGraw Falls Power.

Foster, R.F. P.J.Colby, and A.G. Harris. in prep. Camp 43 Dam: Feasibility of Removal. Unpublished report prepared for Ontario Ministry of Natural Resources, Nipigon District.

Harris, A.G. and R.F. Foster. 2008. Life science inventory of Ogoki River Provincial Park. Unpublished report prepared for Ontario Parks.

Foster, R.F. 2008. Shebandowan West Baseline Aquatic Biological Assessment. Report. Prepared for North American Palladium Ltd. by Northern Bioscience.

Foster, R.F. and A.G. Harris. 2008. COSEWIC Status Report on Patterned Green Tiger Beetle (*Cicindela patruela).* Committee on the Status of Endangered Wildlife in Canada (COSEWIC), Ottawa, Ontario.

Harris, A.G. and R.F. Foster. 2008. Raptor and waterfowl migration Greenwich Wind Farm Sept - Oct 2007. Unpublished report prepared for Dillon Consulting Limited.

2007

Harris, A.G. and R.F. Foster. 2007. COSEWIC Status Report on Rapids Clubtail Dragonfly (*Gomphus quadricolor*). Committee on the Status of Endangered Wildlife in Canada (COSEWIC), Ottawa, Ontario.

Honsberger, T., R. F. Foster, B.E. McLaren, and F.W. Bell. 2007. Effects of vegetation control on small mammals in northwestern Ontario. Unpublished manuscript.

Foster, R.F., A.G. Harris. and J. Tost. 2007. Fish and fish habitat assessment Aguasabon River 2007. Unpublished report prepared for Ontario Power Generation.

Foster, R.F. and A.G. Harris. 2007. Kapuskasing River Odonate Monitoring. Unpublished report prepared for Hatch Ltd.

Foster, R.F., A.G. Harris and J. Tost. 2007. Namewaminikan River Aquatic and Terrestrial Inventory Existing Conditions - Background Report. Unpublished report prepared for KGS.

Foster, R.F. and A.G. Harris 2007. Proposed Indicators for State of the NMCA Reporting: Proposed National Marine Conservation Area in Lake Superior. Unpublished report prepared for Parks Establishment Branch, Parks Canada. 50 p.

Harris, A.G. and R.F. Foster. 2007. Shoreline flora of Little Eva Lake and Bill Lake. Unpublished report prepared for Bio-Consulting.

Foster, R.F. and A.G. Harris. 2007. Hay Bay Rare Plant Inventory. Unpublished report prepared for Rainy River First Nations.

Foster, R.F. and A.G. Harris. 2007. Kaministiquia River Larval Sturgeon Sampling 2007 Feasibility Study. Unpublished report prepared for Ontario Power Generation, Thunder Bay.

Foster, R.F. 2005. Lakeshore Drive Fisheries Assessment. Unpublished report prepared for TBT Engineering. 15 p. + append.

2006

Foster, R.F. and A.G. Harris. 2006. Wetland Evaluation Poshkokagan River. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District.

Foster, R.F. and A.G. Harris. 2006. Fish Habitat Assessment of Poshkokagan and Kabitotikwia River Wetlands. Unpublished report prepared for Nipigon District, Ontario Ministry of Natural Resources.

Foster, R.F. and A.G. Harris. 2006. COSEWIC Status Report on Rapids Clubtail Dragonfly (*Gompus quadricolor).* Committee on the Status of Endangered Wildlife in Canada (COSEWIC), Ottawa, Ontario.

Foster, R.F. and A.G. Harris. 2006. COSEWIC Status Report on Patterned Green Tiger Beetle (*Cicindela patruela).* Committee on the Status of Endangered Wildlife in Canada (COSEWIC), Ottawa, Ontario.

Forbes, A.C., R.F. Foster, M.H. Nelson, and S.F. Lamoureux. 2006. Onion Lake Dam Environmental Impact Study. Unpublished report prepared for Ont. Min. Natur. Resour., Thunder Bay. 97 p. + append.

Furlong, P., R.F. Foster, and P. Colby. 2006. Black Sturgeon River Dam: Implications for the passage and recovery of Black Bay walleye. Unpublished report. Ontario Ministry of Natural Resources, Thunder Bay.

Harris, A.G. and R.F. Foster. 2006. Rare Plant Survey for the Schreiber – White Lake Area of the Lake Superior Basin. Prepared for Wildlife Assessment Program, Northwest Region. Ontario Ministry of Natural Resources.

Harris, A.G. and R.F. Foster. 2006. Reptile and Amphibian Survey for the Schreiber – White Lake Area of the Lake Superior Basin. Prepared for Wildlife Assessment Program, Northwest Region. Ontario Ministry of Natural Resources.

Harris, A.G. and R.F. Foster. 2006. Wetland Evaluation Kabitotikwia River. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District.

Harris, A.G., B. Ratcliff and R.F. Foster. 2006. Aquatic invasive species assessment for the Hudson Bay Drainage of Central Canada. Unpublished report.

2005

Foster, R.F. 2005. Lakeshore Drive Fisheries Assessment. Unpublished report prepared for TBT Engineering. 15 p. + append.

Foster, R.F. and A.G. Harris. 2005. Contribution of the Peat Resources study area to representation targets for Ecodistrict 3W-2. Unpublished report prepared for Peat Resources Ltd.

Foster, R.F. and A.G. Harris. 2005. Preliminary Wetland Assessment Dog River – Matawin Forest. Unpublished report prepared for Thunder Bay District Ontario Ministry of Natural Resources.

Foster R.F., B. Ratcliff, and A.G. Harris. 2005. 2004-2005 Herpetofaunal Survey for the Lake Nipigon West and Adjacent Areas. Prepared for Wildlife Assessment Program, Northwest Region. Ontario Ministry of Natural Resources.

Foster R.F., B. Ratcliff, and A.G. Harris. 2005. 2004 Rare Plant Survey for the Lake Nipigon West Area 2004. Prepared for Wildlife Assessment Program, Northwest Region. Ontario Ministry of Natural Resources.

Foster, R.F. and A.G. Harris. 2005. Life Science Inventory: Gravel River Provincial Nature Reserve. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District. 73 p.

Foster, R.F. and A.G. Harris. 2005. Life Science Inventory: Gravel River Conservation Reserve. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District. 97 p.

Byford, B. R.F. Foster, P. Schantz, and J.P. Gladu. 2005. SmartWood Certification Assessment Report for Clergue Forest Management Inc.: Algoma Forest & Wawa Forest. 102 p.

Harris, A.G. and R.F. Foster. 2005. Life Science Inventory Nakina Northeast Waterway Conservation Reserve. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District.

Harris, A.G. and R.F. Foster. 2005. Reconnaissance Life Science Inventory for Lake Nipigon – Beardmore Enhanced Management Area. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District.

Harris, A.G. and R.F. Foster. 2005. Vascular plant and odonate survey Voyageurs National Park Unpublished report prepared for The Great Lakes Network Inventory and Monitoring Program.

Harris, A.G. and R.F. Foster. 2005. A survey for rare flora and fauna in peatlands: GG1 – GG6 and ML1 – ML4. Unpublished report prepared for Peat Resources Ltd.

Harris, A.G. and R.F. Foster. 2005. Life Science Inventory Wabakimi Provincial Park. Unpublished report prepared for Ontario Parks.

Harris, A.G. and R.F. Foster. 2005. Manitou Mounds Prairie: Vegetation and Insect Monitoring 2004. Unpublished report prepared for Rainy River First Nations.

Harris, A.G. and R.F. Foster. 2005. Wetland Evaluation Nipigon River. Unpublished Report prepared for Ontario Ministry of Natural Resources, Nipigon District.

Harris, A.G., R.F. Foster, C. Foster, C. Hamel. 2005. National Recovery Strategy for Western Silvery Aster (*Symphyotrichum sericeum*). Unpublished Report prepared for: Ontario Ministry of Natural Resources, Northwest Region.

2004
Foster, R.F., C. Blackburn, and A.G. Harris. 2004. Reconnaissance surveys summary report: nine Northwestern Ontario parks and conservation reserves. Unpublished report. 23 p. + factsheets and appendices

Foster, R.F. and A.G. Harris. 2004. Life science inventory of Eagle - Dogtooth Provincial Park. Unpublished report prepared for Ontario Parks. 58 p + appendices.

Foster, R.F. and A.G. Harris. 2004. Life science inventory of Lake of the Woods Provincial Park. Unpublished report prepared for Ontario Parks. 54 p + appendices.

Foster R.F., B. Ratcliff, and A.G. Harris. 2004. Amphibians and Reptiles of the Ontario portion of the Lake Superior Basin. Prepared for Wildlife Assessment Program, Northwest Region. Ontario Ministry of Natural Resources.

Harris, A.G. and R.F. Foster. 2004. Life science inventory of Agassiz Peatlands Provincial Park. Unpublished report prepared for Ontario Parks. 51 p + appendices.

Harris, A.G. and R.F. Foster. 2004. Life science inventory of Spruce Islands Provincial Park. Unpublished report prepared for Ontario Parks. 52 p + appendices.

Harris, A.G. and R.F. Foster. 2004. Life science inventory of Sable Islands Provincial Park. Unpublished report prepared for Ontario Parks. 62 p + appendices.

Harris, A.G., R.F. Foster, W.D. Bakowsky, and M.J. Oldham. 2004. Life science inventory of Aulneau Peninsula Enhanced Wildlife Management Area. Unpublished report prepared for Ontario Ministry of Natural Resources. 34 p + appendices.

Harris, A.G. and R.F. Foster. 2004. Recovery Strategy for Small-flowered Lipocarpha (*Lipocarpha micrantha*) in Ontario. Unpublished report prepared for Ontario Ministry of Natural Resources. 29 p.

2003
Foster, R.F. and A.G. Harris. 2003. Life science inventory of West English River Provincial Park. Unpublished report prepared for Ontario Parks. 59 p + appendices.

Harris, A.G. and R.F. Foster. 2003. Hurkett Marsh Wetland Evaluation. Report prepared for Ducks Unlimited Canada. 41 p + appendices.

Harris, A.G. and R.F. Foster. 2003. Life science inventory of East English River Provincial Park. Unpublished report prepared for Ontario Parks. 59 p + appendices.

Harris, A.G. and R.F. Foster. 2003. Life science inventory of Lake of the Woods Provincial Park Addition. Unpublished report prepared for Ontario Parks. 57 p + appendices.

IBI, The Tourism Company, Dobbin International, Northern Bioscience, Engel Consulting Group, Callaghan and Associates, and Northern Ontario Native Tourism Association. 2003. Great Lakes Heritage Coast Strategy. Unpublished report prepared for Ont. Min. Natur. Resour.

Bioforest Inc. 2003. An independent audit of forest management on the Nagagami Forest for the period 1997 - 2002. Unpublished report prepared for the Forestry Future Commission.

Foster, R.F., C. Blackburn, and A.G. Harris. 2003. Reconnaissance surveys summary report: western Northwestern Ontario. Unpublished report prepared for Ontario Parks, Northwest Region, Thunder Bay. 21 p. + factsheets and appendices

2002

Callaghan and Associates. 2002. An independent audit of forest management on the Lake Nipigon and Auden Forests for the period 1996 - 2001. Unpublished report. 127 p.

Callaghan and Associates. 2002. An independent audit of forest management on the Armstrong Forest for the period 1996 - 2001. Unpublished report. 79 p.

Callaghan and Associates. 2002. An independent audit of forest management on the Kiashke Forest for the period 1996 - 2001. Unpublished report. 51 p.

Jones, M., A.G. Harris,. 2002. Life science inventory of Black Sturgeon River Provincial Park. Unpublished report. 63 p. + appendices.

Foster, R.F., C. Blackburn, and A.G. Harris. 2002. Reconnaissance surveys summary report: western Northwestern Ontario. Unpublished report. 18 p. + factsheets and appendices

Foster, R.F. and A.G. Harris. 2002. Black Bay Bog Wetland Evaluation. Report prepared for Nipigon District, Ontario Ministry of Natural Resources. 41 p + appendices.

Foster, R.F. and A.G. Harris. 2002. Little Falls Wetland Evaluation. Report prepared for Fort Frances District, Ontario Ministry of Natural Resources. 41 p + appendices.

Foster, R.F. and A.G. Harris. 2002. Rat River Wetland Evaluation. Report prepared for Fort Frances District, Ontario Ministry of Natural Resources. 41 p + appendices.

Foster, R.F. and A.G. Harris. 2002. Life science inventory of St. Raphael Signature Site. Unpublished report. 68 p. + appendices

Foster, R.F. and A.G. Harris. 2002. Shesheeb Bay Wetland Evaluation. Report prepared for Nipigon District, Ontario Ministry of Natural Resources. 41 p + appendices.

Foster, R.F., B. Ratcliff, and A.G. Harris. 2002. Peregrine Falcon Habitat Analysis. Draft report. 13 p. + appendices.

Harris, A.G, D. Elder, B. Ratcliff, and R. Foster. 2002. Bird Monitoring and Research Lake of the Woods Sand Spit Archipelago. Unpublished report. 20 p. + appendices.

Harris, A.G. and R.F. Foster. 2002. Potential flora of Voyageurs National Park. Unpublished report. 5 p. + appendices.

Harris, A.G., R.F. Foster, and M. Jones. 2001. Life science inventory of Woodland Caribou Provincial Park Signature Site. Unpublished report. 82 p. + appendices.

Harris, A.G., R.F. Foster, M.J. Oldham, and W.D. Bakowsky. 2002. Life science inventory of Rainy Lake. Unpublished report. 43 p. + appendices

Harris, A.G, R.F. Foster, W.D. Bakowsky, and M. J.Oldham. 2001. Manitou Mounds Prairie: Baseline vegetation and invertebrate monitoring and life science inventory. Unpublished report. 22 p. + appendices.

Harris, A.G., D. Gauthier, and R.F. Foster. 2002. Reconnaissance surveys summary report: eastern Northwestern Ontario. Unpublished report. 18 p. + factsheets and appendices

Smartwood. 2002. Field-Testing the FSC Boreal Ontario Draft Standards. Unpublished Report. 137 p.

2001

Colby, P.J. and R.F. Foster. 2001. Black Bay Walleye Rehabilitation Plan. Report prepared for Black Bay Walleye Restoration Committee. Thunder Bay. 63 p.

Foster, R.F. and A.G. Harris. 2001. Invasive Plants Survey Voyageurs National Park. Report prepared for Voyageurs National Park, MN, U.S. National Parks Service. 82 p.

Foster, R.F., A.G. Harris, and S. Robertson. 2001. Sleeping Giant Provincial Park vegetation history. Report prepared for Ontario Parks, Ont. Min. Natur. Resour. 67 p.

Foster, R.F., R. Hartley, M. Oldham, B. Ritchie, B. Ross, M. Smyk, D.A. Sutherland, L. Woodruff. 2001. Lake Superior National Marine Conservation Area Marine Attributes Study: Field Verification. Unpublished report prepared for Parks Canada, Department of Canadian Heritage by Northern Bioscience. 32 p.

Foster, R.F., S. Robertson, A.G. Harris, and G.D. Racey. 2001. Multivariate analysis of vegetation and environment data comparing mature forest conditions and young logging- and -fire-origin stands in northwestern Ontario. Draft Report. Northwest Sci. & Technol., Ont. Min. Natur. Resour., Thunder Bay, Ont. TR.

Harris, A.G., R.F. Foster, W.D. Bakowsky, and M. J. Oldham. 2001. Manitou Mounds Prairie: Baseline Vegetation and Invertebrate Monitoring and Life Science Inventory. Report prepared for Rainy River First Nations.

Harris, A.G., R.F. Foster, and M. Jones. 2001. Life Science Inventory: Woodland Caribou Signature Site. Report prepared for Ontario Parks.

2000

Harris, A.G. and R.F. Foster. 2000. Status of Habitat in the Lake Superior Basin (Draft). Lake Superior Lakewide Management Plan. Unpublished report prepared for Lakewide Management Plan Habitat Committee. 250 p.

Callaghan and Associates. 2000. An independent audit of forest management on the Kenogami Forest for the period 1995 - 2000. Unpublished report. 81 p.

Callaghan and Associates. 2000. An independent forest audit of forest management on the Brightsand Forest for the period 1995 - 2000. Unpublished report. 62 p.

Foster, R.F. and A.G. Harris. 2000. Chapleau Wetland Evaluation. Report prepared for Chapleau District Ontario Ministry of Natural Resources. 41 p + appendices.

Foster, R.F. and A.G. Harris. 2000. Cloud Bay Wetland Evaluation. Unpublished report. . 41 p. + app

Foster, R.F. and A.G. Harris. 2000. Rice Bay Wetland Evaluation. Report prepared for Fort Frances District, Ontario Ministry of Natural Resources. 41 p. + app

Foster, R.F and A.G. Harris. 2000. Rosslyn Oxbow Wetland Evaluation. Report prepared for Thunder Bay District, Ontario Ministry of Natural Resources. 53 p. + appendices.

Foster, R.F., A.G. Harris, B. Callaghan, T. Timmermann, M. Lankester. 2000. Draft Aulneau Peninsula Enhanced Wildlife Management Plan. Report prepared for Kenora District, Ont. Min. Natur. Resour. 99 p.

Foster, R.F., A.G. Harris and B. Ratcliff. 2000. Marten on the Lakehead Forest. Report prepared for Thunder Bay District, Ont. Min. Natur. Resour. 38 p.

Foster, R.F, T.L. Socha, and T.G. Potter. 2000. Survey of attitudes for the National Marine Conservation Area proposal for Lake Superior. Unpublished report prepared for Parks Canada, Department of Canadian Heritage by Northern Bioscience. 53 p.

Harris, A.G., P.J. Colby, J. Hall-Armstrong, and B. Ratcliff. 2000. Status of lake sturgeon in the Winnipeg River: Recovery considerations and implications. Report prepared Kenora District, Ont. Min. Natur. Resour. 42 p.

Harris, A.G, M. Oldham, R.F. Foster, W.D. Bakowsky. 2000. Preliminary Life Science Inventory of Rainy Lake. Unpublished report prepared for the Rainy Lake Conservancy. 44 p.+ appendices.

Jones, M, A.G. Harris, and R.F. Foster. 2000. Life Science Inventory: Woodland Caribou Signature Site. Unpublished report prepared for Ontario Parks, Ont. Min. Natur. Resour. 110 p.

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EDUCATION

M.Sc. Biology	1990	Lakehead University, Thunder Bay, Ontario
B.Sc. Biology	1984	University of Guelph, Guelph, Ontario

PROFILE

Al Harris is a biologist with 25 years experience in northern Ontario. After spending seven years as a biologist with Ontario Ministry of Natural Resources, he co-founded Northern Bioscience, an ecological consulting company based in Thunder Bay, Ontario. He has conducted life science inventory in over 60 protected areas in northern Ontario, 27 wetland evaluations, and was Canadian co-lead on wetland monitoring on the Rainy Lake – Namakan system for the International Joint Commission and at Isle Royale National Park.

He is senior author of the *Wetland Ecosystem Classification for Northwestern Ontario* and co-author of *Terrestrial and Wetland Ecosites for Northwestern Ontario* and *Wetland Plants of Ontario*.

Al has also been heavily involved in woodland caribou population monitoring, habitat assessment, and management guidelines development in northwestern Ontario.

He is currently a member of the Committee on the Status of Species at Risk in Ontario (COSSARO).

CONSULTING EXPERIENCE

Principal, Northern Bioscience 1996 - present
Carried out over 100 projects for government, industry, First Nations, and non-government organizations in Canada and the United States. Main areas of focus (and sample projects) have included:

Ecological inventory and monitoring

- Conducted life science inventories for over 60 provincial parks and conservation reserves
- Established wetland monitoring programs at Voyageurs and Isle Royale national parks
- Conducted life science inventory of Rainy Lake area for Rainy Lake Conservancy
- Conducted rare and invasive plant surveys for Voyageurs National Park (MN)(2002-2004), Lake Nipigon area (2004), and Atikokan (1997)
- Conducted herpetofaunal surveys Lake Nipigon area (2004).

- Conducted prairie vegetation, rare plant and invertebrate monitoring at Kay-Nah-Chi-Wah-Nung (Manitou Mounds)(2001, 2004) for Rainy River First Nation.
- Conducted bird migration monitoring at the proposed Lake of the Woods Sand Spit Archipelago Important Bird Area (IBA)
- Completed Environmental Impact Statements for Thunder Bay Regional Hospital, City of Thunder Bay, and three property owners within the City of Thunder Bay.

Wetland Evaluation, Inventory, and Monitoring

- Conducted 27 wetland inventories in northwestern Ontario (1997-2009)
- Conducting 5-year wetland inventory and monitoring of effects of water level management on Rainy Lake basin (2001-2005)
- Conducted analysis and field verification of peatlands in Ignace area to develop preliminary wetland evaluation scores (2003-2004)
- Collected field data for 100 wetland ecosystem classification plots in northeastern Ontario (1997)

Forest auditing

- Served as biologist on Independent Forest Audit teams auditing seven forest management units in northwestern Ontario. Primary responsibilities included interviews, review of documentation, and field examination related to the planning and application of environmental and wildlife guidelines, such as area of concern prescriptions, water crossings, and habitat guidelines.
- Served as biologist on Forest Stewardship Council audit team
- Member of team writing Forest Stewardship Council regional certification standards for Ontario boreal forests.

Workshops and training

- Delivered workshops to OMNR District, Regional and forest industry staff on wetland classification (Thunder Bay 1998; Dryden, 1997; Geraldton, 1996); air photo interpretation of wetland ecosites (Sault Ste. Marie, January 1997); an overview of northwestern Ontario wetland ecosystem classification and wetland ecosites to District and Regional staff (10 presentations, November - December 1996); field training of OMNR summer staff on ecosite classification (six sessions; 1996 - 2001).

Data collection

- Field verification of aerial photo interpretation of ecosites
- Collected environmental and vegetation data from 200 wetland plots in northeastern Ontario.
- Conducted mark-recapture study of small mammals at the Fallingsnow Lake Ecosystem Study
- Collection of data from OMNR district offices on vulnerable, threatened and endangered species.

Data analysis

- Conducted multivariate analysis comparing ecological and environmental data of young forest stands in comparison with mature stands
- Compiling OMNR Growth and Yield data for factsheet production

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WORK EXPERIENCE

Northern Bioscience
Thunder Bay, Ontario

- Collected data on human use, current trends, and future impacts on Lake Superior ecosystem for the proposed National Marine Conservation Area on Lake Superior.
- Aquatic invasive species assessment for the Hudson Bay Drainage of central Canada.
- Conducted life science inventories at new parks and protected areas created under the Ontario Living Legacy. Parks included: St.Raphael Lake, Black Sturgeon River, Lake of the Woods, East and West English River. 2002-2005
- Collected data on species at risk (birds) and bird migration monitoring at the south end of Lake of the Woods. 2001.
- Surveyed trappers in Lakehead District as part of a study of Pine Marten (*Martes americana*).
- Researched the history of Lake Sturgeon (*Acipenser fulvenscens*) on the Winnipeg River. 1999.
- Compiled a database of biological and geological studies conducted in far Northern Ontario.
- Researched background information for the vegetation management plan for Sleeping Giant Provincial Park. 2001.
- Conducted small mammal inventory examining the effects of different broad leaf vegetation inhibitors on small mammal populations. 1997, 2003
- Gathered Small Mouth Bass (*Micropterus dolomieu*) and Northern Pike (*Esox lucius*) data on the distribution of these species in Northwestern Ontario. 1997.
- Compiled information on endangered, threatened, and vulnerable species of wildlife in Northwestern Ontario for the Natural Heritage Information Centre. 1996.

Ontario Ministry of Natural Resources
Thunder Bay, Ontario

- Developed, conducted and documented the 2005 Ontario Peregrine Falcon Survey. This survey examined the entire province looking for Peregrine Falcon (*Falco peregrinus*) as part of the National Peregrine Falcon Inventory. April 2005-September 2005.
- Acting Regional Species at Rick Biologist, September 2000- March 2001 and January 2004-July 2004.
- Development of a plan for a public wildlife viewing area close to Thunder Bay. Determining possible sites for a wildlife viewing area that would feature Moose (*Alces alces*) as the feature species. October 2003-March 2004
- Developed, conducted and documented the 2000 Ontario Peregrine Falcon Survey. This survey examined the entire province looking for Peregrine Falcon (*Falco peregrinus*) as part of the National Peregrine Falcon Inventory. May 2000-February 2001.
- Prepared historical documentation of nesting Peregrine Falcons (*Falco peregrinus*) in Ontario. Compiled summary on the status of all young Peregrine Falcons re-introduced into Ontario since 1977.
- Conducted a survey of Piping Plovers (*Charadrius melodus*) on Lake of the Woods, to determine the breeding status of this endangered species. June 1979
- Served as field researcher for the Lakeshore Capacity Study, censusing Common Loons (*Gavia immer*). Project involved canoeing 40 study lakes in the Muskoka-Haliburton region and monitoring the breeding success of loons as affected by cottage development. Summers, 1977 and 1978**.**

Cook Engineering
Thunder Bay, Ontario
- Data collection and report for the Black Bird Creek Terrestrial Ecosystem existing conditions, 2005.

Thunder Bay Field Naturalists
Thunder Bay, Ontario
- Coordinator of the Stanley Grasslands Project. Working with local landowners to identify grassland species of plants and conducted a prescribed burn to discourage weed species and enhance native grassland species. 2002-2004.
- Coordinator of nesting surveys and banding of Peregrine Falcons (*Falco peregrinus*), at cliff nest sites on Lake Superior. 1996-Present.

Canadian Wildlife Service
Toronto, Ontario
- Collection of Herring Gull (*Larus argentatus*) eggs from Granite Island, Lake Superior as part of the Great Lakes Contaminants Study. 1997- Present.
- Survey and data collection of nesting herring Gull on Mutton Island, 2001, and 2007.
- Surveyed colonial nesting waterbirds in Nipigon District, Lake Superior**.** May 1999.
- Completed a breeding evidence inventory of seven species of marsh birds in the Niagara Region. May-June 1992.
- Completed a population survey of breeding colonial waterbirds on the North Cannel, Lake Huron to determine the location and size of all breeding colonies of gulls, terns, herons and cormorants. Summer 1980.

Parks Canada
Thunder Bay, Ontario
- Identified property owners adjacent to and within the proposed National Marine Conservation Area on Lake Superior's north shore, and compiled a mailing list to be used for public consultation. January - April 1997.

Friends of Pukaskwa
Heron Bay, Ontario
- Updated coastal canoe/kayak brochure for Pukaskwa National Park. Also assisted with the capture of Woodland Caribou (*Rangifer caribou*) under the Park's Predator Prey Program. September, October 1995.

Geomatics International Inc.
Burlington, Ontario
- Compiled biophysical and geoscience data pertaining to the Moose River Basin from Ministry of Environment and Energy files. October 1995.

Centre for Northern Forest Ecosystem Research
Thunder Bay, Ontario
- Conducted forest bird monitoring component of Black Sturgeon Boreal Mixed Woods Research Program, investigating breeding bird response to varying intensity of timber harvest in boreal mixed wood forest. May-July 1995.

Manitoba Wildlife Rehabilitation Organization
Glenlea, Manitoba

- Responsible for the building of Manitoba's first wildlife rehabilitation centre. Secured more than $75,000 in capital funding to build outdoor enclosures and to purchase equipment for office and hospital buildings. Coordinated all summer staff and volunteers at centre. May 1993-April 1995.

The Owl Foundation
Vineland Station, Ontario

- Served as wildlife biologist comparing the behaviour of captive wild owls to personal field observation of owls. Installed a 20-camera monitor system to observe and record owl behaviour. Responsible for the complete rebuilding of this facility, and supervised all summer staff hired. September 1985-April 1991.

Manitoba Department of Natural Resources
Winnipeg, Manitoba

- Initiated and secured funding for a research project studying the breeding population of Burrowing Owls (*Athene cunicilaria*) in Manitoba. Studied current status of Burrowing Owls, and initiated landowner cooperation in assisting this threatened species.
- Conducted aerial surveys to determine the breeding population of American White Pelicans (*Pelecanus erythrorhynchos*).
- Flew aerial surveys for Bald Eagles (*Haliaeetus leucocephalus*) in the Interlake region of Manitoba.
- Initiated two other population research projects on Ferruginous Hawk (*Buteo regalis*) and Baird's Sparrow (*Ammodramus bairdii*). Summers 1982-1985.
- Gave papers on the above research at Raptor Research Conference, St. Louis, Missouri, 1983, and at Endangered Species on the Prairie Provinces Conference, Edmonton, Alberta, 1986.

Northern Biomes, Ltd.
Whitehorse, Yukon

- Served as navigator and observer, conducting aerial surveys of Moose (*Alces alces*) in southern Yukon. Fall 1982.

Michigan Department of Natural Resources
Lansing, Michigan

- Surveyed all of Michigan's shoreline to determine the numbers and distribution of breeding Piping Plovers (*Charadrius melodus*). Summer 1979.

EDUCATION

- **Certificate Program in Environmental Assessment,** Lakehead University, 1998.
- **Bachelor of Science, General,** University of Guelph, 1979.

PROFESSIONAL ORGANIZATIONS

- Raptor Research Foundation
- Federation of Ontario Naturalists

ADDITIONAL EXPERIENCE

- Executive, Canada Trust Friends of the Environment Foundation, 1997 – 2007. Chair of the Foundation 2000-2006.
- Author of the birding column "In Flight" for the Thunder Bay Chronicle Journal, June, 2002-present.
- Director, Thunder Bay Field Naturalists, 1996.
- Advisory Committee Member, Thunder Cape Bird Observatory, 1996 – present.
- Volunteer, Ontario Owl Survey, 1996 - present.
- Volunteer Bander at Thunder Cape Bird Observatory, 1995 - present.
- Lakehead Search and Rescue Volunteer, 2002-Present.
- Volunteer, Manitoba Owl Survey and Manitoba Herpetofaunal Survey, 1994 - 1995.
- President, Peninsula Field Naturalists' Club, 1992 - 1993.
- Member, Niagara Region Ecological and Environmental Advisory Committee, 1991-1992.
- Volunteer, Ontario Mammal Atlas, 1991.
- Director, Niagara Peninsula Hawkwatch, 1990 - 1992.
- Volunteer, Ontario Birds at Risk, 1989 - 1991
- Chaired Burrowing Owl Section of Endangered Species in the Prairie Provinces Conference, Edmonton, Alberta, 1986.
- Leader for Canadian Nature Tours wilderness canoe trips, and Quest Nature Tours. Leading trips to Churchill, Greenland, Cuba, Newfoundland and Antarctica. 1985 - present.
- Master Bird Banding Permit, Canadian Wildlife Service, 1982 - present.
- Volunteer, Ontario Breeding Bird Atlas, 1981-85, and 2001-05.
- Have prepared and delivered several workshops on bird identification and other natural history topics to naturalists clubs, and various other community groups.

PUBLICATIONS

- See attached.

REFERENCES

- Available on request.

BRIAN RATCLIFF

PUBLICATIONS

- Harris, A.G., B. Ratcliff, and R.F. Foster. 2006 Aquatic invasive species assessment for the Hudson Bay Drainage of central Canada. Unpublished report. Prepared for Fisheries and Oceans Canada, Central and Arctic Region. 43 pp.

- Ratcliff, Brian. 2006. Project Peregrine: Results of the 2006 Field Season. Report prepared for the Thunder Bay Field Naturalists'. Unpublished Report. 16 pp.

- Ratcliff, Brian, and Ted Armstrong. 2006. 2005 Ontario Peregrine Falcon Survey. Unpublished report prepared for the Ontario Ministry of Natural Resources. 25 pp.

- Ratcliff, Brian. 2005. Update Status Report on American White Pelican (Pelicanus erythrorhynchos) in Ontario. Report prepared for Committee on the Status of Species at Risk in Ontario. OMNR. 22 pp.

- Ratcliff, Brian. 2005. Project Peregrine: Results of the 2005 Field Season. Report prepared for the Thunder Bay Field Naturalists'. Unpublished Report. 14 pp.

- Ratcliff, Brian. 2004. Project Peregrine: Results of the 2004 Field Season. Report prepared for the Thunder Bay Field Naturalists'. Unpublished Report. 13 pp.

- Ratcliff, Brian. 2003. Peregrine Falcons in the Lake Superior Basin. pp. 183, in Return of the Peregrine- A North American saga of tenacity and teamwork. T.J. Cade, and W. Burnham eds. The Peregrine Fund, Boise Idaho. 394 pp.

- Ratcliff, Brian. 2003. Project Peregrine: Results of the 2003 Field Season. Report prepared for the Thunder Bay Field Naturalists'. Unpublished Report. 13 pp.

- Ratcliff, Brian. 2003. Breeding history and diet composition of Double-crested Cormorant (Phalacrocorax auritus) colonies on Black Bay and Thunder Bay, Lake Superior in 2003. Report prepared for Upper Great Lakes Management Unit-Lake Superior, OMNR, Thunder Bay, ON. 11 pp.

- Coady, G., M.K. Peck, D.H. Elder and B. Ratcliff. 2003. Breeding records of Eared Grebe in Ontario. Ontario Birds Volume 20: 106-119.

- Ratcliff, Brian, and Ted Armstrong. 2002. The 2000 Ontario Peregrine Falcon Survey. Ontario Birds Volume 20: 87-94.

- Foster, R.F., B. Ratcliff, and A.G. Harris. 2002. Peregrine Falcon habitat analysis. Draft report prepared for the Ministry of Natural Resources by Northern Bioscience. 13 pp + appendices.

- Ratcliff, Brian. 2002. Project Peregrine: Results of the 2002 Field Season. Report prepared for the Thunder Bay Field Naturalists'. Unpublished Report. 13 pp.

- Harris, Allan, David Elder, Brian Ratcliff and Robert Foster. 2001. Bird Monitoring and Research Lake of the Woods Sand Spit Archipelago Important Bird Area. Report prepared for Ontario Ministry of Natural Resources by Northern Bioscience. 30 pp.

- Ratcliff, Brian. 2001. Project Peregrine: Results of the 2001 Field Season. Report prepared for the

Thunder Bay Field Naturalists’. Unpublished Report. 11 pp.

- Ratcliff, Brian. 2000. Project Peregrine: Results of the 2000 Field Season. Report prepared for the Thunder Bay Field Naturalists’. Unpublished Report. 9 pp.
- Foster, R.F., A.G. Harris, and B. Ratcliff. 2000. Marten on the Lakehead Forest. Report prepared for Thunder Bay District, OMNR. 38 pp.
- Harris, Allan, Dr. Peter Colby, Jean Hall-Armstrong, Brian Ratcliff. 2000. Status of Lake Sturgeon in the Winnipeg River: Recovery Considerations and Implications. Report prepared for Ontario Ministry of Natural Resources by Northern Bioscience. 42 pp.
- Ratcliff, Brian. 1999. Project Peregrine: Results of the 1999 Field Season. Report prepared for the Thunder Bay Field Naturalists’. Unpublished Report. 14 pp.
- Foster, Robert, Allan Harris, Julian Holenstein and Brian Ratcliff. 1999. Lake Superior National Marine Conservation Area: Current Trends and Future Impacts on the Lake Superior Ecosystem. Report prepared for Parks Canada, Department of Canadian Heritage by Northern Bioscience. 91 pp.
- Foster, Robert F., Brian D. Ratcliff, and Allan G. Harris. 1999. Lake Superior National Marine Conservation Area: Human Use Report. Report prepared for Parks Canada, Department of Canadian Heritage by Northen Bioscience. 110 pp.
- Foster, R. F., W.D. Bakowsky, B. Ratcliff, B. Ross, C. Wiwcharyk, and L. Woodruff. 1998b. Lake Superior National Marine Conservation Area Attributes Study: Field Verification. Report prepared for Parks Canada, Department of Canadian Heritage by Northen Bioscience. 22 pp.
- Ratcliff, Brian. 1998. Project Peregrine: Results of the 1998 Field Season. Report prepared for the Thunder Bay Field Naturalists’. Unpublished Report. 21 pp.
- Ratcliff, Brian. 1997. Project Peregrine: Results of the 1997 Field Season. Report prepared for the Thunder Bay Field Naturalists’. Unpublished Report. 19 pp.
- Ratcliff, B.D. 1997. Land Tenure in the Study Area of the Proposed National Marine Conservation Area on Lake Superior. Report prepared for Parks Canada. Unpublished Report. 52pp.
- Jackson, Gail, Brian Ratcliff, Andi Dye, Robert Dye. 1996. Project Peregrine: Results of the 1996 Field Season. Report prepared for the Thunder Bay Field Naturalists’. Unpublished Report. 29 pp.
- Ratcliff, B.D. 1996. Ontario Peregrine Falcons: Historical Nesting and the Re-introduction Program. Ontario Ministry of Natural Resources, Thunder Bay District. Unpublished Report. 22 pp.
- Ratcliff, B.D. 1992. Collection of Eggs of Rails, Bitterns, and Other Marsh Nesting Birds for Contaminant Studies. Canadian Wildlife Service, Canada Centre for Inland Waters. Unpublished Report. 9 pp.
- Ratcliff, B.D. 1987. Ferruginous Hawk, Report for Manitoba. pp. 205, in Endangered Species in the Prairie Provinces. (G.L. Holroyd, P.H.R. Stepney, W.B. McGillvary, D.M. Ealey, and K.E. Eberhart, eds.) Natural History Occasional Paper No. 9, Provincial Museum of Alberta, Edmonton, Alberta.
- Ratcliff, B.D. 1987. Burrowing Owls in Manitoba. pp. 275, in Endangered Species in the Prairie Provinces. (G.L. Holroyd, P.H.R. Stepney, W.B. McGillvary, D.M. Ealey, and K.E. Eberhart, eds.)

Natural History Occasional Paper No. 9, Provincial Museum of Alberta, Edmonton, Alberta.

- Ratcliff, B.D. 1987. Baird's Sparrow Survey in Manitoba. pp. 281-282, in Endangered Species in the Prairie Provinces. (G.L. Holroyd, P.H.R. Stepney, W.B. McGillvary, D.M. Ealey, and K.E. Eberhart, eds.) Natural History Occasional Paper No. 9, Provincial Museum of Alberta, Edmonton, Alberta.

- Ratcliff, B.D. 1986. The Manitoba Burrowing Owl Survey 1982 - 1984. Blue Jay 44:31-35.

- Weseloh, D.V., P. Mineau, S.M. Teeple, H. Blokpoel, and B. Ratcliff. 1986. Colonial Waterbirds Nesting in Canadian Lake Huron in 1980. Canadian Wildlife Service Progress Notes No. 165. 28pp.

- Ratcliff, B.D., and J.L. Murray. 1984. Recent Successful Nesting of Ferruginous Hawk in Manitoba. Blue Jay 42: 215-218.

- Lambert, A., and B. Ratcliff. 1981. Present Status of the Piping Plover in Michigan. The Jack-Pine Warbler 59:44-52.

- Ratcliff, B.D. 1979. Piping Plover Survey of Sable Islands, Lake of the Woods, Ontario. Ontario Ministry of Natural Resources, Wildlife Branch. Unpublished Report. 9pp.

LAIRD VAN DAMME, M.Sc.F., R.P.F.

COMPANY POSITION: Consulting Forester and Managing Partner,
KBM Forestry Consultants Inc.

KEY QUALIFICATIONS AND EXPERIENCE

1996- present **Consulting Forester & Managing Partner, KBM Forestry Consultants**

- Responsible for all consulting projects and corporate business development
- Played a key role in developing a new wood harvest and chipping system in Chile and a digital aerial photography system for Central Canada.
- Direct involvement in the following projects :
    - Project manager/peer reviewer for large scale forest management plans, a regional land use plan and several environmental assessments. These projects involved numerous scientists and practitioners from across Canada, spanned several years and had multi-million dollar budgets. Two project s had climate change adaptation and cumulative impacts assessment components.
    - Played a key role in the development and application of decision support systems.
    - Managed numerous forest inventory research projects and field programs.
    - Auditor for national programs and forest operations to several standards (e.g. ISO 14001, SFI, IFA).

1993 - present **Adjunct Professor, Lakehead University, Faculty of Forestry**
Supervising graduate and undergraduate thesis projects, lecturer on several topics each year in silviculture, forest management and forest policy.

1991 - 1996 **Director, Ontario Advanced Forestry Program Lakehead University/ University of Toronto:** Responsible for program development and delivery to meet the continuing education and professional development needs of experienced natural resource managers. Lecturer in Silviculture as needed.

1989 - 1991 **General Manager, KBM Forestry Consultants Inc.**
Responsible for all corporate activities which include contracting, consulting and sale of silvicultural equipment.

1988/89 **Term Lecturer in Silviculture, Lakehead University**

1984 - 1988 **Project Forester, KBM Forestry Consultants Inc.**
In charge of forest operations and inventory contracts with government and industry Responsibilities also included research and development to support the marketing efforts of the silvicultural equipment sales division.

EDUCATION/Training

Cert. ISO 14001 Lead Auditor Training	QMI	2000
M.Sc.F. Lakehead University		1985
B.Sc.F. Lakehead University		1982

MEMBERSHIPS AND PROFESSIONAL CREDENTIALS:

1984-present	Member of the Ontario Professional Foresters Association. (**President** 1994)
1987-present	Member of the Canadian Institute of Forestry.
1992-present	Member of the Society of American Foresters.
2002-present	Certified Forester, SAF.
2002-2006	Member of the C-Cairn Forest Sector Advisory Committee
2008-present	Chair of Lakehead University Natural Resources Management Faculty Advisory Committee
2009-present	Member Provincial Forest Technical Committee

LANGUAGES: English

CITIZENSHIP: Canada and United States

AUDITS:

- 16 Ontario CFSA Independent Forest Audits
- 6 ISO 14001/SFI audits
- 2 FSC peer reviews for SCS
- Evaluation of Canada's Model Forest Program (2001) & National Forest Strategy (2007)
- 2009 FSC certification support, AbitibiBowater, Caribou Forest, ON

FOREST & LAND USE PLANS:

- 1996 Abitibi Freehold Forest Management Plan, Thunder Bay , ON
- 2000 & 2007 DFMP Millar Western Forest Products, Whitecourt AB
- 2003 NES Regional Land Use Plan, Edmonton, AB.
- 2005 Forest Management Plan, Bowater, Thunder Bay , ON
- 2006 Forest Management Plan, LP Canada, Swan River MB
- 2008 Forest Management Plan Bowater, Sioux Lookout, ON
- 2010 Foot Hills Research Institute, Support for Upper Athabasca LUF Edmonton, AB

INTERNATIONAL EXPERIENCE; China, Ghana, Sweden, Chile

PUBLICATIONS: 67 reports, 7 peer reviewed journal publications, 3 book chapters, including:

Van Damme, L. 2009, Forest sustainability in Ontario, For. Chron. 85(3): 415-416
A.R. Taylor, H.Y.H. Chen and L. Van Damme, 2009, A review of forest succession models and their suitability for forest management planning. Forest Science 55(1), 23
Van Damme, L., P. Duinker, D. Quintillio, 2008, Embedding science and innovation in forest management: recent experiences at Millar Western in west-central Alberta. For. Chron. 84(3) 301-306.
Van Damme, L. 2008. Can the forest sector adapt to climate change? For. Chron. 84(5): 633-634.
Van Damme, L., J. Russell F. Doyon, P. Duinker, T. Gooding, K. Hirsch, R. Rothwell, and A. Rudy, 2003. The development and application of decision support systems for sustainable forest management on the boreal plain, Journal of Environment Engineering and Science. Vol (2): S23-S34.

PETER E. HIGGELKE, M.Sc. Forestry, R.P.F.

COMPANY POSITION — **Consulting Forester and Managing Partner**, KBM Forestry Consultants Inc.

SPECIALIZATION IN FIRM — Auditing (Ontario Independent Forest Audits, and FSC Forest Management audits and Chain of Custody audits); forest management planning; aerial photography mission coordination; wildlife habitat modelling; wood supply analysis; forest inventory; forestry negotiations, business plan preparation and economic development advice to First Nations; timber harvesting and forest renewal prescriptions; forest inventory.

- Forest management role in the review and development of a Framework For NWT Forest Legislation And Policy report for the Department of Environment and Natural Resources Forest Management Division.
- Lead in the development of Habitat Suitability Index Models for 17 wildlife species in support of Forest Management Planning for Millar Western, Whitecourt, Alberta
- Lead Auditor for four FSC scoping audits. Auditor in three FSC certification audits and eight FSC annual surveillance audits
- Lead author for six FSC HCVF assessment reports
- Acted in several roles in Independent Forest Audits in Ontario including lead auditor
- Developed digital colour aerial photography system for harvest depletion tracking in northern Ontario
- Co-developer of first forest harvesting/chipper system in Chile

KEY QUALIFICATIONS AND EXPERIENCE

1995-Present — **Consulting Forester and Managing Partner,** KBM Forestry Consultants Inc.
- Manager of Contracting Division. Responsible for site preparation contracts, aerial photography services, consulting projects and business development activities.

1994-1995 — **Sessional Lecturer** in Principles of Integrated Forest Resources Management, Geographic Information Systems, Integrated Forest Resources Management, Lakehead University.

1993-1994 — **Consulting Forester**, Self-employed
- Consulting services to First Nations in the development of forest management plans with the protection of traditional native values.
- Established land-use zones using a GIS database and prepared development guidelines for various land-use classes.
- Development of spatially based Marten and Moose HIS models for land use territory of Algonquins of Barriere Lake in Quebec.

1992-1993 — **Research Associate**, Chair, Forest Management and Policy, School of Forestry, Lakehead University.

1988-1991 — **Coordinator**, LU-CARIS (Lakehead University – Center for the Application of Resource Information Systems), School of Forestry, Lakehead University.

1990 and 1989 — **Lecturer** in GIS applications, Lakehead University

1987-1988 **Research Assistant**, LU-CARIS, School of Forestry Lakehead University

1980-1986 **Forest Manager**, Von Wendt Enterprises of Gevelinghausen, West Germany.

- Forest management and operations planning, operational implementation of plans, and annual budget formulation, on two forest estates (West Germany and Quebec, Canada).

EDUCATION and TRAINING

B.Sc.F., Lakehead University - 1980
M.Sc.F., Lakehead University – 1994

ISO 14001 EMS Essentials – 2000
ISO 14001 EMS Internal Auditor – 2000
QMI EMS Lead Auditor Training – 2006 Certificate # 0000176544

PROFESSIONAL MEMBERSHIPS

1985-present Ontario Professional Foresters Association
2004-present Canadian Institute of Forestry

AUDIT REPORTS

Lead auditor and author for numerous Independent Forest Audits and FSC (Forest Stewardship Certification) audits. For example:

Higgelke, P., B. Chaulk, L. Van Damme, T. Dawyd and K. Hautala. *In Progress.* Trout Lake Forest Independent Forest Audit. KBM Forestry Consultants Inc. Thunder Bay, ON. Ministry of Natural Resources.
Higgelke, P., B. Chaulk, L. Van Damme, T. Dawyd and K. Hautala. 2009. Dryden Forest Independent Forest Audit. KBM Forestry Consultants Inc. Thunder Bay, ON. Ministry of Natural Resources.
Higgelke, P. and W.R. Mark. 2008. FSC Certification Report for the 2008 Annual Audit of The Sudbury Forest Under The Sustainable Forest Licence of Vermilion Forest Management Company Ltd.: Certificate Number: SCS-FM/COC-094N

Lead auditor or auditor for several FSC forest management certification and annual surveillance audits.

FIRST NATIONS RELATED PUBLICATIONS examples

Higgelke, P. May 2004. First Nations Forestry Program National Conference. *Making Forestry Services Viable.* Thunder Bay, Ontario.

Higgelke, P. March 2003. Wood Supply Strategies for Biomass Heating in Remote Communities. CANBIO Technical Workshop: Biomass-Fired District Heating Opportunities for Remote Communities. Thunder Bay, Ontario.

Terrance H. Gibson, Ph.D.
Senior Manager, Senior Archaeologist
Western Heritage

Summary

Profile

Dr. Terrance (Terry) Gibson has over 36 years archaeological and anthropological experience working with the petroleum, forestry, transportation and residential development industries, and with First Nations organizations from Northwestern Ontario to British Columbia. He has a Ph.D. in Anthropology, specializing in Archaeology. He currently serves as an adjunct professor at the University of Alberta and the University of Saskatchewan. Much of his time is spent supervising corporate staff as they deal with developer and regulator heritage management concerns. He also supervises Western Heritage's Research and Development program, which seeks to develop and incorporate advanced methods and techniques in archaeology and other field to improve corporate scientific expertise in the heritage and related disciplines. His geographic region of specialization in archaeology and anthropology extends from northwestern Ontario westward to the plains, parkland and boreal forest of Western Canada. Current research interests include the application of geophysical methods on archaeological sites, heritage management in the forestry and oil and gas industries and the advancement of data management and geospatial analysis methods on large archaeological sites and in cultural resource management and traditional land use studies.

Experience

Senior Manager, Western Heritage operations in Alberta, Saskatchewan, Manitoba and NW Ontario

As a founding partner of Western Heritage Services Inc. (now Western Heritage), Dr. Gibson expanded the company's archaeological services to Alberta, establishing the St Albert office in 1999 and managing its former subsidiary Alberta Western Heritage operations. He now supervises a number of archaeologists and their support staff in Western Heritage offices in St Albert, Calgary and Grande Prairie, AB. He also oversees the company's Swan River and Winnipeg MB offices, and its newly established Thunder Bay ON office. Dr. Gibson is currently Chair of the Board of Directors of Western Heritage.

Skills

All aspects of Cultural Resource Management including regulatory policy development; Digital Information Management and Software Development; GIS Modeling; Near Surface Geophysical Prospection; University Undergraduate and Graduate Training in Canadian Archaeology and Canadian Cultural Resource Management.

EIA/Heritage Management/Archaeological Background

Dr. Gibson has over three decades of experience conducting historical resources, archaeological and traditional land use studies from Ontario west to British Columbia. This work includes numerous archaeological and historical cultural resource management projects for the oil and gas, forestry and transportation industries, encompassing Stage 1, 2, 3 and 4 levels of investigation. He has participated as an historical resources consultant and traditional land use consultant in numerous multidisciplinary Environmental Impact Assessment projects related to establishment of Forestry Management Allocation Areas in Alberta. Saskatchewan and Manitoba, including development of heritage potential models. He is currently working in conjunction with Lakehead University and regional Northwestern Ontario First Nations in the development of and training in the use of a portable GIS-based traditional use information management system. He is also collaborating with staff of Lakehead University on the application of geophysical methods to improve the effectiveness of archaeological excavation on Northwestern Ontario boreal forest sites, and to acquire site-specific information not easily recognized using standard testing and excavation techniques. Dr. Gibson has considerable experience in directing and reporting on large-scale multi-disciplinary archaeological mitigation projects. He has particular expertise in the excavation and analysis of artifacts from sites requiring extensive and complicated excavation and producing voluminous archaeological materials.

Educational Background:

- [x] B.A. Brandon University 1975
- [x] M.A. University of Alberta 1982
- [x] Ph.D. University of Alberta 1998

Years of Experience: *Total:* 36

Professional Accreditation:

- [x] Saskatchewan Association of Professional Archaeologists
- [x] Association of Manitoba Archaeologists
- [x] Canadian Archaeological Association
- [x] Plains Anthropological Association
- [x] Archaeological Permit Holder for Alberta, Saskatchewan, Manitoba; Professional License Holder, Ontario

Andrew Lints, M.E.S.
Project Archaeologist
Western Heritage

Profile
Andrew Lints is a recent graduate from Lakehead University, receiving a Master's degree in the Northern Environments and Cultures program. Andrew is well versed in the identification of all types of pre-contact archaeological materials (pottery, lithics, and faunal materials) as well as historic items. Andrew has been working on archaeological excavations since 2007 and these sites have ranged from some of the earliest human occupations of northern Ontario to Proto-Historic agricultural sites. Through these archaeological investigations, Andrew has gained field experience in both southern and northern Ontario as well as Manitoba. In addition to archaeological experience, Andrew has participated in Forensic Investigations conducted by Brandon, MB RCMP officers which included the recovery and analysis of human remains.

Experience
<u>Project Archaeologist</u> Western Heritage 1990-2012

<u>Stage 2 Survey of proposed 4-laning of Highway 11/17 near Pass Lake, ON</u>
Role: Project Manager for Stage 2 test pitting completed by First Nation and non-First Nation crew.
Client: Hatch Mott MacDonald
Objective: Completed test pits to determine if archaeological materials were located on proposed development areas.
Date Completed: Aug 7-18, 2012

<u>Stage 4 Excavations at the Woodpecker 2 and 3 sites near Thunder Bay, ON</u>
Role: Supervisor for Stage 4 excavations of Paleoindian site
Client: Ministry of Transportation
Objective: Identify and excavate archaeological site prior to development of Highway 11/17
Date Completed: April 23 to Aug 3, 2012

<u>Stage 2 Survey near Hagersville, ON</u>
Role: Project manager for Stage 2 pedestrian survey and test pitting
Client: GTE Solar Inc.
Objective: Completed pedestrian survey of agricultural fields and test pitting of wooded areas to determine if archaeological materials were located on proposed development areas.
Date Completed: May 6-12, 2012

<u>Stage 1 and 2 Surveys of Proposed Subdivision near Red Lake, ON</u>
Role: License holder for Stage 1 and 2 survey of proposed subdivision near the community of Red Lake, ON.
Client: Goldcorp
Objective: Completed field survey of all areas of the proposed subdivision and fully documented archaeological potential.
Date Completed: March 5-6 and March 27-28

Project Role
Andrew will serve as project archaeologist for all archaeological studies undertaken by Western Heritage as part of this project.

Shabnam Inanloo Dailoo, Ph.D.
Cultural Landscapes and Aboriginal Engagement Adviser
Environmental Designer

Profile

Dr. Shabnam Inanloo Dailoo has been working in the field of heritage conservation for more than a decade. She started her career when employed by the Iranian Cultural Heritage Organization wherein she worked as a conservation landscape designer and planner. She led several projects with a focus on developing conservation and interpretation plans for historic sites and Persian gardens. In Canada, Shabnam researched conservation of cultural landscapes and the challenges of identification and recognition of values, examining the existing issues at multiple levels; international (UNESCO World Heritage Centre), national (Canada and Iran), and provincial (Alberta). Her research outcome was presented in the form of guiding principles and recommendations to the responsible authorities who make decisions for historic environments. Her postdoctoral research work with Canada Research Chair on Built Heritage focused on the study of the application of values-based management in conservation of cultural landscapes. Meanwhile, she collaborated with the City of Calgary to evaluate a number of historic resources and prepare their Statements of Significance and Statements of Integrity.

She acted as a member and director of Calgary Civic Trust for two years and collaborated in arrangements for a traditional First Nation ceremony in honor of John L. Laurie. She joined Western Heritage in 2011 as Cultural Landscapes and Aboriginal Engagement Adviser. She is currently practicing cultural landscape approach in conservation and management of cultural resources as well as Aboriginal cultural places. Shabnam has been active in the heritage conservation community and has attended many international and national events, workshops and conferences, including the 32nd session of the World Heritage Committee in Quebec City. These opportunities equipped her with a better understanding of challenges in cultural resource management in different parts of the world and in Canada.

Experience

Cultural Landscapes and Aboriginal Engagement Adviser, Western Heritage, 2011 - Present

As a cultural landscapes and aboriginal engagement adviser for Western Heritage, Dr Inanloo Dailoo has work on projects involving First Nations and Metis communities in Alberta east to Southern Ontario, including research on Aboriginal Cultural Landscapes and Conservation Activities in Canada. Recent work includes preparation of a guide for Aboriginal Engagement and development of a standardized method for undertaking and reporting engagement activities for Western Heritage's archaeological programs in each province. As part of her doctoral research she specialize in the identification of values and conservation planning of cultural landscapes, developing recommendations for improving the recognition and protection of cultural landscapes, in including World Heritage cultural landscapes. This work was based on direct investigation of Aboriginal Peoples' ways of life, worldviews, traditional knowledge and land use practices and their approaches toward sacred sites and cultural landscapes. As a postdoctoral researcher, she held a Canada Research Chair on Built Heritage at the Université de Montréal frtom 2009 - 2011. There she researched documents related to policies, guidelines, standards and manuals and consulted professionals in the field of heritage conservation at different levels of government. This cultminated in the editing and publication two series of proceedings on heritage conservation, cultural landscapes and sustainability.

Skills

Shabnam has been involved in cultural resources management, both in theory and practice, for the past 12 years and has gained valuable experience in working with various types of cultural resources (buildings, sites, sacred places and landscapes). She has a broad understanding of Aboriginal traditional knowledge and land use practices. She is well acquainted with provincial, federal and international heritage regulations and policy development and has a knowledge of historic resources impact assessment reports. Shabnam is an experienced researcher and is expert in conducting field-based interviews, data collation and analysis, and archival research related to civic and industrial projects. She has the skills to review, analyze and summarize data gathered from historic sites and produce analytical reports. She also is an experienced historic garden/landscape planner and designer.

Project Role

Dr. Inanloo Dailoo will serve as project manager and primary interviewer and data collector for all traditional land use and occupancy studies undertaken by Western Heritage as part of this project.

TBT ENGINEERING
CONSULTING GROUP

WAYNE HURLEY, P.ENG.
Vice President - Engineering

SUMMARY OF QUALIFICATIONS

- 25+ years Consulting Engineering experience providing geotechnical design, materials testing, construction supervision, environmental and inspection services for a wide variety of clients.
- 2 years with MTO providing regional geotechnical services for pavement design and rehabilitation
- Designated Consultant in Ontario
- Qualified Person by MOE for Environmental Record of Site Condition

DEGREES / CERTIFICATES / COURSES

- B. Sc. Civil Engineering, University of Manitoba, 1978, Winnipeg, Manitoba
- Memberships in Professional Engineers of Ontario, American Society of Civil Engineers, Canadian Geotechnical Society, Association of Professional Engineers of Manitoba, Professional Engineers and Geoscientists of British Columbia
- Certified under Ontario Reg. 903 as Well Technician

RELEVANT EXPERIENCE

VICE PRESIDENT - ENGINEERING *(2000 – Present)*
TBT Engineering Limited, Thunder Bay, ON

- Provide technical and project management services for TBTE's geotechnical, foundation and environmental engineering services. Project responsibilities included geotechnical investigations and design for commercial, industrial and government sectors; highway foundation and geotechnical projects; environmental investigations, materials testing and design activities. Co-ordination of TBTE's geotechnical and environmental drilling contracting

Typical Projects:

- ✓ Geotechnical Investigations for MTO Highway Rehabilitations
- ✓ Geotechnical/Foundation Investigations for MTO Structures, Bridges and Earthworks
- ✓ Aggregate Source Investigations
- ✓ Slope Stability Investigations
- ✓ Geotechnical Recommendations for residential, commercial and industrial buildings
- ✓ Review of Failed Sheet Pile Systems
- ✓ Phase I Environmental Assessments
- ✓ Phase II Environmental Assessments
- ✓ Pavement Failure Investigations
- ✓ Pavement Condition Surveys

MANAGER *(1994 - 2000)*
Consulting Engineers, Thunder Bay, ON

- Management of all staff for geotechnical, environmental, material testing and construction sectors
- Technical review and supervision for all projects from Thunder Bay office. Technical advisor for other offices
- Project responsibilities included geotechnical investigations and design for commercial, industrial and government sectors; highway foundation and geotechnical projects; environmental investigations, designs and cleanups; materials testing and design activities; geotechnical and horizontal drilling contracting
- Responsible for all testing certification programs such as CSA, CCIL, MTO

Typical Projects:

- ✓ Foundation investigations for MTO Highway bridges
- ✓ Foundation investigations for commercial/institutional structures
- ✓ Slope Stability investigations

- ✓ River Erosion investigations/remediation
- ✓ Foundation Investigations for Industrial Structures

MANAGER *(1992 - 1994)*
Dominion Soil Investigation Inc., Windsor, ON

- ➢ Responsible for all aspects of Windsor office for geotechnical and materials consultant
- ➢ Prepared all proposals, provided client liaison and reviewed all technical reports
- ➢ Preparation and review of geotechnical investigations, soils and concrete testing, and roof inspections

Typical Projects:

- ✓ Foundation Investigations for Industrial Structures
- ✓ Investigation for Embankment widening
- ✓ Investigations for Infrastructure Projects

PAVEMENT DESIGN ENGINEER *(1990 - 1992)*
Ministry of Transportation, London, ON

- ➢ Responsible for the co-ordination and review of Geotechnical Design Reports and developing the most cost effective rehabilitation strategies for regions highways. (from urban arterials to 400 series freeways)
- ➢ Planning and directing subsurface investigations
- ➢ Participating in Pavement Management activities
- ➢ Supervising Geotechnical consultant assignments ensuring Ministry standards were met.
- ➢ Provided regional foundation liaison and review of slopes, barrier walls, high-mast lights and embankments

PROJECT ENGINEER *(1986 - 1990)*
Dominion Soil Investigation Inc.

- ➢ Project Engineer for geotechnical and environmental investigation projects
- ➢ Geotechnical supervision of earth fill dam construction
- ➢ Design and field inspection of grouting projects

Typical Projects:

- ✓ Foundation Investigations of Industrial Structures
- ✓ Embankment Design and Inspection
- ✓ Field Investigations of Railway Embankments over soft soils

PROJECT ENGINEER *(1978 - 1986)*
J.A. Smith & Associates Ltd. Calgary, AB

- ➢ Project Engineer for geotechnical investigation projects
- ➢ Provided survey for topographic, construction layout and monitoring projects
- ➢ Field activities such as concrete testing, soil testing, drill supervision, construction inspection

Typical Projects:

- ✓ Foundation Investigations of Commercial Structures (Multi-story condominiums, Underground Parking structures)
- ✓ Investigations for Arterial and freeway extensions
- ✓ Investigation, Design and Supervision of Underpinning Projects

TBT ENGINEERING
CONSULTING GROUP

GORDON MAKI, P.ENG.
Manager of Geotechnical Engineering

SUMMARY OF QUALIFICATIONS

- 20 years experience providing geotechnical/foundations design, construction supervision and inspection services for a wide variety of clients
- Professional Engineers of Ontario
- The Canadian Geotechnical Society

DEGREES / CERTIFICATES / COURSES

- Bachelor of Civil Engineering Degree, First Class Standing, Lakehead University, 1994
- Civil Engineering Technology Diploma, Lakehead University, 1989
- Slope Stability and Landslide Short Course, 1995
- Hogentogler Piezocone Training Course, 1995
- Finite Elements in Geotechnical Engineering, Colorado School of Mines, 1997
- Short Course “Soft Clay Engineering: Onshore and Offshore”, University of Western Ontario, 1998
- Air Emission Summary and Dispersion Modelling Report Workshop, 1998

RELEVANT EXPERIENCE

MANAGER OF GEOTECHNICAL ENGINEERING *(2005 – Present)*
TBT Engineering Limited, Thunder Bay, ON

- Geotechnical/Foundation analysis and design for industrial, commercial and residential structures, bridges, embankments, slopes, dams, retaining walls, pavements and landfills, soil and rock characteristics with field and laboratory tests.
- Advanced modeling of geotechnical and foundation problems

MANAGER OF GEOTECHNICAL SERVICES, ASSOCIATE *(1994 - 2005)*
DST Consulting Engineers, Thunder Bay, ON

CIVIL ENGINEERING TECHNOLOGIST *(1990 – 1992)*
Dominion Soils Investigation Inc.

KEY PROJECTS

Design of Dam Monitoring and Instrumentation Plan, Agrium Inc., Kapuskasing, ON:
Agrium Kapuskasing Phosphate Operations
Design of a monitoring and instrumentation plan for two dams at Agrium’s tailings management area. Preparation of the plan involved seepage modeling, stress distribution analyses and stability modeling to determine locations of and alarm levels for various instruments. Instrumentation included piezometers, settlement gauges, and slope inclinometers. The instrumentation plan provided detailed procedures for monitoring and reporting both during construction and operation of the dams.

Weir Replacement Berm, Musselwhite Mine, ON:
Goldcorp Canada Ltd.
Design and construction inspection of a berm and associated partial flume to replace and existing weir to measure the discharge volumes from an existing retention pond. Design included stability analyses and seepage modeling.

Dam Upgrades, West Arm Dam No. 1, Steep Rock Lake, ON:
Ministry of Natural Resources
Design of shoreline and crest rehabilitation measures for an existing dam. Design included: wave assessment, rip rap design, filter design, stability analyses, and seepage modeling.

Design of Dams 3A and 3B North, Lac des Iles Mine, ON:
North American Palladium
Geotechnical dam design of new tailings dams to be construction over an existing tailings pond. Detailed design work included interpretation of electronic cone penetration testing, seepage analyses, piping assessment, settlement analysis and stability analyses. The dams were designed as lined rockfill dams with downstream blanket drains to improve resist to piping. Dam 3A was also designed with a low permeable upstream liner to facilitate a temporary settling pond.

Design of Dam 6, Lac des Iles Mine, ON:
North American Palladium
Geotechnical design of a new perimeter tailings dam to facilitate an increase in tailings storage capacity. The dam was designed as a rockfill dam with an upstream geosynthetic clay liner. The dam was constructed over an abandoned spillway cut through bedrock.

River Bank Stabilization, Kaministiquia River, Thunder Bay, ON:
Lakehead Region Conservation Authority
Design build project to stabilize a 30 m high over steepened riverbank. The design involved soil nail reinforcement and biotechnical facing. Detailed analyses of slope stability and soil-nail interaction were required.

Design of West Cell Dams, Agrium Inc., Kapuskasing, ON:
Agrium Kapuskasing Phosphate Operations
Design of two tailings pond dams. The West Cell Dam was designed as a lined rockfill dam founded on soft sensitive clay foundation soils to replace an existing dam and increase the total height of the dam to 13 m. Splitter Dyke No. 1 was designed as flow through rockfill dam with a downstream toe drain to prevent piping of the foundation soils. This dam was founded over a layer of tailings slims. Key design analyses included assessment of strain softening within the foundation soils and seismic stability analyses.

Design of 2004 Raise of Dam 5, Lac des Iles Mine, ON:
North American Palladium
Dam 5 is a splitter dam which separates two tailings ponds. The functions of the dam are to provide road access, support for mill pipelines and retain tailings while allowing water to pass through. The design of the dam included an innovative upstream blanket drain to facilitate passing of water and to mitigate the potential for piping. Staged construction was utilized to ensure stability during construction.

Raise of Emergency Spillway, Lac des Iles Mine, ON:
North American Palladium
In order to optimize the operating efficiency of the Tailings Management Facility, an assessment of raising the Emergency Spillway of the Water Reservoir was carried out. The assessment concluded that spillway could be raised significantly leading to a substantial increase in available. The assessment included review of dam stability, wave effects and modeling of seepage losses.

Geotechnical Investigation, Proposed Marina Park Expansion, Thunder Bay, ON:
Earthtech Canada Inc..
Geotechnical investigation to determine the marine subsurface conditions within the area of the proposed expansion and to provide commentary on any geotechnical engineering concerns with respect to the proposed development.

Various Tailings Dams, Pickle Crow Mine, Pickle Lake, ON:
Cantera Mining Ltd.
Detailed design of various dams for tailings and water retention. Work included: geotechnical investigations, detailed design, construction drawings, technical specifications and quality control and inspection services.

Island Drive Bridge, Thunder Bay, ON:
Cook Engineering Ltd.
At 234 m, the Island Drive Bridge is the longest integral abutment bridge in Canada. This project involved detailed field investigations (both on and off shore), extensive geotechnical laboratory analyses and advanced geotechnical modeling. Key foundation design issues included:

- assessment of integral abutment pile deflections and soil stiffness,
- slope stability and consolidation analyses for staged construction for a 10 m high approach embankment over weak clays (assessed for both subexcavation methods and wick drains),

- determination of lateral soil deflections on adjacent hydro tower foundation utilizing finite element modeling,
- and constructability assessment for the placement of more than 10 m of fills for three piers to be constructed over soft riverbed sediments.

Building Settlement Evaluation, Terry Fox Elementary School, Ottawa, ON:
IRC Batten Sears Group Inc.
Geotechnical engineering assessment of building settlements. Various possibilities of the reported settlements were investigated and included, long term consolidation, ground loss, frost heave, changes in moisture content, and bearing capacity. Two primary causes of settlements were identified for separate sections of the school. Slope instability of a 6 m high creek valley slope was identified as the root cause for settlements along one section of the school, while consolidation from tree roots below the foundations was identified as a source of settlement at another location. Through detailed slope stability analyses of the slope, it was determined that extensive slope re-grading and removal of some port-a-pack classroom additions would be the most feasible remediation option.

Tailings Impoundment Dams, Kam Kotia Mine Rehabilitation Project, Timmins, ON:
Ministry of Northern Development and Mines
Design of new impoundment dams and assessment of the stability and seepage characteristics of an existing dam for the Kam Kotia Mine Rehabilitation project. Design included: liquefaction assessment, slope stability analyses considering seismic loading and design of measures to control seepage losses.

Proposed New Marina and CDF, Carden Cove, Marathon, ON
Town of Marathon
Geotechnical investigation, preliminary engineering, assessment of options and costing for a proposed new marina on Lake Superior including assessment for a potential contaminant disposal facility. Geotechnical engineering included analyses of various foundation options for the proposed breakwater, marina and CDF. Due to the variable nature of the lake bottom, which included both deep deposits of soft normally consolidated clays and shallow bedrock, a detailed field investigation was carried out to optimize the location of the facilities to avoid problematic soils. Detailed engineering assessment included predictions of lakebed displacement and stability requirements for various construction options including displacement techniques, sheet piling, and staged construction methods. Long-term differential settlements were assessed for various construction methods and were used to predict future maintenance items and liner requirements.

Investigation of Failed Breakwater, Haileybury, ON:
Town of Haileybury
Assessment of failed section of breakwater. Scope of work Included: field investigation, laboratory testing of subsurface conditions, forensic assessment of failure, assessment of current stability, and development of conceptual improvement measures.

New Marina and Breakwater, Bayport Village Recreation Resort, Haileybury, ON:
Town of Haileybury
Geotechnical design and recommendations for new breakwater, marina and associated shoreline stabilization. Scope of work included, marine field investigation, laboratory testing, geotechnical design and analyses.

Impacts on Trunk Sewer from Proposed Commercial Development, Thunder Bay, ON:
OPUS
The proposed commercial development involved a significant raise in grade and the construction of several commercial buildings adjacent an existing trunk sewer buried at a depth of approximately 10 m. Given the compressible nature of the clay soils on site and large loads from the proposed construction, stresses and settlement induced onto the sewer were of concern. This assessment determined there was significant risk to the sewer in terms of hydraulic and structural integrity. Alternate foundation types and various modifications to site grading (including lightweight fills) were developed to mitigate these risks.

Highway Embankment Failure, Hwy 11 South of Polly Lake Road:
Ministry of Transportation
Geotechnical investigation for stabilization recommendations for an embankment failure which occurred on the west side of Highway 11, approximately 100 m south of Polly Lake Road. The failed embankment (approximately 8 m high) partially filled in an existing creek located near the toe of the embankment. Scope of work for this project was to assess slope stability and provide comparative costs for various remedial options. Key geotechnical tasks and issues included:

- back analyses of existing conditions
- design of various slope stabilization measures including:
    - mechanically stabilized earth (geogrid),
    - lightweight fills (foam insulation),
    - construction of a toe berm, and
    - excavation and replacement of failed materials

Moosonee Water and Wastewater Design Build Project, Moosonee, ON:
Reid Crowther and Partners
Geotechnical investigation and design recommendations for the construction of a water treatment plant with associated reservoir, a low raw water pump system, sewage lagoon, sewage pumping stations, forcemain and watermains. Key geotechnical tasks and issues included:

- design of containment berms for 18 ha sewage lagoon utilizing cut and fills operations in native silts. covering an area of 18 ha,
- piled foundation design for water treatment plant,
- riverbank slope stability improvement design for water intake structure

Bridge Approach Grading, Eleanor Bay and Big Grassy River Bridges, Morson, Ontario:
McCormick Rankin Corporation
Geotechnical investigations for bridge approach grading for two bridges. The existing approaches were to be raised by 1 to 2 m. The approaches were situated over existing causeways, which were underlain by soft clays. To facilitate construction of the grade raise while maintaining embankment stability and improving settlement performance various geotechnical treatments were designed and evaluated. Extensive consolidation and strength testing of the foundation soils were required for detailed design. Key geotechnical tasks and issues included:

- back analyses of existing conditions
- assessment of various stabilization and settlement improvement options including:
    - construction of flanking berms,
    - lightweight slag fills,
    - Elastizell foam concrete, and/or
    - foam insulation

Construction Impacts on Segmental Sewer, Famous Players Theatre, Thunder Bay, ON:
Tom Jones Corporation Inc.
Geotechnical assessment and recommendations for a piled foundation, grade raise and impacts of construction on a near by buried segmental sanitary trunk sewer. Project involved the prediction of construction effects (including piling operations) on the adjacent sewer. Later, a series of test piles were driven to confirm pile capacity and to optimize the design with respect to potential construction effects on the sewer. During driving a test piles an extensive monitoring program was implemented to measure vibrations, ground movements, sewer deflections, and porewater pressure generation in the surrounding soils. In addition, visual inspections of the sewer were carried out. Based on the results of the monitoring program, it was determined that the planned piling operations would not pose any significant risk to the sewer.

Revetment Design, Pic River, ON:
Pic River First Nation
Geotechnical investigation and design of a rip rap revetment to stabilize an actively eroding section of riverbank.

Containment Berm, Northern Wood, Thunder Bay Harbour, ON:
Environment Canada, Ministry of Environment, Abitibi-Consolidated, CN Rail, Northern Wood Preservers
Geotechnical investigation for design of a rockfill containment berm to contain contaminated sediments and clean capping materials, constructed of shale fill in 8 m of water with heavy rip rap protection, incorporating innovative fish habitat features. The geotechnical investigation included advanced in-situ testing utilizing an electronic cone penetrometer, convention geotechnical drilling and sampling together with a comprehensive laboratory testing program. Geotechnical analyses and modeling were carried out to assess the stability of the proposed berm, which included analysis of lakebed displacements, staged construction and long-term consolidation settlements. Wave and ice analysis for rip rap/armor stone design was completed to optimize gradation requirements and placement location. In addition, a comprehensive monitoring and instrumentation program was carried out to ensure stability during staged construction and refine predictions of settlement performance.

<u>Various Structures</u>

- ***Grain Silos, Mission Terminal Inc., Thunder Bay, ON – Piled Foundation***
- ***Geraldton Hospital Addition, Geraldton, ON – Shallow Foundation***
- ***Mine Centre School, Mine Centre, ON – Shallow Foundation***
- ***Sacred Heart School, Thunder Bay, ON – Piled Foundation***
- ***Robert Moore School, Fort Frances, ON – Site Preload with Shallow Foundation***
- ***Tank Foundation, Kennecott Canada Exploration Inc., Stanley, ON – Shallow Foundation***
- ***Tank Farm, Canadian Operators Petroleum, Thunder Bay, ON – Mat Foundation***
- ***Crusher, North American Palladium Mine Mill, Lac des Iles, ON – Site Preload, Rock Socket Piles***
- ***Boat Lift, Mission River, Thunder Bay, ON – Soldier Piles***

TBT ENGINEERING
CONSULTING GROUP

STEVEN SELLER, P. ENG.
Project Engineer

SUMMARY OF QUALIFICATIONS

- 11 years Geotechnical experience in the North-western Ontario region
- Design of preloads, embankment stability, tower foundations, building foundations, and small dams
- Advanced modelling and analysis for slope stability, seepage and flows, thermal analysis, stress analysis, settlement, and bearing pressures
- Inspection and Supervision for construction projects, drilling operations, subgrade inspections, testpiting, and pile installation
- Material testing including concrete, compaction, soil sampling and analysis
- Extensive report writing skills including Geotechnical Investigation and Design reports
- Computer design skills –MS Word & Excel, Sigma\W, Temp\W, Slope\W, Seep\W

DEGREES / CERTIFICATES / COURSES

- Bachelor of Engineering (Civil) Degree – Lakehead University, Thunder Bay, Ontario
- Civil Engineering Technologist Diploma – Lakehead University, Thunder Bay, Ontario
- Certified CSA Concrete Testing
- Survey Training for Asbestos Projects
- Slope Stability in Rock & Soil: Slope Failure Mechanism, Monitoring and Stability Analysis
- Non- Destructive Testing of Drilled Shafts Short Course

RELEVANT EXPERIENCE

PROJECT ENGINEER *(Sept 2005 - Present)*
TBT Engineering Limited, Thunder Bay, ON

- Computer modeling using finite element software to analyze stress distribution in soils, seepage and flow in soils, and slope stability. Computer aided assessments of bearing pressures, settlement response and loading configurations
- Project Management and Analysis services for TBTE's foundation engineering services
- Co-ordinate and conduct field investigations including instrument installation, and monitoring operations
- Provide computer modelling and analysis for various foundation projects
- Client liaison and management

DESIGN ANALYSIST/PROJECT MANAGER *(1998 –August 2005)*
Consulting Engineering Firm, Thunder Bay, ON

- Computer modeling using finite element software to analyze stress distribution in soils, seepage and flow in soils, and slope stability
- Geotechnical analysis and design for industrial, commercial and residential buildings, bridges, embankments, slopes, dams, retaining walls, pavements, and soil characteristics with field and laboratory tests. Advanced modeling of geotechnical problems
- Field supervision and project management of site characterization programs
- Inspection on piling, earthworks and foundation works. Installation, monitoring and interpretation of ground instrumentation
- Construction inspection for concrete, rebar, compaction of granular excavation and subgrade material and pile driving
- Geotechnical drilling supervision. Geotechnical investigation including shallow foundation computations and slope stability assessment. Geotechnical investigation fieldwork for settlement gauges, thermocouples, slope indicator and pneumatic piezometer

KEY PROJECTS

- Asbestos identification and survey of hazardous materials for commercial building and pre-demolition

Geotechnical Design of Bridge Abutments, Redfern Resources Ltd., Vancouver, BC: 2007
Tulsequah Chief Mine
Geotechnical design of several bridge abutments for multiply river crossings. The geotechnical design consisted of allowable bearing pressures, slope stability modeling, and settlement predictions, within a highly seismically active zone. Due to locations of the river crossings, side hill fills edge of slope effects and high flood levels were required to be analyzed.

Design of PAG and NAG Containment Areas, Redfern Resources Ltd., Vancouver, BC: 2007
Tulsequah Chief Mine
Geotechnical design of a new perimeter dams to facilitate the placement of existing PAG and NAG materials. The geotechnical design consisted of slope stability modeling, settlement predictions, bearing pressures, strain compatibility with subsurface materials and liners within a highly seismically active zone. The dam was designed as a rockfill dam fully lined with a HDPE liner.

Design of Dam Monitoring and Instrumentation Plan, Agrium Inc., Kapuskasing, ON: 2006
Agrium Kapuskasing Phosphate Operations
Design of a monitoring and instrumentation plan for two dams at Agrium's tailings management area. Preparation of the plan involved seepage modeling, stress distribution analyses and stability modeling to determine locations of and alarm levels for various instruments. Instrumentation included piezometers, settlement gauges, and slope inclinometers. The instrumentation plan provided detailed procedures for monitoring and reporting both during construction and operation of the dams.

Dam Upgrades, West Arm Dam No. 1, Steep Rock Lake, ON: 2005-2006
Ministry of Natural Resources
Design of shoreline and crest rehabilitation measures for an existing dam. Design included: wave assessment, rip rap design, filter design, stability analyses, and seepage modeling.

Subdivision Development at Gull Bay, ON: 2005
UMA Engineering Ltd.
The investigation included a subsurface investigation followed by a report outlining the expected settlements, allowable bearing pressures for various loading conditions, frost depth and insulation design, roadway structure recommendations and general construction considerations.

Dewatering and Stability of Deep Excavation, Bowater Mill, Thunder Bay: 2005
Bowater Incorporated
Geotechnical design of a subsurface pump station, to be constructed below groundwater levels in highly permeable materials. Detailed design work included rigorous laboratory testing for material permeability, and strength parameters, seepage and flow modeling, in conjunction with flow estimations and required groundwater extraction volumes. Due to high volumes of groundwater flow into the excavation cutoff walls and relief wells were required to ensure a stable excavation. Other influencing factors on design included the close proximity of adjacent structures and the adjacent river.

Design of Dams 3A and 3B North, Lac des Iles Mine, ON: 2005
North American Palladium
Geotechnical dam design of new tailings dams to be construction over an existing tailings pond. Detailed design work included interpretation of electronic cone penetration testing, seepage analyses, piping assessment, settlement analysis and stability analyses. The dams were designed as lined rockfill dams with downstream blanket drains to improve resist to piping. Dam 3A was also designed with a low permeable upstream liner to facilitate a temporary settling pond.

Design of Dam 6, Lac des Iles Mine, ON: 2005
North American Palladium

Geotechnical design of a new perimeter tailings dam to facilitate an increase in tailings storage capacity. The dam was designed as a rockfill dam with an upstream geosynthetic clay liner. The dam was constructed over an abandoned spillway cut through bedrock.

River Bank Stabilization, Kaministiquia River, Thunder Bay, ON: 2004-2005
Lakehead Region Conservation Authority
Design build project to stabilize a 30 m high over steepened riverbank. The design involved soil nail reinforcement and biotechnical facing. Detailed analyses of slope stability and soil-nail interaction were required.

Design of West Cell Dams, Agrium Inc., Kapuskasing, ON: 2004
Agrium Kapuskasing Phosphate Operations
Design of two tailings pond dams. The West Cell Dam was designed as a lined rockfill dam founded on soft sensitive clay foundation soils to replace an existing dam and increase the total height of the dam to 13 m. Splitter Dyke No. 1 was designed as flow through rockfill dam with a downstream toe drain to prevent piping of the foundation soils. This dam was founded over a layer of tailings slims. Key design analyses included assessment of strain softening within the foundation soils and seismic stability analyses. To ensure adequate factors of safety against piping numerous filter compatibility calculations were required to design the toe drain with the appropriate available materials.

Design of 2004 Raise of Dam 5, Lac des Iles Mine, ON: 2004
North American Palladium
Dam 5 is a splitter dam which separates two tailings ponds. The functions of the dam are to provide road access, support for mill pipelines and retain tailings while allowing water to pass through. The design of the dam included an innovative upstream blanket drain to facilitate passing of water and to mitigate the potential for piping. Due to variations in subsurface materials elaborate seepage modeling was required to confidently analyze potential piping stability, in conjunction with numerous filter compatibility calculations between materials. Staged construction was utilized to ensure stability during construction.

Raise of Emergency Spillway, Lac des Iles Mine, ON: 2004
North American Palladium
In order to optimize the operating efficiency of the Tailings Management Facility, an assessment of raising the Emergency Spillway of the Water Reservoir was carried out. The assessment concluded that spillway could be raised significantly leading to a substantial increase in available. The assessment included review of dam stability, wave effects and modeling of seepage losses.

Servicing and Roadway Development, Whitefish Bay, ON: 2004
Keewatin-Aski Ltd
The proposed development involved placement of new roadways and services. Several routes and areas were investigated to determine the area with the best subsurface conditions to house the new services. Roadway structure recommendations and servicing bedding and installation recommendations were provided.

Terrain Study for Whitefish Bay, ON: 2004
Keewatin-Aski Ltd
Future development of the Whitefish Bay First Nation is planned to extend into the area north of the West End Community. The new developments may consist of underground services, roadways, septic systems and various structures. Existing reports, subsurface data, aerial photos, and studies were reviewed and utilized to determine the best areas for future development. Criteria for future development included the areas ability to support structures, septic fields, roadways and provide adequate cover for services.

School Capital Planning Study for Lac La Croix First Nation, ON: 2003

Number Ten Architects
The scope of work for this project included: a subsurface investigation with detailed geotechnical design recommendations for the proposed school, limited subsurface investigation with general recommendations for the proposed future ice rink and fire hall, and subsurface information at the proposed sports field. Subsurface conditions were utilized to determine allowable bearing pressures and expected settlement for various structures and for feasibility for future development of various areas.

Proposed Addition for a Youth Center at Lac Seul First Nation, On: 2003
Mekena Project Management Group
The proposed addition in at the youth center at Lac Seul First Nation consisted of a 422 m^2 single story heated structure founded on shallow foundations with no basement. The investigation included a subsurface investigation followed by a report outlining the expected settlements, allowable bearing pressures and construction recommendations pertaining to working close to existing structures.

Various Tailings Dams, Pickle Crow Mine, Pickle Lake, ON: 2002 to 2003
Cantera Mining Ltd.
Detailed design of various dams for tailings and water retention. Work included: geotechnical investigations, detailed design, construction drawings, technical specifications and quality control and inspection services, seepage modeling and seepage volume estimations along with dam stability.

Island Drive Bridge, Thunder Bay, ON: 2002
Cook Engineering Ltd.
At 234 m, the Island Drive Bridge is the longest integral abutment bridge in Canada. This project involved detailed field investigations (both on and off shore), extensive geotechnical laboratory analyses and advanced geotechnical modeling. Key foundation design issues included:

- assessment of integral abutment pile deflections and soil stiffness,
- slope stability and consolidation analyses for staged construction for a 10 m high approach embankment over weak clays (assessed for both sub excavation methods and wick drains),
- determination of lateral soil deflections on adjacent hydro tower foundation utilizing finite element modeling,
- and constructability assessment for the placement of more than 10 m of fills for three piers to be constructed over soft riverbed sediments.

Building Settlement Evaluation, Terry Fox Elementary School, Ottawa, ON: 2002
IRC Batten Sears Group Inc.
Geotechnical engineering assessment of building settlements. Various possibilities of the reported settlements were investigated and included, long term consolidation, ground loss, frost heave, changes in moisture content, and bearing capacity. Two primary causes of settlements were identified for separate sections of the school. Slope instability of a 6 m high creek valley slope was identified as the root cause for settlements along one section of the school, while consolidation from tree roots below the foundations was identified as a source of settlement at another location. Through detailed slope stability analyses of the slope, it was determined that extensive slope re-grading and removal of some port-a-pack classroom additions would be the most feasible remediation option.

Tailings Impoundment Dams, Kam Kotia Mine Rehabilitation Project, Timmins, ON: 2000
Ministry of Northern Development and Mines
Design of new impoundment dams and assessment of the stability and seepage characteristics of an existing dam for the Kam Kotia Mine Rehabilitation project. Design included: liquefaction assessment, slope stability analyses considering seismic loading and design of measures to control seepage losses.

Impacts on Trunk Sewer from Proposed Commercial Development, Thunder Bay, ON: 2000
OPUS

The proposed commercial development involved a significant raise in grade and the construction of several commercial buildings adjacent an existing trunk sewer buried at a depth of approximately 10 m. Given the compressible nature of the clay soils on site and large loads from the proposed construction, stresses and settlement induced onto the sewer were of concern. This assessment determined there was significant risk to the sewer in terms of hydraulic and structural integrity. Alternate foundation types and various modifications to site grading (including lightweight fills) were developed to mitigate these risks.

Chimax Inc.
3950 Fourteenth Avenue East, Suite 506
Markham, Ontario, L3R 0A9
Tel: (905) 305-6133 Fax: (905) 305-6132

CURRICULUM VITAE

Kevin Wong, M.A.Sc., B.A.Sc., P.Eng.

EDUCATION

M.A.Sc. University of Windsor, 1980, Civil Engineering

B.A.Sc. University of Windsor, 1977, Civil Engineering

AREAS OF EXPERTISE

Transmission line and distribution line design and analyses

Structural design, foundation design and civil work

Substation station layout and design of electro mechanical items

Project management

Engineering software: STAAD PRO, PLS-CADD, PLS-POLE, PLS-CAISSON, PLS-TOWER, AutoCAD

Ontario Building Code, National Building Code, and CSA Standards relevant to Structural, Civil, Electrical and Transmission Line works

SUMMARY OF EXPERIENCE

Mr. Wong has over 30 years of engineering and management experience in the Civil / structural / transmission line / substation design field. His experience and knowledge covers many aspects of industrial structures, heavy or light equipment foundations, stress analysis, conveyor support structures, high voltage substation and transmission line & support structural design. Extensive experience in the application of computer aided technology for structural and foundation design analysis, transmission line and transmission line structure design and drawing production.

As the President of Chimax Inc., he built the company to become one of the premium engineering firms for the power industry. In the last seventeen years, Chimax Inc. completed more than five hundred design projects for various clients in the utilities, contractors, independent power producers and mining companies. These projects include engineering design, feasibility study in high voltage substation, high voltage switch yard, transmission line, distribution line and high voltage capacitor bank station.

As the Chief Civil Engineer in Markham Electric, Mr. Wong managed and completed more than fifty projects in the power sector. These projects include high voltage substation, high voltage switch yard and transmission line design.

Mr. Wong's first nine years in the profession were spent working for Stone & Webster Canada Limited where 70% of the projects were in the power sector. These projects were piping support structures design for nuclear stations, majority of these projects are in U.S.A...

Curriculum Vitae
Kevin Wong

PROFESSIONAL RECORD

1994 - Present	President. Chimax Inc.
1989 - 1994	Chief Civil Engineer, Markham Electric Ltd.
1980 - 1989	Group Engineer, Stone & Webster Canada Ltd.

PROFESSIONAL AFFILIATIONS

Professional Engineers of the Province of Ontario

Association of Professional Engineers and Geoscientists of the Province of Manitoba

Association of Professional Engineers and Geoscientists of the Province of British Columbia

Association of Professional Engineers, Geologists and Geophysicists of Alberta

Association of Professional Engineers and Geoscientists of Saskatchewan

Association of Professional Engineers and Geoscientists of Newfoundland & Labrador

Association of Professional Engineers and Geoscientists of Yukon

Selected Projects – 2011

- **IPC - Plateau III Wind Farm Project** – Detail Design for 44kV Substation and Tap Line to HONI Line
- **IPC - Plateau I & II Wind Farm Project** – Detail Design for 44kV Substation and Tap Line to HONI Line
- **Trans-Canada Pipelines Limited, Station #134A** – Upgrade Existing 44kV Substation
- **Bahamas 69kV Line** – 6kM of 69kV 2CCT and 34.5kV 1CCT Transmission Line with wood pole, including line Design, structure & foundation design
- **West Kingston Power Partners - Hunts Bay Substation,** Bahamas – Concrete cap with steel pile Foundation Design for 69kV Substation
- **Xstrata – Smelter No.1 Sub. Upgrade** – Sudbury Nickel Smelter Complex – 115/23kV Substation upgrade
- **Hudson Bay Mining-Smelting, Lalor Substation,** Manitoba – 115kV substation, including station layout, bill of material, structures and foundations design
- **Enfinity, Stardale 1 & 2 (North) Solar Farm Power Project**– Detail Design for 44kV Substation and Tap Line to HONI Line
- **Enfinity, Stardale 3 (South) Solar Farm Power Project**– – Detail Design for 44kV Substation and Tap Line to HONI Line
- **IBM Substation,** Barrie – 44kV Substation and Tap Line to HONI Line
- **South Greenfield Power Plant** – 230kV Switchyard, including station layout, bill of material, station structures and transmission line mono-steel pole structures design
- **Vale Inco - Frood Stobie #2 Substation** – 230kV Switchyard upgrade
- **Bahamas Airport Transmission Line** – 22kM of 138kV 2CCT & 33kV 1CCT transmission, including line design, bill of material, mono- Steel pole and concrete caisson foundation design
- **Lake Shore Gold - Bell Creek Mine** – 115kV Substation, including station layout, bill of material, structures design

- **Imperial Oil, Kearl Oil Sand Project Phase II, Alberta** – Phase II of 72kV Overhead Transmission Lines, including line design, wood pole structures and bill of material
- **IPC - East Lake St. Clair** Wind Farm Project – 230kV Substation Design, including station layout, grading, bill of material, steel and foundation design.

Selected Projects - 2010

- **Kiewit-Alarie - Lower Mattagami** – 115kV Substation for temporary power, including station layout, grading, bill of material, steel structures and foundations design.
- **Northland Power - Spy Hill Generating Station, Saskatchewan** – 138kV Substation Detail Design including Site formation, station layout, foundation, structural steel design, bill of material
- **Renewable Energy Systems (RES) - Greenwich Lake** – 230kV Switching Station Detail Design including Site formation, station layout, steel structure, foundation design and bill of material
- **Kiewit-Alarie - Lower Mattagami (D-Line)** – Detail Design for 11kM of12.47kV Distribution Line
- **Great Lakes Power - Third Line Technical Specification** – 115kV Substation - Detail Design for Extension to Existing Facility, including Site formation, station layout, foundation, structural steel design, bill of material
- **Toronto Hydro 11M8** – Detail Design for Feeder Upgrade including qualifying and upgrading the Toronto Hydro distribution line including Railroad Crossing
- **Inco - Vale Levack Line** – Detail Design for 69kV Transmission Line
- **York Energy Center (YEC)** – Detail Design for 230kV Switching Station and Tap Tower to HONI, including Site formation, station layout, foundation, structural steel design, bill of material
- **West Kingston Power Partners - Jamaica Energy P West Kingston** – Detail Design for 69kV including Substation Building and Foundations design
- **IPC-Point Aux Roches Wind Farm Project** – Detail Design for Joint Use Pole Line and 34.5/115kV Substation
- **Inco - Totten 69kV Line** – 3kM of 69kV Transmission Line Design
- **Electrical Consultants Inc. (ECI)/Brookfield - Comber Wind Project** – Detail Design for 34.5-230 kV Substation including Grading and Foundations
- **Newmarket Hydro - Davis Dr. Pole Line Design** –Distribution Line Design for Davis Drive road Widening between Yonge Street and Roxborough Rd of Newmarket including concrete pole and foundation design

Selected Projects – 2009

- **Kruger Ph.II (Chatham) Wind Power** – Detail Design for 230kV Substation (Layout, Steel Detail, BM) and 34.5kV Collector Line (20km)
- **YEC (Yukon) - CSTL Stage 2** – Additional 100kM of 138kV & 10kM of25kV Transmission Lines detail design
- **IPC-Harrow Wind Farm** – Detail Design for 27.6kV Collector line (10km)

- **THESL - 34M7 Upgrade** – Detail Design for Feeder Upgrade including qualifying and upgrading the Toronto Hydro distribution line
- **RES-Talbot Wind Farm** – Detail Design for 230kV Switching Station and Tap Tower to HONI, including Site formation, station layout, foundation, structural steel design, bill of material
- **ENXCO-Elmsley East 10MW Solar Farm Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ENXCO- Elmsley West 10MW Solar Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ENXCO - St. Isidore A – 10MW Solar Farm Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ENXCO-St. Isidore B – 10MW Solar Farm Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ALPAC –EXPORT II – 138kV Substation –** Detail Design for 138kV Substation, including station layout, structural steel design, bill of material

Selected Projects – 2008

- **IPC-Cruickshank SOC Wind Farm Project** – Detail design for 44kV Substation
- **East Windsor Power - Phase II** – 115kV Underground Duct Bank
- **Canadian Hydro Developers Inc.- Melancthon II Wind Power Project -** Detail Design for 230kV Substation, including station layout, structural steel design, bill of material
- **Veridian Connections - Notion Road Hwy 401 Crossing** – Detail Design for 4CCT 44kV OH Line crossing Highway 401 with mono-steel pole and concrete caisson
- **Transcanada Pipeline, Station #139** – 115kV Substation upgrade
- **Transcanada Pipeline, Station #142** **-** 44kV Substation upgrade
- **Canadian Hydro Developers Inc. - Wolfe Island Wind Power Project** –Detail Design for 230kV Substation, including station layout, structural steel, foundation design, bill of material
- **Hydro One Network Inc. – Nobel 500kV Capacitor Bank Station** – Detail design of the site grading, foundation and masonry control building
- **Imperial Oil, Kearl Oil Sand Project Phase II, Alberta** – Detail Engineering Design of70KM of 240kV, 72kV, 13.8kV transmission Line and Station Gantries including mono-steel pole structure for 240kV and wooden pole structure for 72kV and 13.8kV structure.
- **Trinidad & Tobago Electricity Commission** – Union 220/66kV Substation, including structure steel and foundation design

Selected Projects – 2007

- **Thorold Cogen. T-line** – Thorold cogeneration project 230kV transmission line, including mono-steel pole and foundation design
- **City of Toronto** – Kennedy Pumping Station
- **City of Toronto** – Ellesmere Pumping Station
- **City of Toronto** – Keele Pumping Station
- **City of Toronto** – Richmond Pumping Station
- **Halton Hills Generation Station -** 230kV Switchyard design, *Ontario* - Station design and

detail design of all required structural steelwork, foundation, electrical equipment layout and bill of material.

- **Great Lake Power-McKay Sub Refurbishment** -115kV Switch Yard Upgrade
- **YEC (Yukon) - CSTL Stage 1** – 100kM of 138kV & 10kM of25kV Transmission Lines detail design
- **(3) AIMS 10 MW WIND FARMS, Byng Wind Farm, Mohak Wind Farm, Cutlue & Frogmore Wind Farm Projects-** Three 27.6kV substations and 5kM of tap line detail design
- **Kruger Energy Port Alma** Limited, Wind Power Project– 230 kV main Substation, 230kV switching station and 34.5kV collector line detail design
- **East Windsor Cogeneration Plant -**115kV Substation Detail design

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CURRICULUM VITAE

Calvin Ng, M.Sc., B.T.

EDUCATION

M.Sc. State University of New York at Buffalo, 1995, Electrical Engineering

B.T. State University of New York College at Buffalo, 1992, Electrical Engineering Technology

AREAS OF EXPERTISE

Transmission line and distribution line design and analyses

Project coordination

Engineering software: PLS-CADD, PLS-POLE, PLS-TOWER, Mathcad, MatLab, and AutoCAD, and STADD Pro

Familiar with CSA Standards in Electrical and Transmission Line

SUMMARY OF EXPERIENCE

Mr. Ng has over 5 years of engineering and management experience in the transmission line / distribution line / substation design. His experience and knowledge covers many aspects of transmission / distribution lines and substation design. He is highly proficient in the use of powerline design program such as PLS-CADD and various structural analysis programs. His experience is also enriched by his familiar knowledge on Canadian Electrical Standards for substation and transmission line design.

As a project coordinator, Mr. Ng manages the project schedule, technical deliverables, and coordinates with clients for their specific needs. He has taken part in more than 20 engineering projects with strong communication skill.

PROFESSIONAL RECORD

2007 - Present	Project Coordinator / Electrical Designer, Chimax Inc.
2003 - 2007	Computer and Network Consultant, KEIT Computers Ltd
2000 - 2002	Network Administrator Trainee, Kawneer Company Canada

KEY PROJECT INVOLVEMENT

- Imperial Oil – Kearl Oil Sand Expansion Project – Design of 72kV and 13.8kV sub-transmission lines and substation structures
- Imperial Oil – Kearl Oil Sand Project – Design of 240kV & 72kV transmission lines, 13.8kV & 4.16kV distribution lines and substation structures
- Yukon Energy Corporation Power distribution Line – Design of 95km of 138kV transmission Line & 29km of 25kV distribution line (Phase I)

- AIM Wind farm Project – Three 27.6kV substations and 15km of 27.6kV collector line
- AIM Port Alma Wind Farm Project – 230kV substation and 25km of 34.5kV collector line
- Inco - 69kV Transmission Line Project
- Enbridge Ontario Wind Farm Collector Line Project – 22km four circuit 44kV collector line.
- Thorold Cogen Transmission Line Project – 230kV transmission line steel structures and foundation detail design
- Veridian Highway 401 Crossing Distribution Line Project – Two 44kV and two 13.8kV steel structure and foundation design
- Xstrata – Smelter No.1 Sub. Upgrade – Sudbury Nickel Smelter Complex – 115/23kV Substation upgrade

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CURRICULUM VITAE

Edmund Kwong

EDUCATION

M.A.Sc. University of Waterloo, 1995, Chemical Engineering
B.A.Sc. University of Waterloo, 1993, Chemical Engineering

TECHNICAL KNOWLEDGE

STAAD PRO structural program for analysis and design

PLS-CADD program for transmission line analysis and design

PLS-POLE program for transmission line wood pole structure analysis and design

PLS-CAISSON program for caisson analysis and design

PLS-TOWER program for transmission line tower analysis and design

AutoCAD program for drafting

Familiar with Ontario Building Code and National Building Code

Familiar with CSA Standards in structural, Civil, Electrical and Transmission Line

AREAS OF EXPERTISE

Project management

Transmission line and distribution line design and analyses

Substation station layout and design of electro mechanical items

SUMMARY OF EXPERIENCE

Mr. Kwong has over 12years engineering and management experience in the area of high voltage substation and transmission line projects. He is responsible for the work schedule, feasibility study for the transmission lines including information for leave to construct, layout of equipment arrangement according to single line diagrams, design of structures, conductors, transmission line's plan and profile, sag & tension, specification of equipment requirement, etc. He is highly proficient in the use of specialized programs such as PLS-CADD, PLS-POLE, PLS-TOWER and STADD Pro programs to perform the aforementioned tasks. Most recently, for the past five years, he has been heavily involved in the design of transmission line and distribution lines, dealing with clients, Hydro One, Provincial line, contractors, suppliers, etc. Mr. Kwong has completed over two hundred projects consisting of high voltage substations, high voltage switch yards, transmission lines, distribution lines and high voltage capacitor bank stations.

PROFESSIONAL RECORD

1996/Present	Project Manager / Transmission Line Specialist / Substation Chimax Inc.

KEY PROJECT INVOLVEMENT

- NextEra – Adelaide, Jericho and Bornish Wind Farms 115kV Transmission Lines
  Prepare preliminary line design for 3 routes of 115kV Transmission
- Nalcor – 315kV Transmission Line – Feasibility Study for Cost Study,Preliminary design of 3 parallel single circuit 315kV V-guyed lattice tower transmission lines in Newfoundland
- Imperial Oil – Kearl Oil Sand Project – 230kV Transmission Line, to design 70kM of 230kV Transmission Line with combination of mono-steel pole and H-Frame wooden structures.
- Yukon Energy Corporation – 70kM of 138kV Transmission Line (Phase II)
- Yukon Energy Corporation – 95kM of 138kV Transmission Line & 29kM of 25kV Distribution Line (Phase I)
- Fort McMurray, Kearl Oil Sand Project – 72kV, 13.8kV and 4.16 kV sib-transmission line and associated substation structures
- Bahamas, K-line International, Bahamas Airport Highway – 133 kV Transmission Line
- Canada, Toronto, Eastern Power, Greenfield South Power Plant – 230kV substation and transmission line
- Jamaica, K-Line International, West Kingston Project – Two 69kV substations and transmission line
- IPC - Plateau III Wind Farm Project – Detail Design for 44kV Substation and Tap Line to HONI Line
- IPC - Plateau I & II Wind Farm Project – Detail Design for 44kV Substation and Tap Line to HONI Line
- Bahamas 69kV Line – 6kM of 69kV 2CCT and 34.5kV 1CCT Transmission Line with wood pole, including line Design, structure & foundation design
- Enfinity, Stardale 1 & 2 (North) Solar Farm Power Project– Detail Design for 44kV Substation and Tap Line to HONI Line
- Enfinity, Stardale 3 (South) Solar Farm Power Project– – Detail Design for 44kV Substation and Tap Line to HONI Line
- IBM Substation, Barrie – 44kV Substation and Tap Line to HONI Line
- Bahamas Airport Transmission Line – 22kM of 138kV 2CCT & 33kV 1CCT transmission, including line design, bill of material, mono- Steel pole and concrete
- Port Alma Wind Farm Project – 230kV substation and 25km of 34.5kV collector line
- AIM Wind farm Project – Three 27.6kV substations and 15km of 27.6kV collector line
- NovaGold Resources Inc. – Galore Creek 138kV Transmission Line(Feasibility study completed in 2007)
- Terrane Metals, Mt. Milligen, B.C. – 84km 230kVTransmission Line Feasibility study on structure framing comparison, route selection (Feasibility study completed in May 2007)
- Sithe Goreway 230kV Transmission Line project,
- Brookfield Power Corp. - 138kV Gartshore switch yard, Upgrade portion of 138kV Transmission Line

- Greenfield Energy Centre - 230kV Transmission Line and 230kV Switchyard Project,
- Enbridge Wind Farm Project - 230kV Switchyard and 44kV Distribution Line Project,
- EPCOR II Wind Farm Project - 500kV Substation and L.V Distribution Line Project,
- Inco 69kV Transmission Line Project,
- Prince I Wind Farm, 230kV Substation Project
- Prince II Wind Farm, 34.5kV Distribution Line Project,
- Suncor Wind Farm, 34.5 & 69kV Transmission Line Project, etc.
- Fortis B.C.- 230kV Kettle Valley Substation Project,
- Fortis B.C.- 69kV Cottonwood Substation Project,
- Fortis B.C. - 230/69kV Lambert Substation Upgrade Project,
- Inco Totten Mine 69kV Substation Project,
- Inco Coleman Mine 69kV Transmission Line Project,
- Oakville Hydro, 27.6kV Distribution Line and River Crossing, Power Stream - 27.6kV Hwy.407 Crossing,
- EPCOR I Wind Farm Project - 27.6kV Distribution Line Project.
- AIM Wind Farm Project - 115kV Substations and 34.5kV Distribution Line Project,
- EPCOR – Kingsbridge I Wind Power Project – 28km of 27.6kV Transmission/Distribution Line
- Wigton Wind Farm Project, includes one new Wigton 24/69kV substation, expansion of JPSC existing 69kV Spur Tree substation and 11kM of 69kV transmission line, Jamaica

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CURRICULUM VITAE

Miuee Huang

EDUCATION

Wu Yi University, 2003, Mechanical Computer Aided Design

TECHNICAL KNOWLEDGE

PLS-CADD program for transmission line analysis and design

PLS-POLE program for transmission line wood pole structure analysis and design

Micro-Station program for drafting

AutoCAD and Solidwork program for drafting

Familiar with Ontario Building Code and National Building Code

Familiar with CSA Standards in structural, Civil, Electrical and Transmission Line

AREAS OF EXPERTISE

Project management

Transmission line and distribution line design and analyses

SUMMARY OF EXPERIENCE

Ms. Huang has over 9 years extensive experience in using Computer Aided Design software including AutoCAD and Solidwork, she has 3 years design experience in the area of transmission line and distribution line projects. She is responsible for the design for the transmission / distribution lines including information for leave to construct, layout of equipment arrangement according to single line diagrams, design of structures, conductors, transmission / distribution line's plan and profile, sag & tension, specification of equipment requirement, etc. She is highly proficient in the use of specialized programs such as PLS-CADD and PLS-POLE programs to perform the aforementioned tasks. Most recently, for the past three years, she has involved in the design of transmission line and distribution lines, dealing with clients, Hydro One, Provincial line, contractors, suppliers, etc.

PROFESSIONAL RECORD

2009 - Present	Distribution / Transmission Line Designer Chimax Inc.
2008 - 2009	Structural Designer Team Associates LTD. Toronto, Ontario
2003 - 2006	Mechanical Designer Akei Plastic Machine Mfy Ltd., Guangdong Province, China

KEY PROJECT INVOLVEMENT

- NextEra – Adelaide, Jericho and Bornish Wind Farms 115kV Transmission Lines Design,
- Amec - Dufferin Wind Project 66kV Transmission Line Design,
- Wardrop - Carmacks-Stewart Crossing 138kV Transmission Line Project - Stage 2
- A&L - Becker Cogen 44kV Tap Line Design,
- Eptcon - Northland 44kV Tap Line Design,
- Newmarket Hydro - Tay Stub Pole Design,
- PowerTel - Earlton 44kV Tap Line Design,
- IPC - Plateau III Wind Farm Project – Detail Design for 44kV Tap Line to HONI Line,
- IPC - Plateau I & II Wind Farm Project – Detail Design for 44kV Tap Line to HONI Line,
- Bahamas 69kV Line – 34.5kV 1CCT Transmission Line design,
- IBM Substation, Barrie – 44kV Tap Line Design,
- Enbridge Wind Farm Project - 44kV Distribution Line Project,
- IPR - Brockville SolarInco 69kV Transmission Line Project,
- Amec - Recurrent - Smith Falls Solar Projects 44kV Tap Line Design,
- Newmarket Hydro - Davis Dr. Pole Line Design,
- PPDI -A&L - Totten 69kV Line Design.
- KAP - Lower Mattigami 12.47kV Line Design,
- Toronto Hydro, Rogers Road Rebuild - distribution line system rebuild and upgrade,
- Toronto Hydro, 34M7 Upgrade – distribution line system rebuild and upgrade,

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CURRICULUM VITAE

Vicky Wu, P.Eng., B.A.Sc.

EDUCATION

B.A.Sc. Huaqiao University, Quanzhou, P.R. China 1993, Industrial and Civil Engineering

AREAS OF EXPERTISE

Structural design and analysis, foundation design and civil work on Electrical substation, Switchyard, Transmission line and distribution line

Industrial, Commercial & Residential building design and construction

Project management

Engineering software: STAAD PRO, PLS-CADD, PLS-POLE, PLS-TOWER, L-PILE, STAAD PRO FOUNDATION, PLS-CAISSON, ALLPILE, MATHCAD 13, AutoCAD

Ontario Building Code, National Building Code of Canada, CSA Standards relevant to Structural, Civil, Electrical and Transmission Line works, British Standards relevant to Structural Design

SUMMARY OF EXPERIENCE

Ms. Wu has over 14 years of international engineering and management experience in various civil and structural engineering projects including residential and industrial buildings.

With his diverse field experience and knowledge of civil engineering design, Ms. Wu is responsible for the project technical deliverables that includes foundation design and analysis, high voltage switchyard and substation design, transmission and distribution line structural design. She is highly proficient in the use of specialized engineering tools such as STADD PRO and various structural analysis programs.

Ms. Wu joined the company in 2006 and has been heavily involved in the design of high voltage substation and distribution lines; providing technical advice to clients; coordinating technical requirements between the clients, owner, contractors and power authorities or local power utility companies. Her recent projects include a distribution system upgrade for a local distribution utility and substation design for power developers.

PROFESSIONAL RECORD

2006 – Present	Engineer, Chimax Inc.
2006	Structural Technician, Ojdrovic Engineering Inc. (Toronto)
1998-2002	Construction Engineer, Shantou Construction International Ltd. (P.R.China)
1995 - 1998	Senior Engineer, Shantou Construction International Ltd. (P.R.China)
1993 - 1995	Engineer, Architecture Design Institute of Huaqiao University (P.R.China)

PROFESSIONAL AFFILIATIONS

Professional Engineers of the Province of Ontario

Selected Projects – 2011

- **IPC - Plateau III Wind Farm Project** – Detail Design for 44kV Substation and Tap Line to HONI Line
- **IPC - Plateau I & II Wind Farm Project** – Detail Design for 44kV Substation and Tap Line to HONI Line
- **Trans-Canada Pipelines Limited, Station #134A** – Upgrade Existing 44kV Substation
- **Hudson Bay Mining-Smelting, Lalor Substation,** Manitoba – 115kV substation, including station layout, bill of material, structures and foundations design
- **IBM Substation,** Barrie – 44kV Substation and Tap Line to HONI Line
- **South Greenfield Power Plant** – 230kV Switchyard, including station layout, bill of material, station structures and transmission line mono-steel pole structures design
- **Lake Shore Gold - Bell Creek Mine** – 115kV Substation, including station layout, bill of material, structures design
- **IPC Erieau Wind Farm Project** –34.5kV / 230kV Substation Design
- **IPC - East Lake St. Clair** Wind Farm Project – 230kV Substation Design, including station layout, grading, bill of material, steel and foundation design.

Selected Projects - 2010

- **Kiewit-Alarie - Lower Mattagami** – 115kV Substation for temporary power, including station layout, grading, bill of material, steel structures and foundations design.
- **Northland Power - Spy Hill Generating Station, Saskatchewan** – 138kV Substation Detail Design including Site formation, station layout, foundation, structural steel design, bill of material
- **Renewable Energy Systems (RES) - Greenwich Lake** – 230kV Switching Station Detail Design including Site formation, station layout, steel structure, foundation design and bill of material
- **Kiewit-Alarie - Lower Mattagami (D-Line)** – Detail Design for 11kM of12.47kV Distribution Line
- **Great Lakes Power - Third Line Technical Specification** – 115kV Substation - Detail Design for Extension to Existing Facility, including Site formation, station layout, foundation, structural steel design, bill of material
- **York Energy Center (YEC)** – Detail Design for 230kV Switching Station and Tap Tower to HONI, including Site formation, station layout, foundation, structural steel design, bill of material

- **IPC-Point Aux Roches Wind Farm Project** – Detail Design for Joint Use Pole Line and 34.5/115kV Substation
- **Electrical Consultants Inc. (ECI)/Brookfield - Comber Wind Project** – Detail Design for 34.5-230 kV Substation including Grading and Foundations
- **Newmarket Hydro - Davis Dr. Pole Line Design** –Distribution Line Design for Davis Drive road Widening between Yonge Street and Roxborough Rd of Newmarket including concrete pole and foundation design

Selected Projects – 2009

- **Kruger Ph.II (Chatham) Wind Power** – Detail Design for 230kV Substation (Layout, Steel Detail, BM) and 34.5kV Collector Line (20km)
- **RES-Talbot Wind Farm** – Detail Design for 230kV Switching Station and Tap Tower to HONI, including Site formation, station layout, foundation, structural steel design, bill of material
- **ENXCO-Elmsley East 10MW Solar Farm Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ENXCO- Elmsley West 10MW Solar Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ENXCO - St. Isidore A – 10MW Solar Farm Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ENXCO-St. Isidore B – 10MW Solar Farm Power Project** – Detail Design for 44kV Substation and solar panel facility station,
- **ALPAC –EXPORT II – 138kV Substation –** Detail Design for 138kV Substation, including station layout, structural steel design, bill of material

Selected Projects – 2008

- **East Windsor Power - Phase II** – 115kV Underground Duct Bank
- **Veridian Connections - Notion Road Hwy 401 Crossing** – Detail Design for 4CCT 44kV OH Line crossing Highway 401 with mono-steel pole and concrete caisson
- **Transcanada Pipeline, Station #139** – 115kV Substation upgrade
- **Transcanada Pipeline, Station #142** **-** 44kV Substation upgrade
- **Canadian Hydro Developers Inc. - Wolfe Island Wind Power Project** –Detail Design for 230kV Substation, including station layout, structural steel, foundation design, bill of material
- **Hydro One Network Inc. – Nobel 500kV Capacitor Bank Station** – Detail design of the site grading, foundation and masonry control building
- **Imperial Oil, Kearl Oil Sand Project Phase II, Alberta** – Detail Engineering Design of70KM of 240kV, 72kV, 13.8kV transmission Line and Station Gantries including mono-steel pole structure for 240kV and wooden pole structure for 72kV and 13.8kV structure.
- **Trinidad & Tobago Electricity Commission** – Union 220/66kV Substation, including structure steel and foundation design

Selected Projects – 2007

- **Thorold Cogen. T-line** – Thorold cogeneration project 230kV transmission line, including mono-steel pole and foundation design
- **City of Toronto** – Kennedy Pumping Station
- **City of Toronto** – Ellesmere Pumping Station
- **City of Toronto** – Keele Pumping Station
- **City of Toronto** – Richview Pumping Station
- **Halton Hills Generation Station -** 230kV Switchyard design, *Ontario* - Station design and detail design of all required structural steelwork, foundation, electrical equipment layout and bill of material.
- **Great Lake Power-McKay Sub Refurbishment** -115kV Switch Yard Upgrade
- **(3) AIMS 10 MW WIND FARMS, Byng Wind Farm, Mohak Wind Farm, Cutlue & Frogmore Wind Farm Projects-** Three 27.6kV substations and 5kM of tap line detail design
- **Kruger Energy Port Alma** Limited, Wind Power Project– 230 kV main Substation, 230kV switching station and 34.5kV collector line detail design
- **East Windsor Cogeneration Plant -**115kV Substation Detail design

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CURRICULUM VITAE

Raymond Leung, M.Eng., B.A.Sc.

EDUCATION

M.Eng. University of Toronto, 1998, Civil (Structural) Engineering

B.A.Sc. University of British Columbia, 1996, Civil Engineering

AREAS OF EXPERTISE

Transmission line and distribution line design, substation layout

Structural design and analysis, foundation design and civil work

Bridge design, underground subway station design and precast concrete construction

Project management

Engineering software: STAAD PRO, PLS-CADD, PLS-POLE, PLS-TOWER, L-PILE, ETABS, PROKON, SADS, SAP2000, SAFE, SLOPE/W, WALLAP, AutoCAD

Ontario Building Code, National Building Code of Canada, CSA Standards relevant to Structural, Civil, Electrical and Transmission Line works, British Standards relevant to Structural Design

SUMMARY OF EXPERIENCE

Mr. Leung has over 14 years of international engineering and management experience in various civil and structural engineering projects including precast segmental vehicular viaducts, underground subway stations, marine and offshore structures, residential and industrial buildings.

With his diverse field experience and knowledge of civil engineering design, Mr. Leung is responsible for the project technical deliverables that includes foundation design and analysis, high voltage switchyard and substation design, transmission and distribution line design. He is highly proficient in the use of specialized engineering tools such as STADD PRO and various structural analysis programs.

Mr. Leung joined the company in 2010 and has been heavily involved in the design of high voltage substation and distribution lines; providing technical advice to clients; coordinating technical requirements between the clients, owner, contractors and power authorities such as Hydro One or local power utility companies. His recent projects include a distribution system upgrade for a local distribution utility and a transmission line and substation design for power developers.

Chimax Inc.

Curriculum Vitae
Raymond Leung

PROFESSIONAL RECORD

2010 – Present	Project Manager, Chimax Inc.
2006 – 2010	Technical Manager, MANK Development Inc. (Toronto)
2002 - 2006	Senior Engineer, YWL Engineering Pte Ltd. (Singapore)
1999 - 2002	Design Engineer, Lambeth Associates Ltd. (Hong Kong)
1997 - 1999	Engineer, JMK Consulting Engineers (Hong Kong)

PROFESSIONAL AFFILIATIONS

Associated Members, Institution of Structural Engineering

SELECTED KEY PROJECTS

- Canada, Fort McMurray, Kearl Oil Sand Project – 72kV, 13.8kV and 4.16 kV sib-transmission line and associated substation structures
- Bahamas, K-line International, Bahamas Airport Highway – 133 kV Transmission Line
- Canada, Toronto, Eastern Power, Greenfield South Power Plant – 230kV substation and transmission line
- Jamaica, K-Line International, West Kingston Project – Two 69kV substations and transmission line
- Canada, Ontario, Brookfield Renewable Power, Comber Wind Farm – 230/34.5kV substations
- Canada, Ontario, International Power Inc, Plateau Wind Farm – 44kV switchyards and joint-use collector line
- Canada, Toronto Hydro, Rogers Road Rebuild – distribution line system rebuild and upgrade
- Canada, Toronto, 263 Wellington St. W – 12-storey residential tower technical management
- Hong Kong Cable Car – 40m long post-tensioning concrete footbridge design
- Hong Kong Shenzhen Western Corridor, Main Span Bridge – method engineering on 300-ton steel segment erection
- Hong Kong Route 9, Ngong Shuen Chau Viaduct – 2.5-km elevated carriageways employed balance cantilever method for erection of pre-stress segmental bridges
- Hong Kong Airport Authority, Asia Expo Convention Center – temporary works for the construction of 12000-m^2 exhibition hall and 11000-seats performance stadium
- Hong Kong Gammon Technology Center – 6500-m^2 steel shed complex and 1800-m^2 jetty structure
- Hong Kong, Tsing Yi North Coastal Road – precast noise enclosure on elevated viaduct
- Singapore, Chinatown Subway Station – interchange subway underground station and vent shafts
- Hong Kong, International Finance Center – elevate-linked steel bridge structures
- Hong Kong, Olympian City – 8 numbers of 45-storey residential towers and 75000-m^2 shopping complex

APPENDIX I

Electrical Safety Authority

Compliance Letters

Electrical Safety Authority

Electrical Distribution Safety

4 July, 2012

Tim Lavoie
General Manager
Algoma Power Inc.
2 Sackville Rd.
Sault Ste. Marie, Ontario
P6B 6J6

Re: Ontario Regulation 22/04 – 2011 Compliance Assessment

After review of Algoma Power's (Algoma) Audit Report for the twelve month period ended February 29, 2012, the Declaration of Compliance and Due Diligence Inspection(s), ESA is submitting this letter assessing Algoma's compliance with Regulation 22/04.

Audit Report
The audit report did not identify any compliance issues for Algoma Power.

Declaration of Compliance
ESA is satisfied with the Declaration of Compliance submitted by Algoma Power.

Due Diligence Inspections
The Due Diligence Inspection Reports from the inspections performed October 24 and 31, 2011 in Sault Ste. Marie were reviewed. There were no compliance issues identified in the inspections.

Martin Post

Martin Post, CMA
Program Coordinator
Electrical Safety Authority

August 22, 2012

Jie Han, P.Eng
Engineering Manager
FortisOntario
1130 Bertie Street
Fort Erie, ON L2A 5Y2
Canada

Jie Han,

Re: Ontario Regulation 22/04 – 2011 Compliance Assessment

After review of FortisOntario's Audit Report for the twelve month period ended February 29, 2012, the Declaration of Compliance, and Due Diligence Inspection(s) ESA is submitting this letter in lieu of an Audit Report follow-up visit. This letter addresses Cornwall Electric, Canadian Niagara Power Inc (Town of Fort Erie, City of Port Colborne - Port Colborne Hydro and the Town of Gananoque - Eastern Ontario Power).

Audit Report
The audit report shows there were no non-compliance issues identified and one needs improvement issue identified. ESA is satisfied with the response to the finding supplied by FortisOntario.

Declaration of Compliance
ESA is satisfied with the Declaration of Compliances submitted by FortisOntario.

Due Diligence Inspections
The following Due Diligence Inspection Reports were reviewed:

- August 15, 16 - 2011 (Fort Erie and/or Port Colborne)
- October 17 – 2011 (Cornwall)
- October 24, 31 – 2011 (Sault Ste. Marie)
- August 19, 26 – 2010 (Fort Erie and/or Port Colborne)
- December 22 – 2011 (Gananoque)

There was only one (1) needs improvement during the inspections. ESA is satisfied with the responses supplied by FortisOntario.

J Hrycyshyn

Jason Hrycyshyn, P.Eng
Electrical Distribution Safety Engineer
Electrical Safety Authority

APPENDIX J

S&P Credit Rating

Research

Summary:

Fortis Inc.

30-Nov-2012

Credit Rating: A-/Stable/--

Rationale

The ratings on St. John's, Nfld.-based utility holding company Fortis Inc. reflect Standard & Poor's Ratings Services' opinion of the company's excellent business risk profile and significant financial risk profile. Our business risk assessment reflects the company's diversified portfolio of low-risk, monopoly utilities; stable regulated cash flow with generally supportive regulatory regimes and independent subsidiaries. Characterizing Fortis' financial risk profile, in our view, are the deemed regulatory capital structure at each of its subsidiaries, which drive the relatively weak consolidated and deconsolidated credit metrics. We believe that exposure, albeit limited, to higher-risk commercial and hospitality real estate, and electricity generation somewhat offset the strengths of both its business risk and financial risk profiles.

Fortis is a holding company with 100% interests in a number of regulated utilities in Canada. They include FortisBC Holdings Inc. (gas distributor in British Columbia [B.C.]; not rated); FortisBC (electricity distributor for portions of B.C.; not rated); Newfoundland Power Inc. (electricity provider for the island portion of the province); **FortisAlberta Inc.** (electricity distributor in parts of Alberta; A-/Stable/--); **Maritime Electric Co. Ltd.** (electricity provider in Prince Edward Island; BBB+/Stable/--); and FortisOntario (electricity provider in parts of Ontario; not rated). The company also has holdings in regulated utilities in the Cayman Islands and Turks and Caicos; and it has nonregulated hydro power generation and real estate and hotel investments. Fortis had C$7.5 billion of Standard & Poor's-adjusted, consolidated debt as of Sept. 30, 2012.

The company continues to benefit from stable, regulated cash flows from its regulated utility portfolio. Regulation is typically cost-of-service-based with limited exposure to commodity price or volume risk. The utilities typically have a monopoly position with limited bypass risk. The ongoing rate-base growth is driving the long-term trend in cash-flow growth.

A key ongoing credit strength for the company is the regulatory, geographic, and market diversification of its subsidiaries and their cash flows. There continues to be some concentration in B.C., where about 50% of the post-acquisition rate base is located. Fortis' diversification is sufficient that it could survive the bankruptcy of its largest subsidiaries.

In our view, the company has limited headroom in both its consolidated and deconsolidated credit metrics. We expect its consolidated adjusted funds from operations (AFFO)-to-debt to remain in the 10%-12% range, with limited headroom above the 10% floor we have established for the ratings. We expect Fortis's deconsolidated AFFO-to-debt to be lower (18%-20%) in 2013-2014 before improving in 2015, when the Waneta hydroelectric project is completed. The key components of deconsolidated FFO include regulated cash flows, which are based on the forecast rate base; and the regulatory determined return on equity (ROE) and deemed capital structure for each regulated utility, unregulated cash flows, and tax benefits driven by the structure. We adjust both FFO and debt in accordance with our ratio definitions and our criteria on preferred shares, which we treat as 50% debt and 50% equity.

We expect the holding company's cash flows from subsidiaries Fortis Properties and Fortis Generation to increase to about 25% from about 15% post Waneta construction. Fortis Properties cash flows are somewhat riskier than the regulated businesses. However, we expect the Waneta power project to generate long term, stable cash flows once operational in 2015. Key contract features in the 40-year power purchase agreement include limited hydrology and price risk, and strong counterparties in British Columbia Hydro & Power Authority and FortisBC, with some construction risk in the interim.

Fortis is structured as a holding company and does not guarantee its subsidiaries' debt. However, we would expect the company to support its subsidiaries provided it had economic incentive to do so. Fortis primarily provides ongoing strategic support to its subsidiaries and provides equity injections as required to finance growth. Each entity has a high degree of independence both from the parent and typically from other operating units.

We believe that the proposed acquisition of CH Energy Group Inc. will slightly improve the company's excellent business risk profile and provides both regulatory and cash flow diversification benefits to the company. CH Energy's primary asset is its 100% ownership of **Central Hudson Gas & Electric Corp.** (A/Watch Neg/--), a regulated electric gas transmission and distribution utility with an excellent business risk profile that provides approximately 90% of CH Energy Group's consolidated EBITDA. The rating on Central Hudson reflects the consolidated credit profile of its parent.

Some of our key assumptions about Fortis include the following:

- In addition to about C$600 million of subscription receipts issued for the CH Energy acquisition and a recent C$200 million in preferred share issuance, we have assumed company will issue about C$50 million more in preferred shares, and C$150 million in debt at the holding company level.
- Fortis will finance the Waneta project with approximately C$350 million in debt. In addition, we assume the project is not delayed beyond 2015 and any cost overruns are not material.
- The company's consolidated rate base grows on average about 3%-4% per year from 2012-2016. Its regulated subsidiaries allowed ROE, deemed equity, and depreciation rates remain in line with current levels, and they are generally able to earn their allowed ROE or better.
- If the CH Energy acquisition closes in early 2013, there are no material changes to the underlying business.

Liquidity

Fortis' liquidity is adequate, in our view. At the holding company level, we expect that liquidity sources will be sufficient to cover uses by more than 1.2x. Our assessment incorporates the following expectations and assumptions:

- We expect that in the event of a 15% decline in deconsolidated earnings, the company's sources of funds would still exceed its uses.
- Liquidity sources include expected remitted cash flows from Fortis' subsidiaries of about C$300 million per year and unused committed credit facilities of about C$764 million as of March 31, 2012.
- Uses of capital include primarily interest and preferred share dividends of about C$100 million, and capital spending and dividends to shareholders of about C$600 million (excluding the CH Energy acquisition), but we believe that some of the capital spending has some deferability.

In our view, the company has sound relationships with its banks and generally satisfactory standing in credit markets.

Outlook

The stable outlook reflects our assessment of the operating companies' underlying operational and financial stability, which mitigates the relatively weak financial measures for the ratings. We could lower the ratings if Fortis were to employ materially more aggressive leverage or if it were to invest in assets with materially higher business risks and cash flow variability, or one of its larger subsidiaries encountered major financial or operational difficulties. We believe that the ratings could also face pressure if company-level AFFO-to-debt deteriorates below our forecasts or consolidated AFFO-to-debt falls below 10% on a sustained basis. A positive outlook or upgrade during our two-year forecast horizon is unlikely, given Fortis' weak credit metrics.

Related Criteria And Research

- **Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers**, Sept. 28, 2011
- Criteria Methodology: **Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent**, March 11, 2010
- **Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry**, Nov. 26, 2008
- **Hybrid Capital Handbook: September 2008 Edition**, Sept. 15, 2008
- **2008 Corporate Criteria: Analytical Methodology**, April 15, 2008
- **2008 Corporate Criteria: Ratios And Adjustments**, April 15, 2008

Primary Credit Analyst: Gavin MacFarlane, Toronto (1) 416-507-2545; **gavin_macfarlane@standardandpoors.com**

Secondary Contact: Nicole D Martin, Toronto (1) 416-507-2560; **nicole_martin@standardandpoors.com**

APPENDIX K

DBRS Credit Report

Rating Report

Report Date:
July 26, 2012

Previous Report:
March 8, 2012

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The Company

Fortis Inc. is a holding company for a number of regulated electric and natural gas utilities, including wholly owned Newfoundland Power Inc., FortisAlberta Inc., FortisBC Inc., Maritime Electric Company, Limited, FortisOntario Inc. and Fortis Turks and Caicos, as well as majority ownership of Caribbean Utilities Company (slightly over 60%). FortisBC Energy companies (formerly Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.) comprise its gas distribution utilities. Non-regulated operations include Fortis Properties, as well as non-regulated generation in Belize, Ontario and upper New York State.

Recent Actions

July 20, 2012
Confirmed

February 21, 2012
Placed Under Review with Developing Implications

September 7, 2011
Confirmed

Insight beyond the rating.

Fortis Inc.

Rating

Debt	Rating	Rating Action	Trend
Unsecured Debentures	A (low)	Confirmed	Stable
Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating Update

On July 20, 2012, DBRS confirmed the ratings of the Unsecured Debentures and Preferred Shares of Fortis Inc. (Fortis or the Company) at A (low) and Pdf-2 (low), respectively, with Stable trends, and removed the ratings from Under Review with Developing Implications following the announced acquisition of CH Energy Group Inc. (CHG) (the Acquisition) on February 21, 2012. The confirmation is based on the closing of subscription receipt offering (approximately $600 million) in June 2012 and further review of the Company's financing plan. DBRS is comfortable that Fortis' funding strategy includes appropriate measures to maintain a reasonable financial profile while executing its growth strategy, particularly the Acquisition (approximately $1.0 billion) and the Waneta hydropower project (approximately $127.5 million in 2012).

Fortis' non-consolidated balance sheet leverage is expected to increase notably. However, given its current financial flexibility, with non-consolidated debt-to-capital at near 14% and strong cash flow coverage, DBRS believes that Fortis' financing plan is reasonable such that debt leverage within the 20% range can be maintained in line with DBRS's rating guidelines for notching a holding company relative to its subsidiaries (see DBRS's methodology Rating Parent/Holding Companies and Their Subsidiaries, dated March 2010). Following the Acquisition and the financing of the Waneta project, cash flow coverage is expected to weaken temporarily but should remain within the current rating category.

With the proposed Acquisition, Fortis' business risk profile is expected to improve moderately, as approximately 97% of CHG's earnings are generated from its regulated electric and gas regulated businesses. This regulated earnings mix is higher than the Company's current mix at approximately 90%. The remaining 10% of Fortis' consolidated earnings are generated from higher-risk hotel properties and non-regulated generation businesses. The regulatory framework in New York is viewed as reasonable, as CHG is allowed to recover prudently incurred operating, capital and commodity costs and earn good returns on investments.

Fortis is currently rated the same as some of its subsidiaries (FortisBC Inc. and FortisAlberta Inc.), despite the structural subordination and double leverage at the parent. DBRS believes that Fortis' ratings are supported by strong and stable cash flows from diversified sources, with a significant portion of dividends coming from its regulated subsidiaries with "A" ratings (FortisBC Energy Inc. and Newfoundland Power Inc.).

Rating Considerations

Strengths

(1) Strong and stable dividends and cash income
(2) Diversified sources of cash flow
(3) 100% ownership of most subsidiaries
(4) Good liquidity/reasonable interest coverage

Challenges

(1) Potential higher debt levels at the parent
(2) Structurally subordinated to debt at the subsidiaries
(3) Strong ring-fencing at its wholly owned utilities
(4) Considerable capex for Waneta Expansion Project

Financial Information

Non-consolidated Fortis Inc.	**12 mos.**	Year ended December 31				
($ millions)	**Mar. 2012**	**2011**	**2010**	**2009**	**2008**	**2007**
EBIT	424	419	385	350	326	260
Cash flow from operations	225	216	155	216	145	40
Total debt	780	755	949	832	606	709
Total debt/Capital	13.9%	13.6%	18.4%	17.7%	14.0%	18.9%
EBIT-interest coverage (x)	9.40	9.29	8.65	8.05	8.40	7.67
Cash flow-interest coverage (x)	5.99	5.79	4.48	5.98	4.73	2.18
Cash flow/Total debt	28.9%	28.6%	16.4%	27.5%	25.9%	6.0%

Fortis Inc.

Report Date:
July 26, 2012

Rating Considerations Details

Strengths

(1) **Strong and stable dividends and cash income.** Cash income and dividends have been strong, largely supported by stable earnings and cash flow from regulated entities and long-term power contracts. Regulated operations account for approximately 90% of consolidated EBITDA (12 months to March 2012).

(2) **Diversified sources of cash flow.** Fortis benefits from diversified sources of cash flow through its ownership of regulated natural gas utilities in British Columbia and electric utilities in five Canadian provinces and three Caribbean countries.

(3) **100% ownership of most subsidiaries.** Fortis owns 100% of most of its operating entities. This provides Fortis, within the boundaries of regulatory oversight, with some discretionary powers over the manner in which cash flows are paid to it by its operating companies.

(4) **Good liquidity/reasonable interest coverage.** At the end of March 2012, Fortis had approximately $814 million in available credit facilities (at the parent level), which is sufficient to finance its near-term operational and capital needs. Non-consolidated cash flow-to-interest coverage remained strong for the 12 months ended March 2012.

Challenges

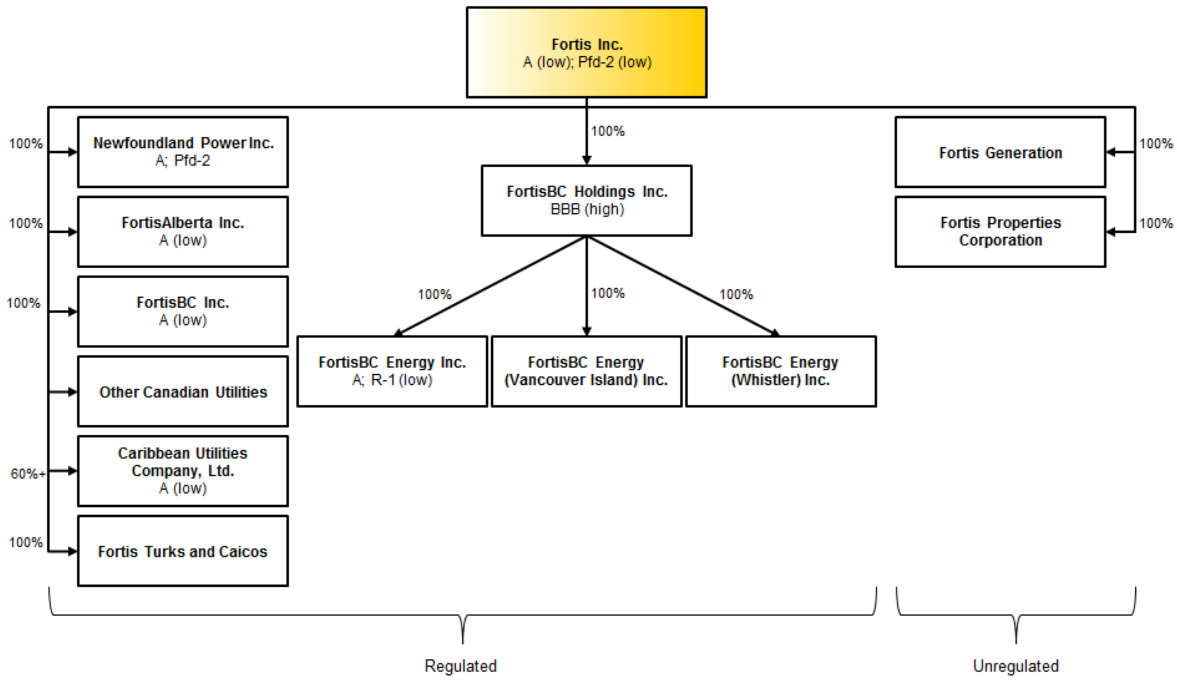
(1) **Potential high debt levels at the parent.** Fortis' agreement to acquire CHG could increase debt levels at the parent considerably. As at March 31, 2012, the non-consolidated debt-to-capital ratio was at 13.9%, which provided Fortis with significant financial flexibility. However, Fortis' non-consolidated leverage will likely increase with the proposed Acquisition.

(2) **Structural subordination.** Fortis is a holding company whose debt is structurally subordinated to the debt obligations of its operating companies. This accounts for the lower debt rating of Fortis relative to the debt ratings of some its key regulated subsidiaries.

(3) **Strong ring-fencing.** Fortis faces strong ring-fencings imposed on FortisBC Energy Inc. and FortisBC (Vancouver Island) Inc. with respect to their capital structure and dividend payouts. In addition, it is common for utilities to maintain their capital structure in line with the regulatory capital structure. As a result, dividend payouts to Fortis could be affected should these utilities have a large capital expenditure program.

(4) **Large capital expenditures for the Waneta Expansion Project (WEP).** The WEP is a hydroelectric project in British Columbia that is 51% owned by Fortis. The Company's share of capital expenditures is approximately $450 million. Approximately $250 million will be required in 2012 for the project (51% will be contributed by Fortis). The project is expected to be in service in early 2015.

Simplified Corporate Structure*



*Note: The above chart only includes Fortis' major regulated and non-regulated subsidiaries, which directly or indirectly contribute dividends to Fortis.

Based on 2011 Data

Name	Operations	Customers	Rate base (CAD millions)	Allowed Roe for 2012	Net income (CAD millions)	Deemed equity
FortisBC Holdings Inc.	Holding company		3,300	9.6%	139	40%
FortisBC Energy Inc.	Natural gas distribution	851,000	2,500	9.5%	102	40%
FortisBC Energy (Vancouver Island)	Natural gas distribution	102,000	700	10.0%	N/A	40%
FortisBC Energy (Whistler)	Natural gas distribution	2,600	100	10.0%	N/A	40%
FortisAlberta	Electricity distribution	499,000	1,715	8.8%	75	41%
FortisBC	Integrated utility	162,000	1,093	9.9%	48	40%
Newfoundland Power	Electricity distribution	247,000	875	8.4%	34	45%
Other Canadian Utilities	-	177,000	513	8.0-9.8%	22	40%
Fortis Properties	Real estate	22 hotels	-	-	23	-
Caribbean Utilities	Integrated utility	26,000	375	12-14%	20	45-50%
Fortis Turks and Caicos	Integrated utility	9,500	155	-	9	-
Fortis Generation	Power generation	Appro. 292 MW		-	18	-

The Proposed Acquisition of CHG

On February 21, 2012, Fortis announced that it had agreed to acquire CHG for a total consideration of approximately US$1.5 billion, including the assumption of US$500 million of debt on closing. The Acquisition is expected to close within 12 months, subject to various regulatory approvals. The CHG shareholders have approved the Acquisition.

CHG's principal businesses comprise: (1) Central Hudson Gas & Electric Corporation (Central Hudson), which is a regulated utility in New York state with approximately 300,000 electric customers and 75,000 gas customers. Central Hudson accounts for 97% of CHG's 2011 net income and 93% of its assets. (2) A non-regulated fuel delivery business (3% of CHG income), which serves 56,000 customers in the Mid-Atlantic Region. CHG's total assets as of December 31, 2011, were US$1.7 billion. Net income and operating cash flow in 2011 were US$45 million and US$115 million, respectively.

Fortis Inc.

Report Date:
July 26, 2012

Non-Consolidated Income & Cash Flows

Earnings - Non-Consolidated	**12 mos.**	Year end December 31	
($ millions)	**Mar. 2012**	**2011**	**2010**
Newfoundland Power	34	34	35
FortisBC Energy Holdings Inc.	138	128	119
FortisWest	80	84	82
Other Canadian utilities/Other	10	10	11
Fortis Energy Bermuda	25	26	28
Regulated investment income	**286**	**282**	**275**
Fortis Properties	34	35	37
FortisUS Inc.	8	12	(3)
Fortis Energy Cayman	17	14	18
Non-regulated	**59**	**61**	**52**
Total Investment Income	**345**	**343**	**327**
Interest income + Management fee	80	77	59
EBITDA	**425**	**420**	**386**

Earnings - Non-Consolidated	**12 mos.**	Year end December 31				
($ millions)	**Mar. 2012**	**2011**	**2010**	**2009**	**2008**	**2007**
EBITDA	**425**	**420**	**386**	**351**	**328**	**262**
Depreciation	2	2	1	2	2	2
EBIT	424	419	385	350	326	260
Interest expense	45	45	44	43	39	34
EBT	379	373	340	306	287	226
Net Income before preferred dividends	367	364	329	297	275	215
Non-consolidated cash flow from operations	225	216	155	216	145	40
Less: Preferred dividends	(45)	(45)	(45)	(35)	(30)	(23)
Less: Common dividends	(145)	(151)	(135)	(133)	(162)	(128)
Free cash flow	35	19	(25)	49	(47)	(111)
Maintenance capex	(5)	(4)	(3)	(0)	(0)	(1)
Acquisitions	0	0	0	0	0	(1,256)
Investments/Advances to subsidiaries	(225)	(208)	(367)	(358)	(306)	(266)
Equity financing (includes preferred)	345	345	264	49	533	1,269
Debt financing	(149)	(165)	141	293	(179)	333
Others, including working capital	(1)	3	(1)	(30)	6	21
Net change in cash flow	(1)	(10)	8	2	7	(11)

Summary

- Overall, Fortis has benefited from good earnings diversification, strongly underpinned by regulated utilities, which account for 90% of consolidated assets.
- EBITDA reflected strong earnings from regulated utilities, long-term contract generation, property management and interest income.
- Earnings have increased over the years, largely reflecting higher ROE in recent years and growing rate bases at the utilities.
- Fortis Properties' performance has been solid, reflecting the recovery of the Canadian economy. Although accounting for 10% of the assets, non-consolidated contributions have been solid at 14% since 2010.

Outlook

- Investment income from regulated utilities is expected to increase considerably in 2013 should the proposed Acquisition of CHG be completed as expected (Q1 2013).
- The Acquisition should also improve Fortis' earnings diversification.
- Non-regulated earnings are expected to increase in 2015 when WEP is scheduled to be in service. The project has obtained a long-term power contract with BC Hydro.

Fortis Inc.

Report Date:
July 26, 2012

Capital Structure and Liquidity

Capital Structure - Non-Consolidated	12 mos.	As at December 31				
($ millions)	Mar. 2012	2011	2010	2009	2008	2007
Short-term debt	-	-	-	100	-	5
Credit facilities	31	-	165	36	110	208
Long-term debt	749	755	779	650	450	450
Sub. convertible debentures	-	-	5	45	46	46
Preferred shares	912	912	912	667	667	442
Common shares	3,909	3,867	3,308	3,195	3,046	2,606
Total non-consolidated capital	**5,600**	**5,534**	**5,169**	**4,694**	**4,319**	**3,757**
% total debt-to-total capital	13.9%	13.6%	18.4%	17.7%	14.0%	18.9%
EBIT-interest coverage (x)	9.40	9.29	8.65	8.05	8.40	7.67
Cash flow-interest coverage (x)	5.99	5.79	4.48	5.98	4.73	2.18
Cash flow-to-total debt	28.9%	28.6%	16.4%	27.5%	25.9%	6.0%

Summary

- Fortis' non-consolidated balance sheet remained strong in Q1 2012, reflecting a modest debt-to-capital ratio at 13.9%, which provided the Company with significant financial flexibility.
- This leverage remained well within the 20% threshold in DBRS's notching guidelines for a holding company relative to its subsidiaries.
- Cash flow-to-interest coverage remained strong for a holding company.

Potential Impact of the Proposed Acquisition of CHG

- The price of the Acquisition is approximately $1 billion.
- In June 2012, Fortis completed a subscription receipt offering for approximately $600 million, which will be used to partially finance the Acquisition, with the remainder expected to be financed with debt and preferred shares.
- Based on the Company's financing strategy, the debt-to-capital ratio will likely increase from the current level should the Acquisition be completed.
- However, the new debt-to-capital ratio is expected to remain within the 20% level.

Liquidity

Credit Facilities as at March 31 2012

($ millions)	HoldCo & other	Regulated Subsidiaries	Non-regulated Subsidiaries	Total
Total credit facilities	845	1389	13	2247
Drawing on credit facilities (S-T)		(73)	(3)	(76)
Drawing on credit facilities (L-T)	(31)	(50)		(81)
Letters of credit	(1)	(65)		(66)
Credit facilities available	813	1201	10	2024

Debt Maturity Schedule

Debt maturities - ($ millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fortis Inc. senior debt	0	0	153	0	0	602	755
Total	0	0	153	0	0	602	755
% of total debt	0%	0%	20%	0%	0%	80%	100%

- Fortis has sufficient liquidity to finance its near-term funding requirements.
- Debt maturity is concentrated in 2014, when 20% of Fortis' total debt is due. DBRS believes that the refinancing of this amount is within the Company's capacity, given its strong credit profile.

Description of Operations

Fortis' main subsidiaries and investments are as follows:

FortisBC Holdings Inc. (100% owned) is a holding company for the following utilities:
(1) **FortisBC Energy Inc. (FEI)** is the largest natural gas distributor in British Columbia, serving approximately 851,000 residential, commercial and industrial customers in an area extending from Vancouver to the Fraser Valley and the interior of British Columbia.
(2) **FortisBC Energy (Vancouver Island) Inc. (FEVI)** owns a combined distribution and transmission system and serves approximately 102,000 residential, commercial and industrial customers along the Sunshine Coast and in Victoria and various communities on Vancouver Island.
(3) **FortisBC Energy (Whistler) Inc. (FEW)** owns and operates a propane distribution system in Whistler, British Columbia, and provides service to approximately 2,600 residential and commercial customers.

FortisAlberta Inc. (100% owned) is a regulated electricity distributor with approximately 499,000 customers. Its franchise area includes central and southern Alberta, the suburbs surrounding Edmonton and Calgary, Red Deer, Lethbridge and Medicine Hat.

FortisBC Inc. (100% owned) is a vertically integrated regulated utility operating in south-central British Columbia, serving approximately 162,000 customers. Its generation assets include four hydroelectric generating plants (totaling 223 MW) on the Kootenay River in south-central British Columbia.

Newfoundland Power Inc. (100% owned) (NP) is a principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 247,000 customers. Fortis also owns 25% of NP's preferred shares.

Other Canadian Utilities
(1) **FortisOntario Inc.** is an integrated electric utility providing services to approximately 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

(2) **Maritime Electric Company Limited (Maritime Electric)** is the principal distributor of electricity on Prince Edward Island, serving approximately 75,000 customers. It also maintains on-island generating facilities with a combined capacity of 150 MW. Maritime Electric is indirectly owned by Fortis through FortisWest.

Fortis Properties Corporation owns and operates 22 hotels in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate, primarily in Atlantic Canada.

Caribbean Utilities Company, Ltd. (Caribbean Utilities) is a fully integrated electricity utility on Grand Cayman, Cayman Islands, serving over 26,000 customers. It has an installed generating capacity of approximately 151 MW. Fortis has an approximate 60% controlling ownership interest in Caribbean Utilities, and the remaining ownership is publicly traded on the Toronto Stock Exchange.

Fortis Turks and Caicos serves approximately 9,500 customers, or 85% of electricity consumers in the Turks and Caicos Islands pursuant to 50-year licenses that expire in 2036 and 2037. The Company has a combined diesel-fired generating capacity of 54 MW.

Belize Electric Company Limited is a non-regulated 32 MW hydro generation facility in Belize. All output is sold to Belize Electricity Limited under a 50-year power purchase agreement expiring in 2055. The US$53 million 19 MW hydroelectric generating facility at Vaca in Belize was commissioned in March 2010.

Belize Electricity Limited is recorded as equity investment following the expropriation by the Government of Belize in June 2011.

Fortis Inc.

Report Date:
July 26, 2012

Rating

Debt	Rating	Rating Action	Trend
Unsecured Debentures	A (low)	Confirmed	Stable
Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008	2007
Unsecured Debentures	A (low)	A (low)	A (low)	BBB (high)	BBB (high)	BBB (high)
Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-3 (high)	Pfd-3 (high)	Pfd-3 (high)

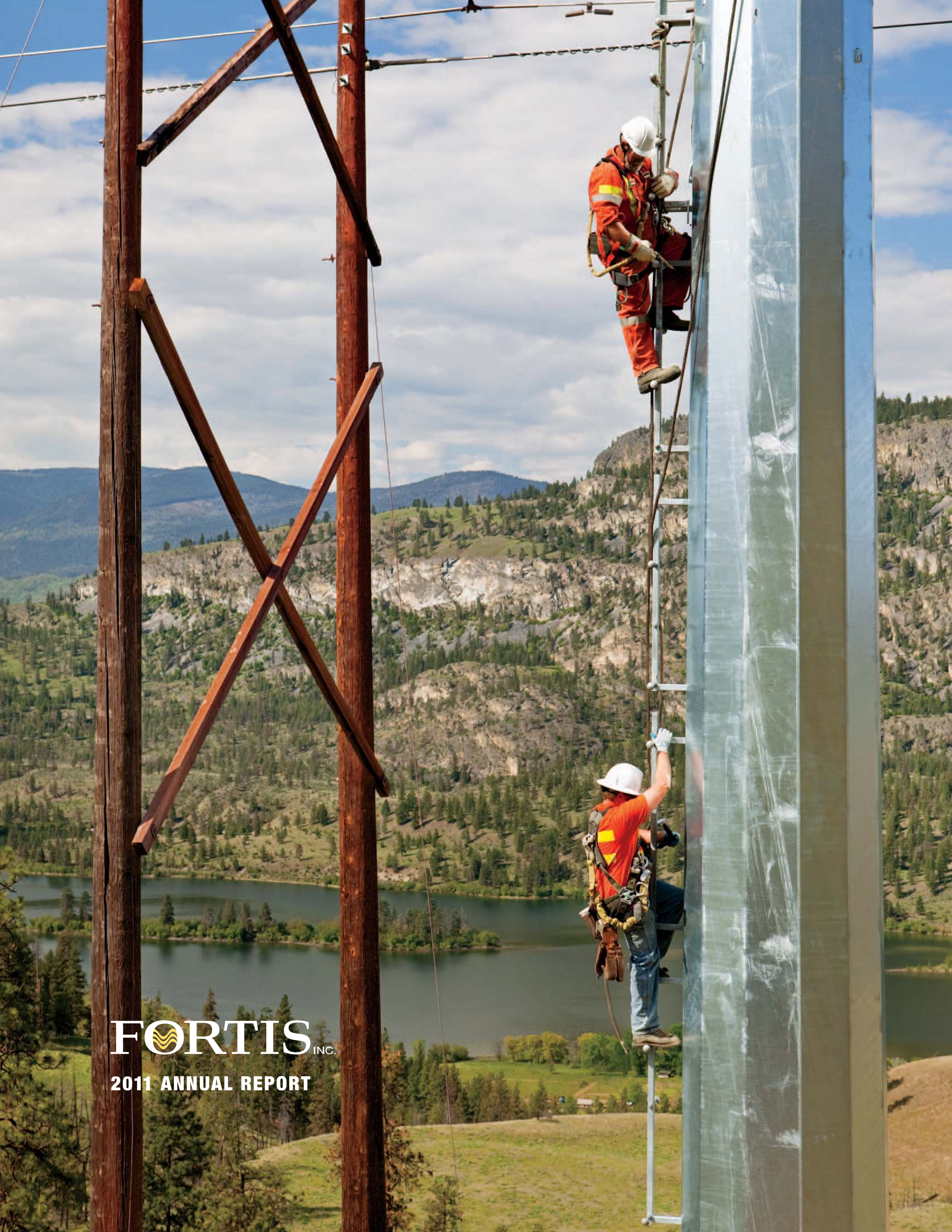
Related Research

- FortisBC Holdings Inc., February 29, 2012.
- FortisBC Energy Inc., February 29, 2012.
- Newfoundland Power Inc., July 18, 2012.
- FortisAlberta Inc., June 28, 2012.
- FortisBC Inc., February 22, 2012.
- Caribbean Utilities Company, Ltd., July 5, 2012.

Note:
All figures are in Canadian dollars unless otherwise noted.

APPENDIX L

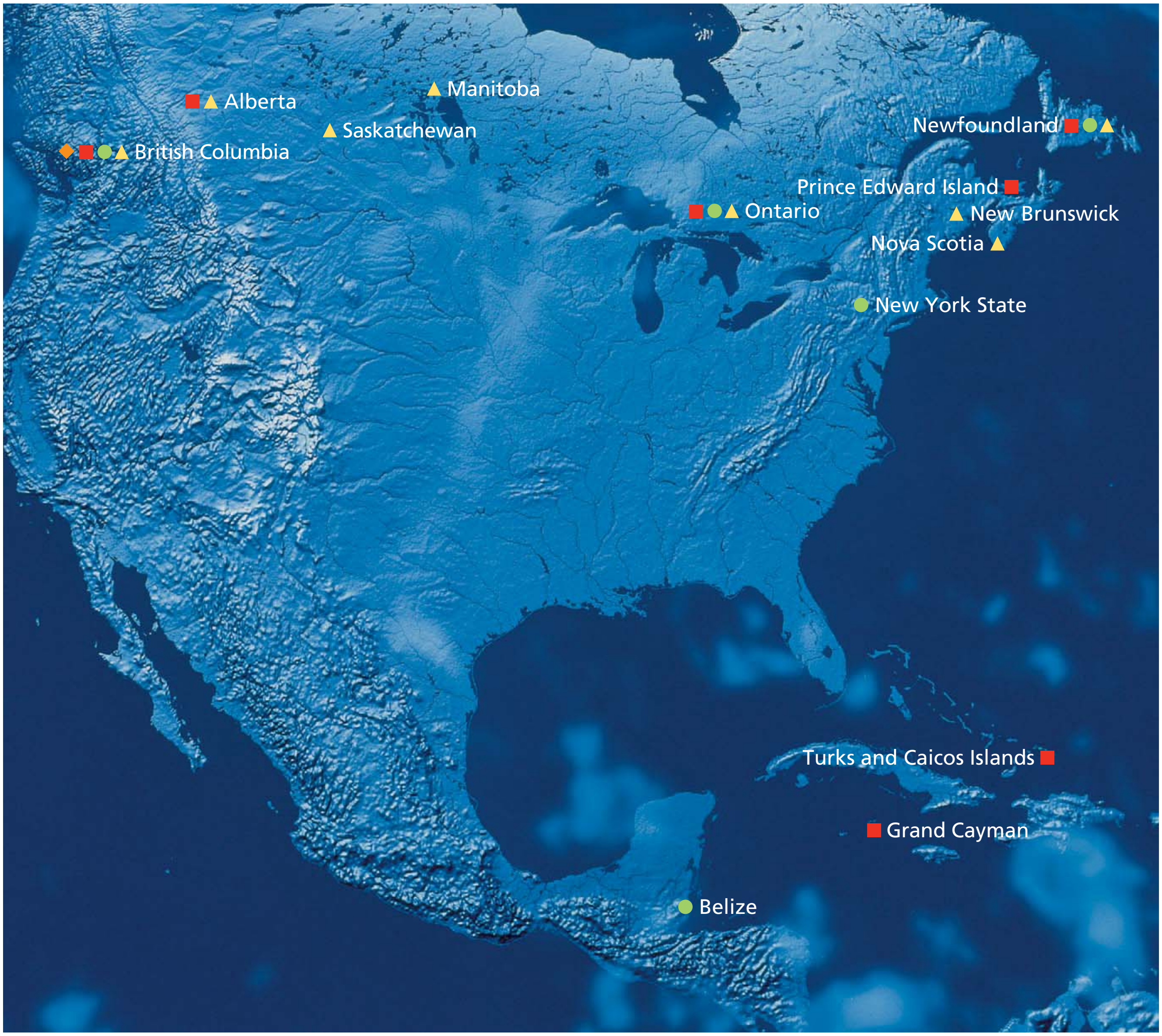
Fortis Annual Report



FORTIS INC.

2011 ANNUAL REPORT

Operations



Regulated Utility Operations

Gas Operations

FortisBC *British Columbia*

Electric Operations

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation

Production Areas

Belize, Ontario, Central Newfoundland, British Columbia, New York State

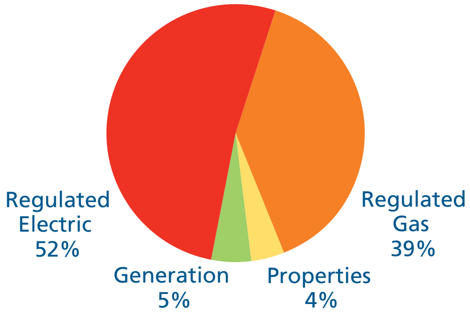
Fortis Properties

Real Estate and Hotels

Across Canada

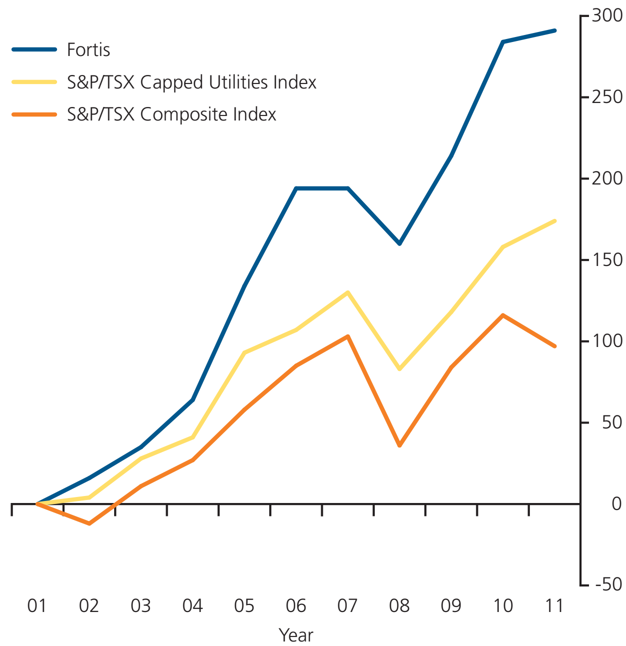
Total Assets $13.6 Billion

(as at December 31, 2011)



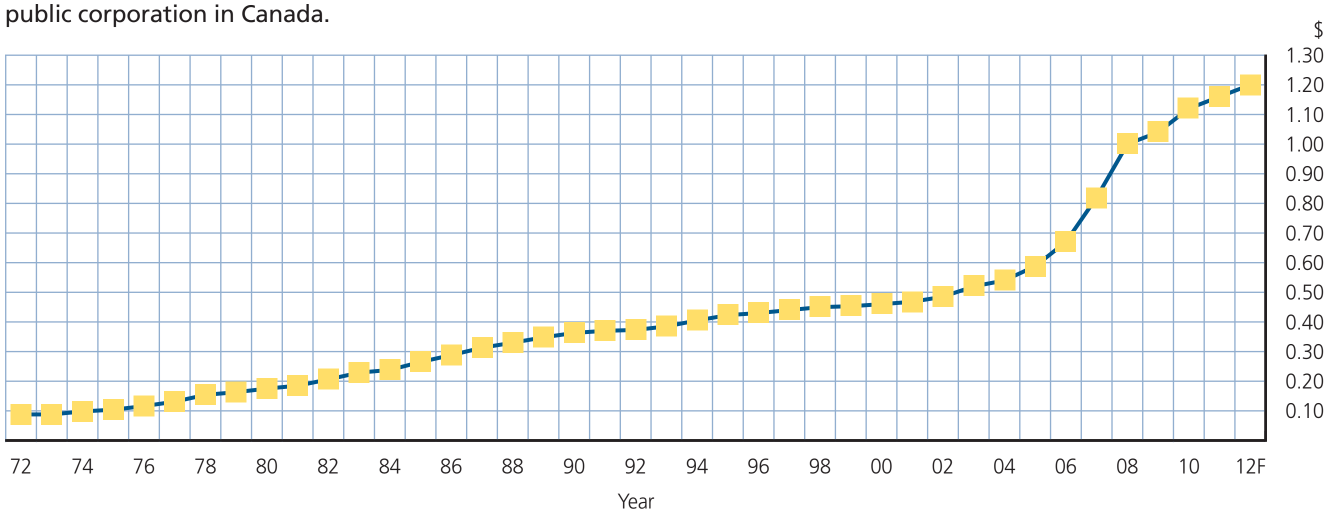
Contents

10-Year Cumulative Total Return



Dividends paid per common share

Fortis has increased its annual dividend to common shareholders for 39 consecutive years, the longest record of any public corporation in Canada.



The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

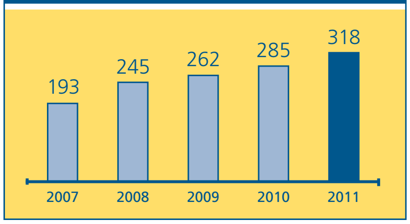
The Corporation will continue to focus on three primary objectives:

i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.

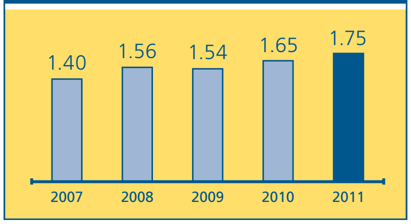
ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

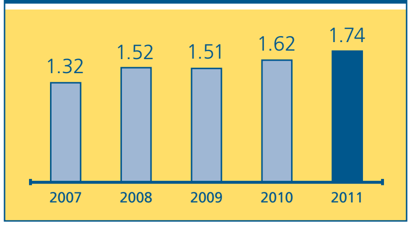
Earnings Attributable to Common Equity Shareholders ($M)



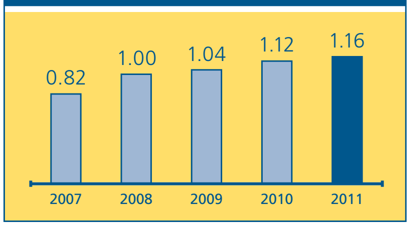
Basic Earnings per Common Share ($)



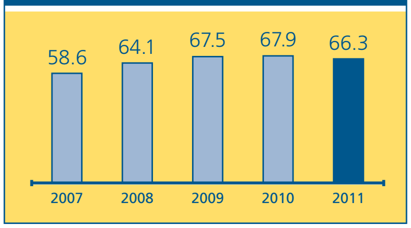
Diluted Earnings per Common Share ($)



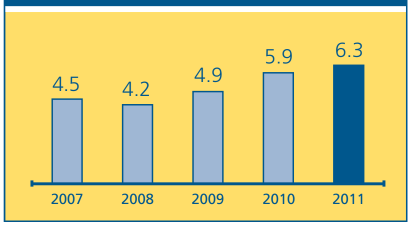
Dividends Paid per Common Share ($)



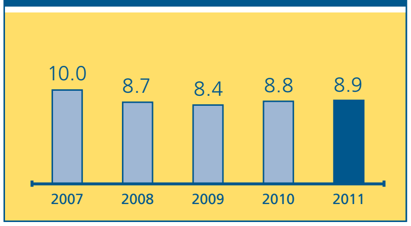
Dividend Payout Ratio (%)



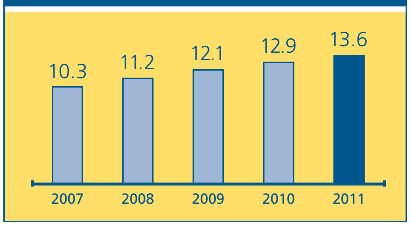
Market Capitalization ($B)



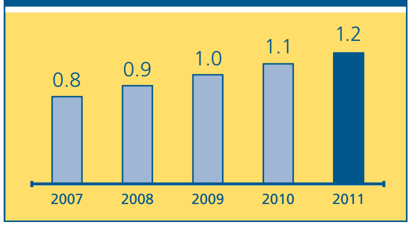
Return on Average Book Common Shareholders' Equity (%)



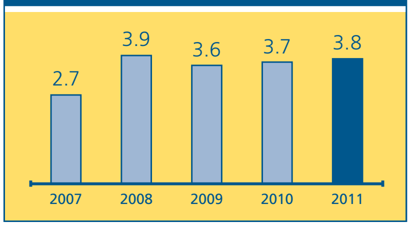
Assets ($B)



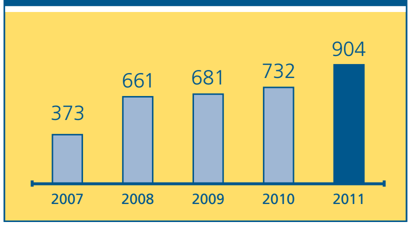
Capital Expenditures ($B)



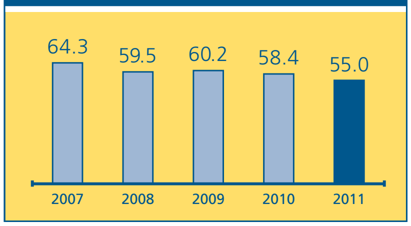
Revenue ($B)



Cash Flow from Operating Activities ($M)



Debt to Total Capitalization (%)



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2011 unless otherwise indicated.

Regulated

Gas

FortisBC (1)	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) (2)	Earnings ($M)	Allowed ROE (%) (3) 2011	2012
Total	956,000	1,789	1,210	203	253	5.3	3.6	139	9.50	9.50 (4)

Electric

	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program ($M)	Total Assets ($B)	Rate Base ($B) (2)	Earnings ($M)	Allowed ROE (%) (3) 2011	2012
FortisAlberta	499,000	1,036	2,505	16,367	416	2.7	2.0	75	8.75	8.75
FortisBC	162,000	528	669	3,143	102	1.6	1.1	48	9.90	9.90 (4)
Newfoundland Power	247,000	640	1,166	5,553	81	1.2	0.9	34	8.38	8.38 (5)
Maritime Electric	75,000	181	224	1,048	27	0.4	0.3	12	9.75	9.75
FortisOntario	64,000	198	276	1,318	20	0.3	0.2	10	8.01/9.85 (6)	8.01/9.85 (6)
Belize Electricity (7)	–	–	76	194	9	0.1	–	–	–	–
Caribbean Utilities (8)	27,000	193	99	554	36	0.5	0.4	11	7.75–9.75 (9)	7.75–9.75 (9) (10)
Fortis Turks and Caicos	9,500	114	30	170	26	0.2	0.2	9	17.50 (9) (11)	17.50 (9) (11)
Total	1,083,500	2,890	5,045	28,347	717	7.0	5.1	199		

(1) Includes the operations of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc., collectively known as the "FortisBC Energy companies"

(2) Forecast midyear 2012

(3) Rate of return on common shareholders' equity ("ROE"). For the gas segment, ROE is for FortisBC Energy Inc. ROE for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. is 50 basis points higher.

(4) The allowed ROEs are to be maintained for 2012 pending determinations made in the regulator-initiated Generic Cost of Capital Proceeding, which will commence in March 2012.

(5) Interim, pending the outcome of a cost of capital review expected during 2012

(6) Canadian Niagara Power 8.01%; Algoma Power 9.85%

(7) Peak demand, energy sales and capital program are up to June 20, 2011, the date Belize Electricity was expropriated by the Government of Belize. Assets represent book value of the Corporation's previous investment in Belize Electricity. Fortis has filed for compensation from the Government of Belize for the fair value of Belize Electricity.

(8) Information in table represents 100% of Caribbean Utilities' operations except for earnings data. Earnings represent Caribbean Utilities' contribution to consolidated earnings of Fortis, based on the Corporation's approximate 60% ownership interest.

(9) Regulated rate of return on rate base assets ("ROA")

(10) Subject to change based on the annual operation of the rate-cap adjustment mechanism to be finalized in June 2012

(11) Amount provided under licence. ROA achieved in 2011 was 6.6%. In February 2012 the Interim Government of the Turks and Caicos Islands approved, among other items, a 26% increase in electricity rates for large hotels, effective April 1, 2012.

Non-Regulated

Fortis Generation (1)

	Generating Capacity (MW)	Energy Sales (GWh)	Assets ($B) (3)	Earnings ($M) (4)	Capital Program ($M) (5)
Total	139	389	0.7	18	174

Fortis Properties (2)

	Employees (#)	Assets ($B)	Earnings ($M)	Capital Program ($M)
Total	2,400	0.6	23	30

(1) Includes investments in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State

(2) Includes approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada and 22 hotels across Canada

(3) Includes $90 million in "Other" non-regulated assets

(4) Contribution to consolidated earnings of Fortis for the fiscal year ended December 31, 2011

(5) Includes $169 million related to the Waneta Expansion hydroelectric generating facility in British Columbia

Information is for the fiscal year ended December 31, 2011 unless otherwise indicated.

Report to Shareholders

2011 marks the 12th consecutive year Fortis has delivered record earnings to our shareholders. Net earnings attributable to common equity shareholders were $318 million, $33 million higher than earnings of $285 million in 2010. Earnings per common share were $1.75 in 2011 compared to $1.65 in 2010.

Stan Marshall,
President and CEO, Fortis Inc.

David Norris,
Chair of the Board, Fortis Inc.

Increased investment in energy infrastructure at our utilities in western Canada and the $11 million after-tax fee paid to Fortis in July 2011, following the termination of the Merger Agreement with Central Vermont Public Service Corporation ("CVPS"), were the primary drivers of earnings growth.

Dividends per common share have grown at a compound annual growth rate of 9.5% over the past 10 years. In December Fortis increased its quarterly common share dividend to 30 cents, commencing with the first quarter dividend paid in 2012. The 3.4% increase in the quarterly common share dividend translates into an annualized dividend of $1.20 and extends the Corporation's record of annual common share dividend increases to 39 consecutive years, the longest record of any public corporation in Canada. The dividend payout ratio was 66% in 2011.

Fortis delivered an average annualized total return to shareholders of approximately 15% over the past 10 years, exceeding the S&P/TSX Capped Utilities and Composite Indices, which delivered annualized performance of approximately 11% and 7%, respectively, over the same period.

Our annual capital expenditure program reached a record $1.2 billion in 2011, including combined expenditures of over $900 million in British Columbia and Alberta. Growth in energy demand accounted for about 45% of the capital expenditures made during the year. The significant investment in energy infrastructure being made by our utilities is focused on ensuring we continue to meet our obligation to provide quality service to our customers.

FortisBC, through its operating businesses, delivers approximately 21% of the total energy consumed in British Columbia – the most energy delivered by any utility in the province. In 2011 FortisBC completed its $212 million 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island. The new facility, brought online late in the year, improves reliability and security of supply to gas customers during periods of system interruptions or increased energy demand. In addition, FortisBC completed its $105 million Okanagan Transmission Reinforcement Project, which involved upgrading an overhead electricity transmission line between Penticton and Vaseux Lake from 161 kilovolts ("kV") to a double-circuit 230-kV line and building a new 230-kV terminal substation in the Oliver area to help ensure the safe and reliable delivery of energy to customers. The Company's $110 million Customer Care Enhancement Project, which included the opening of two new customer service centres in Prince George and Burnaby, came into service at the beginning of 2012.

Construction of the $900 million 335-MW Waneta Expansion hydroelectric generating facility is progressing well.

Construction of the $900 million 335-megawatt Waneta Expansion hydroelectric generating facility (the "Waneta Expansion") on the Pend d'Oreille River in British Columbia is progressing well. Approximately $244 million has been invested in the Waneta Expansion since construction started in late 2010. Fortis holds a 51% interest in the Waneta Expansion and will operate and maintain the facility when it comes into service, slated for spring 2015. The facility output is to be sold under 40-year power purchase agreements with FortisBC and BC Hydro. British Columbia and the Pacific Northwest region provide good potential to pursue additional hydroelectric generation assets that complement the utility operations of Fortis in western Canada, deliver value to our shareholders and enhance service to our customers.

FortisAlberta is our fastest-growing Canadian utility. Its rate base has grown at a compound annual growth rate of 18% over the past five years. The Company continues to invest significant capital in its electricity network, which includes more than 100,000 kilometres of distribution lines, with over $400 million of capital expenditures in 2011 and a similar amount planned for 2012. In early 2011 FortisAlberta completed its $126 million Automated Metering Project, which reduces operating costs and helps customers better monitor and manage their monthly energy usage. The Company has also undertaken a Pole Management Program to replace 96,000 vintage poles to prevent risk of failure due to age. Approximately $335 million is projected to be invested in this initiative through expected completion in 2019. A significant portion of FortisAlberta's franchise territory overlaps with the prominent tight oil and shale gas developments in Alberta, especially the Bakken, Cardium and Duvernay areas, and our business is benefiting from building the energy infrastructure necessary to meet associated customer growth.

Canadian Regulated Gas Utilities delivered earnings of $139 million, up $9 million from $130 million for 2010. Excluding a favourable one-time $4 million item in 2010, earnings increased $13 million year over year. Results for 2011 reflected the impact of growth in energy infrastructure investment, lower-than-expected corporate income taxes, finance charges and amortization costs, and increased gas transportation volumes to the forestry and mining sectors, partially offset by lower-than-expected customer additions.

Regulated utility assets comprise 91% of the total assets of Fortis.

The majority of our gas customers have benefited from the downward trend in natural gas commodity prices. The improving supply and cost fundamentals of natural gas throughout North America, combined with its positive environmental attributes, make natural gas an attractive energy supply source for residential and industrial use and as a fuel for the transportation and power generation sectors.

Canadian Regulated Electric Utilities contributed earnings of $179 million, up $15 million from $164 million for 2010. The increase was driven by improved results at FortisAlberta and FortisBC Electric. The increase in earnings at FortisAlberta mainly resulted from growth in energy infrastructure investment associated with sustaining the electricity grid and customer growth, partially offset by a lower allowed rate of return on common shareholders' equity ("ROE") for 2011. The increase in earnings at FortisBC Electric resulted from growth in energy infrastructure investment, lower purchased power costs and higher electricity sales.

Construction of the $212 million 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was completed in 2011.

At our largest utilities, a number of significant regulatory processes were recently decided or are underway. The Alberta Utilities Commission ("AUC") released its Generic Cost of Capital ("GCOC") decision in December, setting the 2011 allowed ROE at 8.75%, down from 9.0% for 2010. The AUC decided that it would not introduce a formula to automatically adjust allowed ROEs on an annual basis. In this regard, the AUC approved the 8.75% ROE for 2012, along with setting the 2013 interim ROE at 8.75%. Also at FortisAlberta, a regulatory decision is pending related to the Negotiated Settlement Agreement for 2012 customer rates the Company filed in November, following from its 2012/2013 rate application. In addition, FortisAlberta filed its performance-based regulation ("PBR") proposal last July, following from the initiative of the AUC to reform utility rate regulation in Alberta and the regulator's expressed intention to apply a PBR formula to electricity distribution rates. The AUC's decision on PBR is expected in 2012. At FortisBC regulatory decisions are pending at the gas and electric utilities related to their 2012/2013 rate applications. The allowed ROEs for the utilities are to be maintained for 2012 pending determinations made in the regulator-initiated GCOC proceeding, which will commence in March 2012. Newfoundland Power received regulatory approval last December to suspend operation of the automatic adjustment formula used to set the Company's allowed ROE for 2012. Consequently, Newfoundland Power's allowed ROE will remain at 8.38% and current customer electricity rates will continue in effect, both on an interim basis, for 2012. A full cost of capital review is expected to occur in 2012.

Caribbean Regulated Electric Utilities contributed $20 million to earnings compared to $23 million for 2010. Electricity sales at Caribbean Utilities and Fortis Turks and Caicos continue to be impacted by a decline in customer energy consumption resulting from challenging economic conditions in the region and high fuel prices. There was no earnings contribution from Belize Electricity in 2011 due to the expropriation of the Corporation's investment in the utility in June by the Government of Belize ("GOB"). Earnings contribution from Belize Electricity during 2010 was approximately $1.5 million. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation for the value of its investment in Belize Electricity from the GOB.

Fortis utilities serve more than 2,000,000 gas and electricity customers.

Non-Regulated Fortis Generation contributed $18 million to earnings compared to $20 million for 2010. The decline in earnings largely resulted from decreased hydroelectric production in Belize due to lower rainfall. The Corporation retains its indirect ownership and control of the non-regulated hydroelectric generating subsidiary, Belize Electric Company Limited ("BECOL"), and the GOB has indicated it has no intention to expropriate BECOL.

Fortis Properties delivered earnings of $23 million compared to $26 million for 2010. However, results for 2010 were favourably impacted by lower income tax rates, which reduced future income taxes. Results for 2011 reflected lower contribution from the Hospitality Division, primarily due to lower occupancy at the Company's hotels in western Canada. Fortis Properties augmented its portfolio of hotel properties in October 2011 with the acquisition of the 160-room, full-service Hilton Suites Winnipeg Airport hotel for $25 million.

Corporate and other expenses were $61 million for 2011, $17 million lower than $78 million for 2010. Excluding the $11 million after-tax termination fee related to CVPS, corporate and other expenses were $6 million lower year over year, as a result of both decreased business development costs and finance charges.

The 160-room Hilton Suites Winnipeg Airport hotel was acquired for $25 million in 2011.

Fortis and its four largest utilities continue to have strong investment-grade credit ratings. Fortis debt is currently rated A– by Standard & Poor's and A(low) by DBRS. The credit ratings reflect the Corporation's low business-risk profile, reasonable credit metrics and demonstrated ability to acquire and integrate regulated utility businesses.

Fortis and its regulated utilities raised $688 million of long-term capital in 2011. The Corporation received proceeds of $341 million from its public common share issue in mid-2011. These funds were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion Limited Partnership, in support of infrastructure investment, and for general corporate purposes. Consolidated long-term debt totalling $347 million was issued during the year at terms ranging from 15 to 50 years and at rates ranging from 4.25% to 5.118%. Generally, proceeds of the debt offerings were used to repay borrowings under credit facilities incurred to finance capital expenditures, to support further capital spending, and for general corporate purposes.

Two new customer service centres in British Columbia were opened in early 2012.

Strong investment-grade credit ratings, ample credit facilities and low debt maturities continue to provide Fortis with flexibility in the timing of access to the debt and equity capital markets. Fortis has consolidated credit facilities of $2.2 billion, of which $1.9 billion was unused at year-end 2011. Approximately $2.1 billion of the total credit facilities are committed facilities, having maturities ranging from 2012 to 2015. The credit facilities are syndicated mostly with Canadian banks, with no one bank holding more than 20% of these facilities. As at December 31, 2011, the Corporation's long-term debt maturities and repayments are expected to average $270 million annually over the next five years.

The Corporation's continued record of growth and success is directly attributable to the thousands of talented and dedicated people who comprise the Fortis team. We extend sincere appreciation to all our employees for their commitment to providing our customers with quality service. We also express gratitude to our colleagues on the Board of Directors of Fortis for their continuing oversight and support.

We are focused on completing our $1.3 billion capital expenditure program for 2012. Over the next five years through 2016, our capital expenditure program is projected to total $5.5 billion, which will support continuing growth in earnings and dividends.

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated transmission and distribution utility serving approximately 300,000 electric and 75,000 natural gas customers in New York State's Mid-Hudson River Valley, whose operations are similar to our regulated utility operations in Canada. The acquisition, which is subject to CH Energy Group's common shareholders' approval, and regulatory and other approvals, is anticipated to close in approximately 12 months and is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

We remain disciplined and patient in our pursuit of electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders.

As always, our number one priority is to provide our customers with safe, reliable and cost-efficient energy service and to continue to meet their energy needs.

On behalf of the Board of Directors,

David G. Norris
Chair of the Board
Fortis Inc.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

Dated March 13, 2012

FORWARD-LOOKING INFORMATION

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2011 Consolidated Financial Statements and Notes thereto included in the Fortis Inc. ("Fortis" or the "Corporation") 2011 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") and is presented in Canadian dollars unless otherwise specified.

Barry Perry, VP, Finance and CFO, Fortis Inc.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's focus on the United States and Canada in the acquisition of regulated utilities; the pursuit of growth in the Corporation's non-regulated businesses in support of its regulated utility growth strategy; the current environment of low natural gas prices and an abundance of shale gas reserves should help maintain the competitiveness of natural gas versus alternative energy sources in North America; investment to harvest shale oil and gas in Alberta, Canada, is expected to continue and should favourably impact energy sales and rate base investment in FortisAlberta's service territory; the expectation that the Government of British Columbia's new Natural Gas Strategy should favourably impact natural gas throughput at the FortisBC Energy companies; the expected capital investment in Canada's electricity sector over the 20-year period from 2010 through 2030; the Corporation's consolidated forecast gross capital expenditures for 2012 and in total over the next five years; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program should support continuing growth in earnings and dividends; there is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed; the expectation that the Corporation's regulated utilities could experience disruptions and increased costs if they are unable to maintain their asset base; forecast midyear rate base for each of the Corporation's four large Canadian regulated utilities; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expectation that the Corporation's subsidiaries will be able to source the cash required to fund their 2012 capital expenditure programs; the expected consolidated long-term debt maturities and repayments in 2012 and on average annually over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to medium terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; except for debt at the Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2012; the expectation that any increase in interest expense and/or fees associated with renewed and extended credit facilities will not materially impact the Corporation's consolidated financial results for 2012; the expected timing of filing of regulatory applications and of receipt of regulatory decisions; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; no expected material adverse credit rating actions in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2012; the expectation that electricity sales growth at the Corporation's regulated utilities in the Caribbean will be minimal for 2012; the expectation that counterparties to the FortisBC Energy companies' gas derivative contracts will continue to meet their obligations; the expectation that FortisBC will continue efforts in 2012 to further integrate its gas and electricity businesses; the expectation that the Corporation's consolidated earnings and earnings per common share for 2012 will not be materially impacted by the transition to accounting principles generally accepted in the United States ("US GAAP"); the expectation of an increase in consolidated defined benefit net pension cost for 2012 and the fact that there is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future; and the expected timing of the closing of the acquisition of CH Energy Group, Inc. by Fortis and the expectation that the acquisition will be immediately accretive to earnings per common share, excluding one-time transaction expenses. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of *natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of International Financial Reporting Standards ("IFRS") after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology ("IT") infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; interest rate risk, including the uncertainty of the impact a continuation of a low interest rate environment may have on allowed rates of return on common shareholders' equity of the Corporation's regulated utilities; operating and maintenance risks; risk associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; an ultimate resolution of the expropriation of the hydroelectric assets and water rights of the Exploits Partnership that differs from that which is currently expected by management; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risk associated with defined benefit pension plan performance and funding requirements; risks related to FortisBC Energy (Vancouver Island) Inc.; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of IT infrastructure; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in this MD&A for the year ended December 31, 2011.*

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

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CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State, and hotels and commercial office and retail space in Canada. In 2011 the Corporation's electricity distribution systems met a combined peak demand of 5,045 megawatts ("MW") and its gas distribution system met a peak day demand of 1,210 terajoules ("TJ").

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation. Under COS regulation, the respective regulatory authority sets customer gas and/or electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). Generally, the ability of a regulated utility to recover prudently incurred costs of providing service and to earn the regulator-approved allowed rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; and (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and hotels and commercial office and retail space, which are treated as two separate segments. The Corporation's non-regulated generation assets have a combined generating capacity of 139 MW, which is mainly hydroelectric, and are managed as a segment to ensure standard operating practices, to leverage expertise across the various jurisdictions and to allow the pursuit of additional non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide financial, tax and regulatory flexibility and enhance shareholder return. Income from non-regulated investments is used to help offset corporate holding company expenses, a large part of which is interest expense associated with the financing of premiums paid on the acquisition of regulated utilities.

The business segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities: The Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility are as follows:

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Includes FortisBC Energy Inc. ("FEI") (formerly Terasen Gas Inc.), FortisBC Energy (Vancouver Island) Inc. ("FEVI") (formerly Terasen Gas (Vancouver Island) Inc.) and FortisBC Energy (Whistler) Inc. ("FEWI") (formerly Terasen Gas (Whistler) Inc.).

FEI is the largest distributor of natural gas in British Columbia, serving approximately 852,000 customers in more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves more than 102,000 customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler ("Whistler"), British Columbia, which provides service to more than 2,600 customers.

In addition to providing transmission and distribution ("T&D") services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 499,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 162,000 customers directly and indirectly. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC Electric component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving more than 247,000 customers. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving more than 75,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to more than 64,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies serving approximately 38,000 customers.

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 27,000 customers. The Company has an installed diesel-powered generating capacity of 151 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2010 – 59%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Includes FortisTCI Limited (formerly P.P.C. Limited) and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is an integrated electric utility and the principal distributor of electricity in the Turks and Caicos Islands, serving more than 9,500 customers. The Company has a combined diesel-powered generating capacity of 65 MW.

c. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America. Fortis held an approximate 70% controlling ownership interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information refer to the "Key Trends and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of this MD&A.

Non-regulated – Fortis Generation: The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Operations consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the GOB.

b. *Ontario:* Includes six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership (the "Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. Fortis Properties holds directly a 51% interest in the Exploits Partnership and Abitibi holds the remaining 49% interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement ("PPA") expiring in 2033. In December 2008 the Government of Newfoundland and Labrador expropriated the hydroelectric assets and water rights of the Exploits Partnership. As a result of no longer controlling the cash flows and operations of the Exploits Partnership, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership, effective February 2009. For further information, refer to the "Key Trends and Risks – Expropriated Assets" section of this MD&A.

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro under a contract expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The Waneta Expansion is expected to come into service in spring 2015.

e. *Upper New York State:* Includes the operations of four hydroelectric generating facilities, with a combined capacity of approximately 23 MW, in Upper New York State, operating under licences from the U.S. Federal Energy Regulatory Commission. Hydroelectric operations in Upper New York State are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties: Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

Corporate and Other: The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and FortisBC Energy Holdings Inc. ("FHI") (formerly Terasen Inc.) and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which FHI holds a 30% interest. CWLP provides billing and customer care services to utilities, municipalities and certain energy companies. The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011. CWLP's financial results were recorded using the proportionate consolidation method of accounting. The financial results of FortisBC Alternative Energy Services Inc. ("FAES") (formerly Terasen Energy Services Inc.) are also reported in the Corporate and Other segment. FAES is a non-regulated wholly owned subsidiary of FHI that provides alternative energy solutions.

CORPORATE VISION AND STRATEGY

The principal business of the Corporation is the ownership and operation of regulated gas and electric utilities, with a vision to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all of its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders. The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems; deliver safe, reliable, cost-efficient energy to customers; and conduct business in an environmentally responsible manner.

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. Over the past 10 years, earnings per common share of Fortis have grown at a compound annual growth rate of 6.9%. Fortis delivered an average annualized total return to shareholders of approximately 15% over the past 10 years, exceeding the Standard and Poor's ("S&P")/Toronto Stock Exchange ("TSX") Capped Utilities and S&P/TSX Composite Indices, which delivered annualized performance of approximately 11% and 7%, respectively, over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Consolidated midyear regulated utility rate base of Fortis grew at a compound annual growth rate of 6.6% from 2007 to 2011. Fortis also pursues opportunities to acquire additional regulated utilities in the United States and Canada. The acquisition of the FortisBC Energy companies in May 2007, which almost doubled the size of the Corporation's assets at that time, has helped provide Fortis with a platform to acquire larger-sized regulated utilities. While there were no utility acquisitions by the Corporation in 2011 or 2010, Fortis did participate in two significant acquisition processes. In accordance with the terms of a Merger Agreement with Central Vermont Public Service Corporation ("CVPS") in the United States, Fortis received a $17 million fee (US$17.5 million) in July 2011, plus $1.9 million (US$2.0 million) for the reimbursement of expenses, from CVPS upon Fortis terminating the Merger Agreement. The favourable impact on the Corporation's consolidated earnings for 2011 was $11 million, or $0.06 per common share. In 2010 Fortis attempted to acquire a large regulated electric utility, also in the United States. Business development costs of approximately $4 million, net of tax, or $0.02 per common share, were incurred in 2010 in relation to this acquisition attempt.

The non-utility business operations of Fortis support the Corporation's utility growth and acquisition strategy. Once completed in spring 2015, the 335-MW Waneta Expansion is expected to increase earnings from the Non-Regulated – Fortis Generation segment 150% from earnings contributed by this segment in 2011. Fortis Properties is also expected to continue to grow in size and profitability, providing flexibility in financial and tax planning to the Corporation not generally possible with respect to utilities in Canada because of regulatory and public policy constraints. Fortis Properties acquired the 160-room, full-service Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million in October 2011.

KEY TRENDS AND RISKS

General Trends for the Energy Sector: Traditional goals of safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of key issues impacting the energy industry. Utilities must also address such issues as climate change, issues pertaining to security, the development of expanded natural gas resources as a source of energy supply, the increasing deployment of alternative energy resources, as well as a growing desire by customers to have greater control over their energy use to lower costs and decrease their environmental footprint.

According to the Conference Board of Canada, Canada's electricity sector is expected to invest approximately $294 billion from 2010 to 2030 to maintain existing assets and meet market growth. The average annual investment of approximately $15 billion is higher than in any previous decade. Generation investments in Canada over the 20-year period are expected to be approximately $196 billion. These investments are to replace or repower assets at the end of their useful lives and to add new capacity. The majority of the proposed projects in Canada are renewable or low-emission energy sources. Canada faces $36 billion in transmission investments from 2010 to 2030. Approximately $62 billion of distribution investment is also expected over this period to maintain system quality and reliability and to expand to meet energy demand.

Three major trends that are expected to influence future costs in the energy distribution sector in Canada are: (i) investments required as a result of increasing levels of distributed generation, based on renewable energy technologies; (ii) investments associated with the development of a smart grid; and (iii) changing electricity requirements.

Distributed generation relates to generation assets that are downstream of transmission and major transformer substations. The use of solar and wind power, the most common types of distributed generation, results in the need to forecast variable energy supplies and develop appropriate facilities that enhance the ability to predict how much and when power will flow in each direction.

Smart grid initiatives to date have focused primarily on the retail customer. Ontario has installed smart meters for all residential and small commercial customers and other provinces have moved forward as well, including Alberta, where FortisAlberta completed the installation of smart meters in its service territory in 2011. The growing focus on distributed generation and small renewable generation downstream of the transmission grid will likely change the way the grid is operated and will require investment. In several jurisdictions, time-of-use meters are being deployed and time-of-use rates are in the early stage of development. Some key implications of deploying smart grid technology include the need to manage a large volume of data from the meter while ensuring the meters are secure and that customers have access to real-time data in order to manage their energy usage.

There are also trends that could reshape future distribution investment requirements. As consumers become more aware of their energy needs and as their energy consumption decisions change, utilities will need to adjust their distribution investment accordingly. The use of electric vehicles, for example, will change the electricity consumption characteristics of the locations where they are charged, requiring investment by utilities to accommodate the impact this will have on supplying the required electricity.

Natural Gas: The total estimate of natural gas resources in North America has increased dramatically over the past decade. The primary driver of higher gas resources is new natural gas discoveries in both conventional and unconventional fields. The most significant natural gas supply story in North America continues to be the development of shale gas resources. The emergence of shale gas is the result of technological advancements in drilling and production techniques that have allowed producers to unlock increasingly higher volumes of gas at lower costs. The current environment of low natural gas prices and an abundance of shale gas reserves should help maintain the competitiveness of natural gas versus alternative energy sources in North America.

In February 2012 the Government of British Columbia released its new Natural Gas Strategy. The strategy enables the expansion of the production of liquefied natural gas ("LNG") in British Columbia. It recognizes the natural gas industry's role as a global climate solution and seeks to position British Columbia as a global leader in secure and sustainable natural gas investment, development and export. The strategy includes a focus on promoting natural gas in the transportation sector and includes a program to reduce emissions by using natural gas in heavy-duty vehicles. This strategy should favourably impact natural gas throughput at the FortisBC Energy companies.

Investment to harvest shale oil and shale gas in Alberta is expected to continue, which should favourably impact energy sales and rate base investment in FortisAlberta's service territory.

Ultimately the success of unconventional development in the North American natural gas supply is contingent on the interplay of technology, cost, environmental benefits and market prices for natural gas and other energy products and services.

Greenhouse Gas Emissions: Implemented and potential government legislation, driven by concerns over the impact of greenhouse gas ("GHG") emissions in contributing to climate change, has significant implications for the energy industry. Canada accounts for about 2% of the world's GHG emissions, as per Scotia Capital's April 2011 *Energy Infrastructure Outlook*. Canada has one of the cleanest electricity systems in the world, with three quarters of its energy supply having no GHG emissions. In 2009 the electricity sector in Canada was responsible for 14% of the country's GHG emissions, according to Environment Canada's *National Inventory Report 1990–2009*. The most significant impact for Fortis with respect to GHG emissions legislation pertains to FortisBC's gas business as it relates to the combustion of and/or release of natural gas.

The significance of GHG emissions is lower at the Corporation's Canadian Regulated Electric Utilities because their primary business is the distribution of electricity. With respect to FortisAlberta, its operations involve only the distribution of electricity. Additionally, all in-house generating capacity at FortisBC Electric and about 70% at Newfoundland Power, and most of the Corporation's non-regulated generating capacity, is hydroelectric, a clean energy source. There is no coal-fired generation within any of the Corporation's operations. The Canadian Regulated Electric Utilities are indirectly impacted, however, by GHG emissions through the purchase of power generated by suppliers using combustible fuel. Such power suppliers are responsible for compliance with carbon dioxide emissions standards and the cost of compliance with such standards is generally flowed through to end-use consumers.

While renewable energy sources, including wind, solar and biogas, account for a small portion of power generation in the world today, given the realities of climate change and the increasing pressure from policymakers and public opinion, they are projected to be the fastest growing source of energy going forward. However, renewables are starting from a very small base, are still maturing technologically and, in most cases, need government support to be price competitive with other fuels.

The 335-MW Waneta Expansion will be an example of a clean renewable energy source when it comes into service in spring 2015.

FEI is one of the first utility companies in Canada to include alternative energy solutions as part of its regulated energy service offerings. For example, FEI received approval from the British Columbia Utilities Commission ("BCUC") for a new renewable natural gas program, on a limited basis, for an initial two-year period ending in 2012. An equivalent of 10% of the subscribed customers' natural gas requirements will be sourced from local renewable energy projects feeding the gas supply network. As part of this program, FEI has received approval to activate two projects that upgrade raw biogas into biomethane, which is then added to FEI's distribution system. One of the projects is operational and has been injecting gas into FEI's distribution system since September 2010, while the other will be operational by the end of 2012. Use of biomethane will help reduce emissions from waste decomposition and will help address the Government of British Columbia's climate change goals, as described further in the "Business Risk Management – Environmental Risks" section of this MD&A.

The *Renewable Energy Act* (Prince Edward Island) required Maritime Electric to source 15% of its annual energy sales from renewable sources by 2010, which the Company met in both 2010 and 2011. With the PEI Energy Accord (the "Accord") signed between the Government of PEI and Maritime Electric, both parties will work collaboratively to increase electricity produced on PEI from renewable energy sources, principally wind, and sold to Maritime Electric. The Government of PEI intends to install 30 MW of wind turbines on PEI by January 1, 2013, with a view to selling the resultant energy to Maritime Electric. Electricity generated from a 10-MW wind farm, completed on PEI in January 2012, is being purchased by the Government of PEI and, in turn, being sold to Maritime Electric.

Allowed ROEs: The chart below highlights the trend in the allowed ROEs at each of the Corporation's four largest regulated utilities.

Regulator-Approved Allowed ROEs

(%)	2008	2009	2010	2011	2012
FEI	8.62	8.47/9.50	9.50	9.50	9.50 (1)
FortisAlberta	8.75	9.00	9.00	8.75	8.75
FortisBC Electric	9.02	8.87	9.90	9.90	9.90 (1)
Newfoundland Power	8.95	8.95	9.00	8.38	8.38 (2)

(1) Maintained, pending determinations made in the regulator-initiated Generic Cost of Capital ("GCOC") Proceeding, which will commence in March 2012.

(2) Interim, pending the outcome of a full cost of capital review expected in 2012

The use of automatic adjustment mechanisms to annually calculate allowed ROEs was introduced in Canada in the mid to late 1990s, with the goal of providing efficiency in the regulatory process by reducing the frequency of cost of capital reviews. Generally, the mechanisms used a formula that calculated an annual adjustment to allowed ROEs based upon changes in long-term Canada bond rates. As long-term Canada bond rates declined, the use of ROE automatic adjustment mechanisms came under increased scrutiny in many jurisdictions in Canada because they failed to produce allowed ROEs that were high enough to meet the fair return standard. The regulatory decisions received by the Corporation in 2009 regarding cost of capital reviews in British Columbia and Alberta resulted in the elimination of the ROE automatic adjustment mechanism for FortisBC's gas and electric utilities and the suspension of the mechanism at FortisAlberta. The suspension of the automatic adjustment mechanism has been continued in Alberta for 2011 and 2012, with an allowed ROE ordered by the Alberta Utilities Commission ("AUC") of 8.75% for these years. The BCUC issued preliminary notification in November 2011 to all regulated utilities in British Columbia that it plans to initiate a Generic Cost of Capital ("GCOC") Proceeding. The proceeding will commence in March 2012 and will review, among other things, cost of capital and whether the re-establishment of an ROE automatic adjustment mechanism is warranted. An ROE automatic adjustment mechanism was in effect at Newfoundland Power for 2011. In December 2011 the regulator approved Newfoundland Power's request to suspend the operation of the ROE automatic mechanism for 2012 and to review cost of capital in 2012.

Uncertainty exists regarding the duration of the current environment of low interest rates and what effect it may have on allowed ROEs of the Corporation's regulated utilities.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is regulated by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been satisfactory, with reasonably fair decisions reached in the past several years, with the exception of the June 2008 regulatory rate decision received by Belize Electricity. That decision ultimately led to the expropriation of the Corporation's investment in Belize Electricity by the GOB in June 2011. For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this MD&A.

Expropriated Assets: On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. The consequential loss of control over the operations of Belize Electricity resulted in the Corporation discontinuing the consolidation method of accounting for the utility, effective June 20, 2011. The Corporation has classified the book value of the previous investment in Belize Electricity as a long-term other asset on the consolidated balance sheet. As at December 31, 2011, the long-term other asset, including foreign exchange impacts, totalled $106 million.

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

Fortis continues to control and consolidate the financial statements of BECOL. For further information, refer to the "Business Risk Management – Investment in Belize" section of this MD&A.

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities issue debt usually at terms ranging between 10 and 50 years. As at December 31, 2011, approximately 80% of the Corporation's consolidated long-term debt and capital lease obligations, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $2.2 billion in credit facilities, of which approximately $1.9 billion was unused as at December 31, 2011. With strong credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2012.

Western Canadian Economies: A large proportion of the businesses of Fortis serve the economies of western Canada, which have been growing faster than those of other regions of Canada. As at December 31, 2011, regulated utility assets comprised 91% of total assets (December 31, 2010 – 92%) and regulated utility assets in western Canada comprised 77% of total regulated assets (December 31, 2010 – 76%). Organic earnings growth at the Corporation's regulated utilities in western Canada is driven by rate base growth at FortisAlberta and FortisBC Electric. Since they were acquired in May 2004, the combined rate base of FortisAlberta and FortisBC Electric has grown 155%.

Dividend Increases: Dividends per common share increased to $1.16 in 2011. Fortis increased its quarterly common share dividend to 30 cents, commencing with the first quarter dividend paid in 2012. The 3.4% increase in the quarterly common share dividend translates into an annualized dividend of $1.20 for 2012 and extends the Corporation's record of annual common share dividend increases to 39 consecutive years, the longest record of any public corporation in Canada. Fortis expects that its significant capital program should support continuing growth in earnings and dividends.

Caribbean Operating Environment: Regulated assets in the Caribbean region comprised 7% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 8%). Generally, the achieved ROA at electric utilities in the Caribbean region is higher than that achieved by electric utilities in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors, as well as weather conditions, including a significant exposure to hurricanes. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

While still higher than that achieved by regulated utilities in Canada, the allowed ROA at Caribbean Utilities was lowered beginning in 2008 due to the negotiation of new licences at the utility, and the achieved ROA at Fortis Turks and Caicos has been significantly lower than that allowed under its licence due to significant capital investment occurring at the utility in recent years without corresponding increases in base customer electricity rates.

Prior to the global recession that commenced late in 2008, economic growth had been strong in the Corporation's service territories in the Caribbean. The global recession, however, negatively affected local economic conditions which, in turn, unfavourably impacted electricity sales growth beginning in 2009 and that impact is expected to continue.

Integration of the FortisBC Energy Companies and FortisBC Electric: Effective March 1, 2011, the Terasen Gas companies were renamed to operate under a common brand identity with FortisBC. The FortisBC gas and electricity businesses are currently led by one Chief Executive Officer and senior management team with one Board of Directors providing oversight. This approach ensures an integrated focus and strategy in the delivery of energy to customers. FortisBC will continue efforts in 2012 to further integrate the gas and electricity businesses.

Transition to Accounting Principles Generally Accepted in the United States: Fortis will be adopting accounting principles generally accepted in the United States ("US GAAP"), as opposed to the otherwise required adoption of International Financial Reporting Standards ("IFRS"), effective January 1, 2012. US GAAP provides the most useful and relevant presentation of the Corporation's financial results. The decision to transition to US GAAP is consistent with many Canadian investor- and government-owned regulated electric and gas utilities. The necessary exemption from the Ontario Securities Commission ("OSC") and approvals from lenders were obtained by Fortis and its reporting issuer subsidiaries allowing for the use of US GAAP for financial reporting purposes beginning in 2012. Fortis does not expect its consolidated earnings and earnings per common share for 2012 to be materially impacted by the transition to US GAAP; however, material increases in consolidated assets, liabilities and equity are expected, mainly due to differences from Canadian GAAP in the accounting treatment of pensions and capital leases, and the classification of the Corporation's preference shares.

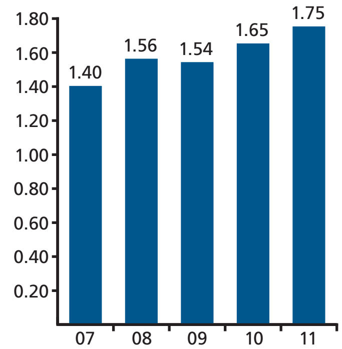
For further information with respect to the Corporation's transition to US GAAP, refer to the "Business Risk Management – Transition to New Accounting Standards" and "Future Accounting Changes" sections of this MD&A.

SUMMARY FINANCIAL HIGHLIGHTS

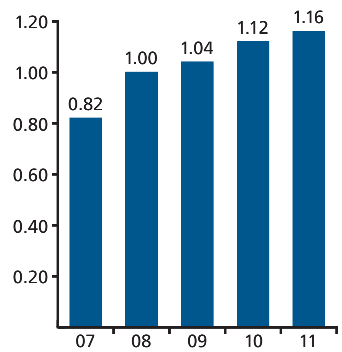
For the Years Ended December 31	2011	2010	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**318**	285	33
Basic Earnings per Common Share *($)*	**1.75**	1.65	0.10
Diluted Earnings per Common Share *($)*	**1.74**	1.62	0.12
Weighted Average Number of Common Shares Outstanding *(millions)*	**181.6**	172.9	8.7
Cash Flow from Operating Activities *($ millions)*	**904**	732	172
Dividends Paid per Common Share *($)*	**1.16**	1.12	0.04
Dividend Payout Ratio *(%)*	**66.3**	67.9	(1.6)
Return on Average Book Common Shareholders' Equity *(%)*	**8.9**	8.8	0.1
Total Assets *($ millions)*	**13,562**	12,909	653
Gross Capital Expenditures *($ millions)*	**1,174**	1,073	101
Public Common Share Offering *($ millions)*	**341**	–	341
Public Preference Share Offering *($ millions)*	**–**	250	(250)
Long-Term Debt Offerings *($ millions)*	**347**	525	(178)

Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $318 million in 2011, up $33 million from $285 million in 2010. The increase in earnings was due to the $11 million after-tax fee paid to Fortis following the termination of the Merger Agreement with CVPS combined with higher earnings from the Corporation's Canadian regulated utilities associated with: (i) rate base growth, driven by the regulated utilities in western Canada; (ii) lower-than-expected corporate income taxes, finance charges and amortization costs, and increased gas transportation volumes to the forestry and mining sectors at the FortisBC Energy companies, partially offset by lower-than-expected customer additions at these companies; (iii) higher capitalized allowance for funds used during construction ("AFUDC") at FortisAlberta, as well as customer growth and increased energy deliveries, return earned on additional investment in automated meters, as approved by the regulator, and an approximate $1 million gain on the sale of property, partially offset by the impact of a lower allowed ROE for 2011 at the utility; (iv) lower purchased power costs and higher electricity sales at FortisBC Electric, partially offset by lower capitalized AFUDC at the utility; (v) an increase in the allowed ROE at Algoma Power; and (vi) lower corporate business development costs and finance charges. The above increases were partially offset by: (i) lower earnings from Caribbean Regulated Electric Utilities, due to the expropriation of Belize Electricity in June 2011, combined with lower earnings at Fortis Turks and Caicos due to higher operating expenses and amortization costs, partially offset by reduced energy supply costs in 2011; (ii) decreased earnings at Fortis Properties reflecting higher corporate income taxes and lower occupancies at hotels in western Canada; (iii) decreased earnings from non-regulated hydroelectric generation operations, largely due to lower production in Belize because of reduced rainfall, and overall lower interest income; (iv) lower earnings at Newfoundland Power, mainly due to a lower allowed ROE for 2011, lower earnings contribution associated with new joint-use pole support structure arrangements with Bell Aliant Inc. ("Bell Aliant") in 2011 and higher operating expenses, partially offset by reduced energy supply costs in 2011 and higher electricity sales; and (v) approximately $1 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated earnings due to the weakening of the US dollar relative to the Canadian dollar year over year.

Basic Earnings per Common Share *($)*



Dividends Paid per Common Share *($)*

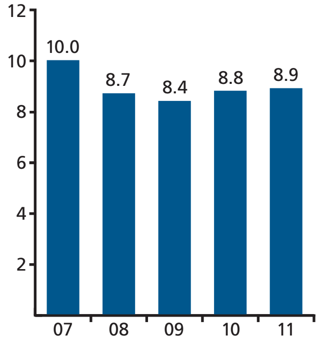


Basic Earnings per Common Share: Basic earnings per common share were $1.75 in 2011 compared to $1.65 in 2010. The increase was due to improved performance, partially offset by the impact of an increase in the weighted average number of common shares outstanding associated with the public common equity offering and shares issued under the Corporation's dividend reinvestment and stock option plans during 2011.

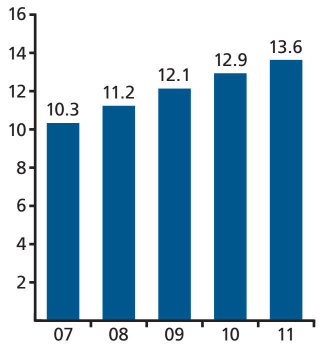
Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was $904 million for 2011, up $172 million from $732 million for 2010. The increase was driven by favourable changes in working capital, mainly related to accounts payable, accounts receivable and inventories driven by the FortisBC Energy companies and FortisAlberta, and higher earnings.

Dividends: Dividends paid per common share increased to $1.16 in 2011, up 3.6% from $1.12 in 2010. Fortis increased its quarterly common share dividend 3.4% to 30 cents from 29 cents, commencing with the first quarter dividend paid on March 1, 2012. The Corporation's dividend payout ratio was 66.3% in 2011 compared to 67.9% in 2010.

Return on Average Book Common Shareholders' Equity *(%)*



Total Assets *($ billions)*
(as at December 31)



Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity was 8.9% in 2011 compared to 8.8% in 2010. The increase largely related to higher net earnings attributable to common equity shareholders, partially offset by an increase in common equity.

Total Assets: Total assets increased 5% to approximately $13.6 billion at the end of 2011 compared to approximately $12.9 billion at the end of 2010. The increase reflected the Corporation's continued investment in regulated energy systems, driven by the capital expenditure programs at the FortisBC Energy companies, FortisAlberta and FortisBC Electric, the continued construction of the non-regulated Waneta Expansion in British Columbia and the favourable impact of foreign exchange associated with translation of foreign currency-denominated assets. The increase was partially offset by the impact of the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility effective June 20, 2011.

Gross Capital Expenditures: During 2011 consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were $1,174 million, up $101 million from $1,073 million in 2010. Total capital investment at the regulated utilities in western Canada was approximately $771 million, representing approximately 66% of total gross capital expenditures. Much of the capital investment was driven by customer growth, and the need to enhance the reliability and efficiency of energy systems and improve customer service. The larger capital projects during 2011 included the completion of the LNG storage facility at FEVI, the Okanagan Transmission Reinforcement Project at FortisBC Electric and the Automated Metering Project at FortisAlberta. Implementation of the Customer Care Enhancement Project at FEI continued in 2011 and came into service in January 2012. Construction of the non-regulated Waneta Expansion, which commenced late in 2010, and FortisAlberta's Pole Management Program also continued during 2011. For a further discussion of the Corporation's 2011 and 2012 consolidated capital expenditure plan, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital: During 2011 Fortis and its regulated utilities raised $688 million of long-term capital. Mid-2011 Fortis issued approximately 10.3 million common shares for $341 million, the net proceeds of which were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion, in support of infrastructure investment, and for general corporate purposes. Total long-term debt raised in 2011 was $347 million and was comprised of: (i) 30-year $125 million 4.54% unsecured debentures at FortisAlberta; (ii) US$40 million unsecured notes at Caribbean Utilities for terms of 15 and 20 years and at rates of 4.85% and 5.10%; (iii) 30-year $100 million 4.25% unsecured debentures at FEI; (iv) 50-year $30 million 4.915% first mortgage bonds at Maritime Electric; and (v) 30-year $52 million 5.118% unsecured notes at FortisOntario. Generally, proceeds of the debt offerings were used to repay borrowings under credit facilities incurred to finance capital expenditures, to support further capital spending, and for general corporate purposes. In the case of FortisOntario, the debt proceeds were used to repay an intercompany loan with Fortis originally incurred in support of the acquisition of Algoma Power in 2009.

CONSOLIDATED RESULTS OF OPERATIONS

The Corporation's consolidated results of operations for 2011 and 2010 are outlined below, including a discussion of the nature of the variances year over year.

Years Ended December 31 *($ millions)*	**2011**	2010	Variance
Revenue	**3,747**	3,657	90
Energy Supply Costs	**1,697**	1,686	11
Operating Expenses	**865**	822	43
Amortization	**419**	410	9
Other Income (Expenses), Net	**40**	13	27
Finance Charges	**370**	362	8
Corporate Taxes	**80**	67	13
Net Earnings	**356**	323	33
Net Earnings Attributable to:			
Non-Controlling Interests	**9**	10	(1)
Preference Equity Shareholders	**29**	28	1
Common Equity Shareholders	**318**	285	33
Net Earnings	**356**	323	33

Factors Contributing to Revenue Variance

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the Corporation's Canadian regulated utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure, forecasted higher regulator-approved expenses recoverable from customers, and a higher allowed ROE at Algoma Power
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities
- Growth in the number of customers, mainly at FortisAlberta
- Higher gas sales
- Higher electricity sales at Canadian Regulated Electric Utilities
- The recognition of $3.5 million of accrued revenue at FortisAlberta in 2011, related primarily to the cumulative 2010 and 2011 allowed return and recovery of amortization on the additional $22 million in capital expenditures associated with the Automated Metering Project, as approved by the regulator to be included in rate base

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower commodity cost of natural gas charged to customers
- Approximately $15 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year
- A rate revenue reduction accrued at FortisAlberta during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE for 2011
- Lower joint-use pole-related revenue at Newfoundland Power, due to new support structure arrangements with Bell Aliant in 2011
- Increased performance-based rate-setting ("PBR")-incentive adjustments to be refunded to customers by FortisBC Electric

Factors Contributing to Energy Supply Costs Variance

Unfavourable

- Increased fuel prices at Caribbean Utilities
- Higher gas sales
- Higher electricity sales at Canadian Regulated Electric Utilities

Favourable

- Lower commodity cost of natural gas
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower purchased power costs at FortisBC Electric
- Approximately $8 million associated with favourable foreign currency translation

Factors Contributing to Operating Expenses Variance

Unfavourable

- Higher operating expenses at the FortisBC Energy companies, mainly due to increased wages and benefit costs and higher asset removal costs, partially offset by lower contractor and consulting expenses and labour savings associated with changes in staffing levels
- The regulator-approved reversal in the third quarter of 2010 at the FortisBC Energy companies of $5 million ($4 million after tax) of project overrun costs previously expensed in 2009, related to the conversion of Whistler customer appliances from propane to natural gas
- Higher operating expenses at Newfoundland Power, mainly due to the regulator-approved change in the accounting treatment for other post-employment benefit ("OPEB") costs, wage and general inflationary cost increases, higher conservation costs related to customer rebate programs and increased employee-related expenses
- Higher operating expenses at FortisBC Electric, largely due to increased vegetation management costs, wage and general inflationary cost increases and higher property taxes

Favourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Operating costs of approximately $2 million incurred during the third quarter of 2010 at Newfoundland Power as a result of Hurricane Igor
- Higher capitalized general overhead expenses, mainly at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power
- Approximately $2 million associated with favourable foreign currency translation

Factors Contributing to Amortization Costs Variance

Unfavourable

- Continued investment in energy infrastructure and income producing properties

Favourable

- Reduced amortization costs in 2011 at the FortisBC Energy companies, mainly due to the retirement late in 2010 of certain general plant assets and the amortization in 2011 of a regulatory deferral account
- Regulator-approved increased amortization costs at Newfoundland Power in 2010, due to approximately $4 million of adjustments related to an amortization study
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Approximately $1.5 million associated with favourable foreign currency translation

Factors Contributing to Other Income (Expenses) Variance

Favourable

- The $17 million (US$17.5 million) fee paid to Fortis in July 2011 following the termination of the Merger Agreement with CVPS
- Lower corporate business development costs, due to $6 million incurred in the first half of 2010
- A net foreign exchange gain of $1 million associated with the previously hedged investment in Belize Electricity

Factors Contributing to Finance Charges Variance

Unfavourable

- Higher long-term debt levels in support of the utilities' capital expenditure programs

Favourable

- The refinancing of maturing corporate debt at lower rates
- Higher capitalized AFUDC, mainly at FortisAlberta, partially offset by lower capitalized AFUDC at FortisBC Electric
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011

Factors Contributing to Corporate Taxes Variance

Unfavourable

- Higher earnings before tax in taxable jurisdictions
- Lower deductions for income tax purposes compared to accounting purposes

Favourable

- Lower statutory income tax rates

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

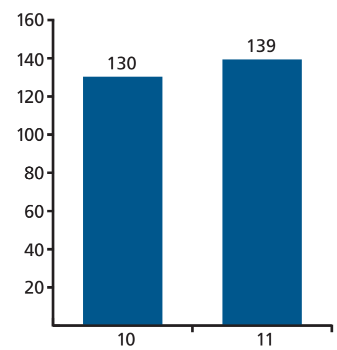
Years Ended December 31 *($ millions)*	**2011**	2010	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**139**	130	9
Regulated Electric Utilities – Canadian			
FortisAlberta	***75***	*68*	*7*
FortisBC Electric	***48***	*42*	*6*
Newfoundland Power	***34***	*35*	*(1)*
Other Canadian Electric Utilities	***22***	*19*	*3*
	179	164	15
Regulated Electric Utilities – Caribbean	**20**	23	(3)
Non-Regulated – Fortis Generation	**18**	20	(2)
Non-Regulated – Fortis Properties	**23**	26	(3)
Corporate and Other	**(61)**	(78)	17
Net Earnings Attributable to Common Equity Shareholders	**318**	285	33

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A. A discussion of the Corporation's consolidated capital expenditure program and breakdown of actual 2011 and forecast 2012 gross capital expenditures by segment is provided in the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2011 regulated earnings in Canada and the Caribbean represented approximately 89% (2010 – 87%) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 91% of the Corporation's total assets as at December 31, 2011 (December 31, 2010 – 92%).

Regulated Gas Utilities – Canadian Earnings *($ millions)*



Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2011 were $139 million (2010 – $130 million), which represented approximately 41% of the Corporation's total regulated earnings (2010 – 41%). Regulated Gas Utilities – Canadian assets were approximately $5.3 billion as at December 31, 2011 (December 31, 2010 – $5.2 billion), which represented approximately 43% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 44%).

FortisBC Energy Companies

Gas Volumes by Major Customer Category

Years Ended December 31 *(TJ)*	**2011**	2010	Variance
Core – Residential and Commercial	**128,161**	113,635	14,526
Industrial	**5,544**	5,259	285
Total Sales Volumes	**133,705**	118,894	14,811
Transportation Volumes	**67,813**	60,363	7,450
Throughput Under Fixed Revenue Contracts	**1,237**	13,765	(12,528)
Total Gas Volumes	**202,755**	193,022	9,733

Factors Contributing to Gas Volumes Variance

Favourable

- Higher average consumption by residential and commercial customers as a result of cooler weather
- Higher transportation volumes reflecting improving economic conditions favourably affecting the forestry and mining sectors

Unfavourable

- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility for significant periods during 2011

Net customer additions were 7,450 for 2011 compared to 9,393 for 2010. Net customer additions decreased year over year due to lower building activity.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and the commodity cost of natural gas from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

Seasonality has a material impact on the earnings of the FortisBC Energy companies as a major portion of the gas distributed is used for space heating. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

FortisBC Energy Companies

Financial Highlights

Years Ended December 31 *($ millions)*	**2011**	2010	Variance
Revenue	**1,568**	1,546	22
Earnings	**139**	130	9

Factors Contributing to Revenue Variance

Favourable

- An increase in the delivery component of customer rates, mainly due to ongoing investment in energy infrastructure and forecasted higher regulator-approved operating expenses recoverable from customers
- Higher average gas consumption by residential and commercial customers
- Higher gas transportation volumes to the forestry and mining sectors

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower-than-expected customer additions

Factors Contributing to Earnings Variance

Favourable

- Rate base growth due to continued investment in energy infrastructure
- Lower-than-expected corporate income taxes, finance charges and amortization costs in 2011
- Higher gas transportation volumes to the forestry and mining sectors

Unfavourable

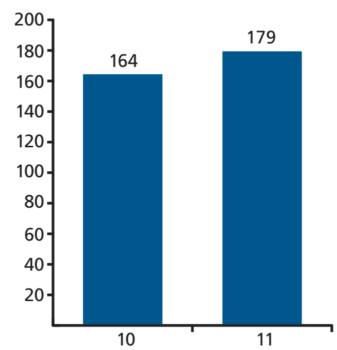
- The regulator-approved reversal in the third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009, related to the conversion of Whistler customer appliances from propane to natural gas
- Lower-than-expected customer additions in 2011

Outlook: The allowed ROEs for the FortisBC Energy companies for 2012 remain unchanged from 2011 at 9.50% for FEI and 10.00% for FEVI and FEWI. Customer delivery rates at the FortisBC Energy companies for 2012 have been approved on an interim basis, effective January 1, 2012, pending final decisions by the regulator on the utilities' 2012–2013 Revenue Requirements Applications. A regulator-initiated GCOC Proceeding in 2012 may result in a change in the utilities' capital structures and/or allowed ROEs.

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2011 were $179 million (2010 – $164 million), which represented approximately 53% of the Corporation's total regulated earnings (2010 – 52%). Regulated Electric Utilities – Canadian assets were approximately $6.1 billion as at December 31, 2011 (December 31, 2010 – $5.8 billion), which represented approximately 50% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 48%).

Regulated Electric Utilities – Canadian Earnings *($ millions)*



FortisAlberta

Financial Highlights

Years Ended December 31	2011	2010	Variance
Energy Deliveries *(GWh)*	**16,367**	15,866	501
Revenue *($ millions)*	**409**	385	24
Earnings *($ millions)*	**75**	68	7

Factors Contributing to Energy Deliveries Variance

Favourable

- Growth in the number of customers, with the total number of customers increasing by approximately 8,000 year over year, driven by favourable economic conditions
- Higher average consumption by farm and irrigation customers, due to differences in rainfall year over year
- Higher average consumption by residential customers, mainly due to cooler-than-normal temperatures during the first quarter of 2011

Unfavourable

- Lower average consumption by the gas sector, due to decreased activity as a result of low gas market prices

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Revenue Variance

Favourable

- The 4.7% increase in base customer electricity distribution rates, effective January 1, 2011. The increase in base rates was primarily due to ongoing investment in energy infrastructure.
- Growth in the number of customers
- The recognition in 2011 of accrued revenue of $3.5 million related primarily to the cumulative allowed return and recovery of amortization on the additional $22 million in capital expenditures approved by the regulator to be included in rate base associated with the Automated Metering Project. Approximately $1.5 million of the accrual related to 2010.

Unfavourable

- An approximate $2 million rate revenue reduction accrued during the fourth quarter of 2011, reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE to 8.75% for 2011 from 9.00% for 2010
- Differences in the amortization to revenue of regulatory deferrals year over year, as approved by the regulator

Factors Contributing to Earnings Variance

Favourable

- Rate base growth due to continued investment in energy infrastructure
- Higher capitalized AFUDC, due to a higher asset base under construction during 2011
- Growth in the number of customers and energy deliveries
- The allowed return and recovery of amortization of approximately $1.5 million recognized in 2011, relating to 2010, on the additional capital expenditures associated with the Automated Metering Project, as discussed above
- An approximate $1 million gain on the sale of property

Unfavourable

- The decrease in the allowed ROE for 2011, as discussed above
- Lower return earned on the Alberta Electric System Operator ("AESO") charges deferral, due to a decrease in the deferral balance

Outlook: FortisAlberta's allowed ROE of 8.75% for 2012 has been set by the regulator. Customer rates at FortisAlberta for 2012 have been approved on an interim basis, effective January 1, 2012, pending a final decision by the regulator on the utility's 2012 Distribution Tariff Application ("DTA").

FortisBC Electric

Financial Highlights

Years Ended December 31	2011	2010	Variance
Electricity Sales *(GWh)*	**3,143**	3,046	97
Revenue *($ millions)*	**296**	266	30
Earnings *($ millions)*	**48**	42	6

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of customers
- Lower average consumption during the first quarter of 2010, due to warmer-than-average temperatures experienced during that period, resulting in higher electricity sales year over year

Factors Contributing to Revenue Variance

Favourable

- A 6.6% increase in customer electricity rates, effective January 1, 2011, mainly reflecting ongoing investment in energy infrastructure
- A 1.4% and a 2.9% increase in customer electricity rates, effective June 1, 2011 and September 1, 2010, respectively, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro
- The 3.2% increase in electricity sales
- Higher revenue contribution from non-regulated operating, maintenance and management services
- Higher wheeling revenue

Unfavourable

- Higher PBR-incentive adjustments to be refunded to customers
- Lower surplus electricity sales

Factors Contributing to Earnings Variance

Favourable

- Rate base growth due to continued investment in energy infrastructure
- Lower-than-expected energy supply costs in 2011, primarily due to lower average market-priced purchased power costs
- Higher electricity sales
- Higher earnings contribution from non-regulated operating, maintenance and management services

Unfavourable

- Lower capitalized AFUDC due to a lower asset base under construction during 2011
- Higher effective corporate income taxes, mainly due to lower deductions for income tax purposes compared to accounting purposes

Outlook: FortisBC Electric's allowed ROE of 9.90% for 2012 remains unchanged from 2011. Customer rates for 2012 have been approved on an interim basis, effective January 1, 2012, pending a final decision by the regulator on the utility's 2012–2013 Revenue Requirements Application. A regulator-initiated GCOC Proceeding in 2012 may result in a change in the utility's capital structure and/or allowed ROE.

Newfoundland Power

Financial Highlights

Years Ended December 31	2011	2010	Variance
Electricity Sales *(GWh)*	**5,553**	5,419	134
Revenue *($ millions)*	**573**	555	18
Earnings *($ millions)*	**34**	35	(1)

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of customers
- Higher average consumption, reflecting the higher concentration of electric-versus-oil heating in new home construction combined with strong economic growth

Factors Contributing to Revenue Variance

Favourable

- The 2.5% increase in electricity sales
- An overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly reflecting higher OPEB costs, partially offset by a decrease in the allowed ROE to 8.38% for 2011 from 9.00% for 2010

Unfavourable

- Decreased amortization to revenue of regulatory liabilities and deferrals, as approved by the regulator
- Lower joint-use pole-related revenue due to new support structure arrangements with Bell Aliant, effective January 1, 2011

Factors Contributing to Earnings Variance

Unfavourable

- The decrease in the allowed ROE, as reflected in customer rates
- Lower earnings contribution associated with the new joint-use pole support structure arrangements with Bell Aliant in 2011
- Higher effective corporate income taxes, primarily due to lower deductions taken for income tax purposes compared to accounting purposes, partially offset by a lower statutory income tax rate
- Higher operating expenses related to wage and general inflationary cost increases, higher employee-related expenses and higher conservation costs related to rebate programs offered to customers, partially offset by lower storm-related costs

Favourable

- Electricity sales growth
- A reduction in energy supply costs in the fourth quarter of 2011 associated with the Company's hydroelectric generating facilities

Outlook: Newfoundland Power's customer rates and allowed ROE of 8.38% for 2011 will remain in effect for 2012, on an interim basis, pending the outcome of a full cost of capital review expected to occur in 2012.

Other Canadian Electric Utilities

Financial Highlights

Years Ended December 31	2011	2010	Variance
Electricity Sales *(GWh)*	**2,366**	2,328	38
Revenue *($ millions)*	**339**	331	8
Earnings *($ millions)*	**22**	19	3

Factors Contributing to Electricity Sales Variance

Favourable

- Growth in the number of residential customers
- Higher average consumption by residential customers in Ontario and on PEI, reflecting colder temperatures, which increased home-heating load

Unfavourable

- Lower average consumption by industrial customers on PEI, due to a reduction in farm-crop storage and warehousing activities

Factors Contributing to Revenue Variance

Favourable

- An average 3.8% increase in customer electricity rates at Algoma Power, effective December 1, 2010, reflecting an increase in the allowed ROE to 9.85% for 2011 from 8.57% for 2010, and the use of a forward test year for rate setting
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- The 1.6% increase in electricity sales

Unfavourable

- A rate of return adjustment at Maritime Electric reducing revenue by approximately $2 million in the fourth quarter of 2011, driven by higher-than-expected electricity sales during 2011
- Lower basic component of customer rates at Maritime Electric associated with the recovery of energy supply costs

Factors Contributing to Earnings Variance

Favourable

- A higher allowed ROE at Algoma Power and the use of a forward test year for rate setting, as reflected in customer rates for 2011
- Rate base growth due to continued investment in energy infrastructure
- Lower effective corporate income taxes, primarily due to higher deductions taken for income tax purposes compared to accounting purposes
- Electricity sales growth

Unfavourable

- The rate of return adjustment at Maritime Electric during the fourth quarter of 2011, as discussed above

Outlook: Maritime Electric's allowed ROE for 2012 of 9.75% remains unchanged from 2011. Largely reflecting lower power purchase costs, customer rates were reduced, effective March 1, 2011, at which time a two-year rate freeze commenced.

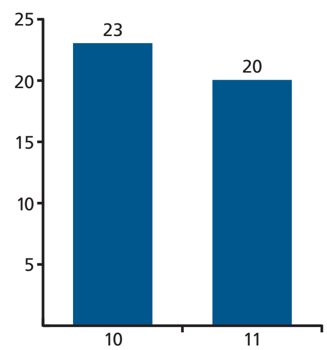
Both Algoma Power's allowed ROE for 2012 of 9.85% and Canadian Niagara Power's allowed ROE for 2012 of 8.01% remain unchanged from 2011.

Electricity distribution rate applications have been filed by Algoma Power and Canadian Niagara Power under the Third-Generation Incentive Rate Mechanism ("IRM") for customer rates effective May 1, 2012.

Regulated Electric Utilities – Caribbean

Earnings contribution from Regulated Electric Utilities – Caribbean for 2011 was $20 million (2010 – $23 million), which represented approximately 6% of the Corporation's total regulated earnings (2010 – 7%). Regulated Electric Utilities – Caribbean assets were approximately $0.9 billion as at December 31, 2011 (December 31, 2010 – $0.9 billion), which represented approximately 7% of the Corporation's total regulated assets as at December 31, 2011 (December 31, 2010 – 8%).

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Financial Highlights

Years Ended December 31	2011	2010	Variance
Average US:CDN Exchange Rate [1]	**0.99**	1.03	(0.04)
Electricity Sales *(GWh)*	**918**	1,150	(232)
Revenue *($ millions)*	**305**	333	(28)
Earnings *($ millions)*	**20**	23	(3)

(1) The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Factors Contributing to Electricity Sales Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. For further information, refer to the "Business Risk Management – Investment in Belize" section of this MD&A.
- Reduced energy consumption, due to challenging economic conditions in the region, the high cost of fuel and the early and extended closure of certain hotel and other commercial customers in the Turks and Caicos Islands resulting from a hurricane in August 2011
- The number of work permit holders in the region has declined significantly, causing some rental properties with active electricity connections to be vacant.
- Excluding Belize Electricity, there was no growth in electricity sales year over year.

Favourable

- Growth in the number of customers in Grand Cayman and the Turks and Caicos Islands

Factors Contributing to Revenue Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Approximately $13 million of unfavourable foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the US dollar relative to the Canadian dollar year over year

Favourable

- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the price of fuel

Factors Contributing to Earnings Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. There was no earnings contribution from Belize Electricity during 2011, while the Company contributed $1.5 million in earnings in 2010.
- Higher amortization, excluding the impact of foreign exchange, largely at Fortis Turks and Caicos, due to investment in utility capital assets, including the commencement of amortization in 2011 of a new operations centre and generating unit
- Higher operating expenses, excluding the impact of foreign exchange, at Fortis Turks and Caicos, largely due to consulting fees associated with ongoing regulatory matters and inflationary cost increases

Favourable

- Lower energy supply costs at Fortis Turks and Caicos, mainly due to more fuel-efficient production realized with the commissioning of new generation units at the utility

Outlook: Electricity sales growth at the Corporation's regulated utilities in the Caribbean is expected to be minimal for 2012, reflecting the expected continuation of the negative impact of challenging economic conditions on electricity consumption by customers in the Caribbean region.

NON-REGULATED

Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	**2011**	2010	Variance
Energy Sales *(GWh)*	**389**	427	(38)
Revenue *($ millions)*	**34**	36	(2)
Earnings *($ millions)*	**18**	20	(2)

Factors Contributing to Energy Sales Variance

Unfavourable

- Decreased production in Belize due to lower rainfall associated with a longer dry season in 2011
- Decreased production in Upper New York State due to a generating plant being out of service since May 2011

Factors Contributing to Revenue Variance

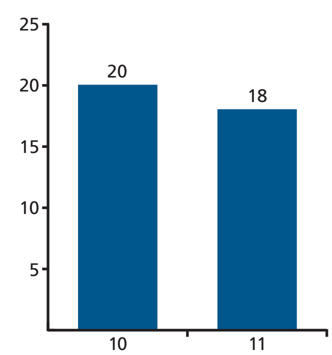
Unfavourable

- Decreased production in Belize

Favourable

- Higher annual average energy sales rate per megawatt hour ("MWh") in Ontario. The annual average rate per MWh was $72.96 in 2011 compared to $53.17 in 2010. Effective May 1, 2010, energy produced in Ontario is being sold under a fixed-price contract with price indexing. Previously, energy was sold at market rates.

Non-Regulated – Fortis Generation Earnings *($ millions)*



Factors Contributing to Earnings Variance

Unfavourable

- Decreased production in Belize
- Lower interest income at Ontario operations, associated with lower intercompany lending to regulated operations in Ontario

Favourable

- Higher annual average energy sales rate per MWh in Ontario
- Lower finance charges and higher interest income associated with operations in Belize

In May 2011 the generator at Moose River's hydroelectric generating facility in Upper New York State sustained electrical damage. Equipment and business interruption insurance claims are ongoing. Revenue for 2011 reflects the accrual of the 2011 earnings impact of the shutdown of the facility that is recoverable from the insurance claim. The generator is under repair and the facility is expected to be operational in late March 2012.

Outlook: Construction of the non-regulated Waneta Expansion in British Columbia will continue in 2012 and is expected to be completed in spring 2015.

Non-Regulated – Fortis Properties

Financial Highlights

Years Ended December 31 *($ millions)*	**2011**	2010	Variance
Hospitality Revenue	**164**	160	4
Real Estate Revenue	**67**	66	1
Total Revenue	**231**	226	5
Earnings	**23**	26	(3)

Factors Contributing to Revenue Variance

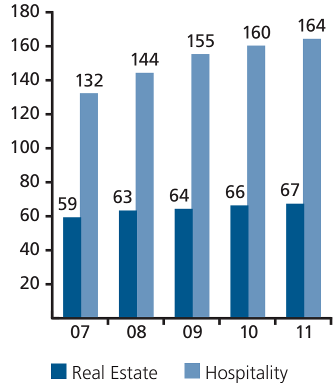
Favourable

- Revenue contribution from the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011
- A 2.1% increase in revenue per available room ("RevPar") at the Hospitality Division, excluding the impact of the Hilton Suites Winnipeg Airport hotel, to $78.48 for 2011 from $76.83 for 2010. RevPar increased due to an overall 2.7% increase in the average daily room rate, partially offset by an overall 0.6% decrease in hotel occupancy. The average daily room rate increased in all regions. Occupancy increases were achieved in Atlantic Canada and central Canada but were more than offset by occupancy decreases experienced in western Canada. Including the Hilton Suites Winnipeg Airport hotel, RevPar was $78.76 for 2011.
- Rental rate increases at the Real Estate Division

Unfavourable

- A decrease in the occupancy rate at the Real Estate Division to 93.2% as at December 31, 2011 from 94.5% as at December 31, 2010

Fortis Properties
Revenue *($ millions)*



Factors Contributing to Earnings Variance

Unfavourable

- Higher corporate income taxes. Lower statutory income tax rates and their effect of reducing future income tax liability balances in the fourth quarter of 2010 favourably impacted corporate income taxes in 2010.
- Lower contribution from the Hospitality Division, reflecting lower performance at operations in western Canada due to decreased occupancy rates, and at operations in central Canada, partially offset by improved performance at operations in Newfoundland in Atlantic Canada, reflecting strong local economic conditions
- Higher corporate administrative expenses

Favourable

- Higher contribution from the Real Estate Division, mainly due to the $0.5 million gain on the sale of the Viking Mall in 2011

Outlook: Hotel revenue increased at Fortis Properties in 2011. Revenue is expected to grow in 2012, due in part to the addition of the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011.

The Real Estate Division is expected to produce stable results in 2012. The Real Estate Division operates primarily in Atlantic Canada, where the majority of properties are located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates that reduce the risk of vacancy exposure.

Corporate and Other

Financial Highlights

Years Ended December 31

($ millions)	2011	2010	Variance
Revenue	**29**	29	–
Operating Expenses	**10**	10	–
Amortization	**7**	7	–
Other Income (Expenses), Net	**21**	(5)	26
Finance Charges [(1)]	**71**	73	(2)
Corporate Tax Recovery	**(6)**	(16)	10
	(32)	(50)	18
Preference Share Dividends	**29**	28	1
Net Corporate and Other Expenses	**(61)**	(78)	17

[(1)] Includes dividends on preference shares classified as long-term liabilities

Factors Contributing to Net Corporate and Other Expenses Variance

Favourable

- Higher other income, net of expenses, due to: (i) a $17 million (US$17.5 million) ($11 million after-tax) fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS; and (ii) a $4.5 million foreign exchange gain associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's former investment in Belize Electricity. The foreign exchange gain was partially offset by a $3.5 million ($3 million after-tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated debt. The favourable net impact to 2011 earnings of the above foreign exchange impacts was approximately $1.5 million. Business development costs of approximately $6 million ($4 million after tax) incurred in the first half of 2010 also had a favourable impact on other income, net of expenses, year over year.
- Lower finance charges due to the refinancing of maturing corporate debt at lower rates, the repayment of credit facility borrowings during the third quarter of 2011 with a portion of the proceeds from the common share offering in June and July 2011, and the favourable foreign exchange impact associated with the translation of US dollar-denominated interest expense.

Unfavourable

- Finance charges were reduced in the fourth quarter of 2010, related to the finalization of capitalized interest on a construction project.
- Higher preference share dividends, due to the issuance of First Preference Shares, Series H in January 2010

On July 11, 2011, the Board of Directors of CVPS determined that the acquisition proposal from Gaz Métro Limited Partnership was a "Superior Proposal", as that term was defined in the Merger Agreement between Fortis and CVPS announced on May 30, 2011, and CVPS elected to terminate the Merger Agreement in accordance with its terms. Prior to such termination taking effect, the Merger Agreement provided Fortis the right to require CVPS to negotiate with Fortis for at least five business days with respect to any changes to the terms of the Merger Agreement proposed by Fortis. Fortis agreed to waive such right in exchange for the prompt payment by CVPS to Fortis of the US$17.5 million termination fee plus US$2.0 million for the reimbursement of expenses as set forth in the Merger Agreement, thereby resulting in the termination of the Merger Agreement. Fortis received the $18.8 million (US$19.5 million) payment on July 12, 2011.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity *(%)*	Allowed Returns *(%)* 2010	2011	2012	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	BCUC	40	9.50	9.50	9.50 (1)	FEI: Prior to January 1, 2010, 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40	10.00	10.00	10.00 (1)	ROEs established by the BCUC
FEWI	BCUC	40	10.00	10.00	10.00 (1)	Future Test Year
FortisBC Electric	BCUC	40	9.90	9.90	9.90 (1)	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC Future Test Year
FortisAlberta	AUC	41	9.00	8.75	8.75	COS/ROE ROE established by the AUC Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.00 +/– 50 bps	8.38 +/– 50 bps	8.38 (2) +/– 50 bps	COS/ROE The allowed ROE is set using an automatic adjustment formula tied to long-term Canada bond yields. The formula has been suspended for 2012. Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE Future Test Year
FortisOntario	Ontario Energy Board ("OEB")					
	Canadian Niagara Power	40	8.01	8.01	8.01 (3)	Canadian Niagara Power – COS/ROE
	Algoma Power	40	8.57	9.85	9.85 (3)	Algoma Power – COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Franchise Agreement Cornwall Electric					Cornwall Electric – Price cap with commodity cost flow through Canadian Niagara Power – 2009 test year for 2010, 2011 and 2012 Algoma Power – 2007 historical test year for 2010; 2011 test year for 2011 and 2012
				ROA		COS/ROA
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 – 9.75	7.75 – 9.75	7.75 – 9.75 (4)	Rate-cap adjustment mechanism ("RCAM") based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings to the Interim Government of the Turks and Caicos Islands ("Interim Government")	N/A	17.50 (5)	17.50 (5)	17.50 (5)	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

(1) The allowed ROEs for the FortisBC Energy companies and FortisBC Electric are to be maintained, pending determinations made in the BCUC-initiated GCOC Proceeding, which will commence in March 2012.

(2) Interim, pending an expected review of Newfoundland Power's cost of capital in 2012 by the PUB

(3) Based on the ROE automatic adjustment formula, the allowed ROE for regulated electric utilities in Ontario is 9.42% for 2012. This ROE is not applicable to the regulated electric utilities until they are scheduled to file full COS rate applications. As a result, the allowed ROE of 9.42% is not applicable to Canadian Niagara Power or Algoma Power in 2012.

(4) Subject to change based on the annual operation of the RCAM to be finalized in June 2012

(5) Amount provided under licence. ROA achieved in 2010 and 2011 was significantly lower than the ROA allowed under the licence due to significant investment occurring at the utility and the lack of rate relief related thereto. In February 2012 the Interim Government approved, among other items, a 26% increase in electricity rates for large hotels, effective April 1, 2012.

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• FEI and FEWI review with the BCUC natural gas and propane commodity prices every three months and midstream costs annually, in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane and contracting for midstream resources, such as third-party pipeline and/or storage capacity. The commodity cost of natural gas and propane and midstream costs are flowed through to customers without markup. The bundled rate charged to FEVI customers includes a component to recover approved gas costs and is set annually. In order to ensure that the balance in the Commodity Cost Reconciliation Account is recovered on a timely basis, FEI and FEWI prepare and file quarterly calculations with the BCUC to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas. These rate adjustments ignore the temporal effect of derivative valuation adjustments on the balance sheet and, instead, reflect the forward forecast of gas costs over the recovery period. • Effective January 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 6%, as approved by the BCUC, to reflect net changes in delivery, commodity and midstream costs. Effective January 1, 2011, FEWI's interim residential customer rates decreased by approximately 5% and FEVI's rates were unchanged. • Natural gas commodity rates were unchanged, effective April 1, 2011 and July 1, 2011, following the BCUC's quarterly reviews of commodity costs. • Effective October 1, 2011, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas decreased by approximately 5% to reflect changes in commodity costs, following the BCUC's quarterly review of such costs. FEWI and FEVI's rates were unchanged. • Effective January 1, 2012, rates for residential customers in the Lower Mainland, Fraser Valley and Interior, North and Kootenay service areas increased by approximately 3% and rates for FEWI's residential customers increased by approximately 6%, reflecting changes in delivery and midstream costs with the rates being set on an interim basis, pending a final decision on the gas utilities' 2012–2013 Revenue Requirements Applications. Interim approval has also been received from the BCUC to hold FEVI customer rates at 2011 levels, effective January 1, 2012. Natural gas commodity rates were unchanged, effective January 1, 2012. • In December 2010 FEI filed an application with the BCUC to provide fuelling services through FEI-owned and operated compressed natural gas and LNG fuelling stations. In July 2011 FEI received a decision from the BCUC that approved the fuelling station infrastructure along with a long-term contract with one counterparty for the supply of compressed natural gas. The BCUC denied the Company's application for a general tariff for the provision of compressed natural gas and LNG for vehicles, unless certain contractual conditions are met. FEI refiled an amended application to reflect the BCUC decision and these conditions have now been approved by the BCUC. • In May 2011, in response to a complaint, the BCUC initiated a public process to develop guidelines under which FEI should be able to provide alternative energy services as regulated utility services. The alternative energy services offered by FEI include providing refuelling services for natural gas vehicles ("NGVs"), owning and operating district energy systems and various forms of geo-exchange systems, and owning facilities that upgrade raw biogas into biomethane for the purpose of selling it to customers. • In July 2011 the BCUC approved the application jointly filed by the FortisBC Energy companies and FortisBC Electric requesting the utilities be permitted to adopt US GAAP effective January 1, 2012 for regulatory reporting purposes. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest up to a combined 15% in the equity component of the capital structure of the new LNG storage facility on Vancouver Island. In late 2011 each band exercised its option and each invested approximately $6 million in equity in the LNG facility on January 1, 2012. • In August 2011 FEI and FEVI received a decision from the BCUC on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for NGVs. The utilities had made these funds available to assist large customers in purchasing NGVs in lieu of diesel-fuelled vehicles. The decision determined that it was not appropriate to use EEC funds for this purpose and the BCUC has requested that the companies provide further submissions to determine the prudence of the EEC incentives at a future time. • In January 2011 FEI and FEVI filed a report of a review of their Price Risk Management Plan ("PRMP") objectives with the BCUC related to their gas commodity hedging plan and FEI also submitted a revised 2011–2014 PRMP. In July 2011 the BCUC issued its decision on the report and determined that commodity hedging in the current environment was not a cost-effective means of meeting the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011–2014 PRMP with the exception of certain elements to address regional price discrepancies. As a result, FEVI and FEI have suspended commodity-hedging activities with the exception of limited swaps as permitted by the BCUC. The existing hedging contracts are expected to continue in effect through to their maturity and the gas utilities' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• In September 2011 the FortisBC Energy companies filed an update to their 2012–2013 Revenue Requirements Applications. FEI has requested an increase in rates of 3.0%, effective January 1, 2012, and 3.1%, effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEI's application assumes forecast midyear rate base of approximately $2,760 million for 2012 and $2,820 million for 2013. FEVI has requested that rates remain unchanged for the two-year period commencing January 1, 2012. FEVI's application assumes forecast midyear rate base of $788 million for 2012 and $816 million for 2013. FEWI has requested an increase in rates of approximately 6.5%, effective January 1, 2012, and approximately 4.3%, effective January 1, 2013, reflecting an increase in the delivery component of customer rates. FEWI's application assumes forecast midyear rate base of $42 million for 2012 and $41 million for 2013. The requested rates reflect allowed ROEs and capital structure unchanged from 2011. The requested rate increases are driven by ongoing investment in energy infrastructure focused on system integrity and reliability, and forecast increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas system, and increasing compliance with codes and regulations. A decision on the rate applications is expected in the first half of 2012. • In October 2011 FEI filed an application for approval of expenditures of approximately $5 million on facilities required to provide thermal energy services to 19 buildings in the Delta School District located in the Greater Vancouver area. When completed, FEI will own, operate and maintain the new thermal plants and charge the Delta School District a single rate for thermal energy consumed. In November 2011 FEI refiled the application with amended third-party contracts related to the thermal energy services to allow more time for a public review process. A decision on the application is expected by the end of the first quarter of 2012. • In November 2011 FEI, FEVI and FEWI filed an application with the BCUC for the amalgamation of the three companies into one legal entity and for the implementation of common rates and services for the utilities' customers across British Columbia, effective January 1, 2013. The amalgamation requires approval by the BCUC and consent of the Government of British Columbia. In late 2011 the utilities temporarily suspended their application while they provide additional information to the BCUC, as requested. • In November 2011 the BCUC gave preliminary notification to public utilities subject to its regulation, including the FortisBC Energy companies and FortisBC Electric, of its intention to initiate a GCOC Proceeding early in 2012. In February 2012 the BCUC issued an order initiating the commencement of the GCOC Proceeding in March 2012. The GCOC Proceeding will take place to review: (i) the setting of the appropriate cost of capital for a benchmark low-risk utility in British Columbia; (ii) the possible return to an ROE automatic adjustment mechanism for setting an ROE for the benchmark low-risk utility; and (iii) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities in British Columbia without third-party debt. FortisBC will be involved in this regulatory process in 2012. The cost of capital review may result in a change in the utilities' capital structures and/or allowed ROEs.
FortisBC Electric	• In December 2010 the BCUC approved a Negotiated Settlement Agreement ("NSA") pertaining to FortisBC Electric's 2011 Revenue Requirements Application and Capital Expenditure Plan. The result was a general customer electricity rate increase of 6.6%, effective January 1, 2011. The rate increase was primarily the result of the Company's ongoing investment in energy infrastructure, including increased amortization and financing costs. • Effective June 1, 2011, the BCUC approved an increase of 1.4% in FortisBC Electric customer electricity rates arising from an increase in purchased power costs due to an increase in BC Hydro rates. • In June 2011 FortisBC Electric filed its 2012–2013 Revenue Requirements Application, which included its 2012–2013 Capital Expenditure Plan, and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. FortisBC Electric requested an interim 4% increase in customer electricity rates effective January 1, 2012 and a 6.9% increase effective January 1, 2013. The rate increases are due to ongoing investment in energy infrastructure, including increased costs of financing the investment, as well as increased purchased power costs. The requested rates reflect an allowed ROE and capital structure unchanged from 2011. In addition to a continuation of deferral accounts and flow-through treatments that existed under the PBR agreement, which expired at the end of 2011, the 2012–2013 Revenue Requirements Application proposes deferral accounts and flow-through treatment for variances from the forecast used to set customer rates for electricity revenue, purchased power costs and certain other costs. • In November 2011 FortisBC Electric filed an updated 2012–2013 Revenue Requirements Application to include updated financial estimates and forecasts, resulting in a revised requested increase in rates of 1.5%, effective January 1, 2012, and 6.5%, effective January 1, 2013. The revised application assumes forecast midyear rate base of approximately $1,146 million for 2012 and $1,215 million for 2013. An oral hearing process is expected to occur in March 2012 with a decision expected during 2012. • An interim, refundable customer rate increase of 1.5%, effective January 1, 2012, was approved by the BCUC pending a final decision on the Company's 2012–2013 Revenue Requirements Application.
FortisAlberta	• In December 2010 the AUC issued its decision on FortisAlberta's August 2010 Compliance Filing, which incorporated the AUC's decision, received in July 2010, on the Company's 2010 and 2011 DTA. The December 2010 decision approved the Company's distribution revenue requirements of $368 million for 2011. Final distribution electricity rates and rate riders were also approved, effective January 1, 2011.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In June 2011 the AUC issued its decision regarding the prudence of additional capital expenditures above $104 million related to the Company's Automated Metering Project. In its decision, the AUC concluded that the full amount of the forecasted total project cost of $126 million could be included in rate base and collected in customer rates. The impact of the decision was the recognition of $3.5 million in accrued revenue in 2011 and an associated regulatory asset as at December 31, 2011. • In October 2010 the Central Alberta Rural Electrification Association ("CAREA") filed an application with the AUC requesting that, effective January 1, 2012, CAREA be entitled to service any new customers wishing to obtain electricity for use on property overlapping CAREA's service area and that FortisAlberta be restricted to providing service in the CAREA service area only to those customers in that service area who are not being provided service by CAREA. FortisAlberta has intervened in the proceeding to oppose CAREA's request. A decision on this matter is expected in 2012. • In 2010 the AUC initiated a process to reform utility rate regulation for distribution utilities in Alberta. The AUC intends to introduce PBR-based distribution service rates beginning in 2013 for a five-year term, with 2012 to be used as the base year. In July 2011 FortisAlberta, along with other distribution utilities operating under the AUC's jurisdiction, submitted PBR proposals to the AUC. The Company's submission outlines its views as to how PBR should be implemented at FortisAlberta. A hearing on the matter is expected to commence in April 2012 with a decision expected in 2012. • In March 2011 FortisAlberta filed its 2012 and 2013 DTA. The AUC allowed FortisAlberta, at the Company's request, to settle the DTA through negotiation, but stipulated that the negotiation apply only to 2012 rates in light of the AUC's target of commencing PBR-based rate setting in 2013. In November 2011 FortisAlberta filed an NSA pertaining to 2012 customer distribution rates. The NSA proposes an average rate increase of approximately 5% effective January 1, 2012. FortisAlberta's midyear rate base is currently forecast at $2.0 billion for 2012 and $2.3 billion for 2013. The requested rate increase is driven primarily by ongoing investment in energy infrastructure, including increased amortization and financing costs. In December 2011 the AUC approved an interim average rate increase of approximately 5%, effective January 1, 2012, reflecting the parameters of the NSA. The Company has also requested that volume variances be included in FortisAlberta's AESO charges deferral account for 2012, consistent with the deferral structure that was in place in 2011. A decision on the NSA is expected in the first half of 2012. • In December 2011 the AUC issued its decision on its 2011 GCOC Proceeding, establishing the allowed ROE at 8.75% for 2011 and 2012 and, on an interim basis, at 8.75% for 2013. The equity component of FortisAlberta's capital structure remains at 41% and will continue at that level until changed by any future order of the AUC. The AUC concluded that it would not return to a formula-based ROE automatic adjustment mechanism at this time and that it would initiate a proceeding in due course to establish a final allowed ROE for 2013 and revisit the matter of a return to a formula-based approach in future periods. FortisAlberta and other distribution utilities in Alberta filed motions for leave to appeal with the Alberta Court of Appeal with respect to the cost of capital decision, challenging certain pronouncements made by the AUC as being incorrectly made regarding cost responsibility for stranded assets. In February 2012 FortisAlberta and other utilities filed requests for the AUC to review and vary its pronouncements.
Newfoundland Power	• In December 2010 the PUB approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset balance of approximately $53 million, associated with adoption of accrual accounting, over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with applicable generally accepted accounting principles and OPEB expense approved by the PUB for rate-setting purposes. • In December 2010 Newfoundland Power received approval from the PUB for an overall average 0.8% increase in customer electricity rates, effective January 1, 2011, mainly resulting from the PUB's approval for the Company to change its accounting for OPEB costs, as described above, partially offset by the impact of the decrease in the allowed ROE for 2011. • On January 1, 2011, new support structure arrangements with Bell Aliant went into effect, including Bell Aliant repurchasing 40% of all joint-use poles and related infrastructure from Newfoundland Power, representing approximately 5% of Newfoundland Power's rate base. In 2001 Newfoundland Power purchased Bell Aliant's (formerly Aliant Telecom Inc.) joint-use poles and related infrastructure under a 10-year Joint-Use Facilities Partnership Agreement ("JUFPA"), which expired on December 31, 2010. Bell Aliant had rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term of the JUFPA. Bell Aliant exercised the option to buy back these poles from Newfoundland Power in 2010. The new support structure arrangements were subject to certain conditions, including PUB approval of the sale of the joint-use poles. The PUB issued an order approving the sale of the joint-use poles in September 2011. Effective January 1, 2011, Newfoundland Power no longer received pole rental revenue from Bell Aliant. Newfoundland Power was responsible for the construction and maintenance of Bell Aliant's support structure requirements in 2011. The new support structure arrangements had no material impact on Newfoundland Power's ability to earn a reasonable return on its rate base in 2011. Proceeds of approximately $46 million from the sale of 40% of the joint-use poles were received by Newfoundland Power from Bell Aliant in October 2011. The sale proceeds were used to pay down credit facility borrowings and pay a special dividend of approximately $30 million to Fortis in order to maintain Newfoundland Power's capital structure at 45% common equity. In January 2012 the transaction with Bell Aliant closed and a purchase price adjustment of approximately $1 million was paid to Bell Aliant by Newfoundland Power. The purchase price adjustment was based on the results of a pole survey completed in the fourth quarter of 2011. • In October 2011 the PUB approved Newfoundland Power's application requesting the deferral of expected increased costs of $2.4 million in 2012, due to expiring regulatory amortizations.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	• In December 2011 the PUB approved Newfoundland Power's application requesting the adoption of US GAAP, effective January 1, 2012, for regulatory reporting purposes. • In December 2011 the PUB approved, as filed, Newfoundland Power's 2012 Capital Expenditure Plan totalling approximately $77 million. • In November 2011 Newfoundland Power's allowed ROE for 2012 was calculated at 7.85% under the ROE automatic adjustment formula, a decrease from 8.38% for 2011. In December 2011 the PUB approved an application filed by Newfoundland Power requesting the suspension of the operation of the ROE automatic adjustment formula for 2012 and to review cost of capital for 2012. As a result, current customer rates and the allowed ROE of 8.38% will continue in effect for 2012 on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012. • Newfoundland Power's midyear rate base for 2012 is forecast at $879 million. • The Company is currently assessing the requirement for it to file a general rate application with the PUB to recover increased costs in 2013.
Maritime Electric	• In November 2010 Maritime Electric signed the Accord with the Government of PEI. The Accord covers the period from March 1, 2011 through February 29, 2016. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. The Government of PEI is financing these costs, which will be recovered from customers. In the event that Point Lepreau does not return to service by fall 2012, the Government of PEI reserves the right to cease the monthly payments. As permitted by IRAC, incremental replacement energy costs totalling approximately $47 million incurred by Maritime Electric during the refurbishment of Point Lepreau up to the end of February 2011 were deferred. The deferred costs are included in rate base. For further information on Maritime Electric's contractual obligations with respect to Point Lepreau, refer to the "Contractual Obligations" section of this MD&A. • The nature and timing of the recovery of the deferred costs related to Point Lepreau is to be determined by the PEI Energy Commission (the "PEI Commission"), which was established by the Government of PEI in 2011. Having authority under the *Public Inquiries Act*, the co-chaired five-member PEI Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the Commission will, among other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. • The Accord also provides for the financing by the Government of PEI of costs associated with Maritime Electric's termination of the Dalhousie Unit Participation Agreement. The costs will be collected from customers over a period to be established by the Government of PEI. As a result of the Accord, including the favourable impact on purchased power costs of the new five-year PPA between Maritime Electric and NB Power, customer electricity rates decreased overall by approximately 14%, effective March 1, 2011, reflecting a decrease in the Energy Cost Adjustment Mechanism ("ECAM") and base component of rates. A two-year customer rate freeze commenced after the March 1, 2011 rate adjustment. The allowed ROE for 2011 and 2012 is 9.75%, as set under the terms of the Accord. • Maritime Electric intends to file an application with IRAC in fall 2012 for 2013 customer rates and allowed ROE.
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation IRM as prescribed by the OEB. In March 2011 the OEB published the applicable inflationary and efficiency targets, which resulted in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. • In November 2010 the OEB approved an NSA pertaining to Algoma Power's electricity distribution rate application for customer rates, effective December 1, 2010 through December 31, 2011, using a 2011 forward test year. The rates reflected an approved allowed ROE of 9.85% on a deemed equity component of capital structure of 40%. The overall impact of the OEB rate decision on an average customer's electricity bill, including rate riders and other charges, was an overall increase of 3.8%. • The present form of Third-Generation IRM will not accommodate Algoma Power's customer rate structure and the RRRP Program. Algoma Power consulted with the intervener community to develop a form of incentive rate-making that may be used between rebasing periods. Due to regulations in Ontario associated with the RRRP Program, customer electricity distribution rates at Algoma Power are tied to the average changes in rates of other electric utilities in Ontario. The balance of Algoma Power's revenue requirement is recovered from the RRRP Program. In September 2011 Algoma Power filed its first Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The Third-Generation IRM maintains the allowed ROE at 9.85%. Algoma Power has proposed that both electricity rates and funding under the RRRP Program be indexed through a price-cap formula. In December 2011 the OEB approved current customer rates as interim rates for 2012 for Algoma Power, pending a final decision on Algoma Power's rate application. In its March 2012 rate decision, the OEB approved a price cap index of 2.81% for customers subject to RRRP funding and 0.38% for those customers not subject to RRRP funding. RRRP funding for 2012 has been set at approximately $11 million. • In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constitutes the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase is subject to OEB approval.

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	• In November 2011 the OEB published the applicable inflationary factor of 1.7% for Third-Generation IRM rate applications having a January 1, 2012 effective date. • In November 2011 FortisOntario filed a Third-Generation IRM application for rates effective May 1, 2012 for its operations in Port Colborne and a similar, but harmonized, rate application for its operations in Fort Erie and Gananoque, effective May 1, 2012. The Third-Generation IRM maintains the allowed ROE at 8.01% for 2012. • FortisOntario expects to file a COS Application in 2012 for harmonized electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The timing of the filing of the COS Application corresponds with the ending of the period that the current Third-Generation IRM applies to FortisOntario. • In November 2011 the OEB published the allowed ROE of 9.42% for 2012, as calculated under the ROE automatic adjustment mechanism. This allowed ROE is not applicable to regulated electric utilities in Ontario until they are scheduled to file full COS rate applications. As a result, this allowed ROE will not be applicable to FortisOntario's utilities in 2012.
Caribbean Utilities	• In March 2011 Caribbean Utilities confirmed to the ERA that the RCAM, as provided in the Company's transmission and distribution licence, yielded no customer rate adjustment effective June 1, 2011. • In March 2011 the ERA approved a Fuel Price Volatility Management Program for the utility. The objective of the program is to reduce the impact of volatility in the fuel cost charge paid by customers of Caribbean Utilities for the fuel that it must purchase in order to provide electric service. The program utilizes call options, creating a ceiling price for fuel costs at predetermined contract premiums. The program currently covers 40% of expected fuel consumption. • In July 2011 the ERA approved Caribbean Utilities' request to use US GAAP for regulatory reporting purposes, effective January 1, 2012. • In March 2011 the ERA approved $134 million of proposed non-generation installation expenditures in Caribbean Utilities' 2011–2015 Capital Investment Plan ("CIP"). The remaining $85 million of the CIP related to new generation installation, which would be subject to a competitive solicitation process. • In November 2011 CUC issued a Certificate of Need to the ERA for 18 MW of new generating capacity to be installed in 2014 and for an additional 18 MW of generating capacity to be installed in either 2015 or 2016, contingent on load growth over the next two years. The primary driver for the new generating capacity in 2014 is the upcoming scheduled retirements of several of Caribbean Utilities' generating units, which are reaching the end of their useful lives. As a result of the Company expressing its need for replacement capacity, the ERA will be conducting a competitive solicitation process in 2012 in accordance with Caribbean Utilities' licences, which will allow all interested and qualified parties, including Caribbean Utilities, to submit bids to fill the Company's firm capacity requirement. • In December 2011 Caribbean Utilities filed its 2012–2016 CIP totalling approximately US$192 million, including generation capital expenditures. The 2012–2016 CIP has been prepared in line with the Certificate of Need that was filed with the ERA in November 2011, as discussed above. A decision on the CIP is expected during the first quarter of 2012. • In December 2011 Caribbean Utilities conducted and completed a competitive bidding process to fill 13 MW of non-firm renewable energy capacity. There are currently no viable renewable energy sources on Grand Cayman that meet Caribbean Utilities' reliability requirements for firm capacity; however, Caribbean Utilities expects that there are third parties that can build and maintain renewable energy plants on Grand Cayman and sell energy to Caribbean Utilities at a price competitive with diesel. Any resulting PPAs, however, are subject to ERA review and approval.
Fortis Turks and Caicos	• In August 2011 Fortis Turks and Caicos filed with the Interim Government an Electricity Rate Variance Application, which requested a change in the rate structure and an overall approximate 6% increase in base rates to government and commercial customers. After a series of negotiations, in February 2012, the Interim Government approved a 26% increase in electricity rates for large hotels, effective April 1, 2012. A two-step approach to standardize rates across the service territory was also approved. In addition, other qualitative enhancements to the franchise were also achieved, including: (i) improved wording in the Electricity Rate Regulation; (ii) an approved increase in kilowatt hour ("kWh") consumption thresholds on both medium and large hotels; and (iii) an expansion of service territory. • An independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed during the third quarter of 2011 on behalf of the Interim Government. The purpose of the review was to: (i) assess the effectiveness of the current regulatory framework in terms of its administrative and economic efficiency; (ii) assess the current and proposed electricity costs and tariffs in the Turks and Caicos Islands in relation to comparable regional and international utilities; (iii) make recommendations for a revised regulatory framework and *Electricity Ordinance*; and (iv) make recommendations for the implementation and operation of the revised regulatory framework. Fortis Turks and Caicos provided a comprehensive response to the Interim Government in January 2012 stating that the Company supports limited mutually agreed upon reforms, but that its current licences must be respected and can only be changed by mutual consent. Specifically, Fortis Turks and Caicos would support reforms that strengthen the role of the regulator in the rate-setting process and that are fair to all stakeholders. • Earlier in 2011 the Interim Government publicly stated its intention to implement a carbon tax, effective September 2011, that would be applicable to Fortis Turks and Caicos but which may not be permitted to be passed on to Fortis Turks and Caicos' customers. To date, no carbon tax has been implemented. Under the terms of an agreement with the Government of the Turks and Caicos Islands when Fortis Turks and Caicos was granted its licence, the Company is exempt from any taxes other than customs duties where applicable by law. • In March 2012 Fortis Turks and Caicos submitted its 2011 annual regulatory filing outlining the Company's performance in 2011. Included in the filing were the calculations, in accordance with the utility's licence, of rate base of US$166 million for 2011 and cumulative shortfall in achieving allowable profits of US$72 million as at December 31, 2011.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2011 and December 31, 2010.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2011 and December 31, 2010

Balance Sheet Account	Increase/ (Decrease) *($ millions)*	Explanation
Regulatory assets – current and long-term	100	The increase was mainly due to an increase in the deferral of: (i) future income taxes; (ii) AESO charges and deferred operating overhead costs at FortisAlberta; and (iii) various costs at the FortisBC Energy companies, as permitted by the regulator. The above increases were partially offset by a decrease in the 2010 accrued distribution revenue adjustment rider at FortisAlberta as it was collected in 2011 rates, and the deferral at the FortisBC Energy companies associated with the change in the fair market value of the natural gas derivatives.
Inventories	(34)	The decrease was driven by the impact of a decrease in gas in storage and lower natural gas commodity prices at the FortisBC Energy companies.
Assets held for sale	(45)	The decrease was due to the sale of Newfoundland Power's joint-use poles to Bell Aliant in October 2011.
Other assets	102	The increase was due to the discontinuance of the consolidation method of accounting for Belize Electricity in June 2011, due to the expropriation of the Company by the GOB, and the resulting classification of the book value of the Corporation's previous investment in Belize Electricity, including reclassified unrealized net foreign currency translation losses of $17 million, to long-term other assets.
Utility capital assets	502	The increase primarily related to $1,086 million invested in electricity and gas systems and the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets, partially offset by amortization and customer contributions during 2011, and the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011.
Income producing properties	34	The increase primarily related to $30 million in capital expenditures and the acquisition of the Hilton Suites Winnipeg Airport hotel in October 2011 for approximately $25 million, partially offset by amortization costs for 2011.
Intangible assets	17	The increase primarily related to $58 million in capital expenditures, partially offset by amortization costs for 2011.
Short-term borrowings	(199)	The decrease reflected the repayment of short-term borrowings at FEI, Maritime Electric and Caribbean Utilities using proceeds from the issuance of long-term debt and at FEVI using proceeds from an equity injection from Fortis.
Accounts payable and accrued charges	(39)	The decrease was mainly due to: (i) a $49 million deferred payment made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002; (ii) the change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; (iii) lower amounts owing for purchased natural gas at the FortisBC Energy companies due to lower volumes; and (iv) the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011. The above decreases were partially offset by higher payables associated with transmission-connected projects and cost accruals at FortisAlberta and higher accounts payable at the Waneta Partnership associated with the Waneta Expansion.
Regulatory liabilities – current and long-term	74	The increase was mainly due to: (i) increased deferrals at the FortisBC Energy companies; (ii) an increase in the ECAM account at Maritime Electric; and (iii) an increase in the provision for asset removal and site restoration costs at FortisAlberta. The increased deferrals at the FortisBC Energy companies were driven by the Rate Stabilization Deferral Account at FEVI, reflecting amounts collected in customer rates in excess of the cost of providing service during 2011, and the Revenue Stabilization Adjustment Mechanism at FEI, reflecting the margin impact of natural gas volumes consumed by residential and commercial customers in 2011 being in excess of forecast gas volumes. The above increases were partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011.
Future income tax liabilities – current and long-term	55	The increase was driven by tax timing differences related mainly to capital expenditures at the FortisBC Energy companies, FortisAlberta and FortisBC Electric.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2011 and December 31, 2010 (cont'd)

Balance Sheet Account	Increase/ (Decrease) ($ millions)	Explanation
Long-term debt and capital lease obligations (including current portion)	120	The increase was driven by long-term debt issued in 2011 and the impact of foreign exchange on the translation of foreign currency-denominated debt. The issuance of long-term debt was comprised of a $125 million debenture offering by FortisAlberta, a $100 million debenture offering by FEI, a $52 million note offering by FortisOntario, a $30 million bond offering by Maritime Electric and a US$40 million note offering by Caribbean Utilities. The above increases were partially offset by the repayment of the Corporation's committed credit facility borrowings with a portion of the proceeds from a $341 million common equity offering, the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011, the conversion of the Corporation's US$40 million unsecured convertible debentures into common equity and regularly scheduled debt repayments.
Shareholders' equity	572	The increase was driven by the public issuance of $341 million in common equity in June and July 2011. The remainder of the increase in shareholders' equity was primarily due to: (i) net earnings attributable to common equity shareholders during 2011, less common share dividends; (ii) the issuance of common shares under the Corporation's dividend reinvestment and stock option plans; (iii) the conversion of the Corporation's US$40 million unsecured convertible debentures into common equity; and (iv) the reclassification of $17 million of unrealized net foreign currency translation losses related to the Corporation's previous investment in Belize Electricity from accumulated other comprehensive loss to long-term other assets.
Non-controlling interests	46	The increase was driven by advances from the 49% non-controlling interests in the Waneta Partnership, partially offset by the impact of the discontinuance of the consolidation method of accounting for Belize Electricity in 2011.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2011 compared to 2010, followed by a discussion of the nature of the variances in cash flows year over year.

Summary of Consolidated Cash Flows

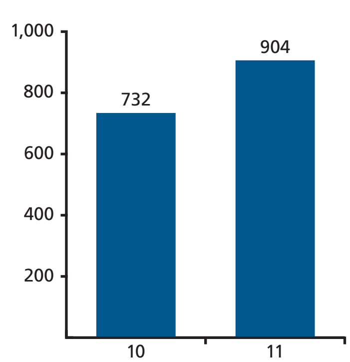
Years Ended December 31

($ millions)	**2011**	2010	Variance
Cash, Beginning of Year	**109**	85	24
Cash Provided by (Used in):			
Operating Activities	**904**	732	172
Investing Activities	**(1,125)**	(991)	(134)
Financing Activities	**201**	283	(82)
Cash, End of Year	**89**	109	(20)

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2011 was $172 million higher than in 2010. The increase was driven by favourable changes in working capital and higher earnings. The favourable working capital changes, associated primarily with accounts payable, accounts receivable and inventories, were driven by the FortisBC Energy companies and FortisAlberta.

Investing Activities: Cash used in investing activities in 2011 was $134 million higher than in 2010. The increase was due to higher gross capital expenditures and a $49 million deferred payment being made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002. The deferred payment was originally classified in long-term other liabilities. Cash used in investing activities also increased as a result of the acquisition of the Hilton Suites Winnipeg Airport hotel in 2011. The above increases were partially offset by higher proceeds from the sale of utility capital assets associated with the sale of joint-use poles at Newfoundland Power in October 2011.

Cash Flow from Operating Activities
($ millions)



Gross capital expenditures in 2011 were $1,174 million, $101 million higher than in 2010. The increase was primarily due to higher capital spending related to the non-regulated Waneta Expansion and higher capital spending at FortisAlberta, partially offset by lower capital spending at FortisBC Electric.

Financing Activities: Cash provided by financing activities in 2011 was $82 million lower than in 2010. The decrease was due to: (i) lower proceeds from the issuance of preference shares; (ii) lower proceeds from long-term debt; (iii) higher repayments of short-term borrowings; (iv) higher repayments of committed credit facility borrowings classified as long term; and (v) higher common share dividends, partially offset by: (i) higher proceeds from the issuance of common shares; (ii) lower repayments of long-term debt; and (iii) higher advances from non-controlling interests in the Waneta Partnership.

Net repayment of short-term borrowings was $198 million in 2011 compared to $56 million for 2010. The increase in the repayment of short-term borrowings was driven by the FortisBC Energy companies, Maritime Electric and Caribbean Utilities.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations, and net borrowings (repayments) under committed credit facilities for 2011 compared to 2010 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2011**	2010	Variance
FortisBC Energy Companies	**100** [(1)]	100 [(2)]	–
FortisAlberta	**123** [(3)]	124 [(4)]	(1)
FortisBC Electric	**–**	99 [(5)]	(99)
Maritime Electric	**30** [(6)]	–	30
FortisOntario	**52** [(7)]	–	52
Caribbean Utilities	**38** [(8)]	–	38
Corporate	**–**	200 [(9)]	(200)
Total	**343**	523	(180)

(1) Issued December 2011, 30-year $100 million 4.25% unsecured debentures by FEI. The net proceeds were used to repay short-term credit facility borrowings.

(2) Issued December 2010, 30-year $100 million 5.20% unsecured debentures by FEVI. The net proceeds were used to repay credit facility borrowings.

(3) Issued October 2011, 30-year $125 million 4.54% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(4) Issued October 2010, 40-year $125 million 4.80% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings and for general corporate purposes.

(5) Issued December 2010, 40-year $100 million 5.00% unsecured debentures. The net proceeds were used to repay committed credit facility borrowings, finance capital expenditures and for general corporate purposes.

(6) Issued December 2011, 50-year $30 million 4.915% secured first mortgage bonds. The net proceeds were used to repay short-term credit facility borrowings.

(7) Issued December 2011, 30-year $52 million 5.118% unsecured notes. The net proceeds were used to repay intercompany borrowings with Fortis originally incurred to support the acquisition of Algoma Power in 2009.

(8) Issued 15-year US$15 million 4.85% and 20-year US$25 million 5.10% unsecured notes. The first tranche of US$30 million was issued in June 2011 and the second tranche of US$10 million was issued in July 2011. The net proceeds were used to repay current installments on long-term debt and short-term credit facility borrowings and to finance capital expenditures.

(9) Issued December 2010, 10-year US$125 million 3.53% and 30-year US$75 million 5.26% unsecured notes. The net proceeds were used to repay indebtedness outstanding under the Corporation's committed credit facility related to amounts borrowed to repay the Corporation's $100 million 7.4% senior unsecured debentures that matured in October 2010, and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

($ millions)	**2011**	2010	Variance
Newfoundland Power	**(5)**	(5)	–
Maritime Electric	**–**	(15)	15
Caribbean Utilities	**(15)**	(15)	–
Fortis Properties	**(8)**	(59)	51
Corporate	**–**	(225) [(1)]	225
Other	**(8)**	(10)	2
Total	**(36)**	(329)	293

(1) In April 2010 FHI redeemed in full for cash its $125 million 8% Capital Securities with proceeds from borrowings under the Corporation's committed credit facility. In October 2010 Fortis repaid its maturing $100 million 7.4% unsecured debentures with proceeds from borrowings under the Corporation's committed credit facility.

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31

($ millions)	**2011**	2010	Variance
FortisAlberta	**6**	1	5
FortisBC Electric	**9**	(35)	44
Newfoundland Power	**5**	1	4
Corporate	**(165)**	41	(206)
Total	**(145)**	8	(153)

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

Advances of approximately $84 million for 2011 and $44 million for 2010 were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion.

In June 2011 Fortis publicly issued 9.1 million common shares for gross proceeds of approximately $300 million. In July 2011 an additional 1.2 million common shares were publicly issued upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million. The total net proceeds of $327 million from the common share offering were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the non-regulated Waneta Expansion, in support of infrastructure investment, and for general corporate purposes.

Fortis also received proceeds of $18 million in 2011 and $22 million in 2011, net of dividends reinvested into common shares, related to common shares issued under its stock option and share purchase plans.

In January 2010 Fortis completed a $250 million public offering of 10 million First Preference Shares, Series H. The net proceeds of approximately $242 million were used to repay borrowings under the Corporation's committed credit facility and to fund an equity injection into FEI.

Common share dividends paid in 2011 totalled $151 million, net of $59 million in dividends reinvested, compared to $135 million, net of $58 million in dividends reinvested, paid in 2010. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.16 in 2011 compared to $1.12 in 2010. The weighted average number of common shares outstanding was 181.6 million for 2011 compared to 172.9 million for 2010.

Contractual Obligations

The Corporation's consolidated contractual obligations with external third parties over the next five years and for periods thereafter, as at December 31, 2011, are outlined in the following table.

Contractual Obligations

As at December 31, 2011

($ millions)	**Total**	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt (1)	**5,788**	103	791	440	4,454
Waneta Partnership promissory note (2)	**72**	–	–	–	72
Brilliant Terminal Station ("BTS") (3)	**87**	3	6	6	72
Gas purchase contract obligations (4)	**300**	180	120	–	–
Power purchase obligations					
FortisBC Electric (5)	**2,430**	47	85	81	2,217
FortisOntario (6)	**413**	48	99	103	163
Maritime Electric (7)	**190**	50	78	48	14
Capital cost (8)	**461**	17	36	36	372
Joint-use asset and shared service agreements (9)	**64**	3	8	7	46
Office lease – FortisBC Electric (10)	**17**	2	4	2	9
Operating lease obligations (11)	**152**	26	33	32	61
Defined benefit pension funding contributions (12)	**58**	26	28	2	2
Other (13)	**22**	3	8	7	4
Total	**10,054**	508	1,296	764	7,486

(1) In prior years, FEVI received non-interest bearing repayable loans from the federal government and Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government loans, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure, as will FEVI's rate base, which is used in determining customer rates. As at December 31, 2011, the outstanding balance of the repayable government loans was $49 million. Timing of the repayments of the government loans is dependent upon the ability of FEVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms and, therefore, the repayments have not been included in the contractual obligations table above. FEVI, however, estimates making payments under the loans of $20 million in 2012, $4 million in 2013, $10 million in each of 2014 and 2015 and $5 million in 2016.

(2) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion.

(3) On July 15, 2003, FortisBC Electric began operating the BTS under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination). The BTS is jointly owned by CPC/CBT and is used by the Company on its own behalf and on behalf of CPC/CBT. The agreement provides that FortisBC Electric will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.

(4) Gas purchase contract obligations relate to various gas purchase contracts at the FortisBC Energy companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2011.

(5) Power purchase obligations for FortisBC Electric include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and capacity agreements with Powerex Corp. ("Powerex"). On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The Brilliant plant is owned by Brilliant Power Corporation ("BPC"), a corporation owned equally by CPC/CBT. FortisBC Electric operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The PPA with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements. During September 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity purchases through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. Additionally, in November 2011, FortisBC Electric entered into a second agreement to purchase fixed-price winter capacity purchases through to March 2012 from Powerex.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (the "WECA"). The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The total amount estimated to be paid by FortisBC Electric to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The executed version of the WECA was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of the BCUC's acceptance of filing of the executed WECA. The amount has not been included in the Contractual Obligations table above as it is to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

(6) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of energy and capacity and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(7) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In November 2010 the Company signed a new five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The new contract includes fixed pricing for the entire five-year period and covers, among other things, replacement energy and capacity for Point Lepreau. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

[8] Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

[9] FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of the agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this agreement, the calculation of future payments after 2016 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2010 and are subject to extension based on mutually agreeable terms.

[10] On September 29, 1993, FortisBC Electric began leasing an office building in Trail, British Columbia for a term of 30 years. The terms of the agreement grant FortisBC Electric repurchase options at approximately year 20 and year 28 of the lease term.

[11] Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases. They also include the operating lease obligations, up to April 2012, associated with the electricity distribution assets of Port Colborne Hydro and $7 million for the exercised election under the operating lease agreement to purchase the remaining assets of Port Colborne Hydro in April 2012.

[12] Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2011 – Newfoundland Power
December 31, 2012 – FortisBC Energy companies (covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (covering unionized employees)
December 31, 2013 – FortisBC Electric

[13] Other contractual obligations primarily include capital lease obligations, building operating leases, AROs and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

Other Contractual Obligations: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The gross consolidated capital program of the Corporation, including capital spending at the non-regulated operations, is forecast to be approximately $1.3 billion for 2012, which is not included in the Contractual Obligations table above.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2011, no such termination notice has been given by either party. As such, the contract is effectively renewed until May 2012. The quantity of fuel to be purchased under the contract for 2012 is approximately 10 million imperial gallons.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Capital Structure

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

The consolidated capital structure of Fortis as at December 31, 2011 compared to December 31, 2010 is presented in the following table.

Capital Structure	**2011**		2010	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease obligations (net of cash) *(1)*	**5,855**	**55.0**	5,914	58.4
Preference shares *(2)*	**912**	**8.6**	912	9.0
Common shareholders' equity	**3,877**	**36.4**	3,305	32.6
Total *(3)*	**10,644**	**100.0**	10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash

(2) Includes preference shares classified as both long-term liabilities and equity

(3) Excludes amounts related to non-controlling interests

The improvement in the capital structure was driven by the public offering of approximately $341 million of common shares in June and July 2011, combined with common shares issued under the Corporation's dividend reinvestment and stock option plans, the conversion of US$40 million of debentures into common equity and the reclassification of net unrealized foreign currency translation losses related to the Corporation's previous investment in Belize Electricity to long-term other assets. Also contributing to the improvement was net earnings attributable to common equity shareholders, net of dividends, combined with an overall decrease in total debt. A portion of the proceeds from the public common equity offering were used to repay credit facility borrowings in 2011.

Credit Ratings

As at December 31, 2011, the Corporation's credit ratings were as follows:

S&P	A– (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

The above credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. During the third quarter of 2011, DBRS confirmed the Corporation's existing debt credit rating at A(low). S&P is expected to complete its annual review of the Corporation's debt credit rating in the first quarter of 2012. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire all of the shares of CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing, DBRS placed the Corporation's credit rating under review with developing implications. Similarly, S&P placed the Corporation's credit rating on credit watch with negative implications. For further information, refer to the "Subsequent Event" section of this MD&A.

Capital Expenditure Program

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $98 million in maintenance and repairs was expensed in 2011 compared to approximately $96 million in 2010.

Gross consolidated capital expenditures for 2011 were approximately $1.2 billion. A breakdown of gross consolidated capital expenditures by segment and asset category for 2011 is provided in the following table.

Gross Consolidated Capital Expenditures (1)

Year Ended December 31, 2011

($ millions)	FortisBC Energy Companies	Fortis Alberta (2)	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility (3)**	**Fortis Properties**	**Total**
Generation	–	–	18	10	2	**30**	**32**	**172**	**–**	**234**
Transmission	73	–	26	6	3	**108**	**1**	**–**	**–**	**109**
Distribution	103	279	26	56	38	**502**	**26**	**–**	**–**	**528**
Facilities, equipment, vehicles and other	61	122	27	4	1	**215**	**11**	**2**	**30**	**258**
Information technology	16	15	5	5	3	**44**	**1**	**–**	**–**	**45**
Total	253	416	102	81	47	**899**	**71**	**174**	**30**	**1,174**

(1) Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows. Includes asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures were permissible in rate base in 2011.

(2) Includes payments made to AESO for investment in transmission-related capital projects

(3) Includes non-regulated generation, mainly related to the Waneta Expansion, and corporate capital expenditures

Gross consolidated capital expenditures of $1,174 million for 2011 were $38 million lower than $1,212 million forecast for 2011, as disclosed in the MD&A for the year ended December 31, 2010. Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts. Lower-than-forecasted capital spending was mainly due to: (i) a shift in the timing of certain capital expenditures from 2011 to 2012 and various small capital projects determined to be not required at the FortisBC Energy companies; (ii) the discontinuance of the consolidation method of accounting for Belize Electricity, effective June 2011; and (iii) a shift in capital expenditures from 2011 to 2012 related to the timing of payments associated with the Waneta Expansion.

Gross consolidated capital expenditures for 2012 are expected to be approximately $1.3 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2012 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures (1)

Year Ending December 31, 2012

($ millions)	FortisBC Energy Companies	Fortis Alberta (2)	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities – Canadian	**Total Regulated Utilities – Canadian**	**Regulated Electric Utilities – Caribbean**	**Non-Regulated – Utility (3)**	**Fortis Properties**	**Total**
Generation	–	–	10	12	3	**25**	**21**	**255**	**–**	**301**
Transmission	68	–	38	6	9	**121**	**1**	**–**	**–**	**122**
Distribution	110	252	34	55	43	**494**	**25**	**–**	**–**	**519**
Facilities, equipment, vehicles and other	46	149	23	5	3	**226**	**6**	**1**	**63**	**296**
Information technology	20	18	6	4	3	**51**	**2**	**–**	**–**	**53**
Total	244	419	111	82	61	**917**	**55**	**256**	**63**	**1,291**

(1) Relates to forecast cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows. Includes forecast asset removal and site restoration expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2012.

(2) Includes forecast payments to be made to AESO for investment in transmission-related capital projects

(3) Includes forecast non-regulated generation, mainly related to the Waneta Expansion, and corporate capital expenditures

The percentage breakdown of 2011 actual and 2012 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows:

Gross Consolidated Capital Expenditures

Year Ending December 31 *(%)*	**Actual 2011**	Forecast 2012
Growth	**44**	40
Sustaining [(1)]	**30**	33
Other [(2)]	**26**	27
Total	**100**	100

[(1)] Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

[(2)] Relates to facilities, equipment, vehicles, information technology systems and other assets, including AESO transmission-related capital expenditures at FortisAlberta and the Customer Care Enhancement Project at FEI.

Significant capital projects for 2011 and 2012 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) **Company**	**Nature of project**	Pre- 2011	**Actual 2011**	Forecast 2012	Forecast Post- 2012	Expected Year of Completion
FortisBC Energy Companies	LNG storage facility – Vancouver Island	176	**34**	2 [(2)]	–	2011
	Customer Care Enhancement Project	29	**51**	30	–	2012
	Fraser River South Bank South Arm Rehabilitation Project	21	**11**	4 [(2)]	–	2011
FortisAlberta	Automated Metering Project	112	**11**	3 [(2)]	–	2011
	Pole Management Program	60	**28**	27	220	2019
FortisBC Electric	Okanagan Transmission Reinforcement Project	86	**14**	5 [(2)]	–	2011
	Generation Asset Upgrade and Life-Extension Program	17	**15**	3	–	2012
	Environmental Compliance Project	–	**2**	11	15	2014
Fortis Turks and Caicos	Three new 9-MW diesel-powered generating units	15	**6**	–	8	2014
Waneta Partnership	Waneta Expansion [(3)]	75	**169**	254	359	2015
Fortis Properties	Office Building – St. John's	–	**8**	32	7	2013

[(1)] Relates to utility capital asset, income producing property and intangible asset expenditures combined with both the capitalized interest and equity components of AFUDC, where applicable

[(2)] Project costs to be incurred in 2012 subsequent to the 2011 in-service date.

[(3)] Excludes forecast capitalized interest of the Corporation's partners, CPC/CBT, in the Waneta Partnership

FEVI's construction of the estimated $212 million 1.5 billion-cubic foot LNG storage facility at Mount Hayes on Vancouver Island was completed in the second quarter of 2011 and was brought online in late 2011. The storage facility provides a reliable, cost-competitive means of storing gas close to customers while reducing dependence on out-of-province storage facilities. The facility provides greater flexibility to meet customer needs during winter months when demand for natural gas is at its highest and to meet planned and unplanned system interruptions.

FEI's Customer Care Enhancement Project, at an estimated total project cost of $110 million, came into service in January 2012. The Company estimates approximately $30 million of the project cost to be incurred in the first half of 2012 related to final contractor payments, with the total project cost expected to come in under budget. The project entailed the insourcing of core elements of FEI's customer care services, including two Company-owned call centres and billing operations, and implementation of a new customer information system. The BCUC approved the project upon the Company's acceptance of a cost risk-sharing condition, whereby FEI agreed to equally share with customers any costs or savings outside a band of plus or minus 10% of the approved total project cost.

The Fraser River South Bank South Arm Rehabilitation Project involved the installation and replacement of underwater transmission pipeline crossings that were at potential risk of failure from a major seismic event. During 2010 difficulties were experienced with one of the directional drills, delaying the project, which was subsequently completed and came into service in 2011, rather than in 2010 as originally expected, at an estimated total cost of approximately $36 million.

During the first quarter of 2011, FortisAlberta substantially completed its $126 million Automated Metering Project, which involved the replacement of approximately 477,000 conventional meters.

During 2011 FortisAlberta continued the replacement of vintage poles under its Pole Management Program, which involves 96,000 poles in total, to prevent risk of failure due to age. The total capital cost of the program through to 2019 is now expected to be approximately $335 million, an increase from the $283 million forecast as at December 31, 2010. The increase is primarily due to a revised forecast estimating higher labour and material costs later in the program and a change in the program scope to include minor-line rebuilds.

FortisBC Electric's $105 million Okanagan Transmission Reinforcement Project was substantially completed in fall 2011. The project related to upgrading the existing overhead transmission line between Penticton and Vaseux Lake, near Oliver, from 161 kilovolts ("kV") to a double-circuit 230-kV line and building a new 230-kV terminal substation in the Oliver area.

Since 1998 hydroelectric generating facilities at FortisBC Electric have been subject to an upgrade and life-extension program. Newly installed equipment will enhance reliability and efficiency, while the use of standardized components will reduce future maintenance and capital expenditures. Approximately $15 million was spent during 2011 with a remaining $3 million expected to be incurred in 2012 related to this initiative.

The Environmental Compliance Project at FortisBC Electric relates to work required to ensure compliance of the utility's substation equipment with the *Canadian Environmental Protection Act PCB Regulations (SOR/2008-273)* by 2014. The project is estimated to cost approximately $28 million through to 2014. Regulatory approval was obtained for 2011 costs with the remaining project costs subject to BCUC approval.

Fortis Turks and Caicos had an agreement with a supplier to purchase two diesel-powered generating units, each with a capacity of 9 MW. The units were delivered in 2010 and 2011. Assuming demand for additional generating capacity in 2014, an additional 9-MW unit is forecast for delivery at an estimated cost of approximately $8 million (US$8 million). An agreement for the additional unit has not yet been formalized as it is dependent on future demand trends.

Construction progress on the $900 million 335-MW Waneta Expansion, in partnership with CPC/CBT, is going well and the project is currently on schedule. Fortis owns a 51% interest in the Waneta Partnership and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015. Major construction activities on-site include the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $244 million has been spent on the Waneta Expansion since construction began late in 2010. The Waneta Expansion will be included in the amended and restated Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to 234 MW on an average annual basis, is expected to be sold to FortisBC Electric under a long-term capacity purchase agreement. The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table above, includes capitalized interest of Fortis during construction and a $72 million payment expected to be made in 2020 related to certain intangible assets and project design costs previously incurred by CPC/CBT. The table above excludes forecast capitalized interest of the Corporation's partners, CPC/CBT.

In August 2011 Fortis Properties received municipal government approval to construct a $47 million 12-storey office building in downtown St. John's, Newfoundland. The building will feature 152,000 square feet of Class A office space and include 261 parking spaces. Construction is expected to be completed in the second half of 2013.

Over the five-year period 2012 through 2016, gross consolidated capital expenditures are expected to be approximately $5.5 billion. Approximately 64% of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 13% of the capital spending is expected to be incurred at the regulated gas utilities and non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, 39% of utility capital spending is expected to be incurred to meet customer growth; 38% is expected to be incurred to ensure continued and enhanced performance, reliability and safety of generation and T&D assets (i.e., sustaining capital expenditures); and 23% is expected to be incurred for facilities, equipment, vehicles, information technology and other assets.

Cash Flow Requirements

At the operating subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The subsidiaries expect to be able to source the cash required to fund their 2012 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be $103 million in 2012 and to average approximately $270 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at December 31, 2011 (December 31, 2010 – $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For a further discussion of the Exploits Partnership, refer to the "Key Trends and Risks – Expropriated Assets" section of this MD&A.

Except for the debt at the Exploits Partnership, as described above, Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2011 and are expected to remain compliant in 2012.

Credit Facilities

As at December 31, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.9 billion was unused, including the Corporation's unused $800 million committed credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.1 billion of the total credit facilities are committed facilities with maturities ranging from 2012 through 2015.

The cost of renewed and extended credit facilities has been increasing as a result of current economic conditions; however, any increase in interest expense and/or fees is not expected to materially impact the Corporation's consolidated financial results in 2012.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

($ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2011**	Total as at December 31, 2010
Total credit facilities	845	1,390	13	**2,248**	2,109
Credit facilities utilized:					
Short-term borrowings	–	(157)	(2)	**(159)**	(358)
Long-term debt (including current portion)	–	(74)	–	**(74)**	(218)
Letters of credit outstanding	(1)	(65)	–	**(66)**	(124)
Credit facilities unused	844	1,094	11	**1,949**	1,409

As at December 31, 2011 and 2010, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Significant changes in total credit facilities from December 31, 2010 to December 31, 2011 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2011 are detailed in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

In February 2011 Maritime Electric renewed its unsecured committed revolving credit facility and reduced it from $60 million to $50 million. In February 2012 Maritime Electric renewed the credit facility for a further two years.

In April 2011 FortisBC Electric renegotiated and amended its credit facility agreement, resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility, with $100 million now maturing in May 2014 and $50 million now maturing in May 2012.

In April 2011 FHI extended the maturity date of its $30 million unsecured committed revolving credit facility to May 2012.

In June 2011 Newfoundland Power renegotiated and amended its $100 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility to August 2015 from August 2013. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In August 2011 the Corporation renegotiated and amended its unsecured committed revolving credit facility, increasing the amount available under the facility to $800 million from $600 million and extending the maturity date of the facility to July 2015 from May 2012. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the facility to $1 billion. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In September 2011 FortisAlberta amended its unsecured committed revolving credit facility to increase the amount available under the facility to $250 million from $200 million and extend the maturity date to September 2015 from May 2012. The amended credit facility agreement reflects an increase in pricing.

In November 2011 FEVI renegotiated and amended its unsecured committed revolving credit facility, decreasing the amount available under the facility from $300 million to $200 million and extending the maturity date of the facility to December 2013 from May 2012. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2011, the Corporation had no off-balance sheet arrangements, with the exception of letters of credit outstanding of $66 million, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with its regulator and local government to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93% of the Corporation's operating revenue was derived from regulated utility operations in 2011 (2010 – 93%), while approximately 89% of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2011 (2010 – 87%). Regulated utility assets comprised approximately 91% of total assets of Fortis as at December 31, 2011 (December 31, 2010 – 92%). The Corporation's regulated utilities primarily operate under COS methodologies. The utilities are subject to the normal uncertainties faced by regulated entities, including approval by the respective regulatory authority of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base and, in the case of Caribbean Utilities and Fortis Turks and Caicos, the continuation of licences. Generally, the ability of the utilities to recover the actual costs of providing services and to earn the approved ROEs and/or ROAs is impacted by achieving the forecasts established in the rate-setting processes. Upgrades of, and additions to, gas and electricity infrastructure require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS.

There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable in customer rates.

Through the regulatory process, the regulators approve the allowed ROEs and deemed capital structures. Fair regulatory treatment that allows the utilities to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth.

Rate applications that reflect COS and establish revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a public hearing process. There can be no assurance that rate orders issued or negotiated settlements approved by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return or appropriate capitalization.

A failure to obtain rates or appropriate ROEs and capital structure as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of proposed capital project upgrades or expansions, ratings assigned by credit rating agencies, the issuance and sale of securities and other matters, which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

As an owner of an electricity distribution network under the *Electric Utilities Act* (Alberta) (the "EUA"), FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or as a default supplier, and no other party is willing to act as a regulated-rate provider or as a default supplier, FortisAlberta would be required, under the EUA, to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced. However, stemming from the outcome of the June 2008 Final Decision of the Public Utilities Commission, regulatory challenges continued at Belize Electricity that impeded the utility's ability to earn a fair and reasonable return in 2010 and through to June 2011, at which time the utility was expropriated from Fortis by the GOB. There was no earnings contribution from Belize Electricity to the consolidated earnings of Fortis in 2011 and only $1.5 million of earnings contribution in 2010. For a further discussion of Belize Electricity, refer to the "Business Risk Management – Investment in Belize" section of this MD&A. Also, an independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed in 2011. The timing and future impact of any newly adopted regulatory framework in this jurisdiction is uncertain at this time.

The Corporation has a concentration of regulatory risk in British Columbia, with 56% of the Corporation's regulated assets under the jurisdiction of the BCUC. The risk is heightened by a significant regulatory calendar for 2012 for FortisBC's gas and electricity businesses.

FEI, FEVI, FEWI and FortisBC Electric are regulated by the BCUC and have used PBR mechanisms from time to time. PBR mechanisms provide utilities an opportunity to earn returns in excess of the allowed ROEs determined by the regulator. The PBR mechanism at FortisBC Electric expired at the end of 2011 and the PBR mechanism at FEI expired at the end of 2009, with a two-year phase-out to the end of 2011. Upon expiry of PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be. FortisBC Electric and the FortisBC Energy companies have filed full COS applications for 2012 and 2013 rates with no assumption of PBR.

The AUC intends to introduce PBR-based distribution service rates in Alberta beginning in 2013 for a five-year term, with 2012 to be used as the base year. FortisAlberta submitted its PBR proposal to the AUC in July 2011 outlining its views as to how PBR should be implemented at FortisAlberta. A hearing on the matter is expected to commence in April 2012 with a decision on PBR expected in 2012.

As a result of the Accord, the PEI Commission was established by the Government of PEI. Having authority under the *Public Inquiries Act*, the co-chaired five-member PEI Commission's goal is to examine and provide advice on ways in which PEI's cost of electricity can be structurally reduced and/or stabilized over the longer term. In carrying out this goal, the PEI Commission will, among other things, examine and provide recommendations on long-term ownership and management of electricity on PEI and provide advice and recommendations as to the future role of the PEI Energy Corporation, IRAC (as it relates to electricity) and the Office of Energy Efficiency. The carrying out of the above goal by the PEI Commission could impact how Maritime Electric is regulated going forward as well as its future ownership.

For additional information on the nature of regulation and various regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Business Risk Management – Interest Rate Risk" section below.

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE automatic adjustment mechanisms or indirectly through a regulatory determined or negotiated process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. The formulaic ROE automatic adjustment mechanisms tied to long-term Canada bond rates, used in recent years at the FortisBC Energy companies, FortisAlberta, FortisBC Electric and Newfoundland Power, had resulted in lower allowed ROEs. A significant decline in interest rates and their impact on allowed ROEs could adversely affect the financial condition and results of operations of the Corporation's regulated utilities.

In response to the decrease in long-term interest rates, many regulators in Canada reviewed the ROE automatic adjustment mechanisms by the end of 2009 and, in many cases, removed the use of ROE automatic adjustment mechanisms. Long-term Canada bond rates continue to be low. At the Corporation's four largest utilities, only Newfoundland Power used an automatic adjustment mechanism to set the allowed ROE for 2011. In December 2011, however, the PUB approved an application filed by Newfoundland Power requesting the suspension of the operation of the ROE automatic adjustment formula for 2012 pending a full cost of capital review for 2012. In the interim, the allowed ROE at Newfoundland Power will remain at 8.38% for 2012. In December 2011 the AUC issued a decision on its GCOC Proceeding, resulting in a 25 basis point reduction in the generic allowed ROE to 8.75% for 2011 and 2012, and 8.75% for 2013 on an interim basis, for utilities under the jurisdiction of the AUC, including FortisAlberta. The AUC did not reinitiate an ROE automatic adjustment mechanism at this time. The BCUC has also initiated a GCOC Proceeding, which will commence in March 2012, and may impact the capital structures and/or allowed ROEs of the FortisBC Energy companies and FortisBC Electric. Uncertainty exists regarding the duration of the current environment of low interest rates and what effect this may have on allowed ROEs of the Corporation's regulated utilities.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with borrowings under credit facilities and floating-rate long-term debt. At the FortisBC Energy companies and FortisBC Electric, however, interest expense variances from forecast for rate-setting purposes, related to floating-rate debt, were recovered through customer rates using regulatory deferral accounts approved by the BCUC to the end of 2011. The FortisBC Energy companies also have a deferral mechanism that captures the impact on interest expense of the differences between forecast and actual long-term interest rates and forecast and actual timing of issuance of long-term debt. There can be no assurance that the above deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions and orders. At the Corporation's other regulated utilities, if new long-term debt is raised at interest rates higher than those forecast and approved in customer rates, the additional interest costs incurred on the new long-term debt are not able to be recovered from customers in rates during the period that was covered by the approved rates.

As at December 31, 2011, approximately 80% of the Corporation's consolidated long-term debt and capital lease obligations, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2011.

Total Debt

As at December 31, 2011	*($ millions)*	*(%)*
Short-term borrowings	**159**	**2.7**
Utilized variable-rate credit facilities classified as long-term	**74**	**1.2**
Variable-rate long-term debt and capital lease obligations (including current portion)	**2**	**–**
Fixed-rate long-term debt and capital lease obligations (including current portion)	**5,709**	**96.1**
Total	**5,944**	**100.0**

Long-term debt was issued by the Corporation's regulated utilities in 2011 at attractive rates ranging from 4.25% to 5.118% and with terms ranging from 15 to 50 years.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2011, is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates, as that change would have affected 2011 financial results, is disclosed in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

Operating and Maintenance Risks: The FortisBC Energy companies are exposed to various operational risks such as: pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas that could result in significant operational disruptions and/or environmental liability. The business of electricity T&D is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets are damaged due to weather conditions and other acts of nature. The FortisBC utilities operate in a remote and mountainous terrain with a risk of loss or damage from forest fires, washouts, landslides, avalanches and other acts of nature. The FortisBC Energy companies, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. Refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the Corporation's utilities.

The Corporation's utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. The failure to do so may disrupt the ability of the utilities to safely distribute gas and electricity, which could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to COS and equipment, regulatory requirements, revenue requirement approvals and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain whether any additional costs will receive regulatory approval for recovery in future customer rates. It is generally expected, however, that prudently incurred costs can be recovered in customer rates. The inability to recover additional costs, however, could have a material effect on the utilities' financial conditions and results of operations.

Economic Conditions: Typical of utilities, energy sales in the Corporation's service territories are influenced by economic factors, such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth. Also, the FortisBC Energy companies are affected by the trend in housing starts from single-family dwellings to multi-family dwellings. The growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, growth in gas distribution volumes may be tempered.

In the Caribbean, the level of, and fluctuations in, tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand at the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region. The Corporation's service territory in the Caribbean region continues to be impacted by challenging economic conditions. Many non-locals working in the construction industry on Grand Cayman and in the Turks and Caicos Islands have returned to their home countries or other jurisdictions, as a result of the strong reduction in construction activity due to the weak local economies. On the positive side, the recent completion and commissioning of phase one of a local airport expansion at the principal airport in Providenciales in the Turks and Caicos Islands in September 2011 should help foster future economic growth, mainly in the tourism and commercial sectors, allowing direct flights from Europe and accommodating more flights from North America. On Grand Cayman, several residential, resort and commercial projects were completed in 2011, which have the potential to increase load and electricity sales for Caribbean Utilities.

Any sustained recovery of the economy in the Caribbean region, however, will hinge on the recovery of the U.S. economy. In line with the general U.S. economic forecast, it is expected that the current local economic weakness in the Caribbean region will continue into 2012 and possibly beyond. Due to continued challenging economic conditions in the Caribbean, combined with the impact on customer bills of high fuel prices, there was no growth in electricity sales at Caribbean Utilities and Fortis Turks and Caicos for 2011. Electricity sales growth for 2012 is projected to be minimal.

Generally, higher energy prices can result in reduced consumption by customers. However, natural gas and crude oil exploration and production activities in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities, which tend to increase with increased energy prices, can influence energy demand, affecting local energy sales in some of the Corporation's service territories.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities' performance despite regulatory measures available to compensate for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending, which would, in turn, affect rate base and earnings growth.

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial office and retail space and hotel properties, with those assets representing 4% of the Corporation's total assets. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 9% per annum over the next five years. Approximately 56% of Fortis Properties' operating income was derived from hotel investments in 2011 (2010 – 55%). Organic revenue and earnings growth at Fortis Properties' Hospitality Division has been low in recent years, due to challenging economic conditions and the overall impact on leisure and business travel and hotel stays. Occupancy increases, however, were achieved in 2011 at the Company's hotel operations in Atlantic Canada and central Canada, but were more than offset by occupancy decreases experienced in western Canada. It is estimated that a 10% decrease in revenue at Fortis Properties' Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Project Budget Overrun, Completion and Financing Risk in the Corporation's Non-Regulated Business: In its non-regulated business, Fortis generally bears the risk of budget overruns on capital projects, including increased costs associated with higher financing expense, schedule delays and lower-than-expected performance. In contrast, these budget overruns, when incurred prudently in the regulated business, can generally be recovered in customer rates as part of COS. Budgets for capital projects are established, in part, on estimates that are subject to a number of assumptions, including future economic conditions, productivity and performance of employees, contractors, subcontractors or equipment suppliers; price and availability of labour, equipment and materials; and other requirements that may affect project costs or schedules, such as obtaining the required environmental permits, licences and approvals on a timely basis. The risk of cost overruns is mitigated by contractual approach, regular and proactive monitoring by employees with appropriate expertise and regular review by senior management. Cost overruns and delays in project completion may also occur when unforeseen circumstances arise. The cost of financing large capital projects is subject to conditions experienced in the capital markets that may result in higher financing costs than originally estimated.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its larger subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and the financial position of the Corporation and the subsidiaries, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) may not be sufficient to fund the repayment of all outstanding liabilities when due, as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Despite the volatility that has occurred in the global capital markets in recent years, the Corporation and its utilities were successful at raising long-term capital at reasonable rates. Volatility in the global financial and capital markets may have the effect of increasing the cost of, and affecting the timing of, issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of borrowing could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

The cost of renewed and extended credit facilities generally increased in 2011; however, increased interest expense and/or fees did not materially impact the results of operations or financial condition of the Corporation and its subsidiaries in 2011 nor are they expected to in 2012. During 2011 the Corporation and FortisAlberta renegotiated their respective credit facility agreements in advance of the scheduled maturity dates, resulting in substantially similar terms as the former credit facilities, but there was an increase in pricing reflecting current general market conditions. Due to their regulated nature, increased cost of borrowing at the utilities is eligible to be recovered in customer rates.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The $800 million committed corporate credit facility is available for interim financing of acquisitions and for general corporate purposes and may be increased to $1 billion at any time prior to maturity upon written notice by Fortis. As at December 31, 2011, Fortis had approximately $2.2 billion in consolidated credit facilities, of which $2.1 billion is committed with maturities ranging from 2012 through 2015. Approximately $1.9 billion of the credit facilities were unused as at December 31, 2011. No amounts were drawn on the corporate credit facility at as December 31, 2011.

Generally, the Corporation and its regulated utilities, which are currently rated, are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt offerings and on the Corporation's and its utilities' credit facilities. Changes in credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Also, a significant downgrade in FEI's credit ratings could trigger margin calls and other cash requirements under FEI's natural gas purchase and natural gas derivative contracts. Fortis and its utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the global financial crisis has prompted increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

DBRS confirmed the Corporation's unsecured debt credit rating in October 2011 but, in February 2012, placed the credit rating under revew with developing implications following the CH Energy Group acquisition announcement by Fortis. S&P is expected to complete its annual review of the Corporation's debt credit rating in the first quarter of 2012 but, in February 2012, placed the credit rating under credit watch with negative implications, also due to the acquisition announcement. For further information, refer to the "Liquidity and Capital Resources – Credit Ratings" and "Subsequent Event" sections of this MD&A. During 2011 DBRS confirmed its existing credit ratings for Newfoundland Power, Caribbean Utilities, FortisBC Electric, FHI and FEI and in March 2012 confirmed FortisAlberta's existing credit rating. Also, Moody's Investors Service confirmed its existing credit ratings for Newfoundland Power, FortisAlberta and FEI, while S&P maintained its existing credit rating for Maritime Electric, but downgraded Caribbean Utilities' credit rating from A to A– due to a weak customer market and increased business risks. FortisAlberta's existing debt credit rating by S&P was confirmed in January 2012, but was put on credit watch with negative implications in February 2012 due to the Corporation's credit rating being placed on credit watch.

Further information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 29 to the Corporation's 2011 Consolidated Financial Statements.

Investment in Belize: In June 2011 the GOB expropriated the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011. The Corporation is exposed to risk associated with the timeliness and the ultimate amount that will be paid, as well as the ability of the GOB to pay the compensation owing to Fortis. The book value of the Corporation's previous investment in Belize Electricity recorded in long-term other assets on the consolidated balance sheet of Fortis as at December 31, 2011 was $106 million, including foreign exchange impacts. For further information, refer to the "Key Trends and Risks – Expropriated Assets" section of this MD&A.

Fortis continues to control and consolidate the financial statements of BECOL, the Corporation's indirect wholly owned non-regulated hydroelectric generation subsidiary in Belize. BECOL generates hydroelectricity from three plants located on the Macal River with a combined generating capacity of 51 MW. The entire output of the plants is sold to Belize Electricity under 50-year contracts expiring in 2055 and 2060. Assuming normal hydrological conditions, Belize Electricity purchases BECOL's normalized annual energy production of 240 GWh at approximately US$0.10 per kWh, which generally is the lowest-cost energy supply source in the country of Belize. As at December 31, 2011, the book value of the Corporation's investment in BECOL was $154 million. In October 2011 the GOB purportedly amended the Constitution of Belize to require majority government ownership of three public utility providers, including Belize Electricity, but excluding BECOL. The GOB has also indicated it has no intention to expropriate BECOL.

As at February 29, 2012, Belize Electricity owed BECOL US$7.5 million for overdue energy purchases, representing almost one-third of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Weather and Seasonality Risk: The physical assets of the Corporation and its subsidiaries could be exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At FEI a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing FEI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers.

At the FortisBC Energy companies, weather has a significant impact on distribution volume as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the FortisBC Energy companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Earnings of the FortisBC Energy companies are highest in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and unusual or severe temperatures. In Canada cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load. In the Caribbean the impact of seasonal changes in weather on air conditioning demand is less pronounced, due to the less variable seasonal changes that exist in the region; however, higher- or lower-than-normal temperatures can have a significant impact on air conditioning demand. Significant fluctuations in weather-related demand for electricity could materially impact the financial condition and results of operations of the electric utilities.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric.

FortisBC Electric's entitlement to capacity and energy under the amended and restated Canal Plant Agreement may be reduced if climate change in the future leads to a significant and sustained loss of precipitation over the entire headwaters of the Kootenay River system. To have an effect on the entitlements of capacity and energy, such change would likely have to persist for a prolonged period.

Despite preparation for severe weather, hurricanes and other natural disasters will always remain a risk to utilities. Climate change, however, may have the impact of increasing the severity and frequency of weather-related natural disasters that affect the Corporation's service territories.

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Newfoundland Power and Maritime Electric are subject to hurricane risk. The Corporation's other utilities may also be subject to severe weather events. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event.

Earnings from non-regulated generation assets are sensitive to rainfall levels; however, the geographic diversity of the Corporation's generation assets helps to mitigate the risk associated with rainfall levels. The Waneta Expansion will be included in the amended and restated Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation.

Commodity Price Risk: The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility. In the past, the FortisBC Energy companies employed a number of tools to reduce exposure of commodity rates charged to customers to natural gas price volatility. Prior to mid-2011, these tools included hedging strategies based on a combination of both physical and financial transactions. As ordered by the BCUC, the FortisBC Energy companies discontinued most hedging activities by mid-2011, with existing hedges being managed to expiry. The use of natural gas derivatives effectively fixes the price of natural gas purchases and any resulting gains or losses effectively accrue entirely to customers. The absence of hedging activities may cause an increase in natural gas price volatility as this affects customer rates.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. Also, a severe and prolonged increase in natural gas commodity costs could materially affect the FortisBC Energy companies despite regulatory measures available to compensate for sharp changes in these costs. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange forward contracts, fuel option contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk and are not used or held for trading purposes. All derivative financial instruments are measured at fair value. If a derivative financial instrument is designated as a hedging item in a designated qualifying cash flow hedging relationship, the effective portion of changes in fair value is recognized in other comprehensive income. Any change in fair value relating to the ineffective portion is recognized immediately in earnings. At the FortisBC Energy companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from, and net investment in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on self-sustaining foreign net investments, which are also recognized in other comprehensive income. As at December 31, 2011, the Corporation's corporately issued US$550 million (December 31, 2010 – US$590 million) long-term debt had been designated as a hedge of substantially all of the Corporation's self-sustaining foreign net investments. As at December 31, 2011, the Corporation had approximately US$6 million (December 31, 2010 – US$7 million) in self-sustaining foreign net investments remaining to be hedged.

Effective from June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity, recorded in long-term other assets, does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, during 2011 a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. As a result, the Corporation recognized a net after-tax foreign exchange gain of approximately $1.5 million in 2011.

It is estimated that a 5 cent, or 5%, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of US$1.00=CDN$1.02, as at December 31, 2011, would increase (decrease) basic earnings per common share of Fortis by 3 cents in 2012.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar earnings streams, where possible, through future US dollar borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including existing natural gas commodity swaps and options. The FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit approval practices. The FortisBC Energy companies did not experience any counterparty defaults in 2011 and do not expect any counterparties to fail to meet their obligations. As events in the recent past have indicated, however, the credit quality of counterparties can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Substantially all of FortisAlberta's distribution service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. Refer also to the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since the majority of electricity prices in British Columbia were set based on the historical average cost of production (primarily associated with hydroelectric generation), rather than based on market forces, the competitive advantage of natural gas was substantially eroded during the decade that followed. More recently, however, there is potentially significant new investment in the electricity generation and transmission sector in British Columbia, which may put upward pressure on electricity rates. Furthermore, the growth in natural gas supply, due to the productivity and cost improvements associated with shale gas production, and subsequent decline in market natural gas prices, have helped to improve natural gas competitiveness on an operating basis. However, differences in upfront capital costs between electric-heated homes and natural gas-heated homes present a challenge for the competitiveness of natural gas on a full-cost basis. Further, there are other competitive factors that are impacting the penetration of natural gas in new housing builds, such as the green attributes of the energy source, government policy and the type of housing being built. A reduction in natural gas supply, due to low market prices and increased industrial and commercial demand due to stronger economic growth, are factors that may lead to materially higher market gas prices and volatility. In the future, if natural gas pricing becomes uncompetitive with pricing for electricity and other alternative energy sources, the ability of the FortisBC Energy companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and could, in an extreme case, ultimately lead to an inability to fully recover COS of the FortisBC Energy companies in rates charged to customers. Refer also to the "Business Risk Management – Risks Related to FEVI" and "Environmental Risks" sections of this MD&A.

Natural Gas, Fuel and Electricity Supply: The FortisBC Energy companies are dependent on a limited selection of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas, where the majority of the natural gas distribution customers of the FortisBC Energy companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the FortisBC Energy companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the FortisBC Energy companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The addition of the new LNG storage facility on Vancouver Island, however, provides short-term supply during cold weather conditions or emergency situations.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on NB Power for over 80% of its customers' energy requirements. In addition, Caribbean Utilities and Fortis Turks and Caicos are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

Power Supply and Capacity Purchase Contracts: FortisBC Electric's indirect customers are directly served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in an extreme case, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in rates charged to customers.

Additionally, the Corporation's regulated electric utilities periodically enter into various power supply and capacity purchase contracts with third and/or related parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts and, if the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity. The utilities are also exposed to power supply availability risk in the event of non-performance by counterparties to the various power supply and capacity contracts.

In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion, the 335-MW hydroelectric generating facility currently under construction adjacent to the existing Waneta hydroelectric generating facility on the Pend d'Oreille River in British Columbia. The Waneta Expansion is owned, being developed and will be operated by a limited partnership between Fortis, which owns a 51% controlling interest, and CPC/CPT, which own a 49% minority interest. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010 and an executed version of the agreement was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of its acceptance of filing of the executed agreement.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of FHI, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, FortisOntario, Algoma Power, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees. Approximately 60% of the above utilities' total employees are members of such plans.

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related net pension cost. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. For a discussion of the critical accounting estimates associated with defined benefit pension plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

Pension benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets. There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. The pension plan assets are valued at fair value. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets, which may cause material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

Market-driven changes impacting discount rates, which are used to value the accrued pension benefit obligations as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future net pension cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of net pension cost, future funding requirements, the accrued benefit asset, the accrued benefit liability and the benefit obligation.

The above-noted risks are mitigated as any increase or decrease in future pension funding requirements and/or net pension cost at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. However, at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power, actual net pension cost above or below the forecast net pension cost approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. There can be no assurance that net pension cost deferral mechanisms that were approved by the BCUC to the end of 2011 for the FortisBC Energy companies and FortisBC Electric will continue in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through net pension costs in customer rates could materially impact the results of operations, financial position and cash flows of the regulated utilities. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta, Newfoundland Power and FortisOntario are closed to all new employees.

Risks Related to FEVI: FEVI operates in the price-competitive service area of Vancouver Island, with a customer base and revenue that are currently sufficient to meet the Company's current COS. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement provided royalty revenue from the Government of British Columbia that covered approximately 20% of FEVI's COS. The royalty revenue expired at the end of 2011, after which time FEVI's customers began absorbing the full commodity cost of natural gas and all other COS. The Company has requested the continuation of the Rate Stabilization Deferral Account mechanism in its 2012–2013 Revenue Requirements Application, which allows FEVI to accumulate the recovery of costs from customers above FEVI's COS. Also, the remaining $49 million of outstanding non-interest bearing government loans, which is currently treated as a government contribution against rate base, is expected to be repaid by the end of 2016. As the debt is repaid, the higher rate base will increase COS and customer rates. With the cessation of royalty revenue and repayment of the government loans, the resultant increase in customer rates, as compared to electricity or alternative forms of energy, may make gas less competitive on Vancouver Island over time.

Environmental Risks: The Corporation's gas and electric utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity, mainly at the Corporation's regulated utilities in the Caribbean. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances.

The management of GHG emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act*. The Energy Plan, released in 2007, is a natural progression from the previous plan, with a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia Legislature amending the *Utilities Commission Amendment Act, 2008* and passing the *Clean Energy Act*. The *Clean Energy Act,* which establishes a long-term vision for the province as a leader in clean energy development, came into force in June 2010. Specifically, the *Clean Energy Act* outlines 16 energy objectives for British Columbia, including the objective to have 93% of British Columbia's electricity generated from clean or renewable resources, to take demand-side measures and to conserve energy to meet a minimum of 66% of the expected increase in BC Hydro's demand for electricity by the year 2020, and to become a net exporter of electricity generated from clean or renewable resources. FortisBC Electric and the FortisBC Energy companies continue to assess and monitor the impact the Energy Plan and the *Clean Energy Act* may have on future operations. Energy to be produced by the Waneta Expansion in British Columbia, upon its completion, is consistent with the objective under the *Clean Energy Act* to reduce GHG emissions. In 2010 the FortisBC Energy companies began reporting and had external verification of GHG emissions generated by its facilities, as required under the *Greenhouse Gas Reduction (Cap and Trade) Act.* While a cap and trade program associated with GHG emissions was expected to begin on January 1, 2012, the Government of British Columbia has delayed the development of this regulatory initiative. If implemented, the cap and trade program is expected to have a declining cap on emissions that all applicable facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for release of GHG emissions over the capped amount.

The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol was extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details on the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

In 2011 Canada announced its decision to invoke its legal right to formally withdraw from the Kyoto Protocol. It is uncertain as to what impact this withdrawal may have going forward.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs can arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment, and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages could become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2011, there were no material environmental liabilities recognized in the Corporation's 2011 Consolidated Financial Statements. Also, there were no material unrecorded environmental liabilities known to management, except for the possibility of liabilities associated with various contingencies as discussed in the "Critical Accounting Estimates – Contingencies" section of this MD&A. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

Each of the utilities of Fortis has an Environmental Management System ("EMS"), with the exception of Fortis Turks and Caicos which expects to complete the implementation of its EMS in 2013. Environmental policies form the cornerstone of the EMS and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regular environmental monitoring and audits of the EMS and striving for continual improvement in environmental performance; (v) set and review environmental objectives, targets and programs regularly; (vi) communicate openly with stakeholders including making available the utility's environmental policy and knowledge on environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

During 2011 direct costs arising from environmental protection, compliance, damages and carrying out the EMSs were not material to the Corporation's consolidated results of operations, cash flows or financial position. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their assets, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economically viable. The insurance coverage is for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authority to recover the loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' results of operations, cash flows and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' results of operations, cash flows and financial position.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Loss of Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government, government agencies and from First Nations bands. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the Corporation's subsidiaries.

FortisBC Electric's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the amended and restated Canal Plant Agreement depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows on the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States. Government authorities in Canada and the United States have the power under the treaty to regulate water flows to protect environmental values in a manner that could adversely affect the amount of water available for the generation of power.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the results of operations, cash flows and financial position of FortisAlberta.

Refer also to the "Material Regulatory Decisions and Applications – FortisAlberta" section of this MD&A for additional information with respect to the risk of loss of service area.

Transition to New Accounting Standards: In June 2011 the OSC issued a decision allowing Fortis and its reporting issuer subsidiaries to prepare their financial statements, effective January 1, 2012 through to December 31, 2014, in accordance with US GAAP without qualifying as U.S. Securities and Exchange Commission ("SEC") Issuers pursuant to Canadian securities laws. The Corporation and its reporting issuer subsidiaries, therefore, will be adopting US GAAP as opposed to IFRS on January 1, 2012. Earnings to be recognized under US GAAP are expected to be closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued recognition of regulatory assets and liabilities under US GAAP. A transition to IFRS would likely have resulted in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities and significant volatility in the Corporation's consolidated earnings.

If the exemption from the OSC does not continue past December 31, 2014, then the Corporation and its reporting issuer subsidiaries will be required to become SEC Issuers in order to continue reporting under US GAAP. If the Corporation and its reporting issuer subsidiaries do not become or qualify as SEC Issuers, they will be required to adopt IFRS effective January 1, 2015. In the absence of an accounting standard for rate-regulated activities under IFRS at that time, the result could be volatility in earnings and earnings per common share from those otherwise recognized under US GAAP.

For further information on the Corporation's transition to US GAAP, effective January 1, 2012, refer to the "Future Accounting Standards" section of this MD&A.

Changes in Tax Legislation: Fortis currently keeps the earnings of its Caribbean operations in offshore tax-free jurisdictions. The Government of Canada enacted legislative changes that challenge the tax-deferred status of offshore earnings. The legislative changes require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada by 2014.

If the jurisdictions are unable to establish tax treaties or TIEAs, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were earned in Canada. Conversely, if tax treaties or TIEAs are reached, the earnings from these jurisdictions can be repatriated to Canada tax-free.

The Government of Canada announced the entry into TIEAs with the Cayman Islands and Bermuda on June 1, 2011 and July 1, 2011, respectively, and with the Turks and Caicos Islands on October 6, 2011. Fortis expects that a TIEA with Belize will be in place by the 2014 deadline.

The income tax regulations were amended to provide that, where a particular TIEA enters into force on a particular day, the agreement is deemed to enter into force and come into effect on the first day of the year that includes the day that the TIEA came into effect. Therefore, earnings from the Corporation's investment in Caribbean Utilities and Fortis Turks and Caicos, beginning January 1, 2011, can be repatriated to Canada tax free. Conversely, if Belize is unable to establish a TIEA with Canada, earnings from BECOL will be taxed on an accrual basis as if they were earned in Canada which, for Fortis, will result in reduced earnings contribution from this subsidiary.

In August 2011 the Government of Canada introduced additional legislative proposals relating to the taxation of multinationals. These changes recommend new rules relating to upstream loans and propose a new regime for the repatriation of capital. The upstream loans, i.e., loans made from a foreign affiliate to its parent, will now be required to be repaid within two years, after which time the loans will be included in the taxable income of the Canadian parent. Fortis uses upstream interest-free loans from its Caribbean subsidiaries as a tax-deferred repatriation of earnings. As at December 31, 2011, the Corporation had approximately $68 million of upstream loans that will now have to be repaid before December 31, 2013, at which time any outstanding balance will be included in the Corporation's taxable income. The Corporation also had approximately $18 million in downstream loans, as at December 31, 2011, that can be used to offset the impacts of having to repay the upstream loans.

The new regime for the repatriation of capital will permit the Canadian parent to repatriate paid-up capital and exempt surplus before any taxable surplus, i.e., earnings, is repatriated. This will allow Fortis to receive a tax-free return of capital from the Caribbean, which can be used to repay upstream loans allowing the Corporation to comply with the above legislative proposals.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

Information Technology Infrastructure Risk: The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information; and support the financial and general operating aspects of their business. System failures could have a material adverse effect on the utilities, such as the inability to provide energy to customers.

Access to First Nations' Lands: The FortisBC Energy companies and FortisBC Electric provide service to customers on First Nations' reserves and maintain gas distribution facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations bands. A treaty negotiation process involving various First Nations bands and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the FortisBC Energy companies and FortisBC Electric is not clear. Furthermore, not all First Nations bands are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the FortisBC Energy companies and FortisBC Electric. However, there can be no certainty that the settlement process will not materially affect the businesses of the FortisBC Energy companies and FortisBC Electric.

Furthermore, the Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals, the BCUC must consider whether the Crown has a duty to consult First Nations and to accommodate First Nations regarding the impact of such approvals and, if so, whether Crown consultation and accommodation have been adequate. The above may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of FortisBC's gas and electricity businesses.

FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations Risk: Approximately 58% of the employees of the Corporation's subsidiaries are members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flows and financial position of the utilities.

In December 2010 FortisAlberta reached a three-year collective agreement with the United Utility Workers' Association of Canada, Local 200.

The collective agreement between FortisBC Electric and Local 378 of the Canadian Office and Professional Employees Union ("COPE") expired January 31, 2011. During 2011 discussions between the Company and COPE focused on renegotiation of the COPE agreement. An agreement has been reached with regard to certain customer service employees. Discussions continue with regard to the remaining COPE bargaining unit.

The collective agreement between FortisBC Electric and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expires on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation and T&D.

The collective agreement between the FortisBC Energy companies and IBEW, Local 213, expired March 31, 2011 and is currently being negotiated. The collective agreement between the FortisBC Energy companies and COPE, Local 378, expires on March 31, 2012.

The two collective agreements between Newfoundland Power and IBEW, Local 1620, expired in September 2011. The Company and IBEW reached a tentative agreement in January 2012, which is subject to ratification by the members.

Human Resources Risk: The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

FUTURE ACCOUNTING CHANGES

Adoption of New Accounting Standards: Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board, Fortis has evaluated the option of adopting US GAAP, as opposed to IFRS, and has decided to adopt US GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to file its financial statements prepared in accordance with US GAAP by qualifying as an SEC Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *U.S. Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the OSC seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently refers to US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

During the fourth quarter of 2010, the Corporation developed a three-phase plan to adopt US GAAP effective January 1, 2012. The following is an overview of the activities under each phase and their current status.

Phase I – Scoping and Diagnostics: Phase I consisted of project initiation and awareness, project planning and resourcing, and identification of high-level differences between US GAAP and Canadian GAAP in order to highlight areas where detailed analysis would be needed to determine and conclude as to the nature and extent of financial statement impacts. External accounting and legal advisors were engaged during this phase to assist the Corporation's internal US GAAP conversion team and to provide technical input and expertise as required. Phase I commenced in the fourth quarter of 2010 and was completed during 2011.

Phase II – Analysis and Development: Phase II consisted of detailed diagnostics and evaluation of the financial statement impacts of adopting US GAAP based on the high-level assessment conducted under Phase I; identification and design of any new, or changes to, operational or financial business processes; initial staff training and audit committee orientation; and development of required solutions to address identified issues.

Phase II had included planned activities for the registration of securities as required to achieve SEC Issuer status and an assessment of ongoing requirements of the United States *Sarbanes-Oxley Act* ("US SOX"), including auditor attestation of internal controls over financial reporting, and a comparison of the requirements under US SOX to those required in Canada under National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*. These activities were no longer required or applicable as a result of the Exemption granted by the OSC as discussed above.

Phase II of the plan commenced in January 2011 and was essentially completed during 2011. Based on the research and analysis completed to date, and the Corporation's continued ability to apply rate-regulated accounting policies under US GAAP, the differences between US GAAP and Canadian GAAP are not expected to have a material impact on consolidated earnings. In addition, adoption of US GAAP is expected to result in limited changes in balance sheet classifications and result in additional disclosure requirements. The impact on information systems and internal controls over financial reporting is expected to be minimal.

Phase III – Implementation and Review: Phase III is currently ongoing and has involved the implementation of financial reporting systems and internal control changes required by the Corporation to prepare and file its consolidated financial statements in accordance with US GAAP beginning in 2012, and the communication of associated impacts.

The Corporation has prepared and filed its audited Canadian GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives, in the usual manner. The Corporation has also voluntarily prepared and filed audited US GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared in accordance with US GAAP and filed.

Phase III will conclude when the Corporation files its annual audited consolidated financial statements for the year ending December 31, 2012 prepared in accordance with US GAAP.

Financial Statement Impacts – US GAAP: The areas identified where differences between US GAAP and Canadian GAAP have the most significant financial statement impacts are outlined below.

Employee future benefits: Under Canadian GAAP, the accrued benefit asset or liability associated with defined benefit plans is recognized on the balance sheet with a reconciliation of the recognized asset or liability to the funded status being disclosed in the notes to the consolidated financial statements. The accrued benefit asset or liability excludes unamortized balances related to past service costs, actuarial gains and losses and transitional obligations, which have not yet been recognized.

US GAAP requires recognition of the funded status of defined benefit plans on the balance sheet. Unamortized balances related to past service costs, actuarial gains and losses and transitional obligations are separately recognized on the balance sheet as a component of accumulated other comprehensive income or, in the case of entities with activities subject to rate regulation, as regulatory assets or liabilities for recovery from, or refund to, customers in future rates. Subsequent changes to past service costs, actuarial gains and losses and transitional obligations would be recognized as part of pension expense, where required by the regulator, or otherwise as a change in the regulatory asset or liability. Therefore, upon adoption of US GAAP, the Corporation's rate-regulated subsidiaries will recognize the funded status of their defined benefit pension plans on the balance sheet with the above-noted unamortized balances recognized as regulatory assets or liabilities.

US GAAP also requires that OPEB costs be recorded on an accrual basis, and prohibits the recognition of regulatory assets or liabilities associated with OPEB costs that are recovered on a cash basis. FortisAlberta has historically recovered its OPEB costs on a cash basis, as opposed to an accrual basis, and continues to do so as ordered by its regulator. Therefore, FortisAlberta's regulatory asset associated with OPEB costs does not meet the criteria for recognition under US GAAP. Historically, Newfoundland Power had also recovered its OPEB costs on a cash basis. However, in December 2010, the regulator approved Newfoundland Power's application to: (i) adopt the accrual method of accounting for OPEB costs, effective January 1, 2011; (ii) recover the transitional regulatory asset associated with the adoption of accrual accounting over a 15-year period; and (iii) adopt an OPEB cost-variance deferral account to capture differences between OPEB expense calculated in accordance with applicable generally accepted accounting principles and OPEB expense approved by the regulator for rate-setting purposes. The rules under US GAAP related to accounting for OPEBs by rate-regulated entities require that Newfoundland Power derecognize its OPEB regulatory asset as at January 1, 2010 on the premise that, as at that date, Newfoundland Power was recovering its OPEB costs on a cash basis. However, the regulatory asset is re-recognized through earnings in accordance with US GAAP in 2010 based on the regulator's approval of Newfoundland Power's application to adopt the accrual method of accounting for OPEBs, effective January 1, 2011, and to recover the associated transitional regulatory asset over a 15-year period.

Additional differences between Canadian GAAP and US GAAP in terms of accounting for defined benefit plans include the determination of the measurement date and the attribution period over which pension expense is recognized. Canadian GAAP allows for the use of a measurement date up to three months prior to the date of an entity's fiscal year end. However, US GAAP requires the entity's fiscal year end to be used as the measurement date. Canadian GAAP also allows for the use of an attribution period for defined benefit pension plans, under specific circumstances, that extends beyond the date when the credited service period ends, while US GAAP allows for the use of an attribution period for defined benefit pension plans up to the date when credited service ends. The above differences impact the calculation of the Corporation's consolidated benefit obligation, which is mostly offset by a corresponding change to regulatory assets or liabilities.

With the exception of a one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as at January 1, 2010 and its ability to subsequently re-recognize this OPEB regulatory asset through earnings in 2010, the impact of adopting US GAAP with respect to accounting for employee future benefits does not have a material impact on the Corporation's consolidated earnings.

Brilliant Power Purchase Agreement ("BPPA"): FortisBC Electric's BPPA is required to be accounted for as a capital lease under US GAAP. While the requirement to evaluate whether an arrangement includes a lease is similar between Canadian GAAP and US GAAP, the effective date for prospective adoption of lease accounting guidance differs, resulting in an accounting difference with respect to the BPPA.

Fulfillment of the BPPA is dependent on the use of a specific asset, the Brilliant Hydroelectric Plant ("Brilliant"), and the conveyance to FortisBC Electric of the right to use that asset under an arrangement between FortisBC Electric and the legal owner of Brilliant. The BPPA qualifies as a capital lease as the present value of the minimum lease payments to be made by FortisBC Electric represents recovery of the entire amount of the initial investment in Brilliant by the legal owner over the term of the arrangement.

The effect of retrospectively recognizing Brilliant as a capital lease upon adoption of US GAAP includes the recognition on the consolidated balance sheet of a utility capital asset with a corresponding capital lease obligation for an equivalent amount. Each subsequent reporting period, the total amount of amortization and interest expense to be recognized under capital lease accounting will differ from the amount paid under the BPPA and recovered through current electricity rates as permitted by the BCUC. This timing difference is recognized as a regulatory asset, with amounts recovered through electricity rates expected to equal the combined amount of the capitalized lease asset and interest on the lease obligation over the term of the BPPA.

Since US GAAP allows for entities to account for the effects of rate regulation, the impact of adopting capital lease accounting for Brilliant does not affect the Corporation's consolidated earnings.

Lease-In Lease-Out ("LILO") Transactions: FEI had entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI from the municipalities. Under Canadian GAAP, the lease of the assets to the municipalities has been accounted for as a sales-type lease and the leaseback of the assets as an operating lease. Gains recorded on the lease-out of the assets were deferred and are being amortized over the term of the leaseback arrangements.

Under US GAAP, the natural gas distribution assets are considered to be equipment that is integral to FEI's operations and, therefore, the LILO transactions must be evaluated as real estate sale-leaseback transactions. As a result of this evaluation, the transactions are required to be accounted for as financing transactions under US GAAP. Under the financing method, the assets subject to the sale-leaseback arrangements are recorded as utility capital assets on the Corporation's consolidated balance sheet and subsequently depreciated. Sale proceeds received are recorded as long-term debt. Lease payments, less the portion considered to be interest expense, decrease the long-term debt. The deferred gains, and amortization thereof, which were recorded in accordance with Canadian GAAP are not recognized under US GAAP.

The retrospective impact of accounting for FEI's LILO transactions under US GAAP results in a decrease in opening retained earnings as at January 1, 2010. The impact on the Corporation's consolidated earnings is not material.

Reclassification of preference shares: Currently under Canadian GAAP, the Corporation's First Preference Shares, Series C and Series E are classified as long-term liabilities with associated dividends classified as finance charges. Under US GAAP, the First Preference Shares, Series C and Series E do not meet the criteria for recognition as a financial liability. Therefore, upon the adoption of US GAAP, the Corporation is reclassifying its First Preference Shares, Series C and Series E from long-term liabilities to shareholders' equity on the consolidated balance sheet. The associated dividends are not recorded as finance charges on the Corporation's consolidated statement of earnings but, rather, are recorded as earnings attributable to preference equity shareholders.

Corporate income taxes: Under Canadian GAAP, the Corporation has calculated and recognized corporate income taxes using substantively enacted corporate income tax rates. Under US GAAP, the Corporation is required to calculate and record corporate income taxes based on enacted corporate income tax rates. Therefore, upon adoption of US GAAP, the Corporation is required to recognize the impact of the difference between enacted tax rates and substantively enacted tax rates related to the calculation of Part VI.1 tax deductions associated with preference share dividends. The retrospective adjustment to recognize the Part VI.1 tax deductions based on enacted corporate income tax rates results in a reduction in opening retained earnings under US GAAP and annual earnings thereafter. However, the adjustments will reverse once pending Canadian federal legislation is passed and proposed corporate income tax rate changes are enacted.

The above-noted items do not represent a complete list of differences between US GAAP and Canadian GAAP. Other less significant differences have also been identified and accounted for. A detailed reconciliation between the Corporation's audited Canadian GAAP and audited US GAAP financial statements for 2011, including 2010 comparatives, is disclosed as part of the voluntary filing of the Corporation's audited US GAAP consolidated financial statements for the year ended December 31, 2011, with 2010 comparatives.

The audited quantification and reconciliation of the Corporation's consolidated balance sheets as at December 31, 2011 and December 31, 2010, prepared in accordance with US GAAP versus Canadian GAAP, may be summarized as follows.

- Total assets as at December 31, 2011 increase by approximately $603 million (December 31, 2010 – $502 million). The increase is due primarily to increases in regulatory assets and utility capital assets in accordance with US GAAP.

- Total liabilities as at December 31, 2011 increase by approximately $337 million (December 31, 2010 – $234 million). The increase is due primarily to the increases in long-term debt and capital lease obligations and pension liabilities in accordance with US GAAP, partially offset by the reclassification of preference shares from liabilities to shareholders' equity.

- Shareholders' equity as at December 31, 2011 increases by approximately $266 million (December 31, 2010 – $268 million). The increase is due primarily to the reclassification of preference shares from liabilities to shareholders' equity in accordance with US GAAP, partially offset by a reduction in retained earnings of approximately $37 million (December 31, 2010 – $30 million), an increase in accumulated other comprehensive loss of approximately $21 million (December 31, 2010 – $14 million) and other miscellaneous changes in shareholders' equity based on the retrospective application of US GAAP. Approximately half of the reduction in retained earnings results from higher corporate income taxes, as referred to above, and is expected to reverse in a future period once pending Canadian federal income tax legislation is passed and proposed Part VI.1 tax rate changes are enacted.

As previously indicated, and subject to the above-noted one-time adjustment with respect to Newfoundland Power's inability to recognize its OPEB regulatory asset as at January 1, 2010 and its subsequent ability to re-recognize this OPEB regulatory asset in 2010, there are no material adjustments to the Corporation's consolidated 2010 and 2011 earnings under US GAAP due to the Corporation's continued ability to apply rate-regulated accounting policies.

The audited quantification and reconciliation of the Corporation's consolidated statements of earnings for the years ended December 31, 2011 and December 31, 2010, prepared in accordance with US GAAP versus Canadian GAAP, may be summarized as follows.

- *Year ended December 31, 2011:* Consolidated net earnings recognized in accordance with US GAAP increase by $10 million (from $356 million to $366 million). The increase is due primarily to the reclassification of preference share dividends totalling $17 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by a reduction in earnings attributable to common equity shareholders of approximately $7 million.

- *Year ended December 31, 2010:* Consolidated net earnings recognized in accordance with US GAAP, prior to the one-time adjustment to re-recognize Newfoundland Power's OPEB regulatory asset, increase by approximately $6 million (from $323 million to $329 million). The increase is due primarily to the reclassification of preference share dividends totalling $17 million, in accordance with US GAAP, from finance charges to earnings attributable to preference equity shareholders, partially offset by a reduction in earnings attributable to common equity shareholders of approximately $11 million.

- The one-time, non-recurring adjustment to re-recognize Newfoundland Power's OPEB regulatory asset in 2010 increases earnings attributable to common equity shareholders for the year ended December 31, 2010 by approximately $46 million. This adjustment does not impact retained earnings as at December 31, 2010, compared to retained earnings reported in accordance with Canadian GAAP as at December 31, 2010, as it reverses an adjustment made to derecognize the OPEB regulatory asset upon adoption of US GAAP as at January 1, 2010.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments

As at December 31	**2011**		2010	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**45**	**49**	42	40
Long-term debt, including current portion (1)	**5,788**	**7,143**	5,669	6,431
Preference shares, classified as debt (2)	**320**	**348**	320	344

(1) Carrying value as at December 31, 2011 excludes unamortized deferred financing costs of $43 million (December 31, 2010 – $42 million) and capital lease obligations of $40 million (December 31, 2010 – $38 million)

(2) Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $634 million as at December 31, 2011 (December 31, 2010 – carrying value $592 million; fair value $615 million).

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

The Financial Instruments table above excludes the long-term other asset associated with the Corporation's previous investment in Belize Electricity, which was expropriated by the GOB in June 2011. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts.

From time to time the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes.

The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31, 2011 and 2010.

Derivative Financial Instruments

As at December 31	**2011**				2010	
Liability	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *($ millions)*	**Estimated Fair Value** *($ millions)*	Carrying Value *($ millions)*	Estimated Fair Value *($ millions)*
Foreign exchange forward contract	**< 1**	**1**	**–**	**–**	–	–
Fuel option contracts	**< 1**	**2**	**(1)**	**(1)**	–	–
Natural gas derivatives:						
Swaps and options	**Up to 3**	**143**	**(135)**	**(135)**	(162)	(162)
Gas purchase contract premiums	**Up to 3**	**57**	**–**	**–**	(5)	(5)

The foreign exchange forward contract is held by FEI to hedge the cash flow risk related to approximately US$4 million remaining to be paid under a contract for the implementation of a customer care information system. FEVI was also party to a foreign exchange forward contract to hedge the cash flow risk related to US dollar payments under a contract for the construction of the LNG storage facility on Vancouver Island. During 2011 FEVI's foreign exchange forward contract matured.

The fuel option contracts are held by Caribbean Utilities. During 2011 the Company's Fuel Price Volatility Management Program was approved by the regulator to reduce the impact of volatility in fuel prices on customer rates and Caribbean Utilities entered into two fuel option contracts.

The natural gas derivatives are held by the FortisBC Energy companies and are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to temper gas price volatility on customer rates and to reduce the risk of regional price discrepancies. For further information refer to the "Business Risk Management – Commodity Price Risk" section of this MD&A.

The changes in the fair values of the foreign exchange forward contract, fuel option contracts and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the derivative financial instruments were recognized in accounts payable as at December 31, 2011 and 2010.

The foreign exchange forward contract is valued using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. The fuel option contracts are valued using published market prices for similar commodities. The natural gas derivatives are valued using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas. The fair values of the foreign exchange forward contract, fuel option contracts and natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet date.

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Certain amounts are recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings.

Due to changes in facts and circumstances, and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. As at December 31, 2011, Fortis recognized $1,195 million in current and long-term regulatory assets (December 31, 2010 – $1,095 million) and $601 million in current and long-term regulatory liabilities (December 31, 2010 – $527 million).

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2011, the Corporation's consolidated utility capital assets, income producing properties and intangible assets totalled approximately $9.6 billion, or approximately 71% of total consolidated assets, compared to consolidated utility capital assets, income producing properties and intangible assets totalling approximately $9.1 billion, or approximately 70% of total consolidated assets, as at December 31, 2010. The increase in capital assets was primarily associated with capital expenditures, which totalled approximately $1.2 billion in 2011. Amortization costs for 2011 were $419 million compared to $410 million for 2010. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization costs.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authority. As required by their respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. The accrual of the estimated costs is included with amortization costs and the provision balance is recognized as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recognized against the regulatory liability when incurred. The estimate of the asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2011 was $354 million (December 31, 2010 – $339 million). The amount of asset removal and site restoration costs provided for and recognized in amortization costs during 2011 was $53 million (2010 – $50 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party amortization studies are performed at the regulated utilities. Based on the results of these amortization studies, the impact of any over- or under-amortization, as a result of actual experience differing from that expected and provided for in previous amortization rates, is generally reflected in future amortization rates and amortization costs, when the differences are refunded or collected in customer rates as approved by the regulator. A depreciation study performed at Newfoundland Power during the first half of 2011, based on capital assets in service as at December 31, 2010, indicates an accumulated amortization variance of approximately $18 million. Subject to regulator approval, this variance is expected to increase the amortization of capital assets in future years, which will be recovered in future customer rates. Amortization studies were performed at the FortisBC Energy companies, FortisBC Electric and FortisAlberta during 2011 that have been filed as part of rate applications filed with the respective regulators. The impact of those studies will be determined based on final rate decisions by the regulators, which are expected in 2012.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A future income tax asset or liability is determined for each temporary difference based on the future tax rates that are expected to be in effect and management's assumptions regarding the expected timing of the reversal of such temporary differences. Future income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period that the allowance is created or revised. Estimates of the provision for income taxes, future income tax assets and liabilities, and any related valuation allowance might vary from actual amounts incurred.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings.

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. Fair market value is determined using net present value financial models and management's assumption of the future profitability of the reporting units. As at October 1 of each year, the Corporation reviews for impairment of goodwill. There was no impairment provision required on approximately $1.6 billion of goodwill recognized on the Corporation's consolidated balance sheet as at December 31, 2011.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans and OPEB plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligations are the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted-average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2012, is 6.76%, which is down slightly from 6.88% used in 2011. The defined benefit pension plan assets experienced total positive returns of approximately $42 million in 2011 compared to expected positive returns of $47 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed weighted-average discount rate used to measure the accrued pension benefit obligations on the applicable measurement dates in 2011 and determine net pension cost for 2012 is 4.65%, compared to the assumed weighted-average discount rate used to measure the accrued pension benefit obligations in 2010 and determine net pension cost for 2011 of 5.37%. The decrease in the assumed weighted-average discount rate is mainly due to lower credit risk spreads and cost of capital on investment-grade corporate bonds. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

There was a $7 million increase in consolidated defined benefit net pension cost for 2011 compared to 2010, mainly as a result of the impact of lower assumed discount rates for calculating net pension cost in 2011 compared to 2010 and the amortization of net actuarial losses that arose in prior years.

Consolidated defined benefit net pension cost for 2012 is expected to be higher than for 2011, driven mainly by decreases in discount rates assumed in the measurement of the pension obligations. The increased costs are expected to be recovered in customer rates at the regulated utilities, subject to forecast risk at some of the smaller utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2011 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recognized in the Corporation's 2011 Consolidated Financial Statements, as well as the impact on the accrued defined benefit pension obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2011

Increase (decrease)	Net pension benefit cost		Accrued benefit asset		Accrued benefit liability		Accrued benefit obligation [(1)]	
($ millions)	Regulated Gas Utilities [(1)]	Regulated Electric Utilities	Regulated Gas Utilities [(1)]	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities
Impact of increasing the rate of return assumption by 100 basis points	3	(5)	(3)	5	–	–	43	2
Impact of decreasing the rate of return assumption by 100 basis points	(2)	5	2	(5)	–	–	(35)	(6)
Impact of increasing the discount rate assumption by 100 basis points	(7)	(8)	6	8	(2)	–	(66)	(71)
Impact of decreasing the discount rate assumption by 100 basis points	8	10	(6)	(10)	2	–	82	89

(1) At the FortisBC Energy companies and FortisBC Electric, the methodology for determining the pension indexing assumption, which impacts the measurement of the accrued benefit pension obligation, is based off of the expected long-term rate of return on pension plan assets. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the accrued benefit pension obligation. The direction of the impact of a change in the rate of return on plan asset assumption at the FortisBC Energy companies is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring defined benefit net pension cost and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and related obligation. Similar assumptions as described above, except for the assumptions of the expected long-term rate of return on pension plan assets and average rate of compensation increase, along with health care cost trends, were also utilized by management in determining OPEB plan cost and obligations.

As approved by the respective regulator, the cost of OPEB plans at FortisAlberta, and at Newfoundland Power until December 31, 2010, is recovered in customer rates based on the cash payments made. The cost of defined benefit pension plans at FortisAlberta is also recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being recovered in customer rates based on the accrual method of accounting for OPEBs. As discussed in the "Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements" section of this MD&A, the FortisBC Energy companies and FortisBC Electric, and Newfoundland Power beginning in 2011, have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above deferral mechanism at the FortisBC Energy companies and FortisBC Electric will continue in the future as it is dependent on future regulatory decisions and orders.

As at December 31, 2011, for all defined benefit and OPEB plans, the Corporation had a consolidated accrued benefit asset of $87 million (December 31, 2010 – $94 million) and a consolidated accrued benefit liability of $168 million (December 31, 2010 – $157 million). During 2011 the Corporation recognized a consolidated net benefit cost of $54 million (2010 – $38 million) for all defined benefit and OPEB plans.

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, there were no amounts recognized as at December 31, 2011 and 2010, with the exception of AROs recognized by FortisBC Electric.

As at December 31, 2011, FortisBC Electric has recognized an approximate $4 million ARO (December 31, 2010 – $3 million) associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment, which has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating FortisBC Electric's ARO represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. The ARO may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2011, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

Revenue Recognition: Revenue at the Corporation's regulated utilities is recognized on an accrual basis. Gas and electricity consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically, usually monthly, and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2011, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $341 million (December 31, 2010 – $342 million) on annual consolidated revenue of approximately $3,747 million for 2011 (2010 – $3,657 million).

Capitalized Overhead: As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utiltiies and Fortis Turks and Caicos capitalize overhead costs that are not directly attributable to specific utility capital assets but do relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. The general expenses capitalized ("GEC") are allocated to constructed utility capital assets and amortized over their estimated service lives. In 2011 GEC totalled $58 million (2010 – $57 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI has begun the appeal process associated with the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric, dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2011, 2010 and 2009. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected for non-regulated entities.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2011**	2010	2009
Revenue	**3,747**	3,657	3,641
Net earnings	**356**	323	292
Net earnings attributable to common equity shareholders	**318**	285	262
Total assets	**13,562**	12,909	12,139
Long-term debt and capital lease obligations (excluding current portion)	**5,679**	5,609	5,276
Preference shares (1)	**912**	912	667
Common shareholders' equity	**3,877**	3,305	3,193
Basic earnings per common share	**1.75**	1.65	1.54
Diluted earnings per common share	**1.74**	1.62	1.51
Dividends declared per common share (2)	**1.17**	1.41	0.78
Dividends declared per First Preference Share, Series C (2)	**1.3625**	1.7031	1.0219
Dividends declared per First Preference Share, Series E (2)	**1.2250**	1.5313	0.9188
Dividends declared per First Preference Share, Series F (2)	**1.2250**	1.5313	0.9188
Dividends declared per First Preference Share, Series G (2)	**1.3125**	1.6406	0.9844
Dividends declared per First Preference Share, Series H (2) (3)	**1.0625**	1.1636	–

(1) Includes preference shares classified as equity and long-term debt

(2) First quarter 2010 dividends were declared in January 2010, resulting in three quarters of dividends declared in 2009 and five quarters of dividends declared in 2010

(3) A total of 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H were issued on January 26, 2010 at $25.00 per share for net after-tax proceeds of $242 million, which are entitled to receive cumulative dividends in the amount of $1.0625 per share per annum for the first five years.

2011/2010: Revenue increased $90 million, or 2.5%, over 2010 and net earnings attributable to common equity shareholders grew to $318 million, up $33 million from 2010. For a discussion of the reasons for the increases in revenue and net earnings attributable to common equity shareholders year over year, refer to the "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A. The growth in total assets was primarily due to the Corporation's continued investment in energy infrastructure, driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. The increase in long-term debt was in support of energy infrastructure investment, partially offset by the repayment in 2011 of committed credit facility borrowings, classified as long term, with a portion of the proceeds from the $341 million public common equity offering. The increases in total assets and long-term debt were partially offset by the impact of the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility in 2011. Basic earnings per common share increased 10 cents, or 6%, from 2010, mainly due to increased earnings, partially offset by the impact of an increase in the weighted average number of common shares outstanding, mainly associated with the public common equity offering in 2011. Dividends declared per common and preference shares for 2011 decreased from 2010 as a result of the timing of the declaration of dividends, partially offset by a 3.4% increase in the quarterly common share dividend declared in the fourth quarter of 2011. First quarter 2010 dividends were declared in January 2010, when normally they would have been declared in the fourth quarter of the preceding year, resulting in five quarters of dividends per common share being declared in 2010.

2010/2009: Revenue increased $16 million, or 0.4%, over 2009. The increase was mainly due to: (i) base customer rate increases at the regulated utilities in Canada, combined with the accrual of electricity rate revenue at FortisAlberta related to its regulator-approved revenue requirements for 2010; (ii) customer growth; (iii) contribution from Algoma Power for a full year in 2010; and (iv) the flow through to customers of generally higher energy supply costs at the electric utilities. The above increases were partially offset by the flow through to customers of lower natural gas commodity costs, the unfavourable impact of foreign currency translation and lower consumption of natural gas. Net earnings attributable to common equity shareholders grew to $285 million, up $23 million from 2009. The increase in earnings was mainly due to improved performance at the Corporation's Canadian regulated utilities associated with: (i) rate base growth driven by the electric utilities in western Canada; (ii) an increase in the allowed ROEs for the FortisBC Energy companies from July 1, 2009 and for FortisBC Electric from January 1, 2010, as well as an increase in the equity component of capital structure at FEI from January 1, 2010; (iii) customer growth at FortisAlberta; and (iv) electricity sales growth at Newfoundland Power. The improvement in earnings was also due to increased earnings from non-regulated hydroelectric generation operations, mainly due to the newly constructed Vaca hydroelectric generating facility in Belize, and lower effective corporate income taxes at Fortis Properties. The improvement in earnings also reflected the favourable $9 million year-over-year impact of the reversal in 2010, as approved by the regulator, of a provision taken in the fourth quarter of 2009 for the project cost overrun related to the conversion of Whistler customer appliances from propane to natural gas. The increase in earnings was partially offset by lower contributions from Caribbean Regulated Electric Utilities, driven by unfavourable foreign currency translation, the inability of Belize Electricity to earn a fair and reasonable return due to regulatory challenges and continued unfavourable economic conditions, and higher corporate expenses mainly related to dividends on preference shares issued in January 2010 and business development costs incurred in 2010. The growth in total assets was primarily due to the Corporation's continued investment in energy infrastructure, driven by the capital expenditure programs at FortisAlberta, FortisBC Electric and the FortisBC Energy companies. The increase in long-term debt was in support of energy infrastructure investment. Basic earnings per common share increased 11 cents, or 7%, from 2009, mainly due to increased earnings for the reasons discussed above. Dividends declared per common and preference share for 2010 increased over 2009 primarily due to the timing of the declaration of dividends. First quarter 2010 dividends were declared in January 2010, when normally they would have been declared in the fourth quarter of the preceding year.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the quarters ended December 31, 2011 and 2010. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP. A discussion of the financial results for the fourth quarter of 2011 is also contained in the Corporation's fourth quarter 2011 media release, dated and filed on SEDAR at www.sedar.com on February 9, 2012, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue
Fourth Quarters Ended December 31 *(Unaudited)*

	Gas Volumes Energy and Electricity Sales			Revenue ($ millions)		
	2011	2010	Variance	**2011**	2010	Variance
Regulated Gas Utilities – Canadian *(TJ)*						
FortisBC Energy Companies	**62,753**	60,398	2,355	**477**	479	(2)
Regulated Electric Utilities – Canadian *(GWh)*						
FortisAlberta	**4,232**	4,255	(23)	**102**	99	3
FortisBC Electric	**843**	847	(4)	**81**	73	8
Newfoundland Power	**1,527**	1,488	39	**156**	152	4
Other Canadian Electric Utilities	**568**	578	(10)	**84**	87	(3)
	7,170	7,168	2	**423**	411	12
Regulated Electric Utilities – Caribbean	**174**	270	(96)	**70**	84	(14)
Non-Regulated – Fortis Generation	**112**	137	(25)	**9**	9	–
Non-Regulated – Fortis Properties				**58**	57	1
Corporate and Other				**7**	7	–
Inter-Segment Eliminations				**(7)**	(13)	6
Total				**1,037**	1,034	3

Factors Contributing to Gas Volumes Variance

Favourable

- Higher average consumption by residential and commercial customers as a result of cooler weather
- Higher transportation volumes, reflecting improving economic conditions favourably affecting the forestry and mining sectors

Unfavourable

- Lower volumes under fixed revenue contracts, mainly due to higher precipitation, which made it more cost efficient for a large customer to not utilize its natural gas-powered generating facility for significant periods during 2011

Factors Contributing to Energy and Electricity Sales Variances

Unfavourable

- Lower electricity sales at Caribbean Regulated Electric Utilities due to the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, and reduced energy consumption due to challenging economic conditions in the region and the high cost of fuel, partially offset by growth in the number of customers and warmer temperatures in the region during the fourth quarter of 2011, which favourably impacted customer air conditioning load. Excluding Belize Electricity, electricity sales increased 3.7% quarter over quarter.
- Lower energy sales at Non-Regulated – Fortis Generation related to decreased production in Upper New York State, due to a generating plant being out of service since May 2011, partially offset by increased production in Belize because of higher rainfall
- Lower energy deliveries at FortisAlberta, associated with lower average consumption by the gas sector due to decreased activity as a result of low gas market prices; decreased average consumption by the oilfield sector; and lower average consumption by residential customers due to warmer-than-normal temperatures in the fourth quarter of 2011. The above decreases were partially offset by growth in the number of customers and higher average consumption by farm and irrigation customers, due to differences in rainfall year over year.
- Lower electricity sales at Other Canadian Regulated Electric Utilities, driven by lower average consumption by residential customers in Ontario reflecting more moderate temperatures, which decreased home-heating load, and lower average consumption by industrial customers on PEI due to a reduction in farm crop storage and warehousing activities. The above decreases were partially offset by growth in the number of residential customers, and higher average consumption by residential customers on PEI, reflecting cooler temperatures, which increased home-heating load.

Favourable

- Increased electricity sales at Newfoundland Power, associated with growth in the number of customers, and higher average consumption reflecting the higher concentration of electric-versus-oil heating in new home construction, combined with strong economic growth

Factors Contributing to Revenue Variance

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the Corporation's Canadian regulated utilities
- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities
- Growth in the number of customers, mainly at FortisAlberta
- Higher gas sales

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011
- Lower commodity cost of natural gas charged to customers
- A rate revenue reduction accrued at FortisAlberta during the fourth quarter of 2011 reflecting the cumulative impact, from January 1, 2011, of the decrease in the allowed ROE for 2011
- Lower base component of customer rates at Maritime Electric associated with the recovery of energy supply costs
- Lower joint-use pole-related revenue at Newfoundland Power, due to new support structure arrangements with Bell Aliant in 2011

Segmented Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions, except per share amounts)	**2011**	2010	Variance
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**51**	45	6
Regulated Electric Utilities – Canadian			
FortisAlberta	***17***	*17*	–
FortisBC Electric	***11***	*10*	*1*
Newfoundland Power	***8***	*9*	*(1)*
Other Canadian Electric Utilities	***4***	*5*	*(1)*
	40	41	(1)
Regulated Electric Utilities – Caribbean	**3**	4	(1)
Non-Regulated – Fortis Generation	**5**	6	(1)
Non-Regulated – Fortis Properties	**5**	7	(2)
Corporate and Other	**(18)**	(18)	–
Net Earnings Attributable to Common Equity Shareholders	**86**	85	1
Basic Earnings per Common Share *($)*	**0.46**	0.49	(0.03)

Factors Contributing to Earnings Variance

Favourable

- Higher earnings at the FortisBC Energy companies driven by rate base growth, lower-than-expected corporate income taxes and finance charges in 2011, and higher gas transportation volumes to the forestry and mining sectors, partially offset by both lower customer additions and capitalized AFUDC

Unfavourable

- Lower earnings at Newfoundland Power, mainly due to a lower allowed ROE for 2011, lower earnings contribution associated with the new joint-use pole support structure arrangements with Bell Aliant in 2011 and higher operating expenses, partially offset by reduced energy supply costs in the fourth quarter of 2011 and higher electricity sales
- Lower earnings at Other Canadian Regulated Electric Utilities, mainly associated with decreased electricity sales and higher operating expenses
- Lower earnings at Caribbean Regulated Electric Utilities, reflecting lower earnings at Fortis Turks and Caicos associated with higher amortization costs and operating expenses, partially offset by reduced energy supply costs in 2011
- Lower earnings at Fortis Properties, mostly due to higher corporate income taxes

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*

($ millions)	**2011**	2010	Variance
Cash, Beginning of Period	**108**	64	44
Cash Provided by (Used in):			
Operating Activities	**227**	198	29
Investing Activities	**(369)**	(333)	(36)
Financing Activities	**124**	180	(56)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(1)**	–	(1)
Cash, End of Period	**89**	109	(20)

Cash flow from operating activities, after working capital adjustments, was $29 million higher quarter over quarter, mainly due to favourable changes in working capital and higher earnings. Favourable working capital changes associated with accounts receivable and inventories were partially offset by unfavourable changes in accounts payable.

Cash used in investing activities was $36 million higher quarter over quarter. The increase was due to a $49 million deferred payment being made in December 2011, in accordance with an agreement, associated with FHI's acquisition of FEVI in 2002. The deferred payment was originally classified in long-term other liabilities. Cash used in investing activities also increased as a result of the acquisition of the Hilton Suites Winnipeg Airport hotel in October 2011. The above increases were partially offset by higher proceeds from the sale of utility capital assets associated with the sale of joint-use poles at Newfoundland Power in October 2011.

Cash provided by financing activities was $56 million lower quarter over quarter, due to: (i) lower proceeds from long-term debt; (ii) higher repayments of short-term borrowings; and (iii) lower advances from non-controlling interests in the Waneta Partnership, partially offset by lower repayments of both long-term debt and committed credit facility borrowings classified as long-term.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2010 through December 31, 2011. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements, which have been prepared in accordance with Canadian GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses as a result of regulation may differ from that otherwise expected for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results
(Unaudited)

Quarter Ended	Revenue *($ millions)*	Net Earnings Attributable to Common Equity Shareholders *($ millions)*	Earnings per Common Share Basic *($)*	Earnings per Common Share Diluted *($)*
December 31, 2011	1,037	86	0.46	0.45
September 30, 2011	702	57	0.31	0.31
June 30, 2011	849	58	0.33	0.33
March 31, 2011	1,159	117	0.67	0.65
December 31, 2010	1,034	85	0.49	0.47
September 30, 2010	719	45	0.26	0.26
June 30, 2010	834	55	0.32	0.32
March 31, 2010	1,070	100	0.58	0.56

A summary of the past eight quarters mainly reflects the Corporation's continued organic growth, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Earnings for the third quarter ended September 30, 2011 included the $11 million after-tax termination fee paid to Fortis by CVPS. Financial results for the fourth quarter ended December 31, 2011 reflected the acquisition of the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011. Financial results from June 20, 2011 reflected the discontinuance of the consolidation method of accounting for Belize Electricity due to the expropriation of the utility by the GOB. For further information, refer to the "Key Trends and Risks – Expropriated Assets" and "Business Risk Management – Investment in Belize" sections of this MD&A. Revenue for the third quarter ended September 30, 2010 reflected the favourable cumulative retroactive impact associated with the 2010 revenue requirements decision at FortisAlberta. The commissioning of the Vaca hydroelectric generating facility in March 2010 has favourably impacted financial results since that date.

December 2011/December 2010: Net earnings attributable to common equity shareholders were $86 million, or $0.46 per common share, for the fourth quarter of 2011 compared to earnings of $85 million, or $0.49 per common share, for the fourth quarter of 2010. A discussion of the variances between the financial results for the fourth quarter of 2011 and the fourth quarter of 2010 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2011/September 2010: Net earnings attributable to common equity shareholders were $57 million, or $0.31 per common share, for the third quarter of 2011 compared to earnings of $45 million, or $0.26 per common share, for the third quarter of 2010. The increase in earnings was mainly due to the $11 million after-tax fee paid to Fortis in July 2011, following the termination of the Merger Agreement between Fortis and CVPS. Results also improved due to rate base growth associated with energy infrastructure investment, mainly at the regulated utilities in western Canada, a net foreign exchange gain of approximately $2.5 million after tax associated with the previously hedged investment in Belize Electricity, lower-than-expected operating costs at the FortisBC Energy companies due to the timing of spending and capitalization of certain operating expenses in 2011 and a higher allowed ROE at Algoma Power. The above increases in earnings were partially offset by the impact of the regulator-approved reversal in the third quarter of 2010 of $4 million after tax of project overrun costs previously expensed in 2009 related to the conversion of Whistler customer appliances from propane to natural gas, the expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility since June 2011, lower capitalized AFUDC at FortisBC Electric, lower non-regulated hydroelectric generation in Belize and the timing of recording the 2010 revenue requirements decision at FortisAlberta. The favourable cumulative impact of the decision was recorded in the third quarter of 2010 when the decision was received.

June 2011/June 2010: Net earnings attributable to common equity shareholders were $58 million, or $0.33 per common share, for the second quarter of 2011 compared to earnings of $55 million, or $0.32 per common share, for the second quarter of 2010. The increase was mainly due to improved performance at Canadian Regulated Electric Utilities, driven by rate base growth associated with energy infrastructure investment mainly at the electric utilities in western Canada, return earned on additional investment in automated meters at FortisAlberta, as approved by the regulator, lower market-priced purchased power costs at FortisBC Electric and a higher allowed ROE at Algoma Power. Results also improved due to lower corporate business development costs. The above increases in earnings were partially offset by the unfavourable impact of the timing of spending of certain regulator-approved increased operating expenses at the FortisBC Energy companies during 2011, lower non-regulated hydroelectric generation in Belize, and lower contribution from Fortis Properties reflecting lower occupancies at hotel operations in western Canada and increased operating expenses. During the second quarter of 2011, the GOB expropriated the Corporation's investment in Belize Electricity.

March 2011/March 2010: Net earnings attributable to common equity shareholders were $117 million, or $0.67 per common share, for the first quarter of 2011 compared to earnings of $100 million, or $0.58 per common share, for the first quarter of 2010. The increase was mainly due to improved performance at the regulated utilities in western Canada, driven by overall rate base growth associated with energy infrastructure investment, higher energy sales at FortisBC Electric and FortisAlberta, the timing of recording the cumulative impact of FortisAlberta's and FEWI's 2010 revenue requirements decisions and a $1 million gain on the sale of property at FortisAlberta, partially offset by the unfavourable impact of the timing of spending of certain regulator-approved increased operating expenses at the FortisBC Energy companies during 2011. Earnings also increased due to lower corporate business development costs and higher non-regulated hydroelectric generation in Belize.

MANAGEMENT'S EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2011 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2011 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2011, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENT

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing ("the Acquisition"). CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The closing of the Acquisition, which is expected in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

OUTLOOK

The Corporation's significant capital expenditure program, which is expected to be approximately $5.5 billion over the five-year period 2012 through 2016, should support continuing growth in earnings and dividends.

The Corporation continues to pursue acquisitions for profitable growth, focusing on regulated electric and natural gas utilities in the United States and Canada. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

OUTSTANDING SHARE DATA

As at March 12, 2012, the Corporation had issued and outstanding 189.3 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; and 10.0 million First Preference Shares, Series H. Only the common shares of the Corporation have voting rights.

The number of common shares that would be issued upon conversion of share options, and First Preference Shares, Series C and First Preference Shares, Series E as at March 12, 2012 is as follows:

Conversion of Securities into Common Shares

As at March 12, 2012 *(Unaudited)*

Security	**Number of Common Shares** *(millions)*
Stock Options	4.7
First Preference Shares, Series C	4.0
First Preference Shares, Series E	6.5
Total	15.2

Additional information, including the Fortis 2011 Annual Information Form, Management Information Circular and Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

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Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2011 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2011 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2011 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2011 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2011 Annual Consolidated Financial Statements and their report follows.

H. Stanley Marshall
President and Chief Executive Officer

Barry V. Perry
Vice President, Finance and Chief Financial Officer

St. John's, Canada

Independent Auditors' Report

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, retained earnings and cash flows for the years then ended, and 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.

Auditors' 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 audit 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 auditors' 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 auditors consider 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 Fortis Inc. as at December 31, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

St. John's, Canada
March 13, 2012

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

ASSETS	2011	2010
Current assets		*(Note 34)*
Cash and cash equivalents	**$ 89**	$ 109
Accounts receivable *(Note 29)*	**644**	655
Prepaid expenses	**19**	17
Regulatory assets *(Note 5)*	**210**	241
Inventories *(Note 6)*	**134**	168
Future income taxes *(Note 22)*	**24**	14
	1,120	1,204
Assets held for sale *(Note 7)*	**–**	45
Other assets *(Note 8)*	**270**	168
Regulatory assets *(Note 5)*	**985**	854
Future income taxes *(Note 22)*	**8**	16
Utility capital assets *(Note 9)*	**8,687**	8,185
Income producing properties *(Note 10)*	**594**	560
Intangible assets *(Note 11)*	**341**	324
Goodwill *(Note 12)*	**1,557**	1,553
	$ 13,562	$ 12,909
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 29)*	**$ 159**	$ 358
Accounts payable and accrued charges	**914**	953
Dividends payable	**60**	54
Income taxes payable	**33**	30
Regulatory liabilities *(Note 5)*	**43**	60
Current installments of long-term debt and capital lease obligations *(Note 13)*	**106**	56
Future income taxes *(Note 22)*	**5**	6
	1,320	1,517
Other liabilities *(Note 14)*	**323**	308
Regulatory liabilities *(Note 5)*	**558**	467
Future income taxes *(Note 22)*	**685**	629
Long-term debt and capital lease obligations *(Note 13)*	**5,679**	5,609
Preference shares *(Note 15)*	**320**	320
	8,885	8,850
Shareholders' equity		
Common shares *(Note 16)*	**3,032**	2,578
Preference shares *(Note 15)*	**592**	592
Contributed surplus	**14**	12
Equity portion of convertible debentures *(Note 13)*	**–**	5
Accumulated other comprehensive loss *(Note 18)*	**(74)**	(94)
Retained earnings	**905**	804
	4,469	3,897
Non-controlling interests *(Note 19)*	**208**	162
	4,677	4,059
	$ 13,562	$ 12,909

Commitments *(Note 30)*

Contingent Liabilities *(Note 32)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2011**	2010
		(Note 34)
Revenue	**$ 3,747**	$ 3,657
Expenses		
Energy supply costs	**1,697**	1,686
Operating	**865**	822
Amortization	**419**	410
	2,981	2,918
Operating income	**766**	739
Other income (expenses), net *(Note 20)*	**40**	13
Finance charges *(Note 21)*	**370**	362
Earnings before corporate taxes	**436**	390
Corporate taxes *(Note 22)*	**80**	67
Net earnings	**$ 356**	$ 323
Net earnings attributable to:		
Non-controlling interests	**$ 9**	$ 10
Preference equity shareholders	**29**	28
Common equity shareholders	**318**	285
	$ 356	$ 323
Earnings per common share *(Note 16)*		
Basic	**$ 1.75**	$ 1.65
Diluted	**$ 1.74**	$ 1.62

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2011**	2010
Balance, beginning of year	**$ 804**	$ 763
Net earnings attributable to common and preference equity shareholders	**347**	313
	1,151	1,076
Dividends on common shares	**(217)**	(244)
Dividends on preference shares classified as equity	**(29)**	(28)
Balance, end of year	**$ 905**	$ 804

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2011**	2010
Net earnings	**$ 356**	$ 323
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and tax *(Note 18)*	**2**	(12)
Reclassification of unrealized foreign currency translation losses, net of hedging activities and tax, related to Belize Electricity *(Notes 8 and 18)*	**17**	–
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 18)*	**1**	1
	20	(11)
Comprehensive income	**$ 376**	$ 312
Comprehensive income attributable to:		
Non-controlling interests	**$ 9**	$ 10
Preference equity shareholders	**29**	28
Common equity shareholders	**338**	274
	$ 376	$ 312

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2011**	2010
		(Note 34)
Operating activities		
Net earnings	**$ 356**	$ 323
Items not affecting cash:		
Amortization – utility capital assets and income producing properties	**380**	368
Amortization – intangible assets	**42**	40
Amortization – other	**(3)**	2
Future income taxes *(Note 22)*	**4**	(3)
Accrued employee future benefits	**18**	8
Equity component of allowance for funds used during construction *(Note 20)*	**(13)**	(15)
Other	**(4)**	2
Change in long-term regulatory assets and liabilities	**26**	9
	806	734
Change in non-cash operating working capital *(Note 26)*	**98**	(2)
	904	732
Investing activities		
Change in other assets and other liabilities	**(52)**	–
Capital expenditures – utility capital assets	**(1,086)**	(1,008)
Capital expenditures – income producing properties	**(30)**	(19)
Capital expenditures – intangible assets	**(58)**	(46)
Contributions in aid of construction	**75**	67
Proceeds on sale of utility capital assets and income producing properties *(Note 7)*	**51**	15
Business acquisition, net of cash acquired *(Note 24)*	**(25)**	–
	(1,125)	(991)
Financing activities		
Change in short-term borrowings	**(198)**	(56)
Proceeds from long-term debt, net of issue costs	**343**	523
Repayments of long-term debt and capital lease obligations	**(36)**	(329)
Net (repayments) borrowings under committed credit facilities	**(145)**	8
Net advances from non-controlling interests	**81**	45
Issue of common shares, net of costs and dividends reinvested	**345**	22
Issue of preference shares, net of costs	**–**	242
Dividends		
Common shares, net of dividends reinvested	**(151)**	(135)
Preference shares	**(29)**	(28)
Subsidiary dividends paid to non-controlling interests	**(9)**	(9)
	201	283
Change in cash and cash equivalents	**(20)**	24
Cash and cash equivalents, beginning of year	**109**	85
Cash and cash equivalents, end of year	**$ 89**	$ 109

Supplementary Information to Consolidated Statements of Cash Flows *(Note 26)*

See accompanying Notes to Consolidated Financial Statements

December 31, 2011 and 2010

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility are as follows:

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Includes FortisBC Energy Inc. ("FEI") (formerly Terasen Gas Inc.), FortisBC Energy (Vancouver Island) Inc. ("FEVI") (formerly Terasen Gas (Vancouver Island) Inc.) and FortisBC Energy (Whistler) Inc. ("FEWI") (formerly Terasen Gas (Whistler) Inc.).

FEI is the largest distributor of natural gas in British Columbia serving more than 100 communities. Major areas served by FEI are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior regions of British Columbia.

FEVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island, and serves customers on Vancouver Island and along the Sunshine Coast of British Columbia.

FEWI owns and operates the natural gas distribution system in the Resort Municipality of Whistler, British Columbia.

In addition to providing transmission and distribution ("T&D") services to customers, the FortisBC Energy companies also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Included with the FortisBC Electric component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.

c. *Newfoundland Power:* Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. The Company has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.

d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations include Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc. ("Port Colborne Hydro"), which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10% interest in each of Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc., three regional electric distribution companies.

1. Description of the Business (cont'd)

Regulated Utilities (cont'd)

Regulated Electric Utilities – Caribbean

a. *Caribbean Utilities:* Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 151 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2010 – 59%). Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U).

b. *Fortis Turks and Caicos:* Includes FortisTCI Limited (formerly P.P.C. Limited) and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic"). Fortis Turks and Caicos is an integrated electric utility and the principal distributor of electricity in the Turks and Caicos Islands. The Company has a combined diesel-powered generating capacity of 65 MW.

c. *Belize Electricity:* Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize, Central America. Fortis held an approximate 70% controlling ownership interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011 (Notes 8 and 31).

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

a. *Belize:* Operations consist of the 25-MW Mollejon, 7-MW Chalillo and, as of March 2010, 19-MW Vaca hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under 50-year power purchase agreements expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the GOB.

b. *Ontario:* Includes six small hydroelectric generating facilities in eastern Ontario, with a combined capacity of 8 MW, and a 5-MW gas-powered cogeneration plant in Cornwall.

c. *Central Newfoundland:* Through the Exploits River Hydro Partnership (the "Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and AbitibiBowater Inc. ("Abitibi"), 36 MW of additional capacity was developed and installed at two of Abitibi's hydroelectric generating facilities in central Newfoundland. Fortis Properties holds directly a 51% interest in the Exploits Partnership and Abitibi holds the remaining 49% interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement ("PPA") expiring in 2033. In December 2008 the Government of Newfoundland and Labrador expropriated the hydroelectric assets and water rights of the Exploits Partnership. As a result of no longer controlling the cash flows and operations of the Exploits Partnership, Fortis discontinued the consolidation method of accounting for its investment in the Exploits Partnership, effective February 2009 (Note 31).

d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric generating facility near Lillooet, British Columbia, which sells its entire output to BC Hydro under a contract expiring in 2013. Effective October 1, 2010, non-regulated generation operations in British Columbia include the Corporation's 51% controlling ownership interest in the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The Waneta Partnership commenced construction of the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in late 2010, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia. The Waneta Expansion is expected to come into service in spring 2015.

e. *Upper New York State:* Includes the operations of four hydroelectric generating facilities, with a combined capacity of approximately 23 MW, in Upper New York State, operating under licences from the U.S. Federal Energy Regulatory Commission. Hydroelectric generation operations in Upper New York State are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 22 hotels, collectively representing 4,300 rooms, in eight Canadian provinces and approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada (Note 24).

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and FortisBC Holdings Inc. ("FHI") (formerly Terasen Inc.) and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and FHI corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenue; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which FHI holds a 30% interest. CWLP provides billing and customer care services to utilities, municipalities and certain energy companies. The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011. CWLP's financial results were recorded using the proportionate consolidation method of accounting. The financial results of FortisBC Alternative Energy Services Inc. ("FAES") (formerly Terasen Energy Services Inc.) are also reported in the Corporate and Other segment. FAES is a non-regulated wholly owned subsidiary of FHI that provides alternative energy solutions.

2. Nature of Regulation

The nature of regulation at the Corporation's utilities is as follows:

FortisBC Energy Companies and FortisBC Electric

The FortisBC Energy companies and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. FEI, FEVI, FEWI and FortisBC Electric operate under cost of service ("COS") regulation and, from time to time, performance-based rate-setting ("PBR") mechanisms as administered by the BCUC. The PBR mechanism for FEI expired on December 31, 2009 with a two-year phase-out for differences between forecast capital expenditures and those actually spent prior to 2010. The PBR mechanism for FortisBC Electric expired on December 31, 2011.

The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

FEI, FEVI, FEWI and FortisBC Electric apply for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible to be deferred on the consolidated balance sheet for future collection from, or refund to, customers ("deferral account treatment") and/or through the operation of PBR mechanisms.

Under the previous PBR mechanisms, FEI customers equally shared achieved earnings above or below the allowed ROE and FortisBC Electric customers equally shared achieved earnings above or below the allowed ROE up to an achieved ROE that was 200 basis points above or below the allowed ROE. Any excess was subject to deferral account treatment. FortisBC Electric's portion of the PBR incentive was subject to the Company meeting certain performance standards and BCUC approval. The BCUC-approved Negotiated Settlement Agreements for 2010 and 2011 for FEI and the 2012–2013 Revenue Requirements Applications for both FortisBC Electric and FEI did not include new PBR mechanisms.

FEI's allowed ROE was 9.50% for 2011 (2010 – 9.50%) on a deemed capital structure of 40% common equity. FEVI's and FEWI's allowed ROEs were 10.00% for 2011 (2010 – 10.00%) on deemed capital structures of 40% common equity. FortisBC Electric's allowed ROE was 9.90% for 2011 (2010 – 9.90%) on a deemed capital structure of 40% common equity.

Previously the allowed ROE at each of FEI, FEVI, FEWI and FortisBC Electric was adjusted annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond rates. Effective July 1, 2009 for FEI, FEVI and FEWI and effective January 1, 2010 for FortisBC Electric, the BCUC has set the allowed ROEs and has determined that the former automatic adjustment formula used to establish ROEs on an annual basis no longer applies until reviewed further by the BCUC. In November 2011 the BCUC gave notice to the FortisBC Energy companies and FortisBC Electric of its intention to initiate a Generic Cost of Capital Proceeding. The proceeding will take place, beginning in March 2012, to review: (i) the setting of the appropriate cost of capital for a benchmark low-risk utility in British Columbia; (ii) the possible return to an ROE automatic adjustment mechanism for setting an ROE for the benchmark low-risk utility; and (iii) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities in British Columbia without third-party debt.

2. Nature of Regulation (cont'd)

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

FortisAlberta operates under COS regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.75% for 2011 (2010 – 9.00%) on a deemed capital structure of 41% common equity. The Company applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Previously FortisAlberta's allowed ROE was adjusted annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond rates. In its November 2009 Generic Cost of Capital Decision, the AUC ordered that the allowed ROE for utilities it regulates in Alberta be set at 9.00% for 2009, 2010 and, on an interim basis, 2011 and that the automatic adjustment formula used to establish the ROE no longer apply until reviewed further by the AUC. In December 2011 the AUC issued its decision on its 2011 Generic Cost of Capital Proceeding establishing the allowed ROE at 8.75% for 2011 and 2012, and at 8.75% for 2013 on an interim basis. The automatic adjustment formula continues to no longer apply.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power.

Newfoundland Power operates under COS regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which Newfoundland Power's customer rates are determined.

Generally the utility's allowed ROE is adjusted, between test years, annually through the operation of an automatic adjustment formula for forecast changes in long-term Canada bond rates. For 2010, however, the PUB set Newfoundland Power's allowed ROE at 9.00% on a deemed capital structure of 45% common equity. For 2011 the Company's allowed ROE was 8.38%, as calculated under the automatic adjustment formula, on a deemed capital structure of 45% common equity. In December 2011 the PUB approved Newfoundland Power's application to suspend the operation of the automatic adjustment formula for 2012 and to continue using, on an interim basis, the allowed ROE of 8.38% until there is a full cost of capital review, which is expected in 2012.

Newfoundland Power applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Maritime Electric

Maritime Electric operates under a COS regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island), the *Renewable Energy Act* (Prince Edward Island) and the *Electric Power (Electricity Rate-Reduction) Amendment Act* (Prince Edward Island), also known as the PEI Energy Accord (the "Accord"), which covers the period March 1, 2011 to February 29, 2016.

IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a targeted capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 9.75% for 2011 (2010 – 9.75%) on a targeted minimum capital structure of 40% common equity.

In November 2010 Maritime Electric signed the Accord with the Government of PEI. Under the terms of the Accord, the Government of PEI is assuming responsibility for the cost of incremental replacement energy and the monthly operating and maintenance costs related to Maritime Electric's 4.7% entitlement from the New Brunswick Power ("NB Power") Point Lepreau Nuclear Generating Station ("Point Lepreau"), effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012. Maritime Electric also signed a five-year energy purchase agreement with NB Power, effective March 1, 2011. As a result of the Accord and the impact of the new energy purchase agreement, energy supply costs have decreased and customer electricity rates were lowered by approximately 14.0%, effective March 1, 2011, at which time a two-year customer rate freeze commenced.

Maritime Electric applies for tariff revenue based on estimated COS. Once the tariff is approved, it is not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs.

Canadian Niagara Power's allowed ROE was 8.01% for 2011 (2010 – 8.01%) on a deemed capital structure of 40% common equity effective May 1, 2010. Prior to May 1, 2010, the Company's deemed capital structure was 43.3% common equity. Electricity distribution rates for 2011 and 2010 were based upon a 2009 historical test year.

Effective December 1, 2010, Algoma Power's allowed ROE was 9.85% on a deemed capital structure of 40% common equity and the utility's electricity distribution rates were rebased using forecast 2011 costs. Prior to December 1, 2010, the Company's allowed ROE was 8.57% on a deemed capital structure of 50% common equity and the utility's electricity distribution rates were based upon costs derived from a 2007 historical test year. Algoma Power is subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario.

Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth, customer growth and premises vacancies.

Caribbean Utilities

Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The non-exclusive generation licence is for a period of 21.5 years, expiring September 2029.

The licences contain the provision for a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer electricity rates for 2011 were set in accordance with the licences, translating into a targeted allowed rate of return on rate base assets ("ROA") range of 7.75% to 9.75% (2010 – 7.75% to 9.75%). The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the RCAM and annually approves capital expenditures.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through FortisTCI and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated January and October 1987, and November 1986 (collectively, the "Agreements"), respectively. Among other matters, the Agreements describe how electricity rates are to be set by the Interim Government of the Turks and Caicos Islands ("Interim Government"), using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.50% (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall").

Fortis Turks and Caicos makes annual submissions to the Interim Government calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2011 calculated the Allowable Operating Profit for 2011 to be $30 million (US$29 million) and the Cumulative Shortfall at December 31, 2011 to be $73 million (US$72 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses.

In August 2011 Fortis Turks and Caicos filed with the Interim Government an Electricity Rate Variance Application, which requested a change in the rate structure and an overall approximate 6% increase in base rates to government and commercial customers. In February 2012 the Interim Government approved, among other items, a 26% increase in electricity rates for large hotels, effective April 1, 2012.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services, and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licence conditions. The basic customer electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery and the second is the cost of fuel and purchased power, including the variable cost of generation, which is a flow through in customer rates. The value-added delivery component of the tariff allows the Company to recover its operating expenses, T&D expenses, taxes and amortization, and an allowed ROA. As a result of the June 2008 Final Decision by the PUC, the allowed ROA for Belize Electricity was 10.00% for 2011 (2010 – 10.00%). The allowed ROA, however, was not achieved due to regulatory challenges. On June 20, 2011, the Corporation's investment in Belize Electricity was expropriated by the GOB (Note 31).

3. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2011; however, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS, due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the International Accounting Standards Board ("IASB"). As a qualifying entity with rate-regulated activities, Fortis elected the one-year deferral and, therefore, prepared its consolidated financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants ("CICA") Handbook for all interim and annual periods ending on or before December 31, 2011.

The consolidated financial statements include selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected by entities not subject to rate regulation. The differences are described in this note under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Employee Future Benefits, Income Taxes and Revenue Recognition, and in Note 5.

All amounts presented are in Canadian dollars unless otherwise stated.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of deposit.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Certain assets and liabilities arising from rate regulation have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under CICA Handbook Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 5, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100, *Generally Accepted Accounting Principles*, directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Corporation may consult other sources, including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Corporation has determined that all of its regulatory assets and liabilities qualify for recognition under Canadian GAAP, and this recognition is consistent with the general principles of U.S. Financial Accounting Standards Board's Accounting Standard Codification 980, *Regulated Operations*.

Inventories

Inventories are valued at the lower of weighted average cost and net realizable value. When a situation that previously caused inventories to be written down below cost no longer exists, the amount of the write-down is to be reversed.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated amortization, with the following exceptions for rate-setting purposes: (i) utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost; (ii) utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984, with subsequent additions at cost; and (iii) utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions at Fortis Turks and Caicos are at cost, including the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by the Agreements for US$2.00, in aggregate, as valued in the books of the Companies.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. The accrual of the estimated costs is included with amortization costs and the provision balance is recognized as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. As at December 31, 2011, the long-term regulatory liability for asset removal and site restoration costs, net of salvage proceeds, was $354 million (December 31, 2010 – $339 million) (Note 5 *(xx)*).

As permitted by the regulator, FortisBC Electric records actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization as incurred. During 2011 actual asset removal and site restoration costs of approximately $5 million (2010 – $8 million) were incurred at FortisBC Electric, net of salvage proceeds of less than $1 million (2010 – $1 million).

In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, at FortisAlberta, FortisBC Electric, Newfoundland Power and Maritime Electric would be recognized in earnings in the period incurred.

The FortisBC Energy companies, FortisOntario, Caribbean Utilities, Fortis Turks and Caicos and Belize Electricity recognize asset removal and site restoration costs, net of salvage proceeds, in earnings in the period incurred. At the FortisBC Energy companies, actual costs incurred in excess of, or below, the amount provided for in customer rates are recorded in a regulatory deferral account for recovery from, or refund to, customers in future rates. During 2011 actual asset removal and site restoration costs of approximately $15 million were incurred (2010 – $10 million), with $11 million (2010 – $8 million) recorded in operating expenses and $4 million (2010 – $2 million) deferred as a regulatory asset. In the absence of rate regulation, deferral account treatment would not be permitted at the FortisBC Energy companies and all asset removal and site restoration costs, net of salvage proceeds, would be recognized in earnings in the period incurred.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity, as required by their respective regulator, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization costs when they are collected in customer gas and electricity rates. The loss charged to accumulated amortization in 2011 was approximately $18 million (2010 – $24 million).

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval (Note 5 *(viii)*).

In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity would be recognized in earnings in the period incurred.

At FortisOntario and Fortis Turks and Caicos, the regulatory authorities require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets be recognized immediately in earnings.

As required by their respective regulator, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities, Fortis Turks and Caicos and Belize Electricity capitalize overhead costs that are not directly attributable to specific utility capital assets but do relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulator. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated to constructed utility capital assets and amortized over their estimated service lives. In 2011 GEC totalled $58 million (2010 – $57 million).

As required by their respective regulator, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity include an equity component in the allowance for funds used during construction ("AFUDC"), which is included in the cost of utility capital assets. Since AFUDC includes both a debt component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. The debt component of AFUDC is deducted from finance charges and the equity component of AFUDC is recognized in other income. AFUDC capitalized during 2011 was $32 million (2010 – $31 million), including an equity component of $13 million (2010 – $15 million) (Notes 20 and 21). AFUDC is charged to earnings through amortization expense over the estimated service lives of the applicable utility capital assets.

As approved by the regulator, FortisAlberta capitalizes to utility capital assets a portion of the amortization of utility capital assets, such as tools and vehicles, used in the construction of other assets. During 2011 amortization costs of approximately $5 million were capitalized (2010 – $5 million).

December 31, 2011 and 2010

3. Summary of Significant Accounting Policies (cont'd)

Utility Capital Assets (cont'd)

As approved by the regulator, FEVI has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FEVI increases both utility capital assets and long-term debt (Note 30).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets. When put into service, the inventories are amortized using the straight-line method based on the estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments are capitalized.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates for 2011 ranged from 0.4% to 33.3% (2010 – 0.4% to 33.3%). The weighted average composite rate of amortization, before reduction for amortization of contributions in aid of construction, for 2011 was 3.5% (2010 – 3.5%).

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows:

	2011		2010	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Gas	**4–62**	**30**	4–53	30
Electricity	**5–75**	**26**	5–75	27
Transmission				
Gas	**4–82**	**35**	4–75	29
Electricity	**20–65**	**26**	10–75	34
Generation	**5–75**	**29**	5–75	33
Other	**3–70**	**10**	3–70	11

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost less accumulated amortization, where applicable. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate. The lease terms vary to a maximum of 20 years. Equipment is amortized on a straight-line basis over a range of 2 to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred, while replacements and betterments are capitalized.

Leases

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are amortized over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Intangible assets are comprised of computer software costs; land, transmission and water rights; franchise fees; and customer contracts.

The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually either individually or at the reporting unit level. Such intangible assets are not amortized. An intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator. Amortization rates require the use of estimates of the useful lives of the assets.

Amortization rates for 2011 ranged from 1.0% to 25.0% (2010 – 1.0% to 25.0%). The service life ranges and weighted average remaining service life of finite life intangible assets as at December 31 were as follows:

	2011		2010	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**5–10**	**6**	5–10	5
Land, transmission and water rights	**31–75**	**38**	15–65	38
Franchise fees, customer contracts and other	**4–100**	**15**	4–100	10

Intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, the capital cost of the assets is charged to accumulated amortization by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity as required by their respective regulator, with no loss, if any, recognized in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization costs when they are collected in customer gas and electricity rates. In the absence of rate regulation, any loss on the retirement or disposal of intangible assets at FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Belize Electricity would be recognized in earnings in the period incurred. The loss charged to accumulated amortization in 2011 was less than $1 million (2010 – $4 million).

The FortisBC Energy companies record any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval. In the absence of rate regulation, any loss on the retirement or disposal of intangible assets would be recognized in earnings in the period incurred.

At FortisOntario and Fortis Turks and Caicos, the regulatory authorities require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets be recognized immediately in earnings.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2011 and 2010.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and an impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair rate of return on capital or assets, is provided through customer gas and electricity rates approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings.

To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. The annual impairment test was performed as at October 1, 2011. No goodwill impairment provision has been determined for the years ended December 31, 2011 and 2010.

3. Summary of Significant Accounting Policies (cont'd)

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees; and defined contribution pension plans, including group Registered Retirement Savings Plans ("RRSPs"), for employees. The accrued pension benefit obligation and the value of pension cost of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

With the exception of the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension expense. At the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension expense, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at the FortisBC Energy companies and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively adopted CICA Handbook Section 3461, *Employee Future Benefits*. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between pension cost recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment. In the absence of rate regulation, deferral account treatment would not be permitted.

The costs of the defined contribution pension plans and RRSPs are expensed as incurred.

Other Post-Employment Benefit Plans

The Corporation, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits ("OPEBs") through defined benefit plans, including certain health and dental coverage, for qualifying members.

The accrued benefit obligation and the value of the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation at the beginning of the fiscal year and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

As approved by the respective regulator, the cost of OPEB plans at FortisAlberta, and at Newfoundland Power until December 31, 2010, is recovered in customer rates based on the cash payments made. Effective January 1, 2011, as approved by the regulator, the cost of OPEB plans at Newfoundland Power is being recovered in customer rates based on the accrual method of accounting for OPEBs. The transitional regulatory OPEB asset of $53 million as at December 31, 2010 is being amortized on a straight-line basis over 15 years (Note 5 *(iv)*).

Any difference between the cost recognized under Canadian GAAP and that recovered from customers in current rates for OPEB plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 5 *(iv)*). In the absence of rate regulation, deferral account treatment would not be permitted.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 17). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity. Stock option forfeitures, cancellations and expiries are recognized in earnings in the period incurred as a reduction in compensation expense.

The Corporation also records compensation expense associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans using the intrinsic value method, recognizing compensation expense over the vesting period on a straight-line basis. The intrinsic value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period.

Foreign Currency Translation

The assets and liabilities of the Corporation's self-sustaining foreign operations, which include Caribbean Utilities, Fortis Turks and Caicos, BECOL, FortisUS Energy and, up to June 20, 2011, Belize Electricity, are denominated in US dollars or a currency pegged to the US dollar and are translated at the exchange rate in effect at the balance sheet date. The exchange rate in effect as at December 31, 2011 was US$1.00=CDN$1.02 (December 31, 2010 – US$1.00=CDN$0.99). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income. Revenue and expenses of the Corporation's self-sustaining foreign operations are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of self-sustaining foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income.

Effective June 20, 2011, as a result of the expropriation of Belize Electricity by the GOB, the Corporation's asset associated with its previous investment in Belize Electricity (Notes 8 and 31) is no longer a self-sustaining foreign subsidiary of Fortis and, therefore, does not qualify for hedge accounting. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and any corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment are recognized in earnings.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

Financial Instruments

The Corporation designates each of its financial instruments in one of the following five categories: (i) held for trading; (ii) available for sale; (iii) held to maturity; (iv) loans and receivables; or (v) other financial liabilities. All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value, with any change in fair value recognized in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

Derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value, with changes in fair value recognized in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recognized in other comprehensive income. Any change in fair value relating to the ineffective portion is recognized immediately in earnings.

At the FortisBC Energy companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not designated in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to deferral account treatment to be recovered from, or refunded to, customers in future rates (Note 5 *(ii)*). In the absence of rate regulation, deferral account treatment of changes in fair value of derivative financial instruments not in a designated qualifying hedging relationship would not be permitted. Generally, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships" in this note.

The Corporation has selected January 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantially modified on or after January 1, 2003. While some of the Corporation's long-term debt contracts have prepayment options that qualify as embedded derivatives to be separately recorded, none have been recorded as they are immaterial to the Corporation's consolidated results of operations and financial position.

The Corporation's policy is to recognize transaction costs associated with financial assets and liabilities that are classified as other than held for trading as adjustments to the cost of those financial assets and liabilities recorded on the consolidated balance sheet. These transaction costs are amortized to earnings using the effective interest rate method over the life of the related financial instrument.

3. Summary of Significant Accounting Policies (cont'd)

Hedging Relationships

As at December 31, 2011, the Corporation's hedging relationships consisted of fuel option contracts, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

As part of its Fuel Price Volatility Program, as approved by the regulator, Caribbean Utilities entered into two fuel option contracts to reduce the impact of volatility of fuel prices on customer rates. The fair value of the fuel option contracts is calculated using published market prices for similar commodities. Any change in the fair value of the fuel option contracts is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The foreign exchange forward contract is held by FEI to hedge the cash flow risk related to approximately US$4 million (2010 – US$8 million) remaining to be paid under a contract for the implementation of a customer care information system. The fair value of the foreign exchange forward contract is calculated using the present value of cash flows based on a market foreign exchange rate and the foreign exchange forward rate curve. Any change in the fair value of the foreign exchange forward contract at FEI is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the fuel option contracts, the foreign exchange forward contract and the natural gas derivatives are estimates of the amounts that would have to be received or paid to terminate the outstanding contracts as at the balance sheet date. As at December 31, 2011, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The Corporation's earnings from, and net investments in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as hedges are recognized in other comprehensive income and help offset unrealized foreign currency exchange gains and losses on self-sustaining foreign net investments, which are also recognized in other comprehensive income.

Income Taxes

The Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory balances for which deferred income tax is recovered or refunded in current customer rates, as prescribed by the respective regulator. Therefore, current customer rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable. The above utilities recognize an offsetting regulatory asset or liability for the amount of future income taxes that are expected to be collected or refunded in customer rates once they become payable or receivable (Note 5 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher corporate income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the GOB for the terms of its 50-year PPAs. Belize Electricity is subject to corporate tax under the *Income and Business Tax Act* (Belize). Up to April 1, 2010, corporate tax was capped at 1.75% of gross revenue. Effective April 1, 2010, the corporate tax rate increased to 6.50% of gross revenue. The additional 4.75% corporate tax was being deferred by Belize Electricity for recovery from customers in future electricity rates.

Any difference between the income tax expense or recovery recognized under Canadian GAAP and that recovered from, or refunded to, customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 5 *(i)*). In the absence of rate regulation, deferral account treatment would not be permitted.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future, which were $76 million as at December 31, 2011 (December 31, 2010 – $72 million). Tax information exchange agreements were entered into force in 2011 for Bermuda, the Cayman Islands and the Turks and Caicos Islands. As a result, earnings of Caribbean Utilities and Fortis Turks and Caicos after 2010 are considered exempt surplus and can be repatriated on a tax-free basis.

Revenue Recognition

Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

Revenue from the sale of gas by the FortisBC Energy companies and electricity by FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on an accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

As required by the regulator, revenue from the sale of electricity by Belize Electricity was recognized as monthly billings were issued to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. Up to June 20, 2011, the difference between recognizing revenue on a billed versus an accrual basis was recorded on the consolidated balance sheet as a regulatory liability (Note 5 *(xxvii)*).

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with the Alberta Electric System Operator ("AESO") and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. As approved by the regulator, FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers is deferred to be recovered from, or refunded to, customers in future rates (Note 5 *(vi)*). In the absence of rate regulation, deferral account treatment would not be permitted.

FortisOntario's regulated operations primarily consist of the operations of Cornwall Electric, Canadian Niagara Power and Algoma Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power and Algoma Power are not bundled. At Canadian Niagara Power and Algoma Power, the cost of power and/or transmission is a flow through to customers and revenue associated with the recovery of these costs is tracked and recorded separately. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements.

3. Summary of Significant Accounting Policies (cont'd)

Revenue Recognition (cont'd)

The leases are primarily of a net nature, with tenants paying basic rent plus a pro-rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants are recorded as revenue. Base rent and the escalation of lease rates included in long-term leases are recognized in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations

Asset-retirement obligations ("AROs"), including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

As at December 31, 2011, FortisBC Electric has recognized an approximate $4 million ARO (December 31, 2010 – $3 million), which has been classified as a long-term other liability (Note 14) with the offset to utility capital assets.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods.

Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Certain amounts are recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Income Producing Properties, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and AROs, and in Notes 5 and 32.

4. Future Accounting Changes

Effective January 1, 2012, the Corporation will be required to adopt a new set of accounting standards. Due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, Fortis is adopting accounting principles generally accepted in the United States ("US GAAP") effective January 1, 2012.

Canadian securities rules allow a reporting issuer to file its financial statements prepared in accordance with US GAAP by qualifying as a U.S. Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the U.S. *Securities Exchange Act of 1934*, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer. Therefore, on June 6, 2011, the Corporation filed an application with the Ontario Securities Commission ("OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit the Corporation and its reporting issuer subsidiaries to prepare their financial statements in accordance with US GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

The Corporation's application of Canadian GAAP currently refers to US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. Fortis believes that the continued application of rate regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate regulation has on the Corporation's consolidated financial position and results of operations.

The Corporation has voluntarily prepared and filed audited US GAAP consolidated financial statements for the year ending December 31, 2011, with 2010 comparatives, as approved by the OSC. Beginning with the first quarter of 2012, the Corporation's unaudited interim consolidated financial statements will be prepared in accordance with US GAAP and filed.

5. Regulatory Assets and Liabilities

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts expected to be recovered from, or refunded to, customers in future periods.

Regulatory Assets *(in millions)*	**2011**	2010	**Remaining recovery period *(Years)***
Future income taxes *(i)*	**$ 640**	$ 574	To be determined
Rate stabilization accounts – FortisBC Energy companies *(ii)*	**105**	146	1
Rate stabilization accounts – electric utilities *(iii)*	**55**	44	Various
Regulatory OPEB plan assets *(iv)*	**58**	63	Various
Point Lepreau replacement energy deferral *(v)*	**47**	44	To be determined
AESO charges deferral *(vi)*	**44**	19	1
Deferred energy management costs *(vii)*	**36**	23	1–10
Deferred losses on disposal of utility capital assets *(viii)*	**23**	16	To be determined
Deferred operating overhead costs *(ix)*	**22**	11	Various
Income taxes recoverable on OPEB plans *(x)*	**22**	21	To be determined
Whistler pipeline contribution deferral *(xi)*	**16**	17	48
Customer Care Enhancement Project cost deferral *(xii)*	**13**	–	To be determined
Deferred development costs for capital *(xiii)*	**11**	11	18
Pension cost variance deferral *(xiv)*	**10**	2	3
Deferred costs – smart meters *(xv)*	**8**	8	To be determined
Alternative energy projects cost deferral *(xvi)*	**8**	4	To be determined
Deferred lease costs *(xvii)*	**7**	6	12–30
2010 accrued distribution revenue adjustment rider *(xviii)*	**–**	36	–
Other regulatory assets *(xix)*	**70**	50	Various
Total regulatory assets	**1,195**	1,095	
Less: current portion	**(210)**	(241)	1
Long-term regulatory assets	**$ 985**	$ 854	

December 31, 2011 and 2010

5. Regulatory Assets and Liabilities (cont'd)

Regulatory Liabilities

(in millions)	2011	2010	Remaining settlement period *(Years)*
Asset removal and site restoration provision *(xx)*	**$ 354**	$ 339	To be determined
Rate stabilization accounts – FortisBC Energy companies *(ii)*	**127**	60	Various
Rate stabilization accounts – electric utilities *(iii)*	**33**	45	Various
AESO charges deferral *(vi)*	**12**	9	1
Income tax variance deferral *(xxi)*	**12**	–	3
Deferred interest *(xxii)*	**10**	7	1–3
Southern Crossing Pipeline deferral *(xxiii)*	**8**	5	3
PBR incentive liabilities *(xxiv)*	**7**	8	1
Unrecognized net gains on disposal of utility capital assets *(xxv)*	**6**	8	To be determined
2010 FEI revenue surplus *(xxvi)*	**–**	7	–
Unbilled revenue liability *(xxvii)*	**–**	5	–
Other regulatory liabilities *(xxviii)*	**32**	34	Various
Total regulatory liabilities	**601**	527	
Less: current portion	**(43)**	(60)	1
Long-term regulatory liabilities	**$ 558**	$ 467	

Description of the Nature of Regulatory Assets and Liabilities

(i) *Future Income Taxes*

The Corporation recognizes future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Included in future income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the future taxes become payable or receivable. In the absence of rate regulation, future income taxes would have been recognized in earnings as incurred. The regulatory balances related to future income taxes are not subject to a regulatory return.

(ii) *Rate Stabilization Accounts – FortisBC Energy Companies*

The rate stabilization accounts at the FortisBC Energy companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, natural gas cost volatility and changes in the fair value of natural gas commodity derivative instruments.

At FEI a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual versus forecast gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The CCRA also accumulates the changes in fair value of FEI's natural gas commodity derivative instruments. At FEVI a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on FEVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in fair value of FEVI's natural gas commodity derivative instruments.

The RSAM is anticipated to be refunded through customer rates over a three-year period. The CCRA, MCRA and GCVA accounts are anticipated to be fully recovered or refunded within the next fiscal year.

The Rate Stabilization Deferral Account ("RSDA") at FEVI was approved by the regulator to accumulate the difference between the actual 2009 revenue surplus and the forecast amount, and to accumulate excess costs recovered from customers for providing service or to draw down such costs where earnings differed from the allowed ROE for 2010 and 2011. In its 2012–2013 Revenue Requirements Application, FEVI has requested the continuance of the RSDA beyond 2011. The RSDA will be refunded to customers in future rates, as to be determined in future revenue requirements applications of the FortisBC Energy companies.

In the absence of rate regulation, the amounts in the rate stabilization accounts would not be deferred but would be recognized in earnings as incurred. The recovery or refund of the rate stabilization accounts is dependent on actual natural gas consumption volumes and on customer rates, as approved by the regulator.

The rate stabilization accounts at the FortisBC Energy companies are detailed as follows.

(in millions)	**2011**	2010
Current regulatory assets		
CCRA	**$ 68**	$ 91
GCVA	**37**	50
MCRA	**–**	5
Total regulatory assets	**$ 105**	$ 146
Current regulatory liabilities		
MCRA	**$ 8**	$ –
RSAM	**11**	4
RSA	**–**	2
	$ 19	$ 6
Long-term regulatory liabilities		
RSAM	**$ 22**	$ 7
RSDA	**86**	47
	$ 108	$ 54
Total regulatory liabilities	**$ 127**	$ 60

(iii) *Rate Stabilization Accounts – Electric Utilities*

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos) are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. The rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level. Additionally, at Newfoundland Power, the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. The weather normalization account reduces the volatility in Newfoundland Power's year-to-year earnings that would otherwise result from fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, ranges from one to three years and is subject to periodic review by the respective regulatory authority.

The balance in Newfoundland Power's weather normalization account as at December 31, 2011 was a net regulatory liability of $7 million (December 31, 2010 – net regulatory liability of $3 million). The account balance should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB in 2008, a non-reversing asset balance of approximately $7 million of the weather normalization account is being amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recognized in earnings as incurred. The recovery period of the remaining balance of the weather normalization account is yet to be determined as it depends on weather conditions in the future.

As at December 31, 2011, $6 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of $2 million per year over a recovery period of three years. Subsequent to 2003, annual deferral of energy costs to the ECAM account was recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period. In accordance with the PEI Energy Accord which came into effect on March 1, 2011, the balance of the ECAM regulatory liability of $21 million will be refunded to customers commencing in 2013 and, as a result, has been classified as long-term. The remaining settlement period of the post-2003 ECAM is to be determined at a future time.

As at December 31, 2010, the $29 million balance in Belize Electricity's rate stabilization account was in a payable position.

As at December 31, 2011, $5 million (December 31, 2010 – $5 million) of the remaining balance of the rate stabilization accounts in a receivable position at FortisOntario was not subject to a regulatory return. In the absence of rate regulation, the cost of fuel and/or purchased power would be expensed in the period incurred.

5. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(iv) Regulatory OPEB Plan Assets

At FortisAlberta, at Newfoundland Power prior to 2011 and at FortisBC Electric prior to 2005, the cash cost of providing OPEB plans is collected in customer rates as permitted by the respective regulator. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC Electric is based on cash costs plus a partial recovery of the full accrual cost of the OPEB plans. The regulatory OPEB plan assets represent the deferred portion of the benefit cost at FortisAlberta, FortisBC Electric and Newfoundland Power that is expected to be recovered from customers in future rates. Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for the recovery from customers of OPEB plan costs and that Newfoundland Power's $53 million transitional regulatory OPEB plan asset be amortized and collected from customers in rates equally over 15 years. In the absence of rate regulation, the benefit cost would be recognized on an accrual basis as actuarially determined, with no deferral of costs recorded on the consolidated balance sheet. As at December 31, 2011, regulatory OPEB plan assets at FortisAlberta and FortisBC Electric totalling $13 million (December 31, 2010 – $13 million) were not subject to a regulatory return.

(v) Point Lepreau Replacement Energy Deferral

Maritime Electric has regulatory approval to defer the cost of replacement energy related to Point Lepreau during its refurbishment outage. The station has been out of service since 2008 due to refurbishment commencing in that year. The timing and terms of collection of the deferred costs are to be determined by the PEI Energy Commission. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(vi) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates.

As at December 31, 2011, the AESO charges deferral account consisted of the 2011 regulatory asset balance of $44 million, which will be collected in customer rates in 2012 through a transmission adjustment rider and is subject to final regulatory review late in 2012. As at December 31, 2011, the AESO charges deferral account also consisted of the 2010 regulatory liability balance of $12 million, which will be refunded in customer rates in 2012 through a transmission adjustment rider, as approved by the regulator. In the absence of rate regulation, the revenue and expenses would be recognized in earnings in the period incurred and deferral account treatment would not be permitted.

(vii) Deferred Energy Management Costs

The FortisBC Energy companies, FortisBC Electric, Newfoundland Power and Maritime Electric provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, the above regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 4 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(viii) Deferred Losses on Disposal of Utility Capital Assets

As approved by the regulator, effective January 1, 2010, losses on the retirement or disposal of utility capital assets at the FortisBC Energy companies are recorded in a regulatory deferral account to be recovered from customers in future rates. As part of its 2012–2013 Revenue Requirements Application, the FortisBC Energy companies have proposed that this deferral account treatment be continued for 2012 and 2013 and that the deferred losses be amortized over a period of 20 years, which is consistent with the average service life of the assets to which the losses relate. In the absence of rate regulation, the deferral of losses on the retirement or disposal of utility capital assets would not be permitted.

(ix) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital assets. In the absence of rate regulation, the operating costs would be expensed in the period incurred and no deferral account treatment would be permitted.

(x) Income Taxes Recoverable on OPEB Plans

At FEI and FortisBC Electric, the regulator allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. As approved by the regulator, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. In the absence of rate regulation, the income taxes would not be deferred.

(xi) *Whistler Pipeline Contribution Deferral*

The Whistler pipeline contribution deferral represents the capital contribution from FEWI to FEVI on completion of the natural gas pipeline to Whistler, as constructed by FEVI. The deferral is to be recovered from FEWI's customers over a period of 50 years, as approved by the regulator. In the absence of rate regulation, the capital contribution deferral would have been capitalized and amortized to earnings over the life of the asset.

(xii) *Customer Care Enhancement Project Cost Deferral*

The Customer Care Enhancement Project cost deferral represents incremental costs associated with FEI's Customer Care Enhancement Project, as well as amounts resulting from timing differences between when the asset was included in rate base as compared to when the asset was available for use. As part of its 2012–2013 Revenue Requirements Application, FEI has requested that the Customer Care Enhancement Project cost deferral be transferred to utility capital assets and intangible assets and amortized over a period of three years, commencing in 2012. In the absence of rate regulation, the deferral would not have been permitted.

(xiii) *Deferred Development Costs for Capital*

Deferred development costs for capital projects include costs for projects under development at the FortisBC Energy companies that are subject to regulatory approval for recovery in future customer rates. The majority of the balance relates to the project cost overrun incurred on the conversion of FEWI customer appliances from propane to natural gas, for which FEWI received a decision from the BCUC allowing these additional costs to be deferred and collected in FEWI customer rates. In the absence of rate regulation, the deferred development costs for capital would be capitalized; however, the ultimate period of amortization would likely differ.

(xiv) *Pension Cost Variance Deferral*

As approved by the regulator, the pension cost variance deferral at the FortisBC Energy companies reflects the difference between pension and OPEB costs recognized under Canadian GAAP and that recovered from customers in rates. In the absence of rate regulation, the pension and OPEB costs would be expensed in the period incurred.

(xv) *Deferred Costs – Smart Meters*

In 2006 the Government of Ontario committed to install smart electricity meters in all Ontario residences and small commercial businesses by the end of 2010. FortisOntario is eligible to recover from customers in future customer rates all prudent and reasonable costs that were incurred related to this smart metering initiative. These deferred costs represent incremental operating, administrative and capital costs directly related to the smart metering initiative and are subject to regulatory approval. In the absence of rate regulation, these deferred costs would have been capitalized; however, the method of amortization to earnings would likely differ.

(xvi) *Alternative Energy Projects Cost Deferral*

The alternative energy projects cost deferral account at the FortisBC Energy companies represents costs, net of revenue, associated with the investment in alternative energy solutions. The recovery period of the cost deferral is to be determined by the regulator at a future time. In the absence of rate regulation, the costs would be expensed in the period incurred and no deferral treatment would be permitted.

(xvii) *Deferred Lease Costs*

FortisBC Electric defers lease costs associated with the Brilliant Terminal Station ("BTS") and Trail office building. The capital cost of the BTS, the cost of financing the BTS obligation and the related operating costs are not being fully recovered by FortisBC Electric in current customer rates since those rates include only the BTS lease payments on a cash basis. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates. In the absence of rate regulation, these costs would be expensed in the period incurred.

FortisBC Electric is accounting for the lease of the Trail office building as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease term; however, as ordered by the regulator, FortisBC Electric recovers the Trail office lease payments from customers and records the lease costs on a cash basis. This regulatory asset represents the deferred portion of the lease payments that is expected to be recovered from customers in future rates as the stepped lease payments increase. In the absence of rate regulation, these costs would be recognized in earnings on a straight-line basis over the lease term.

The deferred lease costs are not subject to a regulatory return.

(xviii) *2010 Accrued Distribution Revenue Adjustment Rider*

The accrued distribution revenue adjustment rider at FortisAlberta represents the difference in the revenue requirement between the interim rates charged to customers during 2010 and those approved by the regulator for 2010. The balance was collected from customers in 2011. In the absence of rate regulation, revenue would have been $36 million higher in 2011. This balance was not subject to a regulatory return.

5. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xix) *Other Regulatory Assets*

Other regulatory assets relate to all of the Corporation's regulated utilities. The balance is comprised of various items each individually less than $5 million. As at December 31, 2011, $65 million (December 31, 2010 – $43 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2011, $10 million (December 31, 2010 – $7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

(xx) *Asset Removal and Site Restoration Provision*

As required by the respective regulator, amortization rates at FortisAlberta, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for asset removal and site restoration costs, net of salvage proceeds. This regulatory liability represents amounts collected in customer electricity rates at FortisAlberta, Newfoundland Power and Maritime Electric in excess of incurred asset removal and site restoration costs. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

During 2011 the amount included in amortization cost associated with the provision for asset removal and site restoration costs was $53 million (2010 – $50 million). During 2011 actual asset removal and site restoration costs, net of salvage proceeds, were $27 million (2010 – $24 million). In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization cost.

(xxi) *Income Tax Variance Deferral*

The income tax variance deferral account at the FortisBC Energy companies accumulates the difference in income tax expense as a result of changes in tax laws, audit reassessments, accounting policy changes and changes in income tax rates for refund to customers in future rates over a period of three years, as approved by the regulator. In the absence of rate regulation, deferral account treatment would not be permitted and the income tax variance would be reflected in earnings in the period the change occurred.

(xxii) *Deferred Interest*

The FortisBC Energy companies have interest deferral mechanisms, as approved by the regulator, which accumulate variances between actual and approved interest rates associated with long-term and short-term borrowings and between the actual and forecast interest calculated on the average balance of the MCRA account. The deferred interest will be refunded to customers in future rates over one to three years. In the absence of rate regulation, actual interest costs would have been expensed in the period incurred.

(xxiii) *Southern Crossing Pipeline Deferral*

This regulatory liability represents the difference between actual revenue received from third parties for the use of the Southern Crossing pipeline and that which has been approved in revenue requirements. The deferral is amortized over a period of three years. In the absence of rate regulation, the revenue would be recognized in earnings when services are rendered.

(xxiv) *PBR Incentive Liabilities*

FEI and FortisBC Electric's regulatory frameworks included PBR mechanisms that allowed for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined under the PBR mechanisms as approved per BCUC orders (Note 2). FEI's regulatory PBR incentive liability of $5 million was refunded to customers during 2011. A portion of FortisBC Electric's regulatory PBR incentive liability was refunded to customers in 2011, with the remainder approved for settlement in 2012. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xxv) *Unrecognized Net Gains on Disposal of Utility Capital Assets*

As approved by the regulator, this regulatory liability at the FortisBC Energy companies represents the one-time transfer of cumulative unrecognized net gains on disposal of utility capital assets from utility capital asset accumulated amortization. The settlement of this regulatory liability will be determined as part of the final decision on the FortisBC Energy companies' 2012–2013 Revenue Requirements Applications. In the absence of rate regulation, the unrecognized net gains on disposal of utility capital assets would have been recognized in earnings as incurred.

(xxvi) *2010 FEI Revenue Surplus*

The 2010 revenue surplus deferral account captured amounts collected in customer rates at FEI in 2010 in excess of certain costs incurred. The revenue surplus was refunded to customers in 2011. In the absence of rate regulation, the deferral would not have been permitted and the revenue surplus would have been recognized as revenue in the period incurred.

(xxvii) Unbilled Revenue Liability

The unbilled revenue liability as at December 31, 2010 related to the difference between revenue recognized on a billed basis and revenue recognized on an accrual basis at Belize Electricity. In the absence of rate regulation, revenue would have been recorded on an accrual basis and the deferral of unbilled revenue would not have been permitted.

(xxviii) Other Regulatory Liabilities

Other regulatory liabilities relate to the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario. The balance is comprised of various items each individually less than $5 million. As at December 31, 2011, $25 million (December 31, 2010 – $21 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2011, $7 million (December 31, 2010 – $10 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

In the absence of rate regulation and, therefore, in the absence of recording regulatory assets and liabilities as described above, the total impact on the consolidated financial statements would have been as follows:

	(Decrease)/Increase	
(in millions)	**2011**	2010
Regulatory assets	**$ (1,138)**	$ (1,046)
Regulatory liabilities	**(601)**	(527)
Accumulated other comprehensive loss	**32**	45
Opening retained earnings	**(519)**	(457)
Revenue	**$ 323**	$ 341
Energy supply costs	**243**	354
Operating expenses	**82**	62
Amortization	**(51)**	(55)
Finance charges	**(2)**	2
Corporate taxes	**69**	40
Net earnings	**$ (18)**	$ (62)

6. Inventories

(in millions)	**2011**	2010
Gas in storage	**$ 115**	$ 148
Materials and supplies	**19**	20
	$ 134	$ 168

During 2011 inventories of $854 million (2010 – $863 million) were expensed and reported in energy supply costs on the consolidated statement of earnings. Inventories expensed to operating expenses were $15 million for 2011 (2010 – $15 million), which included $10 million for food and beverage costs at Fortis Properties (2010 – $10 million).

7. Assets Held for Sale

In 2010 Bell Aliant Inc. ("Bell Aliant") exercised its option, under an agreement with Newfoundland Power, to buy back 40% of all joint-use poles owned by Newfoundland Power. In October 2011 Newfoundland Power received proceeds of approximately $46 million from Bell Aliant. The proceeds from the sale of the joint-use poles approximated net book value.

8. Other Assets

(in millions)	**2011**	2010
Deferred pension costs *(Note 23)*	**$ 139**	$ 140
Other asset – Belize Electricity *(Note 31)*	**106**	–
Long-term accounts receivable (due 2040)	**9**	9
Other	**16**	19
	$ 270	$ 168

8. *Other Assets (cont'd)*

As a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB and the consequential loss of control over the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The book value of the Corporation's previously 70% controlled foreign net investment in Belize Electricity has been classified as a long-term other asset. The asset is denominated in US dollars and has been translated into Canadian dollars at the exchange rate prevailing as at the balance sheet date. Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity does not qualify for hedge accounting and, as a result, from June 20, 2011, an approximate $4.5 million foreign exchange gain on the translation of the asset was recognized in earnings for 2011 (Note 20).

As at June 20, 2011, approximately $28 million of unrealized foreign currency translation losses related to the translation into Canadian dollars of the Corporation's previous foreign net investment in Belize Electricity, and $13 million ($11 million after tax) of unrealized foreign currency translation gains related to corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in self-sustaining Belize Electricity, were reclassified to long-term other assets from accumulated other comprehensive loss and were included in the $106 million balance as at December 31, 2011 (Note 18).

The other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable.

9. Utility Capital Assets

2011 *(in millions)*	**Cost**	**Accumulated Amortization**	**Contributions in Aid of Construction (Net)**	**Net Book Value**
Distribution				
Gas	**$ 2,566**	**$ (556)**	**$ (179)**	**$ 1,831**
Electricity	**4,683**	**(1,218)**	**(555)**	**2,910**
Transmission				
Gas	**1,615**	**(416)**	**(118)**	**1,081**
Electricity	**1,072**	**(283)**	**(17)**	**772**
Generation	**1,088**	**(304)**	**–**	**784**
Other	**1,068**	**(378)**	**–**	**690**
Assets under construction	**509**	**–**	**–**	**509**
Land	**110**	**–**	**–**	**110**
	$ 12,711	**$ (3,155)**	**$ (869)**	**$ 8,687**

2010 *(in millions)*	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Net Book Value
Distribution				
Gas	$ 2,467	$ (494)	$ (183)	$ 1,790
Electricity	4,453	(1,135)	(534)	2,784
Transmission				
Gas	1,328	(383)	(109)	836
Electricity	1,075	(278)	(18)	779
Generation	1,013	(284)	–	729
Other	993	(371)	–	622
Assets under construction	545	–	–	545
Land	100	–	–	100
	$ 11,974	$ (2,945)	$ (844)	$ 8,185

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

As at December 31, 2011, assets under construction associated with larger projects included the Waneta Expansion and AESO transmission-related capital projects at FortisAlberta.

The cost of utility capital assets under capital lease as at December 31, 2011 was $61 million (December 31, 2010 – $59 million) and related accumulated amortization was $26 million (December 31, 2010 – $25 million).

10. Income Producing Properties

2011

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Buildings	**$ 525**	**$ (76)**	**$ 449**
Equipment	**100**	**(43)**	**57**
Tenant inducements	**29**	**(21)**	**8**
Land	**66**	**–**	**66**
Assets under construction	**14**	**–**	**14**
	$ 734	**$ (140)**	**$ 594**

2010

(in millions)	Cost	Accumulated Amortization	Net Book Value
Buildings	$ 503	$ (68)	$ 435
Equipment	86	(36)	50
Tenant inducements	27	(19)	8
Land	64	–	64
Assets under construction	3	–	3
	$ 683	$ (123)	$ 560

11. Intangible Assets

2011

(in millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
Computer software	**$ 346**	**$ (159)**	**$ 187**
Land, transmission and water rights	**133**	**(17)**	**116**
Franchise fees, customer contracts and other	**16**	**(13)**	**3**
Assets under construction	**35**	**–**	**35**
	$ 530	**$ (189)**	**$ 341**

2010

(in millions)	Cost	Accumulated Amortization	Net Book Value
Computer software	$ 301	$ (151)	$ 150
Land, transmission and water rights	129	(17)	112
Franchise fees, customer contracts and other	16	(11)	5
Assets under construction	57	–	57
	$ 503	$ (179)	$ 324

December 31, 2011 and 2010

11. Intangible Assets (cont'd)

Additions to intangible assets during 2011 were $58 million (2010 – $80 million), approximately $7 million (2010 – $9 million) of which were developed internally. During 2011 fully amortized intangible assets of $25 million (2010 – $35 million) were retired, reducing cost and accumulated amortization.

Included in the cost of land, transmission and water rights as at December 31, 2011 was $64 million (December 31, 2010 – $62 million) not subject to amortization.

As at December 31, 2011, assets under construction primarily related to the Waneta Expansion.

12. Goodwill

(in millions)	**2011**	2010
Balance, beginning of year	**$ 1,553**	$ 1,560
Foreign currency translation impacts	**4**	(7)
Balance, end of year	**$ 1,557**	$ 1,553

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

13. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	**2011**	2010
Regulated Utilities			
FortisBC Energy Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2010 – 10.71%)	2015 – 2016	**$ 275**	$ 275
Unsecured Debentures –			
5.95% weighted average fixed rate (2010 – 6.06%)	2029 – 2041	**1,620**	1,520
Government loan *(Note 30)*	2012	**20**	–
Obligations under capital leases	2012 – 2017	**14**	13
FortisAlberta			
Unsecured Debentures –			
5.51% weighted average fixed rate (2010 – 5.62%)	2014 – 2050	**1,184**	1,059
FortisBC Electric			
Secured Debentures –			
9.12% weighted average fixed rate (2010 – 9.12%)	2012 – 2023	**40**	40
Unsecured Debentures –			
5.84% weighted average fixed rate (2010 – 5.84%)	2014 – 2050	**600**	600
Obligations under capital leases	2032	**26**	25
Newfoundland Power			
Secured First Mortgage Sinking Fund Bonds –			
7.66% weighted average fixed rate (2010 – 7.67%)	2014 – 2039	**459**	464
Maritime Electric			
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2010 – 7.67%)	2016 – 2061	**167**	137
FortisOntario			
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2010 – 7.09%)	2018 – 2041	**104**	52
Caribbean Utilities			
Unsecured US Senior Loan Notes –			
6.03% weighted average fixed rate (2010 – 6.28%)	2013 – 2031	**207**	179

(in millions)	Maturity Date	**2011**	2010
Fortis Turks and Caicos			
Unsecured:			
US Scotiabank (Turks and Caicos) Ltd. Loan –			
4.82% weighted average fixed and variable rate (2010 – 4.79%)	2013 – 2016	**$ 6**	$ 8
US First Caribbean International Bank loan –			
5.65% fixed rate	2015	**2**	2
Belize Electricity			
Unsecured:			
BZ Debentures –			
10.35% weighted average fixed rate		**–**	34
Other loans –			
4.63% weighted average fixed rate		**–**	6
Other variable interest rate loans		**–**	10
Non-Regulated – Fortis Generation			
Secured:			
Mortgage – 9.44% fixed rate	2013	**2**	3
Non-Regulated – Fortis Properties			
Secured:			
First mortgages –			
7.21% weighted average fixed rate (2010 – 7.21%)	2012 – 2017	**131**	139
Senior Notes – 7.32% fixed rate	2019	**12**	13
Corporate – Fortis and FHI			
Unsecured:			
Debentures –			
6.14% weighted average fixed rate (2010 – 6.14%)	2014 – 2039	**326**	326
US Senior Notes –			
5.49% weighted average fixed rate (2010 – 5.49%)	2014 – 2040	**559**	547
US Subordinated Convertible Debentures –			
5.50% fixed rate	2011	**–**	37
Long-term classification of credit facility borrowings *(Note 29)*		**74**	218
Total long-term debt and capital lease obligations		**5,828**	5,707
Less: Deferred financing costs		**(43)**	(42)
Less: Current installments of long-term debt and capital lease obligations		**(106)**	(56)
		$ 5,679	$ 5,609

The purchase money mortgages of the FortisBC Energy companies are secured equally and rateably by a first fixed and specific mortgage and charge on FEI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $425 million.

As identified in the table above, certain long-term debt instruments issued by FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Properties are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the company to which the long-term debt is associated.

Regulated Utilities

FortisBC Electric has a capital lease obligation with respect to the operation of the BTS. Future minimum lease payments associated with this capital lease obligation are approximately $3 million per year over the remaining term of the lease agreement to 2032. The capital lease obligation bears interest at a composite rate of 8.62%.

The majority of the long-term debt instruments at Regulated Utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

December 31, 2011 and 2010

13. Long-Term Debt and Capital Lease Obligations (cont'd)

Corporate – Fortis and FHI

The majority of the unsecured debentures and all of the US senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

The US$40 million unsecured subordinated convertible debentures were converted, at the option of the holder, into 1.4 million common shares of Fortis at $29.63 per share (US$29.11 per share) in November 2011, as permitted under the debt agreement (Note 16).

In April 2010 FHI redeemed in full for cash its $125 million 8.00% capital securities with proceeds from borrowings under the Corporation's committed credit facility. The capital securities were scheduled to mature in April 2040; however, the Company had the option to redeem the capital securities for cash at par on or after April 19, 2010.

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2012	$ 106	$ –	$ 106
2013	97	–	97
2014	422	280	702
2015	152	–	152
2016	294	–	294
Thereafter	3,872	605	4,477

14. Other Liabilities

(in millions)	**2011**	2010
OPEB plan liabilities *(Note 23)*	**$ 168**	$ 157
Defined benefit pension liabilities *(Note 23)*	**52**	46
Waneta Partnership promissory note	**45**	42
Deferred gains on the sale of natural gas T&D assets	**34**	38
DSU and PSU liabilities *(Note 17)*	**8**	8
Customer deposits	**6**	6
Other liabilities	**10**	11
	$ 323	$ 308

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2011, its discounted net present value was $45 million (December 31, 2010 – $42 million). The promissory note was incurred on the acquisition by the Waneta Partnership, from a company affiliated with CPC/CBT, of certain intangible assets and project design costs associated with the construction of the Waneta Expansion. The promissory note is payable on the fifth anniversary of the commercial operation date of the Waneta Expansion, which is projected to be in spring 2015.

The deferred gains on the sale of natural gas T&D assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $71 million on combined cash proceeds of $141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease obligations are included in the table in Note 30.

Other liabilities primarily include AROs at FortisBC Electric and funds received in advance of expenditures.

15. Preference Shares

Authorized

(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding			2011		2010	
First Preference Shares	Annual Dividend Per Share	Classification	**Number of Shares**	**Amount** *(in millions)*	Number of Shares	Amount *(in millions)*
Series C	$ 1.3625	Debt	**5,000,000**	**$ 123**	5,000,000	$ 123
Series E	$ 1.2250	Debt	**7,993,500**	**197**	7,993,500	197
Total classified as debt			**12,993,500**	**$ 320**	12,993,500	$ 320
Series F	$ 1.2250	Equity	**5,000,000**	**$ 122**	5,000,000	$ 122
Series G [(1)]	$ 1.3125	Equity	**9,200,000**	**225**	9,200,000	225
Series H [(1)]	$ 1.0625	Equity	**10,000,000**	**245**	10,000,000	245
Total classified as equity			**24,200,000**	**$ 592**	24,200,000	$ 592

[(1)] The First Preference Shares, Series G and Series H are Five-Year Fixed Rate Reset First Preference Shares.

In January 2010 the Corporation issued 10 million Five-Year Fixed Rate Reset First Preference Shares, Series H at $25.00 per share for net after-tax proceeds of approximately $245 million.

As the First Preference Shares, Series C and Series E are convertible at the option of the holder into a variable number of common shares of the Corporation based on a market-related price of such common shares, they meet the definition of financial liabilities and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

As the First Preference Shares, Series F, Series G and Series H are not redeemable at the option of the holder, they are classified as equity and the associated dividends are deducted on the consolidated statement of earnings to arrive at net earnings attributable to common equity shareholders.

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series C and Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series C and Series E for cash or arrange for the sale of those shares to other purchasers.

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each preference share may be converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G and Series H are entitled to receive fixed cumulative preferential cash dividends in the amounts of $1.3125 and $1.0625 per share per annum, respectively, for each year up to but excluding September 1, 2013 and June 1, 2015, respectively. As at September 1, 2013 and June 1, 2015 and each five-year period thereafter, the holders of First Preference Shares, Series G and Series H, respectively, are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G and Series H, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13% and 1.45%, respectively.

On each Series H Conversion Date, the holders of First Preference Shares, Series H have the option to convert any or all of their First Preference Shares, Series H into an equal number of cumulative redeemable floating rate First Preference Shares, Series I. The holders of First Preference Shares, Series I will be entitled to receive floating rate cumulative preferential cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%.

On or after specified dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

16. Common Shares

Authorized: an unlimited number of common shares without nominal or par value.

Issued and Outstanding	2011		2010	
	Number of Shares (in thousands)	Amount (in millions)	Number of Shares (in thousands)	Amount (in millions)
Common shares	188,828	$ 3,032	174,393	$ 2,578

Common shares issued during the year were as follows:

	2011		2010	
	Number of Shares (in thousands)	Amount (in millions)	Number of Shares (in thousands)	Amount (in millions)
Balance, beginning of year	174,393	$ 2,578	171,256	$ 2,497
Public offering	10,340	331	–	–
Conversion of debentures	1,374	43	–	–
Consumer Share Purchase Plan	43	1	51	1
Dividend Reinvestment Plan	1,888	61	2,100	59
Employee Share Purchase Plan	–	–	193	5
Stock Option Plans	790	18	793	16
Balance, end of year	188,828	$ 3,032	174,393	$ 2,578

In June 2011 Fortis publicly issued 9.1 million common shares for $33.00 per share. The common share issue resulted in gross proceeds of approximately $300 million, or approximately $291 million net of after-tax expenses. In July 2011 an additional 1.24 million common shares of Fortis were publicly issued for $33.00 per share upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million, or approximately $40 million net of after-tax expenses.

The US$40 million unsecured subordinated convertible debentures were converted, at the option of the holder, into 1.4 million common shares of Fortis at $29.63 per share (US$29.11 per share) in November 2011, as permitted under the debt agreement (Note 13).

Effective June 1, 2010, the Employee Share Purchase Plan ("ESPP") was amended as approved by the Corporation's Board of Directors, such that future shares purchased under the ESPP will be on the open market. The first investment date under this amended ESPP was September 1, 2010.

As at December 31, 2011, 6.3 million (December 31, 2010 – 4.0 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans.

As at December 31, 2011, common shares reserved for issuance under the terms of the Corporation's preference shares were 26.0 million (December 31, 2010 – 26.0 million).

As at December 31, 2011, $3 million (December 31, 2010 – $3 million) of common share equity had not been fully paid relating to amounts outstanding under ESPP and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 181.6 million for 2011 and 172.9 million for 2010.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	2011			2010		
	Earnings to Common Shareholders *(in millions)*	**Weighted Average Shares** *(in millions)*	**EPS**	Earnings to Common Shareholders *(in millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**$ 318**	**181.6**	**$ 1.75**	$ 285	172.9	$ 1.65
Effect of potential dilutive securities:						
Stock Options	**–**	**1.0**		–	0.9	
Preference Shares *(Notes 15 and 21)*	**17**	**10.1**		17	11.9	
Convertible Debentures	**2**	**1.2**		2	1.4	
	$ 337	**193.9**		$ 304	187.1	
Deduct anti-dilutive impacts:						
Preference Shares	**(7)**	**(3.9)**		–	–	
Diluted EPS	**$ 330**	**190.0**	**$ 1.74**	$ 304	187.1	$ 1.62

17. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2011, the Corporation had the following stock option plans: the 2006 Plan and the 2002 Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to replace the former Executive Stock Option Plan ("ESOP") and the Directors' Stock Option Plan. All of the outstanding options under the former ESOP were exercised during 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options issued under this plan are exercised or expire in or before 2016. The Corporation ceased granting options under the 2002 Plan and all options granted after 2006 are under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2006 Plan.

Number of Options	**2011**	2010
Options outstanding, beginning of year	**4,700,203**	4,693,493
Granted	**828,512**	892,744
Cancelled	**(29,359)**	(93,864)
Exercised	**(790,127)**	(792,170)
Options outstanding, end of year	**4,709,229**	4,700,203
Options vested, end of year	**2,572,775**	2,541,374

Weighted Average Exercise Prices	**2011**	2010
Options outstanding, beginning of year	**$ 23.52**	$ 21.83
Granted	**32.95**	27.36
Cancelled	**28.16**	25.68
Exercised	**19.56**	17.61
Options outstanding, end of year	**25.81**	23.52

December 31, 2011 and 2010

17. Stock-Based Compensation Plans (cont'd)

Stock Options (cont'd)

Details of stock options outstanding and vested as at December 31, 2011 were as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
5,608	5,608	$ 12.03	2012
79,210	79,210	$ 12.81	2013
204,441	204,441	$ 15.28	2014
10,000	10,000	$ 15.23	2014
1,031	1,031	$ 14.55	2014
313,376	313,376	$ 18.40	2015
28,000	28,000	$ 18.11	2015
6,303	6,303	$ 20.82	2015
341,741	341,741	$ 22.94	2016
489,246	489,246	$ 28.19	2014
34,343	34,343	$ 25.76	2014
678,938	492,949	$ 28.27	2015
863,209	375,937	$ 22.29	2016
835,743	190,590	$ 27.36	2017
818,040	–	$ 32.95	2018
4,709,229	2,572,775		

The weighted average exercise price of stock options vested as at December 31, 2011 was $23.64.

In March 2011 the Corporation granted 828,512 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $32.95 immediately preceding the date of grant. The fair value of each option granted was $4.57 per option.

In March 2010 the Corporation granted 892,744 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of $27.36 immediately preceding the date of grant. The fair value of each option granted was $4.41 per option.

The fair values of the above option grants were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions.

	2011	2010
Dividend yield *(%)*	**3.68**	3.66
Expected volatility *(%)*	**23.1**	25.1
Risk-free interest rate *(%)*	**2.00**	2.54
Weighted average expected life *(years)*	**4.5**	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was $4 million for the year ended December 31, 2011 (2010 – $4 million).

Directors' DSU Plan

The Corporation's Directors' DSU Plan is an optional means for directors to elect to receive credit for their annual retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective 2006 directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of DSUs	2011	2010
DSUs outstanding, beginning of year	146,951	116,904
Granted	27,070	24,426
Granted – notional dividends reinvested	5,429	5,621
DSUs paid out	(31,821)	–
DSUs outstanding, end of year	147,629	146,951

For the year ended December 31, 2011, expense of $1 million (2010 – $2 million) was recorded in relation to the DSU Plan.

During 2011 31,821 DSUs were paid out, subsequent to the death of a Board member, at a price of $33.06 per DSU, for a total of approximately $1 million.

As at December 31, 2011, the total liability related to outstanding DSUs has been recorded at the closing price of the Corporation's common shares of $33.37, for a total of approximately $5 million (December 31, 2010 – $5 million), and is included in other liabilities (Note 14).

PSU Plan

The Corporation's PSU Plan is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period. Each PSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of PSUs	2011	2010
PSUs outstanding, beginning of year	141,408	98,133
Granted	45,000	60,000
Granted – notional dividends reinvested	5,329	5,017
PSUs paid out	(37,079)	(21,742)
PSUs outstanding, end of year	154,658	141,408

In March 2011 37,079 PSUs were paid out to the President and CEO of the Corporation at a price of $33.11 per PSU, for a total of approximately $1 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in February 2008 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2011, expense of $2 million (2010 – $2 million) was recorded in relation to the PSU Plan.

As at December 31, 2011, the total liability related to outstanding PSUs has been recorded at the closing price of the Corporation's common shares of $33.37, for a total of approximately $3 million (December 31, 2010 – $3 million), and is included in other liabilities (Note 14).

18. Accumulated Other Comprehensive Loss

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive loss by category is provided as follows:

	2011		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation (losses) gains on net investments in self-sustaining foreign operations	**$ (138)**	**$ 38**	**$ (100)**
Gains (losses) on hedges of net investments in self-sustaining foreign operations	**56**	**(23)**	**33**
Corporate tax (expense) recovery	**(8)**	**4**	**(4)**
	(90)	**19**	**(71)**
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	**(6)**	**2**	**(4)**
Corporate tax recovery	**2**	**(1)**	**1**
	(4)	**1**	**(3)**
Accumulated other comprehensive loss	**$ (94)**	**$ 20**	**$ (74)**

	2010		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation losses:			
Unrealized foreign currency translation losses on net investments in self-sustaining foreign operations	$ (105)	$ (33)	$ (138)
Gains on hedges of net investments in self-sustaining foreign operations	31	25	56
Corporate tax expense	(4)	(4)	(8)
	(78)	(12)	(90)
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(7)	1	(6)
Corporate tax recovery	2	–	2
	(5)	1	(4)
Accumulated other comprehensive loss	$ (83)	$ (11)	$ (94)

The net change in accumulated other comprehensive loss for 2011 includes the reclassification of $28 million of unrealized foreign currency translation losses, related to the translation into Canadian dollars of the Corporation's previous foreign net investment in self-sustaining Belize Electricity, and $13 million ($11 million after tax) of unrealized foreign currency translation gains related to corporately issued US dollar borrowings previously designated as an effective hedge of the Corporation's previous foreign net investment in self sustaining Belize Electricity, to long-term other assets from accumulated other comprehensive loss. The reclassifications were the result of the expropriation of Belize Electricity on June 20, 2011 (Notes 8 and 31).

19. Non-Controlling Interests

(in millions)	2011	2010
Waneta Partnership	**$ 128**	$ 44
Caribbean Utilities	**73**	73
Preference shares of Newfoundland Power	**7**	7
Belize Electricity	**–**	38
	$ 208	$ 162

20. Other Income (Expenses), Net

(in millions)	2011	2010
Termination fee	**$ 17**	$ –
Equity component of AFUDC *(Note 3)*	**13**	15
Interest income	**4**	2
Net foreign exchange gain	**4**	1
Other income, net of expenses	**2**	1
Business development expenses	**–**	(6)
	$ 40	$ 13

The termination fee was paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and Central Vermont Public Service Corporation.

The net foreign exchange gain includes an approximate $4.5 million foreign exchange gain on the translation into Canadian dollars of the Corporation's long-term other asset associated with Belize Electricity (Note 8), partially offset by an approximate $3.5 million foreign exchange loss on the translation into Canadian dollars of the Corporation's unhedged US dollar borrowings.

The net foreign exchange gain also includes amounts related to foreign currency transactions at Caribbean Utilities.

21. Finance Charges

(in millions)	2011	2010
Interest – Long-term debt and capital lease obligations	**$ 362**	$ 352
– Short-term borrowings	**10**	9
Dividends on preference shares *(Notes 15 and 16)*	**17**	17
Debt component of AFUDC *(Note 3)*	**(19)**	(16)
	$ 370	$ 362

22. Corporate Taxes

Future income taxes are provided for temporary differences. Future income tax assets and liabilities comprised the following:

(in millions)		**2011**		2010
Future income tax liability (asset)				
Utility capital assets	**$**	**605**	$	544
Income producing properties		**27**		27
Intangible assets		**32**		26
Regulatory assets		**81**		78
Other assets and liabilities (net)		**(4)**		2
Regulatory liabilities		**(73)**		(58)
Loss carryforwards		**(19)**		(23)
Unrealized foreign currency translation gains on long-term debt		**7**		9
Share issue and debt financing costs		**2**		–
Net future income tax liability	**$**	**658**	$	605
Current future income tax asset	**$**	**(24)**	$	(14)
Current future income tax liability		**5**		6
Long-term future income tax asset		**(8)**		(16)
Long-term future income tax liability		**685**		629
Net future income tax liability	**$**	**658**	$	605

The components of the provision for corporate taxes were as follows:

(in millions)		**2011**		2010
Canadian				
Current taxes	**$**	**71**	$	68
Future income taxes		**67**		49
Less regulatory adjustments		**(65)**		(50)
		2		(1)
Total Canadian	**$**	**73**	$	67
Foreign				
Current taxes	**$**	**5**	$	2
Future income taxes		**2**		(2)
Total Foreign	**$**	**7**	$	–
Corporate taxes	**$**	**80**	$	67

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before corporate taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2011**	2010
Combined Canadian federal and provincial statutory income tax rate	**30.5%**	32.0%
Statutory income tax rate applied to earnings before corporate taxes	**$ 133**	$ 125
Preference share dividends	**5**	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	**(12)**	(15)
Difference in Canadian provincial statutory rates applicable to subsidiaries in different Canadian jurisdictions	**(13)**	(11)
Items capitalized for accounting purposes but expensed for income tax purposes	**(53)**	(39)
Difference between capital cost allowance and amounts claimed for accounting purposes	**12**	(4)
Non-deductible expenses	**7**	8
Other	**1**	(3)
Corporate taxes	**$ 80**	$ 67
Effective tax rate	**18.3%**	17.2%

As at December 31, 2011, the Corporation had approximately $86 million (December 31, 2010 – $101 million) in non-capital and capital loss carryforwards, of which $13 million (December 31, 2010 – $18 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2031.

23. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group RRSPs for employees. The Corporation, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and Algoma Power also offer OPEB plans for qualifying employees.

For the defined benefit pension plan arrangements, the accrued pension benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, the FortisBC Energy companies, Newfoundland Power and Caribbean Utilities, and as at September 30 of each year for FortisAlberta, FortisBC Electric, FortisOntario and Algoma Power. The most recent actuarial valuation of the pension plans for funding purposes was as of July 1, 2009 for Algoma Power; as of December 31, 2009 for the FortisBC Energy companies (covering non-unionized employees) and FortisOntario; as of December 31, 2010 for the FortisBC Energy companies (covering unionized employees), FortisAlberta and FortisBC Electric; and as of December 31, 2011 for the Corporation, Newfoundland Power and Caribbean Utilities. The next required valuations for funding purposes will be, at the latest, three years from the date of the most recent actuarial valuation of each plan, as noted above.

The Corporation's consolidated defined benefit pension plan asset allocation was as follows:

Plan assets as at December 31

(%)	**2011**	2010
Canadian equities	**43**	45
Fixed income	**43**	41
Foreign equities	**9**	9
Real estate	**5**	5
	100	100

December 31, 2011 and 2010

23. Employee Future Benefits (cont'd)

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and their respective funded or unfunded status:

	2011			2010		
(in millions)	**Accrued Benefit Obligation**	**Plan Assets**	**Net Unfunded**	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
FortisBC Energy Companies	**$ 442**	**$ 315**	**$ (127)**	$ 370	$ 285	$ (85)
FortisAlberta	**33**	**26**	**(7)**	30	22	(8)
FortisBC Electric	**156**	**111**	**(45)**	144	106	(38)
Newfoundland Power	**283**	**276**	**(7)**	256	269	13
Maritime Electric	**2**	**–**	**(2)**	2	–	(2)
FortisOntario [1]	**24**	**22**	**(2)**	24	21	(3)
Algoma Power	**20**	**18**	**(2)**	19	15	(4)
Caribbean Utilities	**7**	**4**	**(3)**	6	4	(2)
Fortis	**25**	**5**	**(20)**	21	5	(16)
Total	**$ 992**	**$ 777**	**$ (215)**	$ 872	$ 727	$ (145)

[1] Covers eligible employees of Canadian Niagara Power

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2011**	2010	**2011**	2010
Change in accrued benefit obligation				
Balance, beginning of year	**$ 872**	$ 752	**$ 204**	$ 181
Current service costs	**21**	16	**5**	4
Employee contributions	**14**	11	**–**	–
Interest costs	**46**	46	**11**	12
Benefits paid	**(39)**	(36)	**(6)**	(5)
Actuarial loss	**78**	88	**28**	27
Past services costs/plan amendments	**–**	(5)	**1**	(15)
Balance, end of year	**$ 992**	$ 872	**$ 243**	$ 204
Change in value of plan assets				
Balance, beginning of year	**$ 727**	$ 661	**$ –**	$ –
Actual return on plan assets	**42**	67	**–**	–
Benefits paid	**(39)**	(36)	**(6)**	(5)
Employee contributions	**14**	11	**–**	–
Employer contributions	**33**	24	**6**	5
Balance, end of year	**$ 777**	$ 727	**$ –**	$ –
Funded status				
Deficit, end of year	**$ (215)**	$ (145)	**$ (243)**	$ (204)
Unamortized net actuarial loss	**294**	231	**90**	66
Unamortized past service costs	**(1)**	(1)	**(25)**	(31)
Unamortized transitional obligation	**7**	8	**10**	12
Employer contributions after measurement date	**2**	1	**–**	–
Accrued benefit asset (liability), end of year	**$ 87**	$ 94	**$ (168)**	$ (157)
Deferred pension costs *(Note 8)*	**$ 139**	$ 140	**$ –**	$ –
Defined benefit pension liabilities *(Note 14)*	**(52)**	(46)	**–**	–
OPEB plan liabilities *(Note 14)*	**–**	–	**(168)**	(157)
	$ 87	$ 94	**$ (168)**	$ (157)

(in millions)	Defined Benefit Pension Plans 2011	Defined Benefit Pension Plans 2010	OPEB Plans 2011	OPEB Plans 2010
Components of net benefit cost				
Current service costs	**$ 21**	$ 16	**$ 5**	$ 4
Interest costs	**46**	46	**11**	12
Actual return on plan assets	**(42)**	(67)	**–**	–
Actuarial loss	**78**	88	**28**	27
Past service costs/plan amendments	**–**	(5)	**1**	(15)
Costs arising in the year	**103**	78	**45**	28
Differences between costs arising and costs recognized in the year in respect of:				
Return on plan assets	**(5)**	21	**–**	–
Actuarial loss	**(58)**	(77)	**(24)**	(25)
Past service costs	**1**	6	**(5)**	13
Transitional obligation and plan amendments	**1**	–	**2**	2
Regulatory adjustment	**(8)**	(1)	**2**	(7)
Net benefit cost	**$ 34**	$ 27	**$ 20**	$ 11
Significant assumptions				
Weighted average discount rate during the year *(%)*	**5.37**	6.16	**5.38**	6.27
Weighted average discount rate as at December 31 *(%)*	**4.65**	5.37	**4.69**	5.38
Weighted average expected long-term rate of return on plan assets *(%)*	**6.76**	6.88	**–**	–
Weighted average rate of compensation increase *(%)*	**3.37**	3.70	**3.41**	3.72
Weighted average health-care cost trend increase as at December 31 *(%)*	**–**	–	**6.59**	6.53
Expected average remaining service life of active employees *(years)*	**4–15**	3–15	**12–16**	10–17

For 2011 the effects of changing the health-care cost trend rate by 1% were as follows:

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accrued benefit obligation	**$ 25**	**$ (21)**
Increase (decrease) in current service and interest costs	**2**	**(2)**

December 31, 2011 and 2010

23. Employee Future Benefits (cont'd)

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2011 net defined benefit pension cost, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

(in millions)	Net Benefit Cost	Accrued Benefit Asset	Accrued Benefit Liability	Accrued Benefit Obligation [1]
Impact of increasing the rate of return assumption by 100 basis points	**$ (2)**	**$ 2**	**$ –**	**$ 45**
Impact of decreasing the rate of return assumption by 100 basis points	**3**	**(3)**	**–**	**(41)**
Impact of increasing the discount rate assumption by 100 basis points	**(15)**	**14**	**(2)**	**(137)**
Impact of decreasing the discount rate assumption by 100 basis points	**18**	**(16)**	**2**	**171**

[1] At the FortisBC Energy companies and FortisBC Electric, the methodology for determining the pension indexing assumption, which impacts the measurement of the accrued benefit pension obligation, is based off of the expected long-term rate of return on pension plan assets. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the accrued benefit pension obligation.

During 2011 the Corporation expensed $13 million (2010 – $11 million) related to defined contribution pension plans.

24. Business Acquisition

2011

NON-REGULATED – FORTIS PROPERTIES

In October 2011 Fortis Properties purchased the Hilton Suites Winnipeg Airport hotel for an aggregate cash purchase price of approximately $25 million, which was allocated to income producing properties. The acquisition has been accounted for using the purchase method, whereby the financial results of the hotel have been consolidated in the financial statements of Fortis commencing October 2011.

25. Segmented Information

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year ended December 31, 2011 *($ millions)*	FortisBC Energy Companies – Canadian	Fortis Alberta	FortisBC Electric	NF Power	Other Canadian	Total Electric Canadian	Electric Caribbean	Fortis Generation	Fortis Properties	Corporate and Other	Inter-segment eliminations	Consolidated
Revenue	1,568	409	296	573	339	1,617	305	34	231	29	(37)	3,747
Energy supply costs	854	–	72	369	218	659	192	1	–	–	(9)	1,697
Operating expenses	307	144	83	75	48	350	40	8	156	10	(6)	865
Amortization	111	134	45	42	24	245	33	4	19	7	–	419
Operating income	296	131	96	87	49	363	40	21	56	12	(22)	766
Other income (expenses), net	10	5	1	–	–	6	3	1	–	21	(1)	40
Finance charges	127	60	39	36	20	155	14	2	24	71	(23)	370
Corporate tax expense (recovery)	40	1	10	16	7	34	1	2	9	(6)	–	80
Net earnings (loss)	139	75	48	35	22	180	28	18	23	(32)	–	356
Non-controlling interests	–	–	–	1	–	1	8	–	–	–	–	9
Preference share dividends	–	–	–	–	–	–	–	–	–	29	–	29
Net earnings (loss) attributable to common equity shareholders	139	75	48	34	22	179	20	18	23	(61)	–	318
Goodwill	908	227	221	–	63	511	138	–	–	–	–	1,557
Identifiable assets	4,408	2,452	1,320	1,202	658	5,632	718	546	610	482	(391)	12,005
Total assets	5,316	2,679	1,541	1,202	721	6,143	856	546	610	482	(391)	13,562
Gross capital expenditures [1]	253	416	102	81	47	646	71	174	30	–	–	1,174
Year ended December 31, 2010 *($ millions)*												
Revenue	1,546	385	266	555	331	1,537	333	36	226	29	(50)	3,657
Energy supply costs	863	–	73	358	215	646	201	1	–	–	(25)	1,686
Operating expenses	288	141	73	62	45	321	48	9	151	10	(5)	822
Amortization	108	126	41	47	23	237	36	4	18	7	–	410
Operating income	287	118	79	88	48	333	48	22	57	12	(20)	739
Other income (expenses), net	9	3	3	–	–	6	3	4	–	(5)	(4)	13
Finance charges	121	54	35	36	21	146	18	4	24	73	(24)	362
Corporate tax expense (recovery)	45	(1)	5	16	8	28	1	2	7	(16)	–	67
Net earnings (loss)	130	68	42	36	19	165	32	20	26	(50)	–	323
Non-controlling interests	–	–	–	1	–	1	9	–	–	–	–	10
Preference share dividends	–	–	–	–	–	–	–	–	–	28	–	28
Net earnings (loss) attributable to common equity shareholders	130	68	42	35	19	164	23	20	26	(78)	–	285
Goodwill	908	227	221	–	63	511	134	–	–	–	–	1,553
Identifiable assets	4,319	2,144	1,263	1,197	646	5,250	779	348	572	505	(417)	11,356
Total assets	5,227	2,371	1,484	1,197	709	5,761	913	348	572	505	(417)	12,909
Gross capital expenditures [1]	253	379	139	78	48	644	72	84	19	1	–	1,073

[1] Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statement of cash flows.

December 31, 2011 and 2010

25. Segmented Information (cont'd)

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011, and to FortisOntario; (ii) electricity sales from Newfoundland Power to Fortis Properties; and (iii) finance charges on related party borrowings. The significant related party inter-segment transactions during the years ended December 31 were as follows:

Significant Related Party Inter-Segment Transactions

(in millions)	2011	2010
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	$ 7	$ 24
Sales from Fortis Generation to Other Canadian Electric Utilities	1	1
Sales from Newfoundland Power to Fortis Properties	5	4
Inter-segment finance charges on borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	1	4
Corporate to Other Canadian Electric Utilities	2	1
Corporate to Regulated Electric Utilities – Caribbean	4	3
Corporate to Fortis Generation	3	4
Corporate to Fortis Properties	13	12

The significant related party inter-segment asset balances as at December 31 were as follows:

(in millions)	2011	2010
Inter-segment borrowings from:		
Fortis Generation to Other Canadian Electric Utilities	$ 20	$ 20
Corporate to Other Canadian Electric Utilities	–	50
Corporate to Regulated Electric Utilities – Caribbean	76	60
Corporate to Fortis Generation	23	51
Corporate to Fortis Properties	249	219
Other inter-segment assets	23	17
Total inter-segment eliminations	$ 391	$ 417

26. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	2011	2010
Interest paid	$ 359	$ 355
Income taxes paid	67	51

The following table provides a breakdown of the Corporation's changes in non-cash operating working capital.

(in millions)	2011	2010
Accounts receivable	$ 5	$ (53)
Prepaid expenses	(2)	(1)
Regulatory assets – current portion	(4)	18
Inventories	30	9
Accounts payable and accrued charges	57	(3)
Income taxes payable	3	14
Regulatory liabilities – current portion	9	14
Change in non-cash operating working capital	**$ 98**	$ (2)

27. Capital Management

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund the maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to support energy infrastructure investment and to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

The consolidated capital structure of Fortis as at December 31, 2011 compared to December 31, 2010 is presented in the following table.

	2011		2010	
	(in millions)	***(%)***	*(in millions)*	*(%)*
Total debt and capital lease obligations (net of cash) [(1)]	**$ 5,855**	**55.0**	$ 5,914	58.4
Preference shares [(2)]	**912**	**8.6**	912	9.0
Common shareholders' equity	**3,877**	**36.4**	3,305	32.6
Total [(3)]	**$ 10,644**	**100.0**	$ 10,131	100.0

(1) Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash
(2) Includes preference shares classified as both long-term liabilities and equity
(3) Excludes amounts related to non-controlling interests

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2011, the Corporation and its subsidiaries, except for the Exploits Partnership, as described below, were in compliance with their debt covenants.

As the hydroelectric assets and water rights of the Exploits Partnership had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $56 million as at December 31, 2011 (December 31, 2010 – $58 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. See Note 31 for further information on the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 29.

28. Financial Instruments

The Corporation has designated its non-derivative financial instruments as at December 31 as follows:

	2011		2010	
(in millions)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents [(1)]	**$ 89**	**$ 89**	$ 109	$ 109
Loans and receivables				
Trade and other accounts receivable [(1) (2) (3)]	**644**	**644**	655	655
Other long-term receivables [(1) (3) (4)]	**13**	**13**	15	15
Other asset – Belize Electricity [(4)]	**106**	–[(5)]	–	–
Other financial liabilities				
Short-term borrowings [(1) (3)]	**159**	**159**	358	358
Trade and other accounts payable [(1) (3) (6)]	**778**	**778**	786	786
Dividends payable [(1) (3)]	**60**	**60**	54	54
Customer deposits [(1) (3) (7)]	**6**	**6**	6	6
Waneta Partnership promissory note [(7) (8)]	**45**	**49**	42	40
Long-term debt, including current portion [(9) (10)]	**5,788**	**7,143**	5,669	6,431
Preference shares, classified as debt [(9) (11)]	**320**	**348**	320	344

(1) Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
(2) Included in accounts receivable on the consolidated balance sheet
(3) Carrying value approximates amortized cost.
(4) Included in long-term other assets on the consolidated balance sheet
(5) The fair value of the Corporation's expropriated investment in Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts.
(6) Included in accounts payable and accrued charges on the consolidated balance sheet
(7) Included in other liabilities on the consolidated balance sheet
(8) Carrying value is a discounted net present value.
(9) Carrying value is measured at amortized cost using the effective interest rate method.
(10) Carrying value as at December 31, 2011 excludes unamortized deferred financing costs of $43 million (December 31, 2010 – $42 million) and capital lease obligations of $40 million (December 31, 2010 – $38 million).
(11) Preference shares classified as equity are excluded from the requirements of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; however, the estimated fair value of the Corporation's $592 million preference shares classified as equity was $634 million as at December 31, 2011 (December 31, 2010 – $615 million).

The carrying values of financial instruments included in current assets, current liabilities, other assets and other liabilities on the consolidated balance sheets of Fortis approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments.

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

	2011				2010	
Liability	**Term to Maturity** *(years)*	**Number of Contracts**	**Carrying Value** *(in millions)*	**Estimated Fair Value** *(in millions)*	Carrying Value *(in millions)*	Estimated Fair Value *(in millions)*
Foreign exchange forward contract [(1) (2)]	**< 1**	**1**	**$ –**	**$ –**	$ –	$ –
Fuel option contracts [(1) (2)]	**< 1**	**2**	**(1)**	**(1)**	–	–
Natural gas derivatives: [(1) (2)]						
Swaps and options	**Up to 3**	**143**	**(135)**	**(135)**	(162)	(162)
Gas purchase contract premiums	**Up to 3**	**57**	**–**	**–**	(5)	(5)

(1) The fair value measurements are Level 2, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value. Level 2 inputs represent inputs, other than quoted prices in active markets for identical assets or liabilities, that are observable for the asset or liability, either directly as prices or indirectly as derived from prices.

(2) The fair values of the derivatives were recorded in accounts payable as at December 31, 2011 and 2010.

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

29. Financial Risk Management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash and cash equivalents, trade and other accounts receivable, and other long-term receivables, the Corporation's credit risk is limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2011, its gross credit risk exposure was approximately $150 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately $3 million by obtaining from the retailers either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the FortisBC Energy companies deal with high credit-quality institutions in accordance with established credit-approval practices. The counterparties with which the FortisBC Energy companies have significant transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

December 31, 2011 and 2010

29. Financial Risk Management (cont'd)

Credit Risk (cont'd)

The Corporation is exposed to credit risk associated with the amount and timing of compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. The Corporation has a long-term other asset of $106 million, including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 8 and 31).

The aging analysis of the Corporation's consolidated trade and other accounts receivable, net of an allowance for doubtful accounts of $16 million as at December 31, 2011 (December 31, 2010 – $16 million), excluding derivative financial instruments recorded in accounts receivable as at December 31, was as follows:

(in millions)		**2011**		2010
Not past due	**$**	**553**	$	584
Past due 0–30 days		**65**		56
Past due 31–60 days		**12**		9
Past due 61 days and over		**14**		6
	$	**644**	$	655

As at December 31, 2011, the aging analysis includes amounts owed to BECOL from Belize Electricity, due to the discontinuance of the consolidation method of accounting for Belize Electricity as a result of the expropriation of the utility by the GOB. As at December 31, 2011, BECOL was owed $9.5 million from Belize Electricity related to energy purchases. Approximately $2 million of the accounts receivable past due 31–60 days and $5 million of the accounts receivable past due 61 days and over related to amounts owing to BECOL from Belize Electricity.

As at December 31, 2011, other long-term receivables at the FortisBC Energy companies, FortisBC Electric and Newfoundland Power totalling $13 million (included in long-term other assets) will be received over the next five years and thereafter, with $3 million expected to be received over 2013 and 2014, $1 million over 2015 and 2016 and $9 million due after 2016.

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $270 million. The combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2011, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.2 billion, of which approximately $1.9 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.1 billion of the total credit facilities are committed facilities with maturities ranging from 2012 through 2015.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Corporate and Other	Regulated Utilities	Fortis Properties	**Total as at December 31, 2011**	Total as at December 31, 2010
Total credit facilities	$ 845	$ 1,390	$ 13	**$ 2,248**	$ 2,109
Credit facilities utilized:					
Short-term borrowings	–	(157)	(2)	**(159)**	(358)
Long-term debt *(Note 13)* [(1)]	–	(74)	–	**(74)**	(218)
Letters of credit outstanding	(1)	(65)	–	**(66)**	(124)
Credit facilities unused	$ 844	$ 1,094	$ 11	**$ 1,949**	$ 1,409

[(1)] As at December 31, 2011, credit facility borrowings classified as long-term debt included $16 million (December 31, 2010 – $16 million) that was included in current installments of long-term debt and capital lease obligations on the consolidated balance sheet.

As at December 31, 2011 and 2010, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other

Fortis has an $800 million unsecured committed revolving credit facility, maturing July 2015, and a $15 million unsecured demand credit facility. At any time prior to maturity, the Corporation may provide written notice to increase the amount available under the committed revolving credit facility to $1 billion. Both facilities are available for general corporate purposes and the committed facility is also available for interim financing of acquisitions.

FHI has a $30 million unsecured committed revolving credit facility, maturing May 2012, that is available for general corporate purposes.

Regulated Utilities

FEI has a $500 million unsecured committed revolving credit facility, maturing August 2013. FEVI has a $200 million unsecured committed revolving credit facility, maturing December 2013. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes. FEVI also has a $20 million unsecured committed non-revolving credit facility, maturing January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing September 2015, that is utilized to finance capital expenditures and for general corporate purposes. FortisAlberta also has a $10 million unsecured demand credit facility.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures May 2012 and the remaining $100 million matures May 2014. Additionally, the Company has the option to increase the credit facility to an aggregate of $200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand credit facility.

Newfoundland Power has $120 million of unsecured credit facilities, comprised of a $100 million committed revolving credit facility, which matures August 2015, and a $20 million demand credit facility.

Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing February 2014, and a $5 million unsecured demand credit facility.

FortisOntario has secured lines of credit totalling $20 million, of which $14 million is authorized solely for letters of credit.

Caribbean Utilities has unsecured credit facilities of approximately US$33 million ($33 million), comprised of a capital expenditure line of credit of US$18 million ($18 million), including amounts available for letters of credit, a US$7.5 million ($7.5 million) operating line of credit and a US$7.5 million ($7.5 million) catastrophe standby loan.

Fortis Turks and Caicos has unsecured credit facilities of US$21 million ($21 million), comprised of a revolving operating credit facility of US$5 million ($5 million), a capital expenditure line of credit of US$7 million ($7 million) and a US$9 million ($9 million) emergency standby loan.

Fortis Properties

Fortis Properties has a $13 million secured revolving demand credit facility that can be utilized for general corporate purposes.

December 31, 2011 and 2010

29. *Financial Risk Management (cont'd)*

Liquidity Risk (cont'd)

The Corporation and its utilities, which are currently rated, target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2011, the Corporation's credit ratings were as follows:

Standard & Poor's	A– (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

The credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis. In February 2012, after the announcement by Fortis that it had entered into an agreement to acquire all of the shares of CH Energy Group, Inc. ("CH Energy Group") for US$1.5 billion, including the assumption of US$500 million of debt on closing (Note 33), DBRS placed the Corporation's credit rating under review with developing implications. Similarly, Standard & Poor's placed the Corporation's credit rating on credit watch with negative implications.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2011.

Financial Liabilities

(in millions)	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years	**Total**
Short-term borrowings	$ 159	$ –	$ –	$ –	**$ 159**
Trade and other accounts payable	778	–	–	–	**778**
Natural gas derivatives [(1)]	88	41	–	–	**129**
Fuel option contracts [(2)]	1	–	–	–	**1**
Foreign exchange forward contract [(3)]	4	–	–	–	**4**
Dividends payable	60	–	–	–	**60**
Customer deposits [(4)]	–	2	1	3	**6**
Waneta Partnership promissory note [(5)]	–	–	–	72	**72**
Long-term debt, including current portion [(6)]	103	791	440	4,454	**5,788**
Interest obligations on long-term debt	356	690	597	5,201	**6,844**
Preference shares, classified as debt	–	123	197	–	**320**
Dividend obligations on preference shares, classified as finance charges	17	25	17	–	**59**
Total	$ 1,566	$ 1,672	$ 1,252	$ 9,730	**$ 14,220**

[(1)] Amounts disclosed are on a gross cash flow basis. The derivatives were recorded in accounts payable at fair value as at December 31, 2011 at $135 million.

[(2)] Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at December 31, 2011 at $1 million.

[(3)] Amounts disclosed are on a gross cash flow basis. The contracts were recorded in accounts payable at fair value as at December 31, 2011 at less than $1 million.

[(4)] Customer deposits were recorded in other liabilities as at December 31, 2011.

[(5)] Amounts disclosed are on a gross cash flow basis. The promissory note was recorded in other liabilities at discounted net present value as at December 31, 2011 at $45 million.

[(6)] Excludes deferred financing costs of $43 million and capital lease obligations of $40 million

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at December 31, 2011, the Corporation's corporately issued US$550 million (December 31, 2010 – US$590 million) long-term debt had been designated as a hedge of substantially all of the Corporation's self-sustaining foreign net investments. As at December 31, 2011, the Corporation had approximately US$6 million (December 31, 2010 – US$7 million) in self-sustaining foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in self-sustaining foreign subsidiaries, which are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its previous investment in Belize Electricity (Note 8) does not qualify for hedge accounting as Belize Electricity is no longer a self-sustaining foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. As a result, the Corporation recognized a net foreign exchange gain of approximately $1 million ($1.5 million after tax) in earnings in 2011 (Note 20).

A 5% appreciation or depreciation of the US dollar relative to the Canadian dollar would have: (i) increased or decreased earnings by approximately $6 million for the year ended December 31, 2011 (2010 – $2 million); (ii) increased or decreased long-term other assets by approximately $4 million as at December 31, 2011 (2010 – nil); and (iii) decreased or increased other comprehensive income by $24 million for the year ended December 31, 2011 (2010 – $25 million). This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense, earnings streams from the Corporation's foreign subsidiaries, the translation of the Corporation's long-term other asset associated with its previous investment in Belize Electricity, and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased or decreased other comprehensive income by $28 million for the year ended December 31, 2011 (2010 – $30 million).

FEI's US dollar payments under a contract for the implementation of a customer care information system are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2011, a 5% appreciation or depreciation of the US dollar relative to the Canadian dollar, as it impacts the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased or decreased earnings by less than $1 million for the year ended December 31, 2011 (2010 – less than $1 million). Furthermore, FEI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

Interest Rate Risk

The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk.

A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by $3 million for the year ended December 31, 2011 (2010 – $4 million). A 25 basis point decrease in interest rates associated with variable-rate debt, with all other variables remaining constant, would have increased earnings by $1 million for the year ended December 31, 2011 (2010 – $1 million). Furthermore, the FortisBC Energy companies and FortisBC Electric have regulatory deferral accounts that mitigate exposure to fluctuations in interest rates associated with variable-rate debt and are recovered from, or refunded to, customers in future rates.

Certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by approximately $1 million for the year ended December 31, 2011 (2010 – $1 million).

Commodity Price Risk

The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk has been minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive with electricity rates, temper gas price volatility on customer rates and reduce the risk of regional price discrepancies. In 2011 the BCUC determined that commodity hedging in the current environment was not a cost-effective means to meet the objectives of price competitiveness and rate stability. The BCUC concurrently denied FEI's 2011–2014 Price Risk Management Plan with the exception of certain elements to address regional price discrepancies. As a result, the FortisBC Energy companies have suspended all commodity hedging activities, with the exception of certain limited swaps as permitted by the BCUC. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

December 31, 2011 and 2010

29. Financial Risk Management (cont'd)

Market Risk (cont'd)

Commodity Price Risk (cont'd)

Had the price of natural gas, with all other variables remaining constant, increased by $1 per gigajoule, the fair value of the natural gas derivatives would have been less out-of-the-money and, in the absence of rate regulation, other comprehensive income would have increased by $59 million for the year ended December 31, 2011 (2010 – $63 million). However, the FortisBC Energy companies defer any changes in the fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by $59 million (December 31, 2010 – $63 million). Had the price of natural gas, with all other variables remaining constant, decreased by $1 per gigajoule, the fair value of the natural gas derivatives would have been further out-of-the-money and, in the absence of rate regulation, other comprehensive income would have decreased by $59 million for the year ended December 31, 2011 (2010 – $62 million). However, subject to regulatory approval of the deferral, instead of decreasing other comprehensive income, current regulatory assets would have increased by $59 million (December 31, 2010 – $62 million).

The Corporation's exposure to market risk related to the foreign exchange forward contract and natural gas derivatives represents an estimate of possible changes in fair value that would occur assuming hypothetical movements in foreign exchange rates and commodity prices. The estimates may not be indicative of actual results and do not represent the maximum possible fair value gains and losses that may occur.

30. Commitments

The Corporation's consolidated commitments in each of the next five years and thereafter, as at December 31, 2011, excluding repayments of long-term debt and capital lease obligations, which are separately disclosed in Note 13, are as follows:

(in millions)	Total	Due within 1 year	Due in year 2	Due in year 3	Due in year 4	Due in year 5	Due after 5 years
Gas purchase contract obligations [(1)]	$ 300	$ 180	$ 74	$ 46	$ –	$ –	$ –
Power purchase obligations							
FortisBC Electric [(2)]	2,430	47	45	40	41	40	2,217
FortisOntario [(3)]	413	48	49	50	51	52	163
Maritime Electric [(4)]	190	50	38	40	47	1	14
Capital cost [(5)]	461	17	17	19	17	19	372
Operating lease obligations [(6)]	152	26	17	16	16	16	61
Waneta Partnership promissory note [(7)]	72	–	–	–	–	–	72
Joint-use asset and shared service agreements [(8)]	64	3	4	4	4	3	46
Defined benefit pension funding contributions [(9)]	58	26	25	3	1	1	2
Office lease – FortisBC Electric [(10)]	17	2	2	2	1	1	9
Other [(11)]	7	1	1	1	1	–	3
Total	**$ 4,164**	$ 400	$ 272	$ 221	$ 179	$ 133	$ 2,959

(1) Gas purchase contract obligations relate to various gas purchase contracts at the FortisBC Energy companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2011.

(2) Power purchase obligations for FortisBC Electric include the Brilliant Power Purchase Agreement (the "BPPA"), the PPA with BC Hydro and capacity agreements with Powerex Corp. ("Powerex"). On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The Brilliant plant is owned by Brilliant Power Corporation ("BPC"), a corporation owned equally by CPC/CBT. FortisBC Electric operates and maintains the Brilliant plant for the BPC in return for a management fee. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The PPA with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements. During September 2010 FortisBC Electric entered into an agreement to purchase fixed-price winter capacity purchases through to February 2016 from Powerex, a wholly owned subsidiary of BC Hydro. As per the agreement, if FortisBC Electric brings any new

resources, such as capital or contractual projects, online prior to the expiry of the agreement, FortisBC Electric may terminate the contract any time after July 1, 2013 with a minimum of three months' written notice to Powerex. Additionally, in November 2011 FortisBC Electric entered into a second agreement to purchase fixed-price winter capacity purchases through to March 2012 from Powerex.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement (the "WECA"). The form of the WECA was originally accepted for filing by the BCUC in September 2010 and allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. The total amount expected to be paid by FortisBC Electric to the Waneta Partnership over the term of the WECA is approximately $2.9 billion. The executed version of the WECA was submitted to the BCUC in November 2011. The BCUC will be seeking submissions on whether further public process is warranted in respect of the BCUC's acceptance of filing of the executed WECA. The amount has not been included in the commitments table above as it is to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

(3) Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 gigawatt hours ("GWh") of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(4) Maritime Electric has two take-or-pay contracts for the purchase of either energy or capacity. In November 2010 the Company signed a new five-year take-or-pay contract with NB Power covering the period March 1, 2011 through February 29, 2016. The new contract includes fixed pricing for the entire five-year period and covers, among other things, replacement energy and capacity for Point Lepreau. The other take-or-pay contract, which is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on an international power line into the United States, expires in November 2032.

(5) Maritime Electric has entitlement to approximately 4.7% of the output from Point Lepreau for the life of the unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, which have been included in the table above. However, as a result of the Accord, the Government of PEI is assuming responsibility for the payment of the monthly operating and maintenance costs related to Point Lepreau, effective March 1, 2011 until Point Lepreau is fully refurbished, which is expected by fall 2012.

(6) Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases. They also include the operating lease obligations, up to April 2012, associated with the electricity distribution assets of Port Colborne Hydro and $7 million for the exercised election under the operating lease agreement to purchase the remaining assets of Port Colborne Hydro in April 2012.

(7) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion.

(8) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission facilities. Due to the unlimited term of this agreement, the calculation of future payments after 2016 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2010 and are subject to extension based on mutually agreeable terms.

(9) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2011 – Newfoundland Power
December 31, 2012 – FortisBC Energy companies (covering non-unionized employees)
December 31, 2013 – FortisBC Energy companies (covering unionized employees)
December 31, 2013 – FortisBC Electric

(10) On September 29, 1993 FortisBC Electric began leasing an office building in Trail, British Columbia for a term of 30 years. The terms of the agreement grant FortisBC Electric repurchase options at approximately year 20 and year 28 of the lease term.

30. Commitments (cont'd)

(11) Other contractual obligations include building operating leases, AROs and a commitment to purchase fibre-optic communication cable at FortisBC Electric.

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. The consolidated capital program of the Corporation, including capital spending at its non-regulated operations, is forecast to be approximately $1.3 billion for 2012 and $5.5 billion in total from 2012 through 2016, which has not been included in the commitments table above.

In prior years, FEVI received non-interest bearing repayable loans from the federal government and the Government of British Columbia of $50 million and $25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. As the loans are repaid and replaced with non-government loans, utility capital assets, long-term debt and equity requirements will increase in accordance with FEVI's approved capital structure, as will FEVI's rate base, which is used in determining customer rates.

As at December 31, 2011, the outstanding balance of the repayable government loans was $49 million. Timing of the repayments of the government loans is dependent upon the ability of FEVI to replace the government loans with non-government subordinated debt financing on reasonable commercial terms and, therefore, the repayments have not been included in the commitments table above. FEVI, however, estimates making payments under the loans of $20 million in 2012, $4 million in 2013, $10 million in each of 2014 and 2015 and $5 million in 2016.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80% of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-powered generating plant. The initial contract was for three years and terminated in April 2010. Caribbean Utilities continues to operate within the terms of the initial contract. The contract contains an automatic renewal clause for the years 2010 through 2012. Should any party choose to terminate the contract within that two-year period, notice must be given a minimum of one year in advance of the desired termination date. As at December 31, 2011, no such termination notice has been given by either party. As such, the contract is effectively renewed until May 2012. The quantity of fuel to be purchased under the contract for 2012 is approximately 10 million imperial gallons.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

31. Expropriated Assets

Belize Electricity

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, the Corporation has discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and has classified the book value of the previous investment in the utility as a long-term other asset on the consolidated balance sheet (Note 8).

In October 2011 Fortis commenced an action in the Belize Supreme Court to challenge the legality of the expropriation of its investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011.

The GOB also commissioned an independent valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's valuation. Pursuant to the expropriation action, Fortis is assessing alternative options for obtaining fair compensation from the GOB.

Exploits Partnership

The Exploits Partnership is owned 51% by Fortis Properties and 49% by Abitibi. The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

32. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI has begun the appeal process associated with the assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI has filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions and all claims are expected to be tried at the same time. The amount and outcome of the actions are indeterminable at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

33. Subsequent Event

On February 21, 2012, Fortis announced that it had entered into an agreement to acquire CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing ("the Acquisition"). CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated T&D utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The closing of the Acquisition, which is expected to occur in approximately 12 months, is subject to receipt of CH Energy Group's common shareholders' approval, regulatory and other approvals, and the satisfaction of customary closing conditions. The acquisition is expected to be immediately accretive to earnings per common share, excluding one-time transaction expenses.

34. Comparative Figures

Certain comparative figures have been reclassified to comply with current period presentation. The most significant changes related to: (i) a $58 million decrease in cash from financing activities associated with the issuance of common shares and a corresponding decrease in cash used in financing activities associated with dividends paid on common shares; (ii) a $17 million increase in long-term regulatory assets and a corresponding decrease in utility capital assets associated with a change in presentation at the FortisBC Energy companies; and (iii) a $13 million increase in other income (expenses) net, offset by a $7 million decrease in revenue, a $6 million decrease in operating expenses and a $12 million increase in finance charges associated with a change in the presentation of other income (expenses), net on the consolidated statement of earnings.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2011**	2010 [1]	2009 [1]
Revenue, including equity income	**3,747**	3,657	3,641
Energy supply costs and operating expenses	**2,562**	2,508	2,577
Amortization	**419**	410	364
Other income (expenses), net	**40**	13	10
Finance charges	**370**	362	369
Corporate taxes	**80**	67	49
Results of discontinued operations, gains on sales and other unusual items	**–**	–	–
Net earnings	**356**	323	292
Net earnings attributable to non-controlling interests	**9**	10	12
Net earnings attributable to preference equity shareholders	**29**	28	18
Net earnings attributable to common equity shareholders	**318**	285	262
Balance Sheets *(in $ millions)*			
Current assets	**1,120**	1,204	1,124
Goodwill	**1,557**	1,553	1,560
Other long-term assets	**1,263**	1,083	917
Utility capital assets, income producing properties and intangible assets	**9,622**	9,069	8,538
Total assets	**13,562**	12,909	12,139
Current liabilities	**1,320**	1,517	1,592
Other long-term liabilities	**1,566**	1,404	1,288
Long-term debt and capital lease obligations (excluding current portion)	**5,679**	5,609	5,276
Preference shares (classified as debt)	**320**	320	320
Total liabilities	**8,885**	8,850	8,476
Shareholders' equity	**4,677**	4,059	3,663
Cash Flows *(in $ millions)*			
Operating activities	**904**	732	681
Investing activities	**1,125**	991	1,045
Financing activities	**390**	455	563
Dividends, excluding dividends on preference shares classified as debt	**189**	172	176
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**8.86**	8.79	8.41
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease obligations (net of cash)	**55.0**	58.4	60.2
Preference shares (classified as debt and equity)	**8.6**	9.0	6.9
Common shareholders' equity	**36.4**	32.6	32.9
Interest Coverage *(x)*			
Debt	**2.1**	2.0	1.9
All fixed charges	**2.0**	1.9	1.8
Total Gross Capital Expenditures *(in $ millions)*	**1,174**	1,073	1,024
Common Share Data			
Book value per share (year end) *($)*	**20.53**	18.92	18.61
Average common shares outstanding *(in millions)*	**181.6**	172.9	170.2
Basic earnings per common share *($)*	**1.75**	1.65	1.54
Dividends declared per common share *($)*	**1.170**	1.410	0.780
Dividends paid per common share *($)*	**1.160**	1.120	1.040
Dividend payout ratio *(%)*	**66.3**	67.9	67.5
Price earnings ratio *(x)*	**19.1**	20.6	18.6
Share Trading Summary			
High price *($)* (TSX)	**35.45**	34.54	29.24
Low price *($)* (TSX)	**28.24**	21.60	21.52
Closing price *($)* (TSX)	**33.37**	33.98	28.68
Volume *(in thousands)* (TSX)	**126,341**	120,855	121,162

(1) Certain 2010 and 2009 comparative figures have been reclassified to comply with current period classifications, including the reporting of other income (expenses), net separately on the statement of earnings. Figures prior to 2009 have not been restated. Refer to Note 34 of the 2011 Annual Consolidated Financial Statements for further details.

(2) As at December 31, 2006, the regulatory provision for asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC Electric due to a change in presentation adopted by FortisBC Electric effective December 31, 2009.

Historical Financial Summary

2008	2007	2006 (2)	2005 (2)	2004	2003	2002
3,907	2,718	1,472	1,441	1,146	843	715
2,859	1,904	939	926	766	579	477
348	273	178	158	114	62	65
–	–	–	–	–	–	–
363	299	168	154	122	86	74
65	36	32	70	47	38	32
–	8	2	10	–	–	–
272	214	157	143	97	78	67
13	15	8	6	6	4	4
14	6	2	–	–	–	–
245	193	147	137	91	74	63
1,150	1,038	405	299	293	191	180
1,575	1,544	661	512	514	65	60
487	424	331	471	418	345	241
7,954	7,276	4,049	3,315	2,713	1,563	1,459
11,166	10,282	5,446	4,597	3,938	2,164	1,940
1,697	1,804	558	412	538	296	334
727	697	482	477	138	62	39
4,884	4,623	2,558	2,136	1,905	1,031	941
320	320	320	320	320	123	–
7,628	7,444	3,918	3,345	2,901	1,512	1,314
3,538	2,838	1,528	1,252	1,037	652	626
661	373	263	304	272	157	134
852	2,033	634	467	1,026	308	349
387	1,826	456	224	777	232	261
191	146	77	64	51	38	35
8.70	10.00	11.87	12.40	11.28	12.30	12.23
59.5	64.3	61.1	58.7	61.4	60.0	65.2
7.3	5.2	10.0	8.6	9.4	6.7	–
33.2	30.5	28.9	32.7	29.2	33.3	34.8
1.9	1.9	2.2	2.5	2.3	2.2	2.3
1.8	1.7	2.0	2.1	2.0	2.1	2.2
935	803	500	446	279	208	229
17.97	16.69	12.19	11.74	10.45	8.82	8.50
157.4	137.6	103.6	101.8	84.7	69.3	65.1
1.56	1.40	1.42	1.35	1.07	1.06	0.97
1.010	0.880	0.700	0.605	0.548	0.525	0.498
1.000	0.820	0.670	0.588	0.540	0.520	0.485
64.1	58.6	47.2	43.7	50.3	48.9	49.9
15.8	20.7	21.0	18.0	16.2	13.9	13.5
29.94	30.00	30.00	25.64	17.75	15.24	13.28
20.70	24.50	20.36	17.00	14.23	11.63	10.76
24.59	28.99	29.77	24.27	17.38	14.73	13.13
132,108	100,920	60,094	37,706	29,254	31,180	21,676

Investor Information

Expected Dividend* and Earnings Dates

Dividend Record Dates	
May 17, 2012	August 17, 2012
November 16, 2012	February 14, 2013
Dividend Payment Dates	
June 1, 2012	September 1, 2012
December 1, 2012	March 1, 2013
Earnings Release Dates	
May 2, 2012	July 31, 2012
November 1, 2012	February 7, 2013

* *The declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Friday, May 4, 2012
10:30 a.m.
Delta St. John's
120 New Gower Street
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")(1) and a Consumer Share Purchase Plan ("CSPP")(2) to Common Shareholders as a convenient method of increasing their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; and First Preference Shares, Series H of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G and FTS.PR.H, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$ 1.531
February 22, 1994	$ 7.156

Analyst and Investor Inquiries

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F: 709.737.5307
E: investorrelations@fortisinc.com

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President and Chief Executive Officer

Barry V. Perry
Vice President, Finance and Chief Financial Officer

Ronald W. McCabe
Vice President, General Counsel and Corporate Secretary

Donna G. Hynes
Assistant Secretary and Manager, Investor and Public Relations

Board of Directors

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Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

Peter E. Case ∗
Corporate Director
Kingston, Ontario

Frank J. Crothers ★
Chairman and CEO, Island Corporate Holdings
Nassau, Bahamas

Ida J. Goodreau ✷
Corporate Director
Vancouver, British Columbia

Douglas J. Haughey ∗
President and CEO, Provident Energy Ltd.
Calgary, Alberta

H. Stanley Marshall
President and CEO, Fortis Inc.
St. John's, Newfoundland and Labrador

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Roy P. Rideout ✷ ★
Corporate Director
Halifax, Nova Scotia

∗ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

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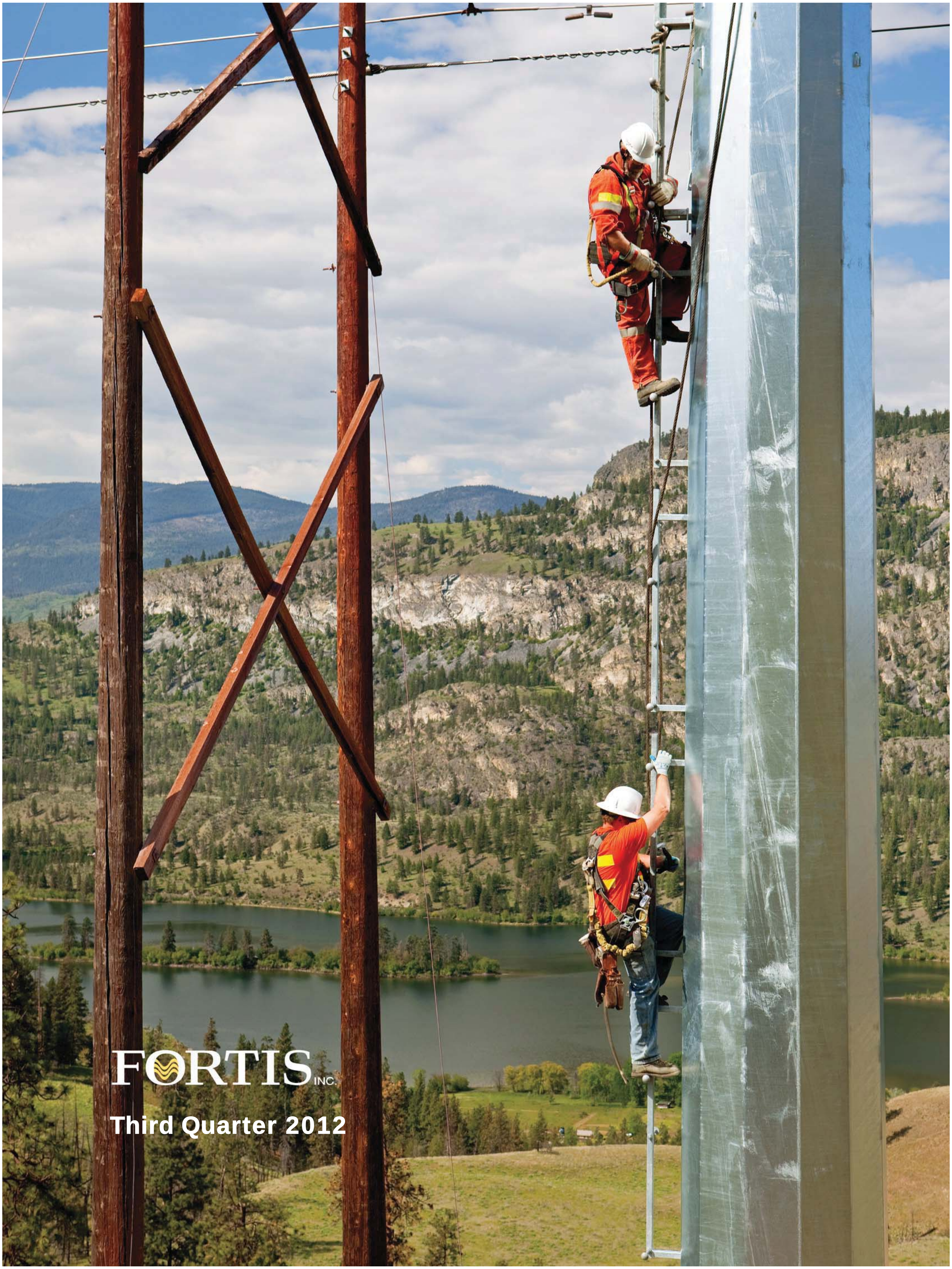
APPENDIX M

Fortis 3rd Quarter 2012 Report



FORTIS INC.

Third Quarter 2012

Dear Shareholder:

Fortis achieved third quarter net earnings attributable to common equity shareholders of $45 million, or $0.24 per common share, compared to $56 million, or $0.30 per common share, for the third quarter of 2011. Year-to-date net earnings attributable to common equity shareholders were $228 million, or $1.20 per common share, compared to $229 million, or $1.28 per common share, for the same period last year.

In 2012 earnings for the third quarter and year to date were reduced by $3.5 million and $10 million, respectively, related to foreign exchange and CH Energy Group, Inc. ("CH Energy Group") acquisition-related expenses. In 2011 earnings for the third quarter and year to date were favourably impacted by a one-time $11 million after-tax merger termination fee paid to Fortis and $2.5 million of foreign exchange.

Excluding the above impacts, improved performance at the western Canadian regulated electric utilities for the quarter was partially offset by decreased non-regulated hydroelectric generation and a higher loss incurred at the regulated gas utilities.

Canadian Regulated Electric Utilities, led by FortisAlberta and FortisBC Electric, contributed earnings of $54 million, up $11 million from the third quarter of 2011. At FortisAlberta, higher net transmission revenue, growth in energy infrastructure investment and timing of operating expenses during 2012 were partially offset by a lower allowed rate of return on common shareholder's equity. At FortisBC Electric, performance was driven by growth in energy infrastructure investment, higher pole-attachment revenue and lower-than-expected finance charges.

FortisBC Electric has offered to purchase the City of Kelowna's electrical utility assets for approximately $55 million. FortisBC Electric has operated and maintained the City of Kelowna's electrical utility assets, which currently serve approximately 15,000 customers, since 2000. Closing of the transaction is subject to certain conditions and receipt of certain approvals, including regulatory approval. FortisBC Electric and the City of Kelowna are working towards closing the transaction by the end of the first quarter of 2013.

Canadian Regulated Gas Utilities incurred a loss of $6 million compared to a loss of $4 million for the third quarter of 2011. The third quarter is normally a period of lower customer demand due to warmer temperatures. The higher loss largely related to the unfavourable impact of the difference in the timing of recognition of revenue associated with seasonal gas consumption and certain increased regulator-approved expenses in 2012, lower capitalized allowance for funds used during construction, and lower-than-expected customer additions in 2012. The above items were partially offset by higher gas transportation volumes to industrial customers and the timing of certain operating and maintenance expenses during 2012.

Year-to-date 2012, regulatory decisions have been received for: (i) 2012-2013 revenue requirements at the FortisBC Energy companies; (ii) 2012 distribution revenue requirements at FortisAlberta; and (iii) 2012-2013 revenue requirements at FortisBC Electric. The Alberta Utilities Commission issued a generic decision in September 2012 on its Performance-Based Regulation ("PBR") Initiative, outlining the PBR framework applicable to distribution utilities in Alberta for a five-year term commencing January 1, 2013. FortisAlberta will file the required PBR-compliance application in November 2012. A Generic Cost of Capital ("GCOC") Proceeding to finalize 2013 cost of capital for distribution utilities in Alberta is expected to commence late 2012 or early 2013. In British Columbia, the GCOC Proceeding to determine cost of capital, effective January 1, 2013, continues with an oral hearing scheduled for December 2012. Newfoundland Power filed a general rate application in September 2012 for 2013 customer rates and cost of capital.

Caribbean Regulated Electric Utilities contributed $7 million of earnings, compared to $6 million for the third quarter of 2011. Fortis Turks and Caicos acquired Turks and Caicos Utilities Limited ("TCU") in August 2012 for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of debt assumed. TCU serves more than 2,000 customers on Grand Turk and Salt Cay with a diesel-fired generating capacity of approximately 9 megawatts ("MW"). The utility currently operates pursuant to a 50-year licence that expires in 2036.

Non-Regulated Fortis Generation contributed $5 million to earnings compared to $8 million for the same quarter last year. The decrease mainly related to lower production in Belize due to lower rainfall.

Fortis Properties delivered earnings of $8 million, compared to $9 million for the third quarter of 2011, reflecting lower occupancy at hotel operations in Atlantic Canada and central Canada, partially offset by earnings contribution from the Hilton Suites Winnipeg Airport hotel, which was acquired in October 2011. In October 2012 Fortis Properties acquired the 126-room StationPark All Suite Hotel in London, Ontario for approximately $13 million.

Corporate and other expenses were $23 million compared to $6 million for the third quarter of 2011. Excluding the $11 million after-tax termination fee paid to Fortis in July 2011, corporate and other expenses increased quarter over quarter, mainly as a result of a $3 million after-tax foreign exchange loss recognized in the third quarter of 2012 compared to a $2.5 million after-tax net foreign exchange gain recognized in the same quarter last year. Acquisition-related expenses associated with the CH Energy Group transaction were approximately $0.5 million after-tax for the third quarter of 2012.

Consolidated capital expenditures, before customer contributions, were approximately $794 million year-to-date 2012. At FortisBC Gas, the Customer Care Enhancement Project came into service at the beginning of January 2012. Construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in British Columbia continues on time and on budget. Approximately $380 million in total has been spent on the Waneta Expansion since construction began in late 2010.

Cash flow from operating activities was $804 million year-to-date 2012, up $120 million from the same period last year, driven by favourable changes in regulatory deferral accounts and receivables and the collection of increased depreciation and amortization expense in customer rates.

Fortis announced in February 2012 that it had entered into an agreement to acquire CH Energy Group for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. CH Energy Group's main business, Central Hudson Gas & Electric Corporation ("Central Hudson"), serves approximately 375,000 electric and gas customers in New York State's Mid-Hudson River Valley. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from the Federal Energy Regulatory Commission and the Committee on Foreign Investment in the United States in July 2012. The waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction. The transaction is subject to approval by the New York State Public Service Commission, which is the only significant regulatory approval outstanding. The acquisition is expected to close by the end of the first quarter of 2013 and be immediately accretive to earnings per common share of Fortis, excluding acquisition-related expenses.

Fortis raised gross proceeds of approximately $601 million in June 2012, upon issuance of 18,500,000 Subscription Receipts at $32.50 each, to finance a portion of the purchase price of CH Energy Group. The proceeds are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, contained in the agreement to acquire CH Energy Group. Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the closing conditions, one common share of Fortis.

In October 2012 FortisAlberta raised $125 million 40-year 3.98% unsecured debentures, largely in support of its capital expenditure program.

Our utilities are focused on completing their remaining capital projects for 2012. Our capital expenditures for the year are expected to reach $1.3 billion. Over the five-year period to 2016, our capital program is expected to total $5.5 billion; Central Hudson's capital program from 2013 through 2016 will add a further approximate $0.5 billion.

Fortis is well positioned for growth in 2013 and beyond.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

Interim Management Discussion and Analysis

For the three and nine months ended September 30, 2012
Dated November 1, 2012

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FORWARD-LOOKING STATEMENT

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. Financial information for 2012 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified. The MD&A should be read in conjunction with the following: (i) the interim unaudited consolidated financial statements and notes thereto for the three and nine months ended September 30, 2012, prepared in accordance with US GAAP; (ii) the audited consolidated financial statements and notes thereto for the year ended December 31, 2011, prepared in accordance with US GAAP and voluntarily filed on the System for Electronic Document Analysis and Retrieval ("SEDAR") by Fortis on March 16, 2012; (iii) the audited consolidated financial statements and notes thereto for the year ended December 31, 2011, prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"); (iv) the "Supplemental Interim Consolidated Financial Statements for the Year Ended December 31, 2011 (Unaudited)" contained in the above-noted voluntary filing, which provides a detailed reconciliation between the Corporation's interim unaudited consolidated 2011 Canadian GAAP financial statements and interim unaudited consolidated 2011 US GAAP financial statements; and (v) the MD&A for the year ended December 31, 2011 included in the Corporation's 2011 Annual Report.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's consolidated forecast gross capital expenditures for 2012 and in total over the five-year period 2012 through 2016; the nature, timing and amount of certain capital projects and their expected costs and time to complete; the expectation that the Corporation's significant capital expenditure program should support continuing growth in earnings and dividends; forecast midyear rate base; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long-term debt offerings; the expected consolidated long-term debt maturities and repayments on average annually over the next five years; except for debt at the Exploits River Hydro Partnership ("Exploits Partnership"), the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout the remainder of 2012; the expected timing of filing regulatory applications and of receipt of regulatory decisions; the expected timing of the closing of the acquisition of CH Energy Group, Inc. ("CH Energy Group") by Fortis and the expectation that the acquisition will be immediately accretive to earnings per common share, excluding *acquisition-related expenses; an expected favourable impact on the Corporation's earnings in future periods upon final enactment of legislative changes to Part VI.1 taxes; the expectation of greater risk under Performance-Based Regulation ("PBR") that FortisAlberta's earnings may be negatively impacted; and the expectation that FortisBC Electric and the City of Kelowna will work towards closing the proposed acquisition of the City of Kelowna's electrical utility assets by FortisBC Electric by the end of the first quarter of 2013.*

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; no material capital project and financing cost overrun related to the construction of the Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity that was expropriated by the GOB; the expectation that Belize Electric Company Limited ("BECOL") will not be expropriated by the GOB; the expectation that the Corporation will receive fair compensation from the Government of Newfoundland and Labrador related to the expropriation of the Exploits Partnership's hydroelectric assets and water rights; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas commodity prices and fuel prices; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the receipt of regulatory approval from the New York State Public Service Commission, absent material conditions imposed, required in connection with the acquisition of CH Energy Group; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; the absence of significant changes in government energy plans and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2014 or the adoption of International Financial Reporting Standards ("IFRS") after 2014 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology ("IT") infrastructure; continued favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk, including increased risk at FortisAlberta associated with the adoption of PBR under a five-year term commencing in 2013; interest rate risk, including the uncertainty of the impact a continuation of a low interest rate environment may have on allowed rates of return on common shareholders' equity of the Corporation's regulated utilities; operating and maintenance risks; risk associated with changes in economic conditions; capital project budget overrun, completion and financing risk in the Corporation's non-regulated business; capital resources and liquidity risk; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis; risk that the GOB may expropriate BECOL; an ultimate resolution of the expropriation of the hydroelectric assets and water rights of the Exploits Partnership that differs from that which is currently expected by management; weather and seasonality risk; commodity price risk; the continued ability to hedge foreign exchange risk; counterparty risk; competitiveness of natural gas; natural gas, fuel and electricity supply risk; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks relating to the ability to close the acquisition of CH Energy Group, the timing of such closing and the realization of the anticipated benefits of the acquisition; risk of having to raise alternative capital to finance the acquisition of CH Energy Group if the closing of the acquisition occurs subsequent to June 30, 2013; the risk associated with defined benefit pension plan performance and funding requirements; risks related to FortisBC Energy (Vancouver Island) Inc.; environmental risks; insurance coverage risk; risk of loss of licences and permits; risk of loss of service area; risk of not being able to report under US GAAP beyond 2014 or risk that IFRS does not have an accounting standard for rate-regulated entities by the end of 2014 allowing for the recognition of regulatory assets and liabilities; risks related to changes in tax legislation; risk of failure of IT infrastructure; risk of not being able to access First Nations lands; labour relations risk; human resources risk; and risk of unexpected outcomes of legal proceedings currently against the Corporation. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the three and nine months ended September 30, 2012 and for the year ended December 31, 2011.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia, Canada. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upstate New York, and hotels and commercial office and retail space in Canada. Year-to-date September 30, 2012, the Corporation's electricity distribution systems met a combined peak demand of approximately 5,225 megawatts ("MW") and its gas distribution system met a peak day demand of 1,335 terajoules ("TJ"). For additional information on the Corporation's business segments, refer to Note 1 to the Corporation's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2012 and to the "Corporate Overview" section of the 2011 Annual MD&A.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably at the lowest reasonable cost and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation.

Generally under COS regulation, the respective regulatory authority sets customer gas and/or electricity rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") depends on the utility achieving the forecasts established in the rate-setting processes. As such, earnings of regulated utilities are generally impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) timing differences within an annual financial reporting period, between when actual expenses are incurred and when they are recovered from customers in rates. When forward test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which was estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, the Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

SIGNIFICANT ITEMS

Pending Acquisition of CH Energy Group, Inc.: In February 2012 Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated transmission and distribution ("T&D") utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from the Federal Energy Regulatory Commission and the Committee on Foreign Investment in the United States in July 2012. In addition, the waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction.

The transaction remains subject to approval by the New York State Public Service Commission ("NYSPSC") and satisfaction of customary closing conditions. The application for approval of the transaction by the NYSPSC was jointly filed by Fortis and CH Energy Group in April 2012. The acquisition is expected to close by the end of the first quarter of 2013 and be immediately accretive to earnings per common share, excluding acquisition-related expenses.

During the third quarter and year-to-date 2012, the Corporation's earnings were reduced by $0.5 million and $7.5 million, respectively, associated with CH Energy Group after-tax acquisition-related expenses.

Subscription Receipts Offering: In June 2012, to finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18,500,000 Subscription Receipts at $32.50 each through a bought-deal offering underwritten by a syndicate of underwriters led by CIBC World Markets Inc., Scotia Capital Inc. and TD Securities Inc., realizing gross proceeds of approximately $601 million. The gross proceeds from the sale of the Subscription Receipts are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, included in the agreement to acquire CH Energy Group (the "Release Conditions"). The Subscription Receipts began trading on the Toronto Stock Exchange on June 27, 2012 under the symbol "FTS.R".

Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares to holders of record during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts.

If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition of CH Energy Group is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount.

For further information on the pending acquisition and the related Subscription Receipts offering, refer to the "Business Risk Management" section of this MD&A.

Receipt of Regulatory Decisions: Year-to-date 2012, regulatory decisions have been received for 2012-2013 revenue requirements at the FortisBC Energy companies, 2012 distribution revenue requirements at FortisAlberta and, recently in August, for 2012-2013 revenue requirements at FortisBC Electric. The Alberta Utilities Commission ("AUC") issued a generic decision in September 2012 on its Performance-Based Regulation ("PBR") Initiative outlining the PBR framework applicable to distribution utilities in Alberta, including FortisAlberta, for a five-year term commencing January 1, 2013. For further information on these regulatory decisions, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Part VI.1 Tax: Under the terms of the Corporation's first preference shares, the Corporation is subject to tax under Part VI.1 of the *Income Tax Act* (Canada) associated with dividends on its first preference shares. For corporations subject to Part VI.1 tax, there is an equivalent Part I tax deduction. As permitted under the *Income Tax Act* (Canada), a corporation may allocate its Part VI.1 tax liability and equivalent Part I tax deduction to its related subsidiaries. In the past, Fortis has allocated these items to Maritime Electric, Newfoundland Power and FortisOntario.

Upon transition to US GAAP, the Corporation reduced its consolidated opening 2012 retained earnings by $20 million to reflect the impact of differences between enacted and substantively enacted tax legislation associated with prior assessments and payments of Part VI.1 taxes, and the recovery of Part I taxes. The adjustment was done as US GAAP requires tax provisions to be based on enacted legislation versus substantively enacted legislation. A number of legislative amendments to Part VI.1 tax in Canada have yet to be enacted. The above-noted transitional US GAAP adjustment will reverse through the Corporation's earnings in future periods when the legislation is finally enacted, which is expected in 2013, or as reassessment of corporate taxation years, upon which the enacted versus the substantively enacted rates were used to calculate taxes payable under US GAAP, become statute barred. The statute-barred reversals will occur between 2012 and 2016 and will increase earnings during these years. During the third quarter of 2012, Newfoundland Power recorded a favourable $2.5 million adjustment to income taxes associated with statute-barred Part VI.1 taxes.

Purchase of the Electricity Distribution Assets in Port Colborne: In April 2012 FortisOntario exercised its option to purchase all of the assets previously leased by the Company under an operating lease agreement with the City of Port Colborne for the purchase option price of approximately $7 million. The exercise of the purchase option, which qualifies as a business combination, provides ownership and legal title to all of the assets, including equipment, real property and distribution assets, which constitute the electricity distribution system in Port Colborne.

Acquisition of Turks and Caicos Utilities Limited: In August 2012 Fortis Turks and Caicos acquired Turks and Caicos Utilities Limited ("TCU") for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of debt assumed of $5 million (US$5 million). TCU is a regulated electric utility operating pursuant to a 50-year licence expiring in 2036. The utility serves more than 2,000 residential and commercial customers on Grand Turk and Salt Cay with a diesel-fired generating capacity of approximately 9 MW.

Hotel Acquisition: In October 2012 Fortis Properties acquired the 126-room StationPark All Suite Hotel ("StationPark Hotel") in London, Ontario for approximately $13 million.

Pending Acquisition of the Electrical Utility Assets from the City of Kelowna: FortisBC Electric has offered to purchase the City of Kelowna's electrical utility assets, which currently serve approximately 15,000 customers, for approximately $55 million. FortisBC Electric provides the City of Kelowna with electricity under a wholesale tariff and has operated and maintained the City of Kelowna's electrical utility assets since 2000. Closing of the transaction is subject to certain conditions and receipt of certain approvals, including regulatory approval. The parties are working towards closing the transaction by the end of the first quarter of 2013.

Expropriation of Shares in Belize Electricity: The Government of Belize ("GOB") expropriated the Corporation's common share ownership in Belize Electricity in June 2011. The Corporation is challenging the legality of the expropriation in the Belize Courts. Although the GOB initiated contact with Fortis, there have been no settlement negotiations to date on the fair value compensation owing to Fortis as a result of the expropriation. For further information, refer to the "Business Risk Management" section of this MD&A.

Transition to US GAAP: Effective January 1, 2012, Fortis retroactively adopted US GAAP with the restatement of comparative reporting periods. For further information, refer to the "New Accounting Standards and Policies" section of this MD&A.

Re-Organization of Non-Regulated Generation Operations: Effective July 1, 2012, the legal ownership of the six small non-regulated hydroelectric generating facilities in eastern Ontario, with a combined generating capacity of 8 MW, was transferred from Fortis Properties to a limited partnership directly held by Fortis. FortisBC Holdings Inc. ("FHI") assumed management responsibility for the operations of the above-noted facilities, as well as for the four non-regulated hydroelectric generating facilities in Upstate New York, with a combined generating capacity of 23 MW, owned by FortisUS Energy Corporation ("FortisUS Energy").

FINANCIAL HIGHLIGHTS

Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's business is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. Key financial highlights for the third quarter and year-to-date periods ended September 30, 2012 and September 30, 2011 are provided in the following table.

Consolidated Financial Highlights (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions, except for common share data)	**2012**	2011	Variance	**2012**	2011	Variance
Revenue	**714**	699	15	**2,655**	2,704	(49)
Energy Supply Costs	**235**	246	(11)	**1,092**	1,207	(115)
Operating Expenses	**203**	200	3	**621**	619	2
Depreciation and Amortization	**118**	104	14	**351**	309	42
Other Income (Expenses), Net	**1**	22	(21)	**(2)**	34	(36)
Finance Charges	**93**	89	4	**276**	274	2
Income Taxes	**7**	12	(5)	**44**	59	(15)
Net Earnings	**59**	70	(11)	**269**	270	(1)
Net Earnings Attributable to:						
Non-Controlling Interests	**3**	3	-	**7**	7	-
Preference Equity Shareholders	**11**	11	-	**34**	34	-
Common Equity Shareholders	**45**	56	(11)	**228**	229	(1)
Net Earnings	**59**	70	(11)	**269**	270	(1)
Basic Earnings per Common Share *($)*	**0.24**	0.30	(0.06)	**1.20**	1.28	(0.08)
Diluted Earnings per Common Share *($)*	**0.24**	0.30	(0.06)	**1.19**	1.27	(0.08)
Weighted Average Number of Common Shares Outstanding *(# millions)*	**190.2**	186.5	3.7	**189.6**	179.5	10.1
Cash Flow from Operating Activities	**221**	151	70	**804**	684	120

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- An increase in gas delivery rates and the base component of electricity rates at most of the regulated utilities, consistent with rate decisions, reflecting ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers
- Net transmission revenue of approximately $3.5 million recognized for the quarter and $6.5 million recognized year to date at FortisAlberta, as a result of the 2012 distribution revenue requirements decision received in April 2012
- Higher gas transportation volumes to industrial customers
- Increased electricity sales at FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Turks and Caicos for the quarter and year to date and at FortisOntario for the quarter
- The flow through in customer electricity rates of higher energy supply costs, where applicable, at most of the regulated electric utilities
- Growth in the number of customers, driven by FortisAlberta
- Differences in the amount of PBR incentives refunded, and flow-through adjustments owing, to FortisBC Electric's customers period over period
- Higher Hospitality revenue at Fortis Properties, driven by revenue from the Hilton Suites Winnipeg Airport hotel ("Hilton Suites Hotel"), which was acquired in October 2011
- Increased non-regulated hydroelectric production in Belize year to date, due to higher rainfall
- Approximately $1 million for the quarter and $5 million year to date of favourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar period over period

Unfavourable

- Lower commodity cost of natural gas charged to customers
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which reduced revenue year to date
- The flow through in customer electricity rates of lower energy supply costs at Caribbean Utilities for the quarter, due to a decrease in the cost of fuel period over period
- Lower average gas consumption by residential and commercial customers year to date
- Revenue at Newfoundland Power in 2011 reflected the favourable impact of support structure arrangements with Bell Aliant Inc. ("Bell Aliant")
- Decreased non-regulated hydroelectric production in Belize for the quarter, due to lower rainfall
- Decreased electricity sales at Caribbean Utilities for the quarter and year to date and at FortisOntario year to date

Factors Contributing to Quarterly and Year-to-Date
Energy Supply Costs Variances

Favourable

- Lower commodity cost of natural gas
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which reduced energy supply costs year to date
- Lower average gas consumption by residential and commercial customers year to date, which reduced natural gas purchases
- Decreased fuel prices at Caribbean Utilities for the quarter
- Decreased electricity sales at Caribbean Utilities for the quarter and year to date and at FortisOntario year to date, which reduced fuel and power purchases

Unfavourable

- Increased fuel prices at Caribbean Utilities year to date and increased purchased power costs at FortisBC Electric and FortisOntario for the quarter and year to date
- An increase in the base amount of energy supply costs expensed at Maritime Electric in accordance with the operation of the Energy Cost Adjustment Mechanism
- Increased electricity sales at FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Turks and Caicos for the quarter and year to date and at FortisOntario for the quarter, which increased fuel and power purchases
- Approximately $1 million for the quarter and $3 million year to date associated with unfavourable foreign currency translation

Factors Contributing to Quarterly and Year-to-Date
Operating Expenses Variances

Unfavourable

- General inflationary and employee-related cost increases at the Corporation's regulated utilities, and timing of certain expenses at FortisBC Electric during 2012
- Operating expenses associated with the Hilton Suites Hotel, which was acquired in October 2011

Favourable

- Reduced operating expenses at the FortisBC Energy companies during 2012, mainly due to the accrual of non-asset retirement obligation ("non-ARO") removal costs in depreciation, effective January 1, 2012, the timing of certain expenditures during 2012 and lower customer care-related costs as a result of insourcing the customer care function, effective January 1, 2012. Non-ARO removal costs were recorded in operating expenses in 2011.
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased operating expenses year to date

Factors Contributing to Quarterly and Year-to-Date
Depreciation and Amortization Expense Variances

Unfavourable

- Continued investment in energy infrastructure
- Increased depreciation at the FortisBC Energy companies, mainly due to the accrual of non-ARO removal costs in depreciation, effective January 1, 2012, as discussed above

Favourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased depreciation year to date
- Lower depreciation rates at FortisAlberta and FortisBC Electric, effective January 1, 2012, as a result of the 2012 revenue requirements decisions received in April 2012 and August 2012, respectively

Factors Contributing to Quarterly and Year-to-Date
Other Income (Expenses), Net Variances

Unfavourable

- The favourable impact in 2011 of the $17 million (US$17.5 million) ($11 million after tax) fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and Central Vermont Public Service Corporation ("CVPS")
- Approximately $0.5 million ($0.5 million after tax) and $8.5 million ($7.5 million after tax) of costs incurred in the third quarter and year-to-date 2012, respectively, related to the pending acquisition of CH Energy Group
- Foreign exchange losses of approximately $3 million and $2.5 million for the third quarter and year-to-date 2012, respectively, associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity. A net foreign exchange gain of approximately $1.5 million ($2.5 million after tax) was recognized for the third quarter and year-to-date 2011 related to the above item.
- Lower capitalized equity component of allowance for funds used during construction ("AFUDC"), mainly at the FortisBC Energy companies
- An approximate $1 million gain on the sale of property at FortisAlberta during the first quarter of 2011

Factors Contributing to Quarterly and Year-to-Date
Finance Charges Variances

Unfavourable

- Higher long-term debt levels in support of the utilities' capital expenditure programs
- Lower capitalized debt component of AFUDC at the regulated utilities, mainly at the FortisBC Energy companies

Favourable

- Higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion hydroelectric generating facility ("Waneta Expansion")
- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011, which decreased finance charges year to date
- Lower short-term borrowings at the regulated utilities year to date, driven by the FortisBC Energy companies

Factors Contributing to Quarterly and Year-to-Date
Income Taxes Variances

Favourable

- Lower statutory corporate income tax rates and lower earnings before income taxes
- Differences in the deductions for income tax purposes compared to accounting purposes period over period

Factors Contributing to Quarterly Earnings Variance

Unfavourable

- Higher corporate expenses, due to the favourable impact in 2011 of the $11 million after-tax fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS, and a foreign exchange loss of approximately $3 million after tax recognized in the third quarter of 2012 compared to a net foreign exchange gain of approximately $2.5 million after tax recognized in the third quarter of 2011
- Decreased non-regulated hydroelectric production in Belize, due to lower rainfall
- A higher loss at the FortisBC Energy companies, largely related to the unfavourable impact of the difference in the timing of the recognition of revenue associated with seasonal gas consumption and certain increased regulator-approved expenses in 2012, lower capitalized AFUDC and lower-than-expected customer additions in 2012. The above items were partially offset by higher gas transportation volumes to industrial customers and the timing of certain operating and maintenance expenses during 2012.

Favourable

- Increased earnings at FortisAlberta, mainly due to higher net transmission revenue, rate base growth and the timing of operating expenses during 2012, partially offset by a lower allowed ROE
- Increased earnings at FortisBC Electric, due to rate base growth, higher pole-attachment revenue and lower-than-expected finance charges in 2012
- Increased earnings at Newfoundland Power, mainly due to lower effective income taxes and a higher allowed ROE, partially offset by the impact of the support structure arrangements with Bell Aliant during 2011

Factors Contributing to Year-to-Date Earnings Variance

Unfavourable

- Higher corporate expenses due to: (i) the favourable impact in 2011 of the $11 million after-tax fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS; (ii) approximately $7.5 million, after tax, of costs incurred year-to-date 2012 related to the pending acquisition of CH Energy Group; and (iii) a foreign exchange loss of approximately $2.5 million after tax recognized year-to-date 2012 compared to a net foreign exchange gain of approximately $2.5 million after tax recognized year-to-date 2011. The increase in corporate expenses was partially offset by lower finance charges, primarily due to higher capitalized interest associated with financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion.

Favourable

- Increased earnings at FortisAlberta, due to rate base growth, higher net transmission revenue, the timing of operating expenses during 2012, lower effective income taxes and lower-than-expected finance charges, partially offset by a lower allowed ROE and an approximate $1 million gain on the sale of property during the first quarter of 2011
- Increased earnings at Newfoundland Power, for the same reasons discussed above for the quarter, in addition to increased electricity sales year to date
- Increased earnings at the FortisBC Energy companies, mainly due to rate base growth, higher gas transportation volumes to industrial customers and timing of certain operating and maintenance expenses during 2012, partially offset by lower-than-expected customer additions in 2012, lower capitalized AFUDC and the unfavourable impact of the difference in the timing of recognition of revenue associated with seasonal gas consumption and certain increased regulator-approved expenses in 2012
- Increased non-regulated hydroelectric production in Belize, due to higher rainfall

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2012**	2011	Variance	**2012**	2011	Variance
Regulated Gas Utilities - Canadian						
FortisBC Energy Companies	**(6)**	(4)	(2)	**89**	86	3
Regulated Electric Utilities - Canadian						
FortisAlberta	***26***	*19*	*7*	***73***	*58*	*15*
FortisBC Electric	***13***	*10*	*3*	***38***	*38*	*-*
Newfoundland Power	***9***	*8*	*1*	***28***	*24*	*4*
Other Canadian Electric Utilities	***6***	*6*	*-*	***18***	*18*	*-*
	54	43	11	**157**	138	19
Regulated Electric Utilities - Caribbean	**7**	6	1	**16**	16	-
Non-Regulated - Fortis Generation	**5**	8	(3)	**15**	13	2
Non-Regulated - Fortis Properties	**8**	9	(1)	**17**	18	(1)
Corporate and Other	**(23)**	(6)	(17)	**(66)**	(42)	(24)
Net Earnings Attributable to Common Equity Shareholders	**45**	56	(11)	**228**	229	(1)

For a discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Regulatory Highlights" section of this MD&A. A discussion of the financial results of the Corporation's reporting segments is as follows.

REGULATED GAS UTILITIES - CANADIAN

FORTISBC ENERGY COMPANIES [(1)]

Financial Highlights (Unaudited)	Quarter			Year-to-Date		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Gas Volumes *(petajoules ("PJ"))*	**26**	23	3	**138**	140	(2)
Revenue *($ millions)*	**192**	197	(5)	**1,004**	1,090	(86)
(Loss) Earnings *($ millions)*	**(6)**	(4)	(2)	**89**	86	3

[(1)] Includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI")

Factors Contributing to Quarterly Gas Volumes Variance

Favourable

- Higher gas transportation volumes to industrial customers, due to certain customers switching to natural gas from alternative sources of fuel as a result of lower natural gas prices

Factors Contributing to Year-to-Date Gas Volumes Variance

Unfavourable

- Lower average gas consumption by residential and commercial customers, driven by overall warmer temperatures

Favourable

- Higher gas transportation volumes to industrial customers, for the same reason discussed above for the quarter

With the implementation of the new Customer Care Enhancement Project on January 1, 2012, the FortisBC Energy companies changed their definition of a customer. As a result of this change, the FortisBC Energy companies adjusted their combined customer count downwards by approximately 18,000, effective January 1, 2012. As at September 30, 2012, the total number of customers served by the FortisBC Energy companies was approximately 938,000.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulator-approved deferral mechanisms, changes in consumption levels and the commodity cost of natural gas from those forecast to set residential and commercial customer gas rates do not materially affect earnings.

Seasonality has a material impact on the earnings of the FortisBC Energy companies as a major portion of the gas distributed is used for space heating. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters.

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- Lower commodity cost of natural gas charged to customers
- Lower-than-expected customer additions in 2012

Favourable

- A net increase in the delivery component of customer rates, effective January 1, 2012, mainly due to ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers as reflected in the 2012-2013 revenue requirements decision received in April 2012
- Higher gas transportation volumes to industrial customers

Factors Contributing to Year-to-Date Revenue Variance

Unfavourable

- The same factors discussed above for the quarter
- Lower average gas consumption by residential and commercial customers

Favourable

- The same factors discussed above for the quarter

Factors Contributing to Quarterly Earnings Variance

Unfavourable

- The difference in the timing of recognition of revenue and certain expenses in 2012. Revenue is recognized based on seasonal gas consumption while certain expenses are generally incurred evenly throughout the year, which, combined with an approved increase in those expenses in 2012, has resulted in timing differences contributing to lower earnings quarter over quarter
- Lower capitalized AFUDC, due to lower assets under construction period over period
- Lower-than-expected customer additions in 2012

Favourable

- Higher gas transportation volumes to industrial customers
- The timing of certain operating and maintenance expenses during 2012

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- The same factors discussed above for the quarter

Unfavourable

- Lower-than-expected customer additions in 2012
- Lower capitalized AFUDC, for the same reason discussed above for the quarter
- The difference in the timing of recognition of revenue and certain expenses in 2012, for the reasons discussed above for the quarter, which reduced earnings year to date compared to the same period last year

REGULATED ELECTRIC UTILITIES - CANADIAN

FORTISALBERTA

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Energy Deliveries *(gigawatt hours ("GWh"))*	**4,099**	3,911	188	**12,434**	12,135	299
Revenue *($ millions)*	**117**	103	14	**335**	306	29
Earnings *($ millions)*	**26**	19	7	**73**	58	15

Factors Contributing to Quarterly Energy Deliveries Variance

Favourable

- Higher average consumption by oilfield and commercial customers, due to increased activity mainly as a result of higher market prices for oil
- Higher average consumption by residential customers, due to warmer temperatures which increased air conditioning load
- Growth in the number of customers, with the total number of customers increasing by approximately 9,000 year over year as at September 30, 2012, driven by favourable economic conditions
- Higher average consumption by farm and irrigation customers, due to warmer temperatures and lower precipitation levels

Factors Contributing to Year-to-Date Energy Deliveries Variance

Favourable

- Higher average consumption by oilfield and commercial customers, for the same reason discussed above for the quarter
- Growth in the number of customers, for the same reason discussed above for the quarter

As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

Factors Contributing to Quarterly Revenue Variance

Favourable

- An increase in customer electricity distribution rates, effective January 1, 2012, driven primarily by ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers
- Net transmission revenue of approximately $3.5 million recognized for the quarter and $6.5 million recognized year to date. In its April 2012 distribution revenue requirements decision, the regulator did not approve the continuation of the deferral of transmission volume variances associated with FortisAlberta's Alberta Electric System Operator ("AESO") charges deferral account. In the absence of full deferral, FortisAlberta is subject to volume risk on actual transmission costs relative to those charged to customers based on forecast volumes and price. Net transmission revenue is influenced by many factors, which may result in actual transmission volumes varying from those forecasted.
- Growth in the number of customers
- An increase in franchise fee revenue of approximately $1 million for the quarter and $3 million year to date

Unfavourable

- A lower allowed ROE. The cumulative impact on revenue, from January 1, 2011, of the decrease in the allowed ROE to 8.75%, effective for both 2011 and 2012, from 9.00% for 2010 was recognized during the fourth quarter of 2011, when the regulatory decision was received.

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- The same factors discussed above for the quarter

Unfavourable

- The recognition in the second quarter of 2011 of accrued revenue related to the cumulative 2010 and year-to-date 2011 allowed debt return and recovery of depreciation on the additional $22 million in capital expenditures approved by the regulator to be included in rate base associated with the Automated Metering Project, which had the impact of reducing revenue by approximately $2 million period over period.
- The same factor discussed above for the quarter

Factors Contributing to Quarterly Earnings Variance

Favourable

- Net transmission revenue of approximately $3.5 million recognized for the quarter and $6.5 million recognized year to date, as a result of the distribution revenue requirements decision received in April 2012
- Rate base growth, due to continued investment in energy infrastructure
- The timing of operating expenses during 2012

Unfavourable

- A lower allowed ROE, as discussed above

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- The same factors discussed above for the quarter
- Lower effective income taxes, primarily due to additional loss carryforwards being utilized in FortisAlberta's 2011 income tax return filed in 2012, which decreased income tax expense in 2012, and higher income taxes in 2011 related to the sale of property
- Lower-than-expected finance charges in 2012

Unfavourable

- The same factor discussed above for the quarter
- An approximate $1 million gain on the sale of property during the first quarter of 2011

FORTISBC ELECTRIC [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Electricity Sales *(GWh)*	**728**	713	15	**2,313**	2,300	13
Revenue *($ millions)*	**71**	67	4	**225**	215	10
Earnings *($ millions)*	**13**	10	3	**38**	38	-

(1) Includes the regulated operations of FortisBC Inc. and operating, maintenance and management services related to the Waneta, Brilliant and Arrow Lakes hydroelectric generating plants and the electrical utility assets owned by the City of Kelowna. Excludes the non-regulated generation operations of FortisBC Inc.'s wholly owned partnership, Walden Power Partnership

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Favourable

- Growth in the number of customers
- Higher average consumption, due to differences in weather conditions period over period

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- A net increase in customer electricity rates, effective January 1, 2012, mainly due to ongoing investment in energy infrastructure and forecasted certain higher expenses recoverable from customers as reflected in the 2012-2013 revenue requirements decision received in August 2012
- A 1.4% increase in customer electricity rates, effective June 1, 2011, as a result of the flow through to customers of increased purchased power costs charged to FortisBC Electric by BC Hydro, which increased revenue year to date
- Higher pole-attachment revenue
- Differences in the amount of PBR incentives refunded, and flow-through adjustments owing, to customers period over period
- The 2.1% and 0.6% increase in electricity sales for the quarter and year to date, respectively

Factors Contributing to Quarterly Earnings Variance

Favourable

- Rate base growth, due to continued investment in energy infrastructure
- Higher pole-attachment revenue
- Lower-than-expected finance charges in 2012. As approved in the 2012-2013 revenue requirements decision received in August 2012, variances between actual finance charges and those forecasted in determining customer electricity rates, beginning January 1, 2012, are no longer permitted deferral account treatment and, therefore, favourably impacted earnings in 2012

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- The same factors discussed above for the quarter

Unfavourable

- The expiry of the PBR mechanism on December 31, 2011. Year-to-date 2011, lower-than-expected costs, primarily purchased power costs, were shared equally between customers and FortisBC Electric under the PBR mechanism. Pursuant to the Company's 2012-2013 revenue requirements decision received in August 2012, variances between actual electricity revenue and purchased power costs and those used in determining customer electricity rates are subject to full deferral account treatment and, therefore, did not impact earnings year-to-date 2012.

NEWFOUNDLAND POWER

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Electricity Sales *(GWh)*	**940**	923	17	**4,113**	4,026	87
Revenue *($ millions)*	**100**	101	(1)	**422**	417	5
Earnings *($ millions)*	**9**	8	1	**28**	24	4

Factors Contributing to Quarterly and Year-to-Date Electricity Sales Variances

Favourable
- Growth in the number of customers
- Higher concentration of electric-versus-oil heating in new home construction combined with economic growth, which increased consumption

Unfavourable
- Sunnier weather conditions, which reduced average consumption

Factors Contributing to Quarterly Revenue Variance

Unfavourable
- Revenue for 2011 included amounts related to support structure arrangements, which were in place with Bell Aliant during 2011, associated with the joint-use poles held for sale to Bell Aliant. The joint-use poles were sold in October 2011.

Favourable
- The 1.8% increase in electricity sales

Factors Contributing to Year-to-Date Revenue Variance

Favourable
- The 2.2% increase in electricity sales

Unfavourable
- The impact of the support structure arrangements with Bell Aliant during 2011, as discussed above for the quarter

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable
- Lower effective income taxes, primarily due to lower Part VI.1 taxes, including the favourable impact of reversals of statute-barred Part VI.1 taxes period over period, and a lower statutory income tax rate. For further information on Part VI.1 tax, refer to the "Significant Items" section of this MD&A.
- A higher allowed ROE, effective January 1, 2012, which is being accrued in 2012, as approved by the regulator, as a decrease in operating expenses for deferred recovery from customers
- Electricity sales growth year to date

Unfavourable
- The impact of the support structure arrangements with Bell Aliant during 2011, as discussed above
- Approximately $1 million in additional operating labour and maintenance costs incurred as a result of Tropical Storm Leslie in September 2012
- Higher depreciation expense, due to continued investment in energy infrastructure

OTHER CANADIAN ELECTRIC UTILITIES [1]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Electricity Sales *(GWh)*	**595**	582	13	**1,803**	1,798	5
Revenue *($ millions)*	**91**	87	4	**264**	256	8
Earnings *($ millions)*	**6**	6	-	**18**	18	-

[1] Includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power, Cornwall Electric and Algoma Power.

Factors Contributing to Quarterly Electricity Sales Variance

Favourable

- Higher average consumption by commercial customers in the agricultural processing sector on Prince Edward Island ("PEI")
- Higher average consumption by residential customers and several large commercial customers in Ontario

Factors Contributing to Year-to-Date Electricity Sales Variance

Favourable

- Higher average consumption by commercial customers in the agricultural processing sector on PEI
- Growth in the number of, and higher average consumption by, residential customers on PEI and an increase in the number of such customers using electricity for home heating

Unfavourable

- Lower average consumption by residential and industrial customers in Ontario, primarily during the first quarter of 2012, reflecting more moderate temperatures and weak economic conditions in the region

Factors Contributing to Quarterly and Year-to-Date Revenue Variances

Favourable

- The overall 2.2% and 0.3% increase in electricity sales for the quarter and year to date, respectively, for the reasons discussed above
- An increase in the basic component of customer rates at Maritime Electric, effective March 1, 2012, associated with the higher flow through and recovery of energy supply costs
- The flow through in customer electricity rates of higher energy supply costs at FortisOntario
- Increased customer rates at FortisOntario

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Favourable

- Lower operating expenses at FortisOntario for the quarter, largely due to the timing of certain operating expenses during 2012
- Electricity sales growth
- Increased customer rates at FortisOntario

Unfavourable

- Increased depreciation expense and finance charges at Maritime Electric, due to continued investment in energy infrastructure and increased short-term borrowings, respectively
- Higher operating expenses at FortisOntario year to date, largely due to an increase in employee-related costs and the timing of certain operating expenses during 2012

REGULATED ELECTRIC UTILITIES - CARIBBEAN [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Average US:CDN Exchange Rate [(2)]	**1.00**	0.98	0.02	**1.00**	0.98	0.02
Electricity Sales *(GWh)*	**197**	197	-	**547**	744	(197)
Revenue *($ millions)*	**72**	74	(2)	**202**	234	(32)
Earnings *($ millions)*	**7**	6	1	**16**	16	-

(1) Includes Caribbean Utilities on Grand Cayman, Cayman Islands, in which Fortis holds an approximate 60% controlling interest; three small wholly owned utilities in the Turks and Caicos Islands, which include Turks and Caicos Utilities Ltd., acquired in August 2012, FortisTCI Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. (collectively "Fortis Turks and Caicos"); and the financial results of the Corporation's approximate 70% controlling interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the Government of Belize expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. For further information, refer to the "Significant Items" and "Business Risk Management" sections of this MD&A.

(2) The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity was the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Factors Contributing to Quarterly Electricity Sales Variance

Favourable

- Growth in the number of customers
- Warmer temperatures experienced in the Turks and Caicos Islands, which increased air conditioning load
- Higher tourism activity in the Turks and Caicos Islands
- Electricity sales in the Turks and Caicos Islands during the third quarter of 2011 were reduced, due to the early and extended closure of a certain hotel and other commercial customers resulting from a hurricane

Unfavourable

- Higher rainfall experienced on Grand Cayman, which decreased air conditioning load

Factors Contributing to Year-to-Date Electricity Sales Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for the utility, effective June 20, 2011. Excluding Belize Electricity, electricity sales decreased approximately 0.5% year to date.
- The same factor discussed above for the quarter

Favourable

- The same factors discussed above for the quarter

Factors Contributing to Quarterly Revenue Variance

Unfavourable

- The flow through in customer electricity rates of lower energy supply costs at Caribbean Utilities, due to a decrease in the cost of fuel period over period
- Decreased electricity sales at Caribbean Utilities
- The discontinuance of government subsidization of Fortis Turks and Caicos' South Caicos operations, effective April 1, 2012, in accordance with a rate decision received in February 2012

Favourable

- Increased electricity sales at Fortis Turks and Caicos
- An increase in electricity rates for Fortis Turks and Caicos' large hotel customers, effective April 1, 2012, in accordance with a rate decision received in February 2012
- Approximately $1 million for the quarter and $5 million year to date of favourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar period over period
- An increase in base electricity rates at Caribbean Utilities, effective June 1, 2012

Factors Contributing to Year-to-Date Revenue Variance

Unfavourable

- The expropriation of Belize Electricity and the resulting discontinuance of the consolidation method of accounting for Belize Electricity, effective June 20, 2011, which decreased revenue by approximately $45 million period over period
- Decreased electricity sales at Caribbean Utilities
- The discontinuance of government subsidization of Fortis Turks and Caicos' South Caicos operations, as discussed above for the quarter

Favourable

- The flow through in customer electricity rates of higher energy supply costs at Caribbean Utilities, due to an increase in the cost of fuel period over period
- The same factors discussed above for the quarter

Factors Contributing to Quarterly Earnings Variance

Favourable

- Lower finance charges at Caribbean Utilities
- Increased electricity sales at Fortis Turks and Caicos

Unfavourable

- Overall higher depreciation expense, and higher finance charges at Fortis Turks and Caicos, largely due to investment in utility capital assets
- Decreased electricity sales at Caribbean Utilities

Factors Contributing to Year-to-Date Earnings Variance

Favourable

- Lower energy supply costs at Fortis Turks and Caicos, mainly due to more fuel-efficient production realized with the commissioning of new generation units at the utility
- Lower operating expenses at Caribbean Utilities, driven by the timing of capital projects
- Increased electricity sales at Fortis Turks and Caicos

Unfavourable

- Overall higher depreciation expense and finance charges, for the same reason discussed above for the quarter
- Increased operating expenses at Fortis Turks and Caicos, mainly associated with the timing of capital projects

Fortis Turks and Caicos acquired TCU in August 2012 for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of debt assumed of $5 million (US$5 million). For further information refer to the "Significant Items" section of this MD&A.

NON-REGULATED - FORTIS GENERATION [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Energy Sales *(GWh)*	**81**	111	(30)	**256**	277	(21)
Revenue *($ millions)*	**8**	11	(3)	**26**	25	1
Earnings *($ millions)*	**5**	8	(3)	**15**	13	2

(1) Includes the financial results of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upstate New York, with a combined generating capacity of 139 MW, mainly hydroelectric

Factor Contributing to Quarterly Energy Sales Variance

Unfavourable

- Decreased production in Belize and Upstate New York, due to lower rainfall

Factors Contributing to Year-to-Date Energy Sales Variance

Unfavourable
- Decreased production in Upstate New York, due to a generating facility being out of service and lower rainfall
- Decreased production in Ontario, due to lower rainfall

Favourable
- Increased production in Belize, driven by higher rainfall during the first half of 2012

Factor Contributing to Quarterly Revenue and Earnings Variances

Unfavourable
- Decreased production in Belize

Factors Contributing to Year-to-Date Revenue and Earnings Variances

Favourable
- Increased production in Belize

Unfavourable
- Decreased production in Upstate New York

In May 2011 the generator at Moose River's hydroelectric generating facility in Upstate New York sustained electrical damage. Repairs to the generator were completed in the second quarter of 2012 but another repair continues to keep the generating facility offline. Revenue for the first half of 2012 reflected insurance amounts received related to the loss of earnings during the period in the first half of 2012 when the generator was being repaired due to the electrical damage. The generating facility is expected to be online by the end of 2012.

NON-REGULATED - FORTIS PROPERTIES [(1)]

Financial Highlights (Unaudited)	**Quarter**			**Year-to-Date**		
Periods Ended September 30	**2012**	2011	Variance	**2012**	2011	Variance
Hospitality - Revenue per Available Room ("RevPAR") *($)*	**94.04**	94.83	(0.79)	**82.09**	80.54	1.55
Real Estate - Occupancy Rate *(as at, %)* [(2)]	**91.8**	94.2	(2.4)	**91.8**	94.2	(2.4)
Hospitality Revenue *($ millions)*	**48**	47	1	**130**	123	7
Real Estate Revenue *($ millions)*	**17**	16	1	**51**	50	1
Total Revenue *($ millions)*	**65**	63	2	**181**	173	8
Earnings *($ millions)*	**8**	9	(1)	**17**	18	(1)

(1) Fortis Properties owns and operates 23 hotels, collectively representing more than 4,400 rooms, in eight Canadian provinces, including the acquisition of the StationPark Hotel in London, Ontario, which was acquired in October 2012 for approximately $13 million. Fortis Properties also owns and operates approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

(2) Reduced occupancy rate is primarily due to increased vacancy in New Brunswick.

Factors Contributing to Quarterly Revenue Variance

Favourable
- Increased Hospitality Division revenue, driven by contribution from the Hilton Suites Hotel, which was acquired in October 2011

Unfavourable
- A 0.8% decrease in RevPar at the Hospitality Division. Excluding the impact of the Hilton Suites Hotel, RevPAR was $93.20 for the third quarter of 2012, a decrease of 1.7% quarter over quarter. The decrease in RevPAR was due to an overall 2.0% decrease in hotel occupancy, partially offset by an overall 0.3% increase in the average daily room rate. Hotel occupancy in Atlantic Canada and central Canada decreased, while occupancy in western Canada increased. The average daily room rate increased in western Canada and central Canada, and decreased in Atlantic Canada.

Factors Contributing to Year-to-Date Revenue Variance

Favourable

- A 1.9% increase in RevPAR at the Hospitality Division, driven by contribution from the Hilton Suites Hotel
- Excluding the impact of the Hilton Suites Hotel, RevPAR was $80.80 year-to-date 2012, an increase of 0.3% period over period. The increase in RevPAR was due to an overall 1.7% increase in the average daily room rate, partially offset by an overall 1.4% decrease in hotel occupancy. The average daily room rate increased in all regions. Hotel occupancy in Atlantic Canada and central Canada decreased, while occupancy in western Canada increased.

Factors Contributing to Quarterly and Year-to-Date Earnings Variances

Unfavourable

- Lower performance at the Hospitality Division, excluding the Hilton Suites Hotel, primarily due to the impact of decreased occupancy at hotel operations in Atlantic Canada and central Canada, and increased depreciation due to capital additions and improvements
- A $0.5 million gain on the sale of the Viking Mall during the first quarter of 2011

Favourable

- Contribution from the Hilton Suites Hotel

CORPORATE AND OTHER [1]

Financial Highlights (Unaudited)						
Periods Ended September 30	Quarter			Year-to-Date		
($ millions)	**2012**	2011	Variance	**2012**	2011	Variance
Revenue	**5**	4	1	**18**	17	1
Operating Expenses	**2**	4	(2)	**8**	9	(1)
Depreciation and Amortization	**-**	-	-	**1**	1	-
Other Income (Expenses), Net	**(3)**	20	(23)	**(11)**	20	(31)
Finance Charges	**13**	12	1	**36**	38	(2)
Income Tax (Recovery) Expense	**(1)**	3	(4)	**(6)**	(3)	(3)
	(12)	5	(17)	**(32)**	(8)	(24)
Preference Share Dividends	**11**	11	-	**34**	34	-
Net Corporate and Other Expenses	**(23)**	(6)	(17)	**(66)**	(42)	(24)

[1] Includes Fortis net corporate expenses, net expenses of non-regulated FortisBC Holdings Inc. ("FHI") corporate-related activities and the financial results of FHI's wholly owned subsidiary FortisBC Alternative Energy Services Inc. and FHI's 30% ownership interest in CustomerWorks Limited Partnership ("CWLP"). The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011.

Factors Contributing to Quarterly Net Corporate and Other Expenses Variance

Unfavourable

- Increased other expenses, net of other income, primarily due to: (i) the favourable impact in 2011 of the $17 million (US$17.5 million) ($11 million after tax) fee paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and CVPS; (ii) approximately $0.5 million ($0.5 million after tax) and $8.5 million ($7.5 million after tax) of costs incurred during the third quarter and year-to-date 2012, respectively, related to the pending acquisition of CH Energy Group; and (iii) foreign exchange losses of approximately $3 million and $2.5 million for the third quarter and year-to-date 2012, respectively, associated with the translation of the US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity. During the third quarter of 2011, a foreign exchange gain of $7 million associated with the translation of the above-noted US dollar-denominated long-term other asset was partially offset by a $5.5 million ($4.5 million after tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated long-term debt. The favourable net impact to earnings during the third quarter of 2011 of the above-noted foreign exchange impacts was approximately $2.5 million.
- Excluding income tax expense associated with the merger termination fee paid to Fortis in July 2011, income tax recovery decreased, primarily due to higher Part VI.1 taxes

Factors Contributing to Year-to-Date Net Corporate and Other Expenses Variance

Unfavourable

- The same factors discussed above for the quarter

Favourable

- Lower finance charges, primarily due to higher capitalized interest associated with the financing of the construction of the Corporation's 51% controlling ownership interest in the Waneta Expansion and the impact of the conversion of the Corporation's US$40 million convertible debentures into common shares in November 2011. The above decreases were partially offset by higher interest on credit facility borrowings in 2012, due to higher average credit facility borrowings and higher fees associated with the increase in the Corporation's committed revolving credit facility to $1 billion in May 2012. During the third quarter of 2011, credit facility borrowings were repaid with a portion of the proceeds from the common share offering in June and July 2011.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities year-to-date 2012 are summarized as follows.

NATURE OF REGULATION

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2010	2011	2012	Supportive Features: Future or Historical Test Year Used to Set Customer Rates
				ROE		COS/ROE
FEI	British Columbia Utilities Commission ("BCUC")	40	9.50	9.50	9.50	FEI: Prior to January 1, 2010, 50/50 sharing of earnings above or below the allowed ROE under a PBR mechanism that expired on December 31, 2009 with a two-year phase-out
FEVI	BCUC	40	10.00	10.00	10.00	
FEWI	BCUC	40	10.00	10.00	10.00	ROEs established by the BCUC
						Future Test Year
FortisBC Electric	BCUC	40	9.90	9.90	9.90	COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE established by the BCUC
						Future Test Year
FortisAlberta	AUC	41	9.00	8.75	8.75	COS/ROE ROE established by the AUC
						Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.00 +/- 50 bps	8.38 +/- 50 bps	8.80 +/- 50 bps	COS/ROE The allowed ROE had been set using an automatic adjustment formula tied to long-term Canada bond yields. The formula was suspended for 2012.
						Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	9.75	9.75	9.75	COS/ROE
						Future Test Year
FortisOntario	Ontario Energy Board ("OEB")					Canadian Niagara Power - COS/ROE
	Canadian Niagara Power	40	8.01	8.01	8.01 (1)	Algoma Power - COS/ROE and subject to Rural and Remote Rate Protection ("RRRP") Program
	Algoma Power	40	8.57	9.85	9.85 (1)	
	Franchise Agreement Cornwall Electric					Cornwall Electric - Price cap with commodity cost flow through
						Canadian Niagara Power - 2009 historical test year for 2010, 2011 and 2012 Algoma Power - 2007 historical test year for 2010; 2011 test year for 2011 and 2012

NATURE OF REGULATION (cont'd)

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2010	2011	2012	Supportive Features Future or Historical Test Year Used to Set Customer Rates
				ROA		COS/ROA
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	7.75 - 9.75	7.75 - 9.75	7.25 - 9.25	Rate-cap adjustment mechanism based on published consumer price indices The Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane.
						Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings to the Interim Government of the Turks and Caicos Caicos Islands ("Interim Government")	N/A	17.50 [(2)]	17.50 [(2)]	17.50 [(2)]	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year.
						Future Test Year

[(1)] Based on the ROE automatic adjustment formula, the allowed ROE for electric utilities in Ontario is 9.12% for utilities with rates effective May 1, 2012. This ROE is not applicable to regulated electric utilities in Ontario until they are scheduled to file their next full COS rate applications. As a result, the allowed ROE of 9.12% is not applicable to Canadian Niagara Power or Algoma Power for 2012.

[(2)] Amount provided under licence. ROA achieved in 2010 and 2011 was significantly lower than the ROA allowed under the licence due to significant investment occurring at the utility and the lack of rate relief thereto.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS

Regulated Utility	Summary Description
FEI/FEVI/FEWI	• FEI and FEWI review with the BCUC natural gas commodity prices and midstream costs every three months in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and contracting for midstream resources, such as third-party pipeline and/or storage capacity. The commodity cost of natural gas and midstream costs are flowed through to customers without markup. • Effective January 1, 2012, rates for typical residential customers in the Lower Mainland increased by approximately 3%, reflecting changes in delivery and midstream costs. Interim approval was also received to hold FEVI customer rates at 2011 levels, effective January 1, 2012. Natural gas commodity rates were unchanged, effective January 1, 2012. • Effective April 1, 2012, due to a decrease in natural gas commodity rates, rates for typical residential customers in the Lower Mainland decreased by approximately 10%, and rates for residential customers at FEWI decreased approximately 6%, following the BCUC's quarterly review of commodity costs. • Natural gas commodity rates were unchanged, effective July 1, 2012, following the BCUC's quarterly review of commodity costs. • In July 2011 FEVI received a BCUC decision approving the option for two First Nations bands to invest up to a combined 15% in the equity component of the capital structure of the liquefied natural gas ("LNG") storage facility on Vancouver Island. In late 2011 each band exercised its option and each invested approximately $6 million in equity in the LNG storage facility on January 1, 2012. • In February 2012 the BCUC approved FEI's amended application for a general tariff for the provision of compressed natural gas ("CNG") and LNG for transportation vehicles. FEI has filed applications for and received interim rate approval for two projects under the general tariff. FEI has also applied for approval of its LNG sales and dispensing service rate schedule on a permanent basis. In October 2012 FEI received approval for rate treatment of expenditures incurred related to the provision of CNG and LNG services, under the *Greenhouse Gas Reductions (Clean Energy) Regulation* ("GHG Regulation") under the *Clean Energy Act.*

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• FEI is awaiting a decision from the BCUC on the Alternative Energy Services Inquiry, which is a proceeding to determine, among other things, whether the provision of alternative energy services is a regulated utility service and whether FEI or an affiliate, i.e., FortisBC Alternative Energy Services Inc. ("FAES"), should provide these services. The alternative energy services subject to the inquiry include providing refuelling services for LNG-fuelled vehicles; owning and operating district energy systems and various forms of geo-exchange systems; and owning facilities that upgrade raw biogas into biomethane for the purpose of selling it to customers. • In November 2011 FEI, FEVI and FEWI filed an application with the BCUC for the amalgamation of the three companies into one legal entity and for the implementation of common rates and services for the utilities' customers across British Columbia, effective January 1, 2014. In late 2011 the utilities temporarily suspended their application while they provided additional information to the BCUC, as requested. In April 2012 the utilities refiled their application. The amalgamation requires approval by the BCUC and consent of the Government of British Columbia. The evidence in the regulatory proceeding has closed and a BCUC decision is pending. • In November 2011 the BCUC issued preliminary notification to public utilities subject to its regulation, including the FortisBC gas and electric utilities, that it would initiate a Generic Cost of Capital ("GCOC") Proceeding in early 2012. In February 2012 the BCUC established that a GCOC Proceeding would take place and in April 2012 issued a final scoping document outlining the items that will be reviewed as part of the GCOC Proceeding, which include: (i) the appropriate cost of capital for a benchmark low-risk utility, effective January 1, 2013, which includes capital structure, ROE and interest on debt; (ii) the establishment of a benchmark ROE based on a benchmark low-risk utility effective from January 1, 2013 through December 31, 2013 for the initial transition year; (iii) the determination of whether a return to an ROE automatic adjustment mechanism is warranted, which would be implemented January 1, 2014 or, if not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013; (iv) a generic methodology on how to establish each utility's cost of capital in reference to the cost of capital for a benchmark low-risk utility; (v) a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt; and (vi) for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism and, if not warranted, a future regulatory process will be set on how the deemed interest rate would be adjusted beyond December 31, 2013. The GCOC Proceeding is not intended to set each utility's risk premium. As part of the GCOC Proceeding, the BCUC retained an independent consultant to report on regulatory practices in Canadian jurisdictions. The timetable sets the evidence portion of the GCOC Proceeding to take place through to early December 2012 with an oral hearing to commence on December 12, 2012. The result of the GCOC Proceeding could materially impact the earnings of the FortisBC Energy companies and FortisBC Electric. • In April 2012 the BCUC issued its decision on the FortisBC Energy companies' 2012-2013 Revenue Requirements Application ("RRA"). The interim increases in customer rates, effective January 1, 2012, at FEI and FEWI reflected the applied for rate increases. The final approved increase in customer delivery rates, effective January 1, 2012, was 4.2% at FEI, approximately 1.4% lower than the interim customer delivery rates. The final approved increase in customer delivery rates, effective January 1, 2012, was 3.6% at FEWI, approximately 1.4% lower than the interim customer delivery rates. In its decision, the BCUC approved FEVI's 2012 and 2013 customer rates to remain unchanged from 2011 customer rates. The difference between interim and final customer rates at FEI and FEWI is being refunded to customers, which commenced June 1, 2012. The final approved customer delivery rates reflect allowed ROEs and capital structure unchanged from 2011, pending the outcome of the GCOC Proceeding as it may impact 2013 rates. The cumulative impacts of the 2012-2013 revenue requirements decision, where such impacts were different from those estimated, were recorded in the second quarter of 2012. The final rate increases were driven by ongoing investment in energy infrastructure focused on system integrity and reliability, forecasted increased operating expenses associated with inflation, a heightened focus on safety and security of the natural gas system, and increasing compliance with codes and regulations.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FEI/FEVI/FEWI (cont'd)	• Following the announcement by the Government of British Columbia of the GHG Regulation under the *Clean Energy Act*, FEI announced an incentive funding program to assist eligible vehicle operators in purchasing LNG-fuelled vehicles. The incentive program funding includes up to $62 million to offset a percentage of the incremental capital cost for eligible operators in purchasing qualifying LNG-fuelled vehicles. The eligible applicants for the incentive program are commercial return-to-base fleet operators of heavy-duty trucks, buses, vocational vehicles and marine vessels. Incentives are expected to be awarded beginning in late 2012 and will cover up to 80% of the eligible incremental capital costs in the initial year. Additionally, the GHG Regulation allows FEI to invest up to $30 million for LNG fuelling stations and up to $12 million for CNG fuelling stations. FEI has filed an application with the BCUC for rate treatment of the above expenditures under the GHG Regulation.
FortisBC Electric	• In August 2012 the BCUC issued its decision on FortisBC's 2012-2013 RRA, its 2012-2013 Capital Expenditure Plan ("2012-2013 CEP") and its Integrated System Plan ("ISP"). The ISP includes the Company's Resource Plan, Long-Term Capital Plan and Long-Term Demand Side Management Plan. The resulting final revenue requirements for 2012 and 2013 reflect an allowed ROE and capital structure unchanged from 2011, pending the outcome of the GCOC Proceeding as it may impact 2013 rates. The decision includes an approved forecast midyear rate base of approximately $1,112 million for 2012 and $1,173 million for 2013. Under the 2012-2013 CEP, capital expenditures, before customer contributions, of approximately $100 million for 2012 and approximately $120 million for 2013, were approved by the BCUC. Approximately $25 million of approved capital expenditures for 2012 are expected to be incurred in 2013, due to the timing of receipt in 2012 of the BCUC decision. The cumulative impacts of the 2012-2013 revenue requirements decision, where such impacts were different from those estimated, were recorded in the third quarter of 2012. In its decision the BCUC approved deferral accounts and flow-through treatment for variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates; however, flow-through treatment for finance charges was denied. FortisBC Electric requested, and the BCUC approved, that the interim refundable 1.5% increase in customer rates, effective January 1, 2012, as approved by the BCUC in November 2011, be maintained for the remainder of 2012. The difference between the final approved increase in 2012 customer rates of 0.6% and the interim increase in customer rates of 1.5% has been approved for deferral as a regulatory liability in 2012, to be used in 2013 to reduce the increase in customer rates to 4.2%, effective January 1, 2013. The rate increases are due to ongoing investment in energy infrastructure, including increased costs of financing the investment, as well as increased purchased power costs. • In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion and submitted the agreement to the BCUC. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010. In May 2012 the BCUC determined that the executed agreement is in the public interest and a hearing is not required. The agreement has been accepted for filing as an energy supply contract and FortisBC Electric has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Electric's next RRA. • In March 2012 the BCUC issued an order establishing a written hearing process to review the prudency of approximately $29 million in capital expenditures incurred related to the Kettle Valley Distribution Source Project, which was substantially completed in 2009. FortisBC Electric believes that the capital expenditures were prudently incurred and, therefore, cannot reasonably determine if any of such expenditures may be permanently disallowed from rate base and any resulting financial impact. The written hearing process is expected to continue through the remainder of 2012. • In July 2012 FortisBC Electric filed its Advanced Metering Infrastructure ("AMI") application, which is currently being reviewed by the BCUC and various interveners. The AMI project proposes to improve and modernize FortisBC Electric's grid by exchanging its manually read meters with advanced meters. The AMI project is expected to cost approximately $48 million and be completed in 2015.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta	• In December 2011 the AUC issued its decision on its 2011 GCOC Proceeding, establishing the allowed ROE at 8.75% for 2011 and 2012 and, on an interim basis, at 8.75% for 2013. The deemed equity component of FortisAlberta's capital structure remains at 41%. The AUC concluded that it would not return to a formula-based ROE automatic adjustment mechanism at that time and that it would initiate a proceeding in due course to establish a final allowed ROE for 2013 and revisit the matter of a return to a formula-based approach at a future proceeding. A GCOC Proceeding is expected to commence late 2012 or early 2013. • In March 2012 the AUC issued a bulletin regarding maintaining regulated electricity rates. The bulletin addressed the Government of Alberta's letter requesting that regulated electricity rates be maintained until the government responds to the recommendations of the Retail Market Review Committee ("Committee"), announced in February 2012. The Committee's mandate includes the review of the default electricity rate charged to customers who do not obtain retail service from a retailer. The AUC will continue processing applications and may approve applications that maintain existing rates or propose rate reductions; however, the AUC will not issue decisions that result in rate increases. The Committee's recommendations were provided to the Alberta Minister for review in September 2012. Further process has yet to be established and the government-sanctioned rate freeze has not been lifted. • In January 2012 FortisAlberta and other distribution utilities in Alberta filed motions for leave to appeal with the Alberta Court of Appeal with respect to the 2011 GCOC decision, challenging certain pronouncements made by the AUC as being incorrect regarding cost responsibility for stranded assets. In June 2012 the AUC decided that it would not permit a review and variance of the 2011 GCOC decision which had been requested by the utilities, but would examine the issue in a future proceeding. The court process has been temporarily adjourned pending the AUC's follow-up proceeding. • In April 2012 the AUC approved, substantially as filed, a Negotiated Settlement Agreement ("NSA") pertaining to FortisAlberta's 2012 distribution revenue requirements, resulting in an average increase in customer distribution rates of approximately 5%, effective January 1, 2012, consistent with the interim rate increase that was previously approved by the AUC in December 2011. The cumulative impacts of the 2012 revenue requirements decision, where such impacts were different from those estimated, were recorded in the second quarter of 2012. The increase in customer rates was driven primarily by ongoing investment in energy infrastructure, including increased financing costs. The NSA provided for forecast midyear rate base of $2,025 million for 2012. The AUC did not approve the continuation of the deferral of transmission volume variances associated with FortisAlberta's AESO charges deferral account for 2012. The deferral of transmission volume variances, however, was reinstated, effective January 1, 2013, per the AUC's generic decision on its PBR Initiative ("PBR Decision") as discussed further. • In July 2012 the AUC issued a decision denying an application made by the Central Alberta Rural Electrification Association ("CAREA") in which CAREA had requested, effective January 1, 2012, that it be entitled to service any new customers wishing to obtain electricity for use on property overlapping CAREA's service area and that FortisAlberta be restricted to providing service in the overlapping CAREA service area to only those customers who are not being provided service by CAREA. The decision confirms that FortisAlberta is the primary electricity distribution service provider within its service territory, including that portion of the Company's service territory that overlaps with CAREA's service territory. CAREA has not sought leave to appeal this decision. • In June 2012 AESO filed with the AUC a Customer Contribution Policy Application and an Amortized Construction Contribution Rider I Application. The first application proposes a reduction in the level of AESO contributions that transmission customers, including FortisAlberta, would pay versus what the transmission facility owner would pay. The second application proposes that transmission customers be given the option to make the required AESO contributions as a series of payments over a number of years, rather than as an up-front payment. Effectively, this would result in the transmission facility owner financing the AESO contributions. Decisions on the applications are not expected until 2013.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	• In September 2012 the AUC issued a generic PBR Decision outlying the PBR framework applicable to distribution utilities in Alberta, including FortisAlberta, for a five-year term commencing January 1, 2013. Under PBR rate-making, a formula is used to determine customer rates on an annual basis. The implementation of PBR does not alter a utility's right to a reasonable opportunity to recover the prudent COS and the right to earn a reasonable ROE. The formula approved by the AUC in the PBR Decision raises concerns and uncertainty for FortisAlberta regarding the treatment of certain capital expenditures. The Company will be seeking further clarification regarding those capital expenditures in the required compliance application, scheduled to be filed with the AUC in November 2012. FortisAlberta has also sought leave to appeal this issue with the Alberta Court of Appeal.
Newfoundland Power	• In March 2012 Newfoundland Power filed a Cost of Capital Application with the PUB to discontinue the use of the current ROE automatic adjustment mechanism and to approve a just and reasonable rate of return on average rate base for 2012. In June 2012 the PUB ordered that the allowed ROE for 2012 be increased to 8.80% from 8.38% for 2011. The PUB also approved the deferred recovery from customers of approximately $2.5 million before tax, reflecting the difference between the 8.38% allowed ROE currently reflected in customer electricity rates in 2012 and the final approved allowed ROE of 8.80%. • In October 2012 the PUB approved Newfoundland Power's 2013 Capital Expenditure Plan totalling approximately $82 million, before customer contributions. • Effective July 1, 2012, the PUB approved an overall average increase in Newfoundland Power's customer electricity rates of 6.6%. The increase in rates was primarily the result of the normal annual operation of the Newfoundland and Labrador Hydro ("Newfoundland Hydro") Rate Stabilization Plan. Variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power are captured and flowed through to customers through the operation of Newfoundland Power's Rate Stabilization Account ("RSA"). The operation of the RSA further captures variances in certain of Newfoundland Power's costs, such as pension and energy supply costs. The above-noted increase in customer rates does not impact Newfoundland Power's earnings. • In September 2012 Newfoundland Power filed a General Rate Application for 2013 customer electricity rates and cost of capital. A hearing on the application is expected in the first quarter of 2013.
Maritime Electric	• In February 2012 the PEI Energy Commission ("PEI Commission") released its Discussion Paper, *Charting Our Electricity Future,* which outlined discussion points the PEI Commission is seeking input through a consultative process with stakeholders and the general public. These discussion points included: (i) electricity ownership and management on PEI and whether Maritime Electric is doing a good job of balancing safety and reliability with cost of service; (ii) the future role of IRAC, the PEI Energy Corporation and the PEI Office of Energy Efficiency; (iii) a new cable interconnection; (iv) the treatment of the financing of the $47 million of deferred incremental replacement energy costs associated with the New Brunswick Power Point Lepreau nuclear generating station; (v) regional energy collaboration; (vi) demand side management; (vii) renewable energy and environmental stewardship; and (viii) potential options for natural gas-generated electricity. Public forums and stakeholder consultations occurred in February and March 2012, in which Maritime Electric was a participant. The PEI Commission is expected to release a final report of its recommendations to the Government of PEI before the end of 2012. • In March 2012 Maritime Electric received regulatory approval to defer, for refund to customers in a future period to be determined, income tax expense reductions associated with the Company's amendment of corporate income tax filings for the years 2007 through 2010. The amended filings seek to expense certain costs previously capitalized for income tax purposes. • In June 2012 Maritime Electric filed its 2013 Capital Budget Application totaling approximately $26 million, before customer contributions. • Maritime Electric intends to file an application for 2013 customer rates and allowed ROE with IRAC.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
FortisOntario	• In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target under the Third-Generation Incentive Rate Mechanism ("IRM") as prescribed by the OEB. In the first quarter of 2012, the OEB published applicable inflationary and efficiency targets, resulting in minimal changes in base customer electricity distribution rates at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne effective May 1, 2012. The Third-Generation IRM maintains the allowed ROE at 8.01% for 2012. • In April 2012 the OEB issued Final Decisions and Orders for customer rates effective May 1, 2012 at FortisOntario's operations in Fort Erie, Gananoque and Port Colborne. The result was an average 3.1% decrease in residential customer rates in Fort Erie, an average 0.6% increase in residential customer rates in Gananoque and an average 4.6% decrease in residential customer rates in Port Colborne. The above-noted rate changes were mainly due to changes in rate riders associated with regulatory deferral accounts and smart meter funding. • In April 2011 FortisOntario provided the City of Port Colborne and Port Colborne Hydro with an irrevocable written notice of FortisOntario's election to exercise the purchase option, under the then-current operating lease agreement, at the purchase option price of approximately $7 million on April 15, 2012. The purchase constituted the sale of the remaining assets of Port Colborne Hydro to FortisOntario. The purchase transaction was approved by the OEB in March 2012 and closed on April 16, 2012. • In March 2012 the OEB issued its decision on Algoma Power's Third-Generation IRM application for customer electricity distribution rates, effective January 1, 2012. The decision approved a price-cap index of 2.81% for customers subject to RRRP funding and 0.38% for those customers not subject to RRRP funding. RRRP funding for 2012 has been set at approximately $11 million. Algoma Power's allowed ROE is maintained at 9.85% for 2012. • In May 2012 FortisOntario filed a COS Application for electricity distribution rates in Fort Erie, Port Colborne and Gananoque, effective January 1, 2013, using a 2013 forward test year. The application proposes an allowed ROE of 9.12% on a deemed equity component of capital structure of 40%. The allowed ROE is subject to change based on operation of the automatic ROE adjustment formula. In September 2012 a settlement agreement on the COS Application was reached on all issues, except for the disposal of an income tax-related regulatory deferral account of $1 million, which is expected to be decided upon by the OEB by the end of 2012.
Caribbean Utilities	• In April 2012 the ERA approved Caribbean Utilities' 2012-2016 Capital Investment Plan ("CIP") for US$122 million of non-generation installation capital expenditures. The remaining US$62 million of the 2012-2016 CIP relates to new generation installation, which is subject to a competitive solicitation process with the next generation unit scheduled for installation in 2014. The 2012-2016 CIP was prepared in line with the Certificate of Need that was filed with the ERA in November 2011. Proposals for installation of the new generation unit from six qualified bidders, including Caribbean Utilities, was requested by the ERA and Caribbean Utilities' proposal was submitted in July 2012. The ERA's decision on the successful bidder is expected by the end of the 2012. A second increment of 18 MW of new generating capacity is required up to three years later in 2017, contingent on economic growth on Grand Cayman and the related growth in demand for electricity. • The proposed 2013-2017 CIP, totalling approximately US$125 million of non-generation installation capital expenditures, was submitted to the ERA in October 2012 for approval. • In March 2012 the ERA approved the creation of Caribbean Utilities' wholly owned subsidiary DataLink Ltd. ("DataLink"). Subsequently, the Information and Communications Technology Authority ("ICTA") granted a licence to DataLink to provide fibre optic infrastructure and other information and communication technology services on Grand Cayman. The ICTA licence allows DataLink to assume full responsibility for existing pole-attachment agreements and optical fibre lease agreement currently held by Caribbean Utilities with third-party information and communications technology service providers. The reassignment of existing contracts is in progress and is expected to be completed before the end of 2012. The ERA has approved executed management and maintenance, pole attachment and fibre optic agreements between Caribbean Utilities and DataLink.

MATERIAL REGULATORY DECISIONS AND APPLICATIONS (cont'd)

Regulated Utility	Summary Description
Caribbean Utilities (cont'd)	• In December 2011 Caribbean Utilities conducted and completed a competitive bidding process to fill up to 13 MW of non-firm renewable energy capacity. During the third quarter of 2012, Caribbean Utilities commenced discussions with two renewable energy developers that were selected to provide renewable energy to the utility's grid. The proposals being considered are two 5-MW solar photovoltaic power plants and one 3-MW small-scale wind turbine project. The developers will finance, construct, own and operate the renewable generation facilities. Negotiations towards firm power purchase agreements with the developers are ongoing. The power purchase agreements, however, are subject to ERA review and approval. Once the negotiations are completed, and the necessary regulatory approvals received, final power purchase agreements will be established with the two developers who will then start construction of the projects. It is anticipated that the 13 MW of renewable energy capacity will be connected to the grid by 2014. • Effective June 1, 2012, following review and approval by the ERA, Caribbean Utilities' base customer electricity rates increased by 0.7% as a result of changes in the applicable consumer price indices and the utility's achieved ROA for 2011.
Fortis Turks and Caicos	• An independent review of the regulatory framework for the electricity sector in the Turks and Caicos Islands was performed during the third quarter of 2011 on behalf of the Interim Government. Fortis Turks and Caicos provided a comprehensive response to the Interim Government in January 2012 stating that the Company supports limited mutually agreed upon reforms, but that its current licences must be respected and can only be changed by mutual consent. Specifically, Fortis Turks and Caicos would support reforms that strengthen the role of the regulator in the rate-setting process and that are fair to all stakeholders. Negotiations between Fortis Turks and Caicos and the Interim Government commenced during the third quarter of 2012 with Fortis Turks and Caicos presenting a new regulatory framework proposal to the Interim Government. A third-party consultant was engaged by the Interim Government to review the proposal and provide recommendations. • In February 2012 the Interim Government approved an approximate 26% increase in electricity rates, effective April 1, 2012, for Fortis Turks and Caicos' large hotel customers. In addition, other qualitative enhancements to the franchise were also achieved, including: (i) improved wording in the *Electricity Rate Regulation*; (ii) an approved increase in kilowatt hour consumption thresholds for both medium and large hotels; (iii) an expansion of service territory to cover all of the Caicos Islands, except for areas currently serviced by private suppliers' licences, with new 25-year licences issued for the expanded service territory; and (iv) the discontinuance of the government subsidization of the utility's South Caicos operations. • In March 2012 Fortis Turks and Caicos submitted its 2011 annual regulatory filing outlining the Company's performance in 2011. Included in the filing were the calculations, in accordance with the utility's licence, of rate base of US$166 million for 2011 and cumulative shortfall in achieving allowable profits of US$72 million as at December 31, 2011. • In April 2012 Fortis Turks and Caicos entered into a Streetlight Takeover Agreement with the Interim Government, whereby the responsibility for the ownership, installation and maintenance of all streetlights in the utility's service territory was transferred to Fortis Turks and Caicos.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between September 30, 2012 and December 31, 2011.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between September 30, 2012 and December 31, 2011

Balance Sheet Account	Increase / (Decrease) *($ millions)*	Explanation
Cash and cash equivalents	60	The increase was primarily due to cash on hand at the FortisBC Energy companies associated with seasonality of operations and a portion of the proceeds received from an equity injection by Fortis during the second quarter of 2012, and the timing of cash payments at FortisAlberta and the Waneta Expansion Limited Partnership (the "Waneta Partnership").
Accounts receivable	(228)	The decrease was driven by the FortisBC Energy companies, mainly due to a seasonal decrease in sales and the lower commodity cost of natural gas reflected in customer rates. Accounts receivable also decreased at Newfoundland Power, due to seasonality and the timing of collections from customers and decreased at FortisAlberta, due to decreased rate riders and a change in the billing of retailers from a monthly to a weekly basis.
Inventories	23	The increase was driven by the normal seasonal increase of gas in storage at the FortisBC Energy companies, partially offset by the impact of lower natural gas commodity prices.
Regulatory assets – current and long-term	(28)	The decrease was mainly due to: (i) approximately $100 million associated with the deferral of the change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; (ii) the collection of approximately $44 million in AESO charges deferral at FortisAlberta; and (iii) a reduction in regulatory deferred employee future benefits costs. The decrease was partially offset by higher regulatory deferred income taxes, and an increase in the deferral of various other costs, as permitted by the regulators, mainly at the FortisBC regulated utilities.
Other assets	25	The increase was mainly due to financing costs associated with the Corporation's Subscription Receipts offering, an increase in income taxes receivable at Maritime Electric and an increase in defined benefit pension assets at Newfoundland Power.
Utility capital assets	406	The increase primarily related to $737 million invested in electricity and gas systems, partially offset by depreciation and customer contributions year-to-date 2012, and the impact of foreign exchange on the translation of US-dollar denominated utility capital assets.
Short-term borrowings	(62)	The decrease was primarily due to a reduction in borrowings at the FortisBC Energy companies with a portion of the proceeds received from an equity injection by Fortis during the second quarter of 2012 and seasonality of operations, partially offset by increased borrowings at Caribbean Utilities, mainly to repay maturing long-term debt.
Accounts payable and other current liabilities	(135)	The decrease was mainly due to: (i) the $75 million change in the fair market value of the natural gas derivatives at the FortisBC Energy companies; (ii) lower amounts owing for purchased natural gas at the FortisBC Energy companies and purchased power at Newfoundland Power, associated with seasonality of operations; (iii) the timing of payment of property taxes and franchise fees at the FortisBC Energy companies; and (iv) lower accounts payable at the Waneta Partnership associated with the timing of payments related to the construction of the Waneta Expansion. The decrease was partially offset by higher accounts payable associated with transmission-connected projects and timing of AESO payments for transmission costs at FortisAlberta.

Significant Changes in the Consolidated Balance Sheets (Unaudited) between September 30, 2012 and December 31, 2011 (cont'd)

Balance Sheet Account	Increase / (Decrease) *($ millions)*	Explanation
Regulatory liabilities – current and long-term	65	The increase was mainly due to an overall increase in deferrals at the FortisBC Energy companies and an increase in the AESO charges deferral at FortisAlberta. The increase in deferrals at the FortisBC Energy companies was mainly due to: (i) an increase in the Revenue Surplus Deferred Account, reflecting amounts collected in customer rates in excess of the cost of providing service at FEVI year-to-date 2012; (ii) an increase in the Midstream Cost Reconciliation Account and the Commodity Cost Reconciliation Account, as amounts collected in customer rates were in excess of actual midstream and commodity gas-delivery costs, respectively, year-to-date 2012; and (iii) the provisioning for non-ARO removal costs commencing January 1, 2012. The increase was partially offset by approximately $25 million associated with the deferral of the change in the fair market value of the natural gas derivatives at the FortisBC Energy companies.
Deferred income tax liabilities – current and long-term	57	The increase was driven by tax timing differences related mainly to capital expenditures at the regulated utilities.
Long-term debt (including current portion)	149	The increase was primarily due to higher borrowings under the Corporation's committed credit facility, largely in support of the construction of the Waneta Expansion and for other general corporate purposes. The increase was partially offset by regularly scheduled debt repayments at Fortis Properties, the FortisBC Energy companies and Caribbean Utilities, and the impact of foreign exchange on the translation of US-dollar denominated debt.
Shareholders' equity (before non-controlling interests)	110	The increase was primarily due to net earnings attributable to common equity shareholders year-to-date 2012, less common share dividends, and the issuance of common shares mainly under the Corporation's dividend reinvestment and stock option plans.
Non-controlling interests	80	The increase was driven by advances from the 49% non-controlling interests in the Waneta Partnership and an approximate $12 million, or 15%, equity investment by two First Nations bands in the LNG storage facility on Vancouver Island.

LIQUIDITY AND CAPITAL RESOURCES

The table below outlines the Corporation's consolidated sources and uses of cash for the third quarter and year-to-date 2012, as compared to the same periods in 2011, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2012**	2011	Variance	**2012**	2011	Variance
Cash, Beginning of Period	**231**	296	(65)	**87**	107	(20)
Cash Provided by (Used in):						
Operating Activities	**221**	151	70	**804**	684	120
Investing Activities	**(277)**	(265)	(12)	**(761)**	(748)	(13)
Financing Activities	**(28)**	(77)	49	**17**	62	(45)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**-**	1	(1)	**-**	1	(1)
Cash, End of Period	**147**	106	41	**147**	106	41

Operating Activities: Cash flow from operating activities was $70 million higher quarter over quarter. The increase was primarily due to: (i) favourable changes in working capital; (ii) the collection from customers of regulator-approved increased depreciation and amortization expense, mainly at the FortisBC Energy companies; and (iii) favourable changes in long-term regulatory deferral accounts. The favourable changes in working capital were associated with changes in inventories, accounts payable and other current liabilities, and current regulatory deferral accounts, partially offset by unfavourable changes in accounts receivable. The increase was partially offset by lower earnings.

Cash flow from operating activities was $120 million higher year to date compared to the same period last year. The increase was primarily due to favourable changes in working capital and the collection from customers of regulator-approved increased depreciation and amortization expense, mainly at the FortisBC Energy companies. Favourable changes in working capital were associated with changes in current regulatory deferral accounts and accounts receivable. The above increase was partially offset by unfavourable changes in long-term regulatory deferral accounts and a defined benefit pension solvency deficit funding payment made by Newfoundland Power during the second quarter of 2012.

Investing Activities: Cash used in investing activities was $12 million higher for the quarter and $13 million higher year to date. The increases reflected the acquisition of TCU in August 2012 for a net cash purchase price of approximately $7 million (US$7 million), net of cash acquired. The increase year to date also reflected the acquisition of the remaining assets of Port Colborne Hydro by FortisOntario in April 2012 for approximately $7 million.

For the quarter, lower capital spending related to the non-regulated Waneta Expansion and at FortisBC Electric and the Caribbean Regulated Electric Utilities was largely offset by an increase in capital spending at FortisAlberta. Year to date, lower capital spending at the FortisBC Energy companies and FortisBC Electric was largely offset by an increase in capital spending at FortisAlberta and capital spending related to the non-regulated Waneta Expansion. Capital expenditures for the first half of 2011 included those of Belize Electricity up to June 20, 2011, when the utility was expropriated by the GOB.

Financing Activities: Cash used in financing activities was $49 million lower quarter over quarter. The decrease was primarily due to lower net repayments under committed credit facilities classified as long term, partially offset by lower net proceeds from short-term borrowings and lower proceeds from the issuance of common shares.

Cash provided by financing activities was $45 million lower year to date compared to the same period last year. The decrease was primarily due to: (i) lower proceeds from the issuance of common shares; (ii) lower proceeds from long-term debt; (iii) higher repayments of long-term debt; (iv) higher common share dividends paid; and (v) issue costs related to the June 2012 Subscription Receipts offering. The decrease was partially offset by higher net borrowings under committed credit facilities classified as long term and lower net repayments of short-term borrowings.

Net proceeds from short-term borrowings were $69 million lower quarter over quarter, driven by the FortisBC Energy companies. Net repayments of short-term borrowings were $53 million lower year to date compared to same period last year, driven by Caribbean Utilities.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net (repayments) borrowings under committed credit facilities for the quarter and year to date compared to the same periods last year are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2012**	2011	Variance	**2012**	2011	Variance
Caribbean Utilities [(1)]	**-**	9	(9)	**-**	38	(38)
Other	**-**	-	-	**-**	1	(1)
Total	**-**	9	(9)	**-**	39	(39)

[(1)] Issued 15-year US$15 million 4.85% and 20-year US$25 million 5.10% unsecured notes. The first tranche of US$30 million was issued in June 2011 and the second tranche of US$10 million was issued in July 2011. The net proceeds were used to repay current installments on long-term debt and short-term credit facility borrowings and to finance capital expenditures.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2012**	2011	Variance	**2012**	2011	Variance
FortisBC Energy Companies	**-**	(1)	1	**(18)**	(3)	(15)
Caribbean Utilities	**-**	-	-	**(13)**	(12)	(1)
Fortis Properties	**-**	(2)	2	**(24)**	(6)	(18)
Other	**-**	-	-	**(2)**	(6)	4
Total	**-**	(3)	3	**(57)**	(27)	(30)

Net (Repayments) Borrowings Under Committed Credit Facilities (Unaudited)						
Periods Ended September 30	**Quarter**			**Year-to-Date**		
($ millions)	**2012**	2011	Variance	**2012**	2011	Variance
FortisAlberta	**(22)**	33	(55)	**(13)**	50	(63)
FortisBC Electric	**(17)**	(7)	(10)	**(9)**	-	(9)
Newfoundland Power	**(20)**	(13)	(7)	**8**	10	(2)
Corporate	**50**	(191)	241	**235**	(165)	400
Total	**(9)**	(178)	169	**221**	(105)	326

Borrowings under credit facilities by the utilities are primarily in support of their capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility. The borrowings under the Corporation's committed credit facility during 2012 were largely in support of the construction of the Waneta Expansion and for other general corporate purposes.

Advances of approximately $14 million for the quarter and $70 million year to date were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion, compared to $20 million received for the third quarter of 2011 and $76 million received year-to-date 2011. In January 2012 advances of approximately $12 million were received from two First Nations bands representing their 15% equity investment in the LNG storage facility on Vancouver Island.

In June 2011 Fortis publicly issued 9.1 million common shares for gross proceeds of $300 million. In July 2011 an additional 1.2 million common shares were publicly issued upon the exercise of an over-allotment option, resulting in gross proceeds of approximately $41 million. The total net proceeds of $327 million from the common share offering were used to repay borrowings under credit facilities and finance equity injections into the regulated utilities in western Canada and the Waneta Partnership in support of infrastructure investment, and for other general corporate purposes.

Common share dividends paid during the third quarter of 2012 were $42 million, net of $15 million of dividends reinvested, compared to $38 million, net of $16 million of dividends reinvested, paid during the same quarter of 2011. Common share dividends paid year-to-date 2012 were $128 million, net of $43 million of dividends reinvested, compared to $109 million, net of $47 million of dividends reinvested, paid year-to-date 2011. The dividend paid per common share for each of the first, second and third quarters of 2012 was $0.30 compared to $0.29 for each of the first, second and third quarters of 2011. The weighted average number of common shares outstanding for the third quarter and year to date was 190.2 million and 189.6 million, respectively, compared to 186.5 million and 179.5 million for the third quarter and year to date, respectively, in 2011.

CONTRACTUAL OBLIGATIONS

As at September 30, 2012, consolidated contractual obligations of Fortis over the next five years and for periods thereafter are outlined in the following table. A detailed description of the nature of the obligations is provided in the 2011 Annual MD&A and below, where applicable. The presentation of certain contractual obligations has changed from that provided in the 2011 Annual MD&A, due to the adoption of US GAAP. For further information concerning these changes, refer to the 2011 audited consolidated financial statements prepared in accordance with US GAAP and voluntarily filed on SEDAR.

Contractual Obligations (Unaudited) **As at September 30, 2012** *($ millions)*	**Total**	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Long-term debt	**5,937**	90	826	563	4,458
Capital lease and finance obligations [(1)]	**2,605**	47	97	101	2,360
Waneta Partnership promissory note	**72**	-	-	-	72
Gas purchase contract obligations [(2)]	**351**	289	62	-	-
Power purchase obligations					
FortisBC Electric	**20**	11	6	3	-
FortisOntario	**371**	44	99	105	123
Maritime Electric	**148**	37	80	18	13
Capital cost	**446**	17	36	35	358
Joint-use asset and shared service agreements	**63**	4	8	6	45
Operating lease obligations	**26**	4	7	6	9
Defined benefit pension funding contributions [(3)]	**88**	37	34	15	2
Other	**8**	1	3	-	4
Total	**10,135**	581	1,258	852	7,444

(1) Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's Brilliant Power Purchase Agreement and Brilliant Terminal Station

(2) Based on index prices as at September 30, 2012

(3) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations, which generally provide funding estimates for a period of three to five years from the date of the valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes, which are expected to be performed as of the following dates for the larger defined benefit pension plans:

December 31, 2012	FortisBC Energy companies (covering non-unionized employees)
December 31, 2013	FortisBC Energy companies (covering unionized employees)
December 31, 2013	FortisBC Electric
December 31, 2013	FortisAlberta
December 31, 2014	Newfoundland Power

The estimate of defined benefit pension funding contributions includes the impact of the outcome of the December 31, 2011 actuarial valuation, completed in April 2012, associated with the defined benefit pension plan at Newfoundland Power. As a result of the valuation, Newfoundland Power is required to fund a solvency deficiency of approximately $53 million, including interest, over five years beginning in 2012, which is reflected in the above table. The Company fulfilled its 2012 annual solvency deficit funding requirement during the second quarter of 2012.

Other contractual obligations, which are not reflected in the above table, did not materially change from those disclosed in the 2011 Annual MD&A, except as described as follows.

In January 2012 two First Nations bands each invested approximately $6 million in equity in the Mount Hayes LNG storage facility, representing a 15% equity interest in the Mount Hayes Limited Partnership, with FEVI holding the controlling 85% ownership interest. The non-controlling interests hold put options, which, if exercised, would require FEVI to repurchase the 15% ownership interest for cash, in accordance with the terms of the partnership agreement.

In September 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40% of the Company's diesel fuel requirements under each of the contracts, respectively, for the operation of Caribbean Utilities' diesel-powered generating plant. The approximate combined quantities under the contracts, expressed in millions of imperial gallons, on an annual basis by fiscal year are: 2012 - 10.8, 2013 - 32.4 and 2014 - 18.9. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. The renewal options can be exercised only within six months of the expiry dates of the existing contracts.

In February 2012 Fortis entered into an agreement to acquire CH Energy Group for US$1.5 billion, including the assumption of approximately US$500 million in debt on closing. The acquisition is expected to close by the end of the first quarter of 2013. In June 2012, to finance a portion of the purchase price of CH Energy Group, Fortis sold 18,500,000 Subscription Receipts at $32.50 each, realizing gross proceeds of approximately $601 million. Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares to holders of record during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts. For further information on the pending acquisition of CH Energy Group and the Subscription Receipts offering, refer to the "Significant Items" and "Business Risk Management" sections of this MD&A.

FortisBC Electric has offered to purchase the City of Kelowna's electrical utility assets for approximately $55 million. Closing of the transaction is subject to certain conditions and approvals. For further information, refer to the "Significant Items" section of this MD&A.

For a discussion of the nature and amount of the Corporation's consolidated capital expenditure program, which is not included in the preceeding Contractual Obligations table, refer to the "Capital Expenditure Program" section of this MD&A.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40% equity, including preference shares, and 60% debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure (Unaudited)	**As at**			
	September 30, 2012		December 31, 2011	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) *(1) (2)*	**6,328**	**56.6**	6,296	57.1
Preference shares	**912**	**8.2**	912	8.3
Common shareholders' equity	**3,933**	**35.2**	3,823	34.6
Total *(3)*	**11,173**	**100.0**	11,031	100.0

(1) Includes long-term debt and capital lease and finance obligations, including current portion, and short-term borrowings, net of cash

(2) Excluding capital lease and finance obligations, the debt component of the capital structure was 54.9% as at September 30, 2012 and 55.3% as at December 31, 2011.

(3) Excludes amounts related to non-controlling interests

The improvement in the capital structure was primarily due to: (i) lower short-term borrowings; (ii) an increase in cash; (iii) common shares issued, mainly under the Corporation's dividend reinvestment and stock option plans; and (iv) net earnings attributable to common equity shareholders, net of dividends. The capital structure was also impacted by an increase in long-term debt, mainly due to higher borrowings under the Corporation's committed credit facility, largely in support of the construction of the Waneta Expansion and for other general corporate purposes, partially offset by regularly scheduled debt repayments.

CREDIT RATINGS

The Corporation's credit ratings are as follows:

Standard & Poor's ("S&P")	A- (long-term corporate and unsecured debt credit rating)
DBRS	A(low) (unsecured debt credit rating)

In May 2012 and July 2012, S&P and DBRS, respectively, affirmed the Corporation's debt credit ratings. Due to the Corporation's financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget, S&P and DBRS also removed the ratings from credit watch with negative implications and under review with developing implications, respectively, where the ratings had been placed in February 2012.

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

CAPITAL EXPENDITURE PROGRAM

Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred.

A breakdown of the $794 million in gross capital expenditures by segment year-to-date 2012 is provided in the following table.

Gross Consolidated Capital Expenditures (Unaudited) [(1)]
Year-to-Date September 30, 2012
($ millions)

FortisBC Energy Companies	Fortis Alberta [(2)]	FortisBC Electric	Newfoundland Power	Other Regulated Electric Utilities - Canadian	**Total Regulated Utilities - Canadian**	**Regulated Electric Utilities - Caribbean**	**Non-Regulated - Utility** [(3)]	**Fortis Properties**	**Total**
144	304	52	58	35	**593**	**33**	**144**	**24**	**794**

(1) Relates to cash payments to acquire or construct utility capital assets, income producing properties and intangible assets, as reflected in the consolidated statement of cash flows. Includes non-ARO removal expenditures, net of salvage proceeds, for those utilities where such expenditures are permissible in rate base in 2012. Excludes capitalized depreciation and amortization and non-cash equity component of AFUDC.
(2) Includes payments made to AESO for investment in transmission-related capital projects
(3) Includes non-regulated generation capital expenditures, mainly related to the Waneta Expansion

Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

There have been no material changes in the overall expected level, nature and timing of the Corporation’s significant capital projects from those that were disclosed in the 2011 Annual MD&A. Gross consolidated capital expenditures for 2012 are forecasted at approximately $1.3 billion.

FEI’s Customer Care Enhancement Project, at an estimated total project cost of $110 million, came into service at the beginning of January 2012.

Construction progress on the $900 million Waneta Expansion is going well and the project is currently on schedule and on budget. Major construction activities on-site include the completion of the excavation of the intake, powerhouse and power tunnels. Approximately $380 million in total has been spent on the Waneta Expansion since construction began late in 2010.

Over the five-year period 2012 through 2016, consolidated gross capital expenditures are expected to be approximately $5.5 billion, consistent with that disclosed in the 2011 Annual MD&A. The addition of CH Energy Group is expected to add approximately $0.5 billion to the Corporation’s consolidated capital expenditure program from 2013 through 2016. Approximately 64% of the $5.5 billion capital program is expected to be incurred at the regulated electric utilities, driven by FortisAlberta and FortisBC Electric. Approximately 23% and 13% of the capital program is expected to be incurred at the regulated gas utilities and non-regulated operations, respectively. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, excluding CH Energy Group, on average annually, 39% of utility capital spending is expected to be incurred to meet customer growth; 38% is expected to be incurred to ensure continued and enhanced performance, reliability and safety of generation and T&D assets (i.e., sustaining capital expenditures); and 23% is expected to be incurred for facilities, equipment, vehicles, information technology and other assets.

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

As at September 30, 2012, management expects consolidated long-term debt maturities and repayments to average approximately $295 million annually over the next five years. The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

In May 2012 Fortis filed a base shelf prospectus under which Fortis may, from time to time during the 25-month period from May 10, 2012, offer, by way of a prospectus supplement, common shares, preference shares, subscription receipts and/or unsecured debentures in the aggregate amount of up to $1.3 billion (or the equivalent in US dollars or other currencies). The base shelf prospectus provides the Corporation with flexibility to access securities markets in a timely manner. The nature, size and timing of any offering of securities under the Corporation's base shelf prospectus will be consistent with the past capital raising practices of the Corporation and continue to be dependant upon the Corporation's assessment of its requirements for funding and general market conditions.

To finance a portion of the Corporation's pending acquisition of CH Energy Group, Fortis offered and sold, by way of a prospectus supplement, approximately $601 million in Subscription Receipts under a bought-deal offering with a syndicate of underwriters. For further information refer to the "Significant Items" and "Business Risk Management" sections of this MD&A.

As the hydroelectric assets and water rights of the Exploits River Hydro Partnership ("Exploits Partnership") had been provided as security for the Exploits Partnership term loan, the expropriation of such assets and rights by the Government of Newfoundland and Labrador constituted an event of default under the loan. The term loan is without recourse to Fortis and was approximately $55 million as at September 30, 2012 (December 31, 2011 - $56 million). The lenders of the term loan have not demanded accelerated repayment. The scheduled repayments under the term loan are being made by Nalcor Energy, a Crown corporation, acting as agent for the Government of Newfoundland and Labrador with respect to expropriation matters. For further information refer to Note 19 to the Corporation's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2012.

Except for the debt at the Exploits Partnership, as discussed above, Fortis and its subsidiaries were in compliance with debt covenants as at September 30, 2012 and are expected to remain compliant throughout the remainder of 2012.

CREDIT FACILITIES

As at September 30, 2012, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.5 billion, of which $2.0 billion was unused, including $764 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.3 billion of the total credit facilities are committed facilities with maturities ranging from 2013 through 2017.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities (Unaudited)				**As at**	
($ millions)	Regulated Utilities	Fortis Properties	Corporate and Other	**September 30, 2012**	December 31, 2011
Total credit facilities	1,401	13	1,045	**2,459**	2,248
Credit facilities utilized:					
Short-term borrowings	(97)	-	-	**(97)**	(159)
Long-term debt (including current portion)	(63)	-	(236)	**(299)**	(74)
Letters of credit outstanding	(67)	-	(1)	**(68)**	(66)
Credit facilities unused	1,174	13	808	**1,995**	1,949

As at September 30, 2012 and December 31, 2011, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In March 2012 Newfoundland Power renegotiated and amended its $100 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility from August 2015 to August 2017. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In April 2012 FortisBC Electric renegotiated and amended its credit facility agreement resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2015 and $50 million now maturing in May 2013.

In May 2012 FHI extended its $30 million operating credit facility to mature in May 2013 from May 2012. The new agreement contains substantially similar terms and conditions as the previous credit facility agreement.

In May 2012 Fortis increased the amount available for borrowing under its unsecured committed revolving corporate credit facility from $800 million to $1 billion, as permitted under the credit facility agreement.

In May 2012 Caribbean Utilities renegotiated and increased the amount available for borrowing under its unsecured credit facilities to US$47 million from US$33 million.

In June 2012 FortisOntario entered into a new short-term credit facility agreement for $30 million, replacing two short-term credit facilities totaling $20 million. The new credit facility agreement reflects a decrease in pricing and improved terms and conditions. In July 2012 the former credit facilities were terminated.

In July 2012 FEI entered into a one-year extension of its $500 million unsecured committed revolving credit facility, extending the maturity date from August 2013 to August 2014. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In July 2012 FortisAlberta renegotiated and amended its $250 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility from September 2015 to August 2016. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments (Unaudited)	**As at**			
	September 30, 2012		December 31, 2011	
	Carrying	**Estimated**	Carrying	Estimated
($ millions)	**Value**	**Fair Value**	Value	Fair Value
Waneta Partnership promissory note	**46**	**52**	45	49
Long-term debt, including current portion	**5,937**	**7,476**	5,788	7,172

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The financial instruments table above excludes the long-term other asset associated with the Corporation's expropriated investment in Belize Electricity. The fair value of the Corporation's expropriated investment in Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay appropriate fair value compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts, which totalled approximately $103 million as at September 30, 2012.

Risk Management: The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and Belize Electric Company Limited ("BECOL") is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at September 30, 2012, the Corporation's corporately issued US$557 million (December 31, 2011 – US$550 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at September 30, 2012, the Corporation had approximately US$19 million (December 31, 2011 – US$6 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. The Corporation has recognized in earnings foreign exchange losses of approximately $3 million and $2.5 million during the three and nine months ended September 30, 2012, respectively. During the third quarter of 2011, a foreign exchange gain of $7 million associated with the translation of the above-noted US dollar-denominated long-term other asset was partially offset by a $5.5 million ($4.5 million after tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated long-term debt, resulting in a net foreign exchange gain of approximately $2.5 million after tax.

From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and fuel and natural gas prices through the use of derivative financial instruments. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes. As at September 30, 2012, the Corporation's derivative contracts consisted of fuel option contracts, natural gas swap and option contracts, and gas purchase contract premiums. The fuel option contracts are held by Caribbean Utilities and the remaining derivative instruments are held by the FortisBC Energy companies.

The following table summarizes the Corporation's derivative financial instruments.

Derivative Financial Instruments (Unaudited)				**As at**	
				September 30, 2012	December 31, 2011
(Liability) Asset	**Maturity**	**Number of Contracts**	**Volume** [1]	**Carrying Value** [2] ***($ millions)***	Carrying Value [2] *($ millions)*
Foreign exchange forward contract	**2012** [3]	**-**	**-**	**-**	-
Fuel option contracts	**2013** [4]	**4**	**7**	**-**	(1)
Natural gas derivatives:					
Gas swaps and options	**2014**	**99**	**36**	**(60)**	(135)
Gas purchase contract premiums	**2014**	**80**	**112**	**1**	-

(1) The volume for fuel option contracts is reported in millions of imperial gallons and for natural gas derivatives is reported in PJ.
(2) Carrying value is estimated fair value. The (liability) asset represents the gross derivatives balance.
(3) The foreign exchange forward contract held by FEI expired in April 2012. The carrying value of the contract was less than $1 million as at December 31, 2011.
(4) The carrying value of the fuel option contracts was less than $1 million as at September 30, 2012.

The fuel option contracts are used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. In October 2012 Caribbean Utilities executed additional fuel option contracts covering the period from November 1, 2012 to October 31, 2013. With the execution of these new contracts, approximately 70% of the Company's annual diesel fuel requirements are under fuel hedging arrangements.

The natural gas derivatives held by the FortisBC Energy companies are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. The price risk management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to mitigate gas price volatility on customer rates and to reduce the risk of regional price discrepancies. As directed by the BCUC, FEI and FEVI suspended their commodity hedging activities in 2011, which has continued into 2012, with the exception of certain limited swaps as permitted by the BCUC. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged.

The changes in the fair values of the fuel option contracts and natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. The fair values of the derivative financial instruments were recorded in accounts payable and other current liabilities as at September 30, 2012 and as at December 31, 2011.

The fair value of the fuel option contracts reflects only the value of the heating oil derivative and not the offsetting change in the value of the underlying future purchases of heating oil and is calculated using published market prices for heating oil. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas. The fair values of the fuel option contracts and natural gas derivatives were estimates of the amounts that the utilities would have to receive or pay to terminate the outstanding contracts as at the balance sheet dates.

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $68 million, as at September 30, 2012, the Corporation had no off-balance sheet arrangements, such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities, that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

There were no changes in the Corporation's significant business risks year-to-date 2012 from those disclosed in the 2011 Annual MD&A, except for those described below.

Regulatory Risk: In April 2012 regulatory decisions were received for 2012-2013 revenue requirements at the FortisBC Energy companies and for 2012 distribution revenue requirements at FortisAlberta. Similarly, a decision was received in August 2012 for 2012-2013 revenue requirements at FortisBC Electric. The receipt of two-year revenue requirements decisions at the FortisBC utilities helps to provide a level of operating stability for 2012 and 2013.

The recent decision by the AUC to transition distribution utilities in Alberta to PBR for a five-year period commencing in 2013 is a fundamental change in how these utilities are regulated; however, the change provides an opportunity for reduced regulatory burden and the incentive to achieve greater efficiencies and cost savings, which can lead to improved earnings. Under PBR, there is greater risk that FortisAlberta's earnings will be negatively impacted given the length of the PBR term and the uncertainty of resulting rate adjustments. It is possible that the approved PBR formula could have an unfavourable impact on FortisAlberta if the utility's actual costs, including costs associated with certain of its required capital projects, exceed the costs permitted by the PBR formula. In the absence of clarification by the AUC, which would broaden the scope of the recovery of these costs, the PBR formula conflicts with FortisAlberta's legal right to recover prudent costs of providing distribution services and to earn a reasonable ROE. FortisAlberta will be seeking further clarification regarding the application of the PBR formula in proceedings before the AUC and has sought leave to appeal the PBR Decision with the Alberta Court of Appeal.

The regulatory calendar, particularly at the FortisBC utilities, will be busy to the end of 2012 and into 2013 with various filings, interrogatories, inquiries and/or hearings occurring, including that related to the GCOC Proceeding and an expected request for approval of FortisBC Electric's proposed acquisition of the City of Kelowna's electrical utility assets. Determinations of cost of capital and final allowed ROEs for 2013 for FortisAlberta and Newfoundland Power also remain outstanding. The results of cost of capital proceedings could materially impact the earnings of the Corporation's largest utilities.

For further information, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Completion of the Acquisition of CH Energy Group: The acquisition of CH Energy Group remains subject to NYSPSC approval. A delay in receiving the approval, and/or conditions imposed, if any, under such approval, may result in the failure to materialize some, or all, of the expected benefits of the acquisition of CH Energy Group or such benefits may not occur within the time periods anticipated by the Corporation. The realization of such benefits may also be impacted by other factors beyond the control of Fortis.

The agreement and plan of merger may be terminated by the Corporation or CH Energy Group at any time prior to closing in certain circumstances, including if the acquisition has not closed by February 20, 2013 provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to August 20, 2013.

A portion of the acquisition purchase price is expected to be funded by $601 million of escrowed proceeds from the Corporation's June 2012 Subscription Receipts offering. If conditions precedent to the closing of the transaction are not fulfilled or waived, including receipt of NYSPSC approval, by June 30, 2013, or if the agreement and plan of merger related to the acquisition is terminated prior to such time, the proceeds from the Subscription Receipts offering, plus *pro rata* interest earned, are required to be returned to the holders of such receipts. As a result, closing of the transaction subsequent to June 30, 2013 could result in the Corporation having to raise alternative capital to finance the acquisition.

For further information refer to the "Significant Items" section of this MD&A.

Expropriation of Shares in Belize Electricity: In 2008 the newly elected GOB changed the electricity rate-setting methodology in Belize to one that did not allow Belize Electricity to recover its reasonable COS and make a reasonable rate of return on its investment as required by law and, thereby, it is the Corporation's position that the GOB has breached covenants that the GOB made when it sold its shares in Belize Electricity to Fortis in 1999. Relying on the new rate-setting methodology, the Belize Public Utilities Commission denied Belize Electricity a customer rate increase in its June 2008 Final Decision and subsequently amended that decision to decrease customer rates by 15%, notwithstanding the fact that a rate increase was required to adequately finance the utility's operations. The GOB further compounded Belize Electricity's financial problems when it increased the utility's business tax from 1.75% to 6.5%, effective in 2010. Due to an increase in the cost of purchased power, higher business taxes and the above-noted denial of compensatory customer rates, Belize Electricity required short-term financial assistance from the GOB in spring 2011. The GOB chose to prepay some of its electricity bills, as the preferred alternative of financial assistance from the options proposed by Belize Electricity, which allowed the utility to meet its power purchase obligations with the Mexican state-owned Comision Federal de Electricidad ("CFE") to the end of June 2011, after which time Belize Electricity would have been able to source most of its energy power requirements from lower-cost local hydroelectric generating facilities, rather than from the CFE, coinciding with the commencement of the rainy season in Belize.

On June 20, 2011, the GOB enacted in one day the *Electricity (Amendment) Act 2011* ("*Acquisition Act*") and the *Electricity (Assumption of Control over Belize Electricity Limited) Order 2011* ("*Acquisition Order*"), to expropriate the Corporation's majority ownership investment in Belize Electricity but did not expropriate any of the minority ownership investments, which continue to be held by the Social Security Board of Belize and Belizean residents. The purported public purpose stated in the *Acquisition Order*, as the basis of the decision to expropriate Belize Electricity, was "*to maintain an uninterrupted and reliable supply of electricity to the public*". The Corporation's evidence is that there was no risk of interruption or unreliable electricity supply at the time of expropriation and, while Belize Electricity had financial difficulties in 2011, such difficulties were caused by the GOB and, therefore, the GOB cannot rely on a situation it created to justify expropriating Belize Electricity.

Four days after expropriation of the Corporation's investment in Belize Electricity, the Belize Court of Appeal delivered its judgment that a similar expropriation of control of Belize Telemedia Limited ("Belize Telemedia"), a public telecommunications provider in Belize, in 2009 was unconstitutional, null and void. Rather than accept and appeal the judgment, the GOB enacted revised expropriation legislation to retain control of Belize Telemedia and contemporaneously proposed a constitutional amendment, the purported effect of which was to: (i) declare the GOB ownership of three specifically identified public utility providers, including Belize Electricity and Belize Telemedia; (ii) deem the expropriation of Belize Electricity and re-expropriation of Belize Telemedia to have been done for a public purpose; and (iii) oust the jurisdiction of the Belize Courts to review the GOB expropriation actions.

On October 21, 2011, Fortis filed a claim ("Claim No. 673 of 2011") in the Belize Supreme Court challenging the GOB's expropriation of the Corporation's investment in Belize Electricity pursuant to the *Acquisition Act* and *Acquisition Order*. On October 25, 2011, the *Belize Constitution (Eighth Amendment) Act 2011* ("*Eighth Amendment*") was enacted to validate and immunize the GOB's expropriation of Belize Electricity and Belize Telemedia. As a consequence of the above, Fortis subsequently amended its Claim No. 673 of 2011 to additionally challenge the constitutionality of the *Eighth Amendment*.

On June 11, 2012, the trial division of the Belize Supreme Court delivered its judgment in the claims of ***British Caribbean Bank Limited v Attorney General et al*** ("Claim No. 597 of 2011") and ***Dean Boyce v Attorney General et al*** ("Claim No. 646 of 2011") (collectively the "Telemedia Judgment") regarding the purported re-expropriation of Belize Telemedia. The court determined that the re-expropriation of the Claimants' properties by the GOB in those claims was unconstitutional, null and void. The judge determined most of the *Eighth Amendment* to be invalid, but found that he could sever those portions of sections 143 and 144 which declare GOB ownership of the named utilities, and that the severance thereby prevented the judge from ordering divestiture of the GOB's control of Belize Telemedia and hence the judge found himself precluded by the Belize Constitution from granting the Claimants the consequential relief sought.

Hearing of the Corporation's Claim No. 673 of 2011 occurred on July 2, 2012 before the same judge who delivered the Telemedia Judgment. The judge believed he was bound by his reasons in the Telemedia Judgment and dismissed the Corporation's Claim No. 673 of 2011 on the grounds that the severed portions of the *Eighth Amendment* precluded divestiture of the GOB ownership and control of Belize Electricity, notwithstanding the *Acquisition Act* and *Acquisition Order*, which are virtually identical to the provisions of the 2009 expropriation of Belize Telemedia, and were found to be invalid by the Belize Court of Appeal. The judge, therefore, denied the relief sought by Fortis.

On July 5, 2012, Fortis filed its appeal of the above-noted July 2, 2012 trial judgment to the Belize Court of Appeal. The Belize Court of Appeal allowed an application for consolidation of the Corporation's appeal with the appeal and cross-appeal of the Telemedia Judgment, and directed that the appeals be heard on an expedited basis commencing October 8, 2012.

In its appeal, Fortis has submitted that the *Acquisition Act* violates the Belize Constitution and should be struck down as: (i) the *Acquisition Act* does not prescribe the principles and manner in which reasonable compensation is to be determined in a reasonable time; (ii) the *Acquisition Act* does not prescribe the principles and manner in which reasonable compensation is to be given in a reasonable time; (iii) the *Acquisition Act* does not provide a right of access to the Belize Court for the purpose of enforcing a right to compensation; and (iv) certain sections of the *Acquisition Act* violate certain sections of the Belize Constitution. Fortis also submitted that the *Acquisition Order* violates the Corporation's constitutional rights and should be struck down as: (i) it is not proportionate; (ii) the expropriation of Belize Electricity by the GOB was arbitrary as the GOB did not acquire the minority shareholdings of the Social Security Board or Belizean nationals in Belize Electricity and is, therefore, in violation of the Belize Constitution; and (iii) Fortis was not afforded a right to be heard by the Belize Minister of Public Utilities before its property was compulsorily acquired by the GOB. Fortis also contends that the application of saved portions of sections 143 and 144 of the *Eighth Amendment* are also invalid and should not have precluded the ordering of consequential relief to Fortis for several reasons, including that fact that such provisions are void as they: (i) deprive the Belize Court of jurisdiction to conduct the constitutionally mandated inquiry to determine a person's interest or right in property compulsorily acquired, whether such acquisition was for a public purpose, the amount of compensation to which a person is entitled and for enforcement of a person's right to any such compensation; (ii) are in breach of the principle of equality before the law and the rule of law; and (iii) on their own do not fulfill the intention of the legislature of the Belize Government and are inextricably bound up with the legislation ruled to be unconstitutional in the Telemedia Judgment.

The consolidated appeal hearing occurred from October 8 to October 10, 2012. However, since one of the judges on the panel is the subject of a complaint to the Belize Judicial Council by parties to the Telemedia Judgment, an application for disqualification of that judge was made and subsequently denied by a majority of the appeal panel. Reasons for denial of leave to appeal of the disqualification application was delivered and judgment on the consolidated appeal hearing has been suspended, pending the outcome of the appeal in the Caribbean Court of Justice ("CCJ") relating to the disqualification application. Counsel for the GOB admitted during the consolidated appeal hearing that the *Acquisition Act* and *Acquisition Order* were contrary to the laws of Belize as it now stands, on the basis of the Belize Court of Appeal decision regarding the 2009 expropriation of Belize Telemedia, but that the severed provisions of the *Eighth Amendment* preclude return of majority control over Belize Electricity back to Fortis. A possible outcome of the consolidated appeal could be the return to Fortis of the majority ownership interest in Belize Electricity. Alternatively, in the event that the Belize Court of Appeal decision confirms the trial judgment, Fortis could pursue an appeal of the case to the CCJ, the highest court of appeal available for judicial matters in Belize.

Consequent to the deprivation of control over the operations of Belize Electricity, the Corporation discontinued the consolidation method of accounting for the utility, effective June 20, 2011. The Corporation has classified the book value of the expropriated investment in Belize Electricity as a long-term other asset on the consolidated balance sheet. As at September 30, 2012, the long-term other asset, including foreign exchange impacts, totalled \$103 million (December 31, 2011 - \$106 million; September 30, 2011 - \$103 million). Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined under the Corporation's valuation. The GOB also commissioned a valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset. While Fortis and representatives and third-party consultants of the GOB have held discussions in 2012 on differences in assumptions used in the valuations, there have been no discussions on any compensation settlement amount.

Fortis believes it has a strong, well-positioned case before the Belize Courts and will continue to vigorously litigate the legality of the expropriation. There exists, however, a reasonable possibility that the outcome of the above-noted litigation may be unfavourable to the Corporation and the amount of compensation to be paid to Fortis could be lower than the book value of its expropriated investment in Belize Electricity. Based on presently available information, the outcome of the above is not determinable at this time. As such, the long-term other asset is not deemed impaired. Fortis will continue to assess for impairment each reporting period based on the outcomes of court proceedings and/or compensation settlement negotiations, if any. As well as continuing its legal actions, Fortis is also pursuing alternative options for obtaining fair compensation.

Fortis continues to control and consolidate the financial statements of BECOL, the Corporation's indirect wholly owned non-regulated hydroelectric generating subsidiary in Belize. As at October 31, 2012, Belize Electricity owed BECOL US\$10 million for overdue energy purchases representing over 40% of BECOL's annual sales to Belize Electricity. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

Capital Resources and Liquidity Risk - Credit Ratings: In May 2012 and July 2012, S&P and DBRS, respectively, affirmed the Corporation's debt credit ratings. Due to the Corporation's financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion on time and on budget, S&P and DBRS also removed the ratings from credit watch with negative implications and under review with developing implications, respectively, where the ratings had been placed in February 2012. Similarly, FortisAlberta's existing debt credit rating by S&P was confirmed in May 2012 and removed from credit watch with negative implications. There were no other changes in the credit ratings of the Corporation's utilities year-to-date 2012.

Power Supply and Capacity Purchase Contracts: In November 2011 FortisBC Electric executed an agreement to purchase capacity from the Waneta Expansion and submitted the agreement to the BCUC. The agreement allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected to be in spring 2015. The form of the agreement was originally accepted for filing by the BCUC in September 2010. In May 2012 the BCUC determined that the executed agreement is in the public interest and a hearing is not required. The agreement has been accepted for filing as an energy supply contract and FortisBC Electric has been directed by the BCUC to develop a rate-smoothing proposal as part of a separate submission or as part of FortisBC Electric's next RRA.

Defined Benefit Pension Plan Assets: As at September 30, 2012, the fair value of the Corporation's consolidated defined benefit pension plan assets was $850 million, up $65 million or 8.3%, from $785 million as at December 31, 2011.

Labour Relations: The collective agreement between FortisBC Electric and the Canadian Office and Professional Employees Union ("COPE"), Local 378, expired on January 31, 2011. A new collective agreement expiring in March 2014 was reached with regard to certain customer service employees who were previously covered under the expired contract. A tentative agreement has been reached with regard to the remaining support and technical employees. The tentative agreement expires on December 31, 2013 and is subject to ratification by the affected employees.

The collective agreements between the FortisBC Energy companies and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on March 31, 2011. IBEW, Local 213, represents employees in specified occupations in the areas of T&D. A new four-year collective agreement, expiring in March 2015, was reached in June 2012.

The collective agreements between the FortisBC Energy companies and COPE, Local 378, expired on March 31, 2012. COPE, Local 378, represents employees in specified occupations in the areas of administration and operations support. The parties are negotiating the terms of a renewed collective agreement.

The two collective agreements between Newfoundland Power and IBEW, Local 1620, expired on September 30, 2011. One of the two newly negotiated collective agreements was ratified during the first quarter of 2012; the other was ratified in May 2012. The agreements are for three-year terms expiring in September 2014.

NEW ACCOUNTING STANDARDS AND POLICIES

Transition to US GAAP: In June 2011 the Ontario Securities Commission issued a decision allowing Fortis and its reporting issuer subsidiaries to prepare their financial statements, effective January 1, 2012 through to December 31, 2014, in accordance with US GAAP without qualifying as U.S. Securities and Exchange Commission ("SEC") Issuers. The Corporation and its reporting issuer subsidiaries, therefore, adopted US GAAP as opposed to International Financial Reporting Standards ("IFRS") on January 1, 2012 with the restatement of comparative reporting periods. Earnings recognized under US GAAP are more closely aligned with earnings recognized under Canadian GAAP, mainly due to the continued recognition of regulatory assets and liabilities under US GAAP. A transition to IFRS would likely have resulted in the derecognition of some, or perhaps all, of the Corporation's regulatory assets and liabilities and caused significant volatility in the Corporation's consolidated earnings. On March 16, 2012, Fortis voluntarily prepared and filed audited consolidated US GAAP financial statements for the year ended December 31, 2011 with 2010 comparatives on SEDAR. Also included in the voluntary filing were: (i) a detailed reconciliation between the Corporation's audited consolidated Canadian GAAP and audited consolidated US GAAP financial statements for fiscal 2011, including 2010 comparatives; and (ii) a detailed reconciliation between the Corporation's 2011 interim unaudited consolidated Canadian GAAP and 2011 interim unaudited consolidated US GAAP financial statements.

New Accounting Policies: Effective January 1, 2012, the FortisBC Energy companies prospectively adopted the policy of accruing for non-ARO removal costs in depreciation expense, as requested in their 2012-2013 RRA and subsequently approved by the regulator in its April 2012 decision. The accrual of estimated non-ARO removal costs is included in depreciation expense and the provision balance is recognized as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. Non-ARO removal costs are direct costs incurred by the FortisBC Energy companies in taking assets out of service, whether through actual removal of the assets or through disconnection of the assets from the transmission or distribution system. Prior to 2012 estimated non-ARO removal costs, net of salvage proceeds, were recognized in operating expenses with variances between actual non-ARO removal costs and those forecasted for rate-setting purposes recorded in a regulatory deferral account for future recovery from, or refund to, customers in rates commencing in 2012. For the three and nine months ended September 30, 2012, non-ARO removal costs of $5 million and $15 million, respectively, were accrued as a part of depreciation expense. For the three and nine months ended September 30, 2011, non-ARO removal costs of approximately $4 million and $12 million, respectively, were recognized in operating expenses.

Prior to 2012 variances from forecast, adjusted for certain revenue and cost variances which flowed through to customers, for rate-setting purposes were shared equally between customers and FortisBC Electric. As applied for in FortisBC Electric's 2012-2013 RRA and approved by the BCUC, prospectively from January 1, 2012 the above-noted sharing of positive or negative variances is no longer in effect. Beginning in 2012, variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates are subject to full deferral account treatment, to be recovered from, or refunded to, customers in future rates and, therefore, do not impact net earnings in 2012. Effective January 1, 2012, however, the flow through treatment for finance charges, as was applied for in FortisBC Electric's 2012-2013 RRA, was denied by the regulator pursuant to its revenue requirements decision. As a result, a retroactive adjustment was recorded in the third quarter of 2012 to eliminate the flow through treatment. Variances between actual finance charges from those forecasted in determining customer electricity rates, therefore, have an impact on net earnings in 2012.

Effective January 1, 2012, as approved by the regulator, the FortisBC Energy companies are deferring variances between actual depreciation expense and that forecasted in determining customer gas rates.

Effective January 1, 2012, as approved by the regulator, FortisAlberta is no longer permitted to defer transmission volume variances associated with its AESO charges deferral account. For the three and nine months ended September 30, 2012, FortisAlberta recognized approximately $3.5 million and $6.5 million, respectively, of net transmission revenue as a result of this change.

New US GAAP Accounting Pronouncements: The new US GAAP accounting pronouncements that are applicable to, and were adopted by, Fortis effective January 1, 2012 are described as follows:

Presentation of Comprehensive Income
The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income.* The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. Fortis continues to report the components of comprehensive income in a separate but consecutive statement.

Testing Goodwill for Impairment
The Corporation adopted the amendments to ASC Topic 350, *Goodwill.* The amended standard allows entities testing goodwill for impairment to have the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If the qualitative factors indicate that the fair value of the reporting unit is more likely than not (i.e., greater than a 50% chance) to be greater than the carrying value, then the two-step impairment test, including the quantification of the fair value of the reporting unit, would not be required. In adopting the amendments, Fortis will perform a qualitative assessment before calculating the fair value of its reporting units when it performs its annual impairment test as of October 1.

Fair Value Measurement
The Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP. The amendment does not change what items are measured at fair value but instead makes various changes to the guidance pertaining to how fair value is measured. The above-noted changes did not materially impact the Corporation's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2012.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's interim unaudited consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. During the second quarter of 2012, the FortisBC Energy companies and FortisAlberta received revenue requirements decisions, effective January 1, 2012, the cumulative impacts of which, where such impacts were different from those estimated, were recorded in the second quarter of 2012. Similarly, FortisBC Electric recorded the cumulative impacts of its revenue requirements decision, effective January 1, 2012, in the third quarter of 2012 when the decision was received. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates year-to-date 2012 from those disclosed in the 2011 Annual MD&A except for that related to capital asset depreciation. Changes in regulator-approved depreciation rates at FortisAlberta and FortisBC Electric, in conjunction with approved depreciation studies and revenue requirements decisions received in 2012, have impacted consolidated depreciation expense. The composite depreciation rate for utility capital assets at FortisAlberta decreased to 4.0% for 2012 from 4.1% for 2011. FortisBC Electric's composite depreciation rate for utility capital assets decreased to 3.1% for 2012 from 3.2% for 2011. As required by the BCUC, effective January 1, 2012, depreciation rates at the FortisBC Energy companies now include an amount allowed for regulatory purposes to accrue for estimated non-ARO removal costs, net of salvage proceeds. For further information, refer to the "New Accounting Standards and Policies" section of this MD&A. The impact of the above-noted changes in depreciation rates on depreciation expense has been reflected in the utilities' approved revenue requirements and resulting customer rates.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis
In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the proposed acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the proposed acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval.

FHI

During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI is appealing these assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions. FHI was advised that all matters have now been settled and the action has been dismissed by consent.

FortisBC Electric

The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. A date for mediation of this matter has been set for December 2012. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which includes FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $12 million. FortisBC Electric has not been served, however, has retained counsel and has contacted its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2010 through September 30, 2012. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements, which have been prepared in accordance with US GAAP. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using US GAAP for non-regulated entities. The nature of regulation is further disclosed in Notes 2, 3 and 7 to the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with US GAAP. The quarterly financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results (Unaudited) Quarter Ended	Revenue ($ millions)	Net Earnings Attributable to Common Equity Shareholders ($ millions)	Earnings per Common Share Basic ($)	Earnings per Common Share Diluted ($)
September 30, 2012	714	45	0.24	0.24
June 30, 2012	792	62	0.33	0.33
March 31, 2012	1,149	121	0.64	0.62
December 31, 2011	1,034	82	0.44	0.43
September 30, 2011	699	56	0.30	0.30
June 30, 2011	846	57	0.32	0.32
March 31, 2011	1,159	116	0.66	0.64
December 31, 2010	1,032	127	0.73	0.71

A summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the commodity cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Fortis subsidiaries, seasonality may vary. Most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Earnings for the first, second and third quarters of 2012 were reduced by approximately $4 million, $3 million and $0.5 million, respectively, associated with costs incurred related to the pending acquisition of CH Energy Group. During the second quarter of 2012, the FortisBC Energy companies and FortisAlberta received revenue requirements decisions, effective from January 1, 2012, the cumulative impacts of which, where such impacts were different from those estimated, were recorded in the second quarter of 2012. Similarly, FortisBC Electric recorded the cumulative impacts of its rate decision, effective January 1, 2012, in the third quarter of 2012 when the decision was received. Financial results from the fourth quarter ended December 31, 2011 reflected the acquisition of the Hilton Suites Hotel in October 2011. Earnings for the third quarter ended September 30, 2011 included the $11 million after-tax termination fee paid to Fortis by CVPS. Financial results from June 20, 2011 reflected the discontinuance of the consolidation method of accounting for Belize Electricity due to the expropriation of the utility by the GOB. For further information, refer to the "Significant Items" and "Business Risk Management" sections of this MD&A.

September 2012/September 2011: Net earnings attributable to common equity shareholders were $45 million, or $0.24 per common share, for the third quarter of 2012 compared to earnings of $56 million, or $0.30 per common share, for the third quarter of 2011. A discussion of the quarter over quarter variance in financial results is provided in the "Financial Highlights" section of this MD&A.

June 2012/June 2011: Net earnings attributable to common equity shareholders were $62 million, or $0.33 per common share, for the second quarter of 2012 compared to earnings of $57 million, or $0.32 per common share, for the second quarter of 2011. The increase in earnings was mainly due to higher contribution from FortisAlberta, increased non-regulated hydroelectric production in Belize, associated with higher rainfall, and higher earnings at Newfoundland Power, partially offset by higher corporate expenses and decreased earnings at the FortisBC Energy companies. Higher contribution from FortisAlberta related to rate base growth, and increased net transmission revenue and reduced depreciation as approved by the regulator, partially offset by a lower allowed ROE. Higher earnings at Newfoundland Power were the result of lower effective income taxes and a higher allowed ROE. The cumulative impact of the increase in the regulator-approved allowed ROE, effective January 1, 2012, was recorded in the second quarter of 2012. The increase in corporate expenses was due to approximately $4 million ($3 million after tax) of costs incurred during the second quarter of 2012 related to the pending acquisition of CH Energy Group and a lower income tax recovery, partially offset by a foreign exchange gain of approximately $2 million recognized in the second quarter of 2012. Decreased earnings at the FortisBC Energy companies mainly related to lower-than-expected customer additions in 2012 and lower capitalized AFUDC, partially offset by higher gas transportation volumes to industrial customers. A 7% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the issuance of common equity mid-2011, had the impact of lowering earnings per common share in the second quarter of 2012.

March 2012/March 2011: Net earnings attributable to common equity shareholders were $121 million, or $0.64 per common share, for the first quarter of 2012 compared to earnings of $116 million, or $0.66 per common share, for the first quarter of 2011. The increase in earnings was mainly due to higher contribution from the FortisBC Energy companies, increased non-regulated hydroelectric production in Belize, associated with higher rainfall, and higher earnings at Newfoundland Power and Maritime Electric, mainly the result of increased electricity sales and lower effective corporate income taxes. The increase in earnings was partially offset by the impact of the expiry of the PBR mechanism on December 31, 2011 at FortisBC Electric and the timing of certain operating expenses at the utility in 2012, higher corporate expenses and an approximate $1 million gain on the sale of property at FortisAlberta during the first quarter of 2011. The increase in earnings at the FortisBC Energy companies mainly related to the favourable impact of the difference in the timing of recognition of revenue associated with seasonal gas consumption and certain increased regulator-approved expenses in 2012, rate base growth and higher gas transportation volumes to industrial customers, partially offset by lower-than-expected customer additions in 2012 and lower capitalized AFUDC. The increase in corporate expenses was the result of approximately $4 million ($4 million after tax) of costs incurred during the first quarter of 2012 related to the pending acquisition of CH Energy Group and a $1.5 million foreign exchange loss, partially offset by lower finance charges. An 8% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the issuance of common equity mid-2011, had the impact of lowering earnings per common share in the first quarter of 2012.

December 2011/December 2010: Net earnings attributable to common equity shareholders were $82 million, or $0.44 per common share, for the fourth quarter of 2011 compared to earnings of $127 million, or $0.73 per common share, for the fourth quarter of 2010. Excluding the one-time $46 million favourable impact to Newfoundland Power's earnings in the fourth quarter of 2010 due to the rerecognition of a regulatory asset, as required under US GAAP, to recognize amounts recoverable from customers upon regulatory approval of the adoption the accrual method of accounting for OPEB costs, earnings increased $1 million quarter over quarter. The increase in earnings was led by the FortisBC Energy companies, driven by rate base growth, lower-than-expected corporate income taxes and finance charges in 2011, and higher gas transportation volumes to industrial customers, partially offset by both lower customer additions and capitalized AFUDC in 2011. The above-noted increase in earnings was partially offset by a decrease in earnings at Newfoundland Power, Other Canadian Regulated Electric Utilities, Fortis Turks and Caicos and Fortis Properties. The decrease in earnings at Newfoundland Power reflected a lower allowed ROE and higher operating expenses, partially offset by reduced energy supply costs in the fourth quarter of 2011. Lower earnings at Other Canadian Regulated Electric Utilities were due to decreased electricity sales and higher operating expenses. Lower earnings at Fortis Turks and Caicos were due to higher depreciation and operating expenses, partially offset by reduced energy supply costs in 2011 reflecting the use of new, more fuel-efficient generating units. Earnings at Fortis Properties during the fourth quarter of 2010 reflected lower corporate income tax rates, which reduced deferred taxes in that period. An 8% increase in the weighted average number of common shares outstanding quarter over quarter, largely associated with the issuance of common equity in mid-2011, had the impact of lowering earnings per common share in the fourth quarter of 2011.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

In an effort to optimize customer service operations within the FortisBC Energy companies, a Customer Care Enhancement Project was implemented at the beginning of January 2012 with new in-house customer contact and billing centres replacing the services of an external third-party service provider. This represents a material change in the Corporation's internal controls over financial reporting surrounding the revenue, receivable and receipts cycle. Throughout the related systems design and implementation, management had considered the control risks associated with the systems changes and had performed procedures to obtain reasonable assurance on the design of all new and significantly modified internal controls over financial reporting as a result of the project. It has been concluded that year-to-date 2012, other than the above-noted change, there were no changes in the Corporation's internal controls over financial reporting that have materially, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

OUTLOOK

The Corporation's significant capital expenditure program, which is expected to be approximately $5.5 billion over the five-year period 2012 through 2016, should support continuing growth in earnings and dividends. CH Energy Group is expected to add approximately $0.5 billion to the Corporation's consolidated capital expenditure program from 2013 through 2016.

Fortis is focused on closing the CH Energy Group transaction by the end of the first quarter of 2013. Approval of the transaction by the NYSPSC is the one remaining significant regulatory matter.

Fortis remains disciplined and patient in its pursuit of additional electric and gas utility acquisitions in the United States and Canada that will add value for Fortis shareholders. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

SUBSEQUENT EVENT

In October 2012 FortisAlberta issued 40-year $125 million 3.98% senior unsecured debentures, the proceeds of which are being used to repay borrowings under the Company's credit facility, fund future capital expenditures, and for general corporate purposes.

OUTSTANDING SHARE DATA

As at October 31, 2012, the Corporation had issued and outstanding approximately 190.7 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 10.0 million First Preference Shares, Series H; and 18.5 million Subscription Receipts. Only the common shares of the Corporation have regular voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether or not such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options, First Preference Shares, Series C and E, and Subscription Receipts were converted as at October 31, 2012 is as follows.

Conversion of Securities into Common Shares (Unaudited)
As at October 31, 2012

Security	**Number of Common Shares** *(millions)*
Stock Options	**5.1**
First Preference Shares, Series C	**3.9**
First Preference Shares, Series E	**6.2**
Subscription Receipts	**18.5**
Total	**33.7**

Additional information, including the Fortis 2011 Annual Information Form, Management Information Circular and Annual Report, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

FORTIS INC.

Interim Consolidated Financial Statements
For the three and nine months ended September 30, 2012 and 2011
(Unaudited)

Prepared in accordance with accounting principles generally accepted in the United States

Fortis Inc.
Consolidated Balance Sheets (Unaudited)
As at
(in millions of Canadian dollars)

	September 30, 2012	December 31, 2011
		(Note 22)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 147**	$ 87
Accounts receivable	**410**	638
Prepaid expenses	**33**	19
Inventories	**157**	134
Regulatory assets (Note 3)	**98**	219
Deferred income taxes	**24**	24
	869	1,121
Other assets	**209**	184
Regulatory assets (Note 3)	**1,493**	1,400
Deferred income taxes	**1**	8
Utility capital assets	**9,374**	8,968
Income producing properties	**604**	594
Intangible assets	**322**	325
Goodwill (Note 12)	**1,566**	1,565
	$ 14,438	$ 14,165
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 17)	**$ 97**	$ 159
Accounts payable and other current liabilities	**855**	990
Regulatory liabilities (Note 3)	**75**	43
Current installments of long-term debt	**90**	103
Current installments of capital lease and finance obligations	**7**	7
Deferred income taxes	**2**	5
	1,126	1,307
Other liabilities	**577**	573
Regulatory liabilities (Note 3)	**588**	555
Deferred income taxes	**733**	673
Long-term debt	**5,847**	5,685
Capital lease and finance obligations	**434**	429
	9,305	9,222
Shareholders' equity		
Common shares *(a)* (Note 4)	**3,092**	3,036
Preference shares	**912**	912
Additional paid-in capital	**15**	14
Accumulated other comprehensive loss	**(97)**	(95)
Retained earnings	**923**	868
	4,845	4,735
Non-controlling interests (Note 5)	**288**	208
	5,133	4,943
	$ 14,438	$ 14,165

(a) no par value: unlimited authorized shares; 190.7 million and 188.8 million issued and outstanding as at September 30, 2012 and December 31, 2011, respectively

Commitments and Contingent Liabilities (Notes 18 and 20, respectively)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Earnings (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars, except per share amounts)

	Quarter Ended		Nine Months Ended	
	2012	2011	**2012**	2011
Revenue	**$ 714**	$ 699	**$ 2,655**	$ 2,704
Expenses				
Energy supply costs	**235**	246	**1,092**	1,207
Operating	**203**	200	**621**	619
Depreciation and amortization	**118**	104	**351**	309
	556	550	**2,064**	2,135
Operating income	**158**	149	**591**	569
Other income (expenses), net (Note 8)	**1**	22	**(2)**	34
Finance charges (Note 9)	**93**	89	**276**	274
Earnings before income taxes	**66**	82	**313**	329
Income taxes (Note 10)	**7**	12	**44**	59
Net earnings	**$ 59**	$ 70	**$ 269**	$ 270
Net earnings attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 7**	$ 7
Preference equity shareholders	**11**	11	**34**	34
Common equity shareholders	**45**	56	**228**	229
	$ 59	$ 70	**$ 269**	$ 270
Earnings per common share (Note 11)				
Basic	**$ 0.24**	$ 0.30	**$ 1.20**	$ 1.28
Diluted	**$ 0.24**	$ 0.30	**$ 1.19**	$ 1.27

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Comprehensive Income (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Quarter Ended		Nine Months Ended	
	2012	2011	**2012**	2011
Net earnings	**$ 59**	$ 70	**$ 269**	$ 270
Other comprehensive (loss) income				
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	**(3)**	8	**(3)**	5
Reclassification of unrealized foreign currency translation losses, net of hedging activities and tax, related to Belize Electricity	**-**	-	**-**	17
Reclassification to earnings of net losses on discontinued cash flow hedges, net of tax	**-**	1	**-**	1
Unrealized employee future benefits gains, net of tax	**-**	-	**1**	-
	(3)	9	**(2)**	23
Comprehensive income	**$ 56**	$ 79	**$ 267**	$ 293
Comprehensive income attributable to:				
Non-controlling interests	**$ 3**	$ 3	**$ 7**	$ 7
Preference equity shareholders	**11**	11	**34**	34
Common equity shareholders	**42**	65	**226**	252
	$ 56	$ 79	**$ 267**	$ 293

See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Cash Flows (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Quarter Ended		Nine Months Ended	
	2012	2011	**2012**	2011
Operating activities				
Net earnings	**$ 59**	$ 70	**$ 269**	$ 270
Adjustments to reconcile net earnings to net cash provided by operating activities:				
Depreciation - utility capital assets and income producing properties	**105**	95	**316**	284
Amortization - intangible assets	**12**	9	**33**	27
Amortization - other	**1**	-	**2**	(2)
Deferred income taxes	**-**	4	**8**	3
Accrued employee future benefits	**3**	4	**(4)**	13
Equity component of allowance for funds used construction (Note 8)	**(1)**	(2)	**(4)**	(10)
Other	**1**	-	**(10)**	4
Change in long-term regulatory assets and liabilities	**(16)**	(27)	**(25)**	(9)
Change in non-cash operating working capital (Note 14)	**57**	(2)	**219**	104
	221	151	**804**	684
Investing activities				
Change in other assets and other liabilities	**(2)**	3	**2**	1
Capital expenditures - utility capital assets	**(264)**	(259)	**(737)**	(745)
Capital expenditures - income producing properties	**(9)**	(11)	**(24)**	(20)
Capital expenditures - intangible assets	**(10)**	(16)	**(33)**	(39)
Contributions in aid of construction	**15**	18	**45**	49
Proceeds on sale of utility capital assets and income producing properties	**-**	-	**-**	6
Business acquisitions, net of cash acquired (Note 12)	**(7)**	-	**(14)**	-
	(277)	(265)	**(761)**	(748)
Financing activities				
Change in short-term borrowings	**17**	86	**(61)**	(114)
Proceeds from long-term debt, net of issue costs	**-**	9	**-**	39
Repayments of long-term debt and capital lease and finance obligations	**-**	(3)	**(57)**	(27)
Net (repayments) borrowings under committed credit facilities	**(9)**	(178)	**221**	(105)
Advances from non-controlling interests	**14**	20	**83**	77
Subscription Receipts issue costs (Note 4)	**(1)**	-	**(13)**	-
Issue of common shares, net of costs and dividends reinvested	**6**	40	**12**	341
Dividends				
Common shares, net of dividends reinvested	**(42)**	(38)	**(128)**	(109)
Preference shares	**(11)**	(11)	**(34)**	(34)
Subsidiary dividends paid to non-controlling interests	**(2)**	(2)	**(6)**	(6)
	(28)	(77)	**17**	62
Effect of exchange rate changes on cash and cash equivalents	**-**	1	**-**	1
Change in cash and cash equivalents	**(84)**	(190)	**60**	(1)
Cash and cash equivalents, beginning of period	**231**	296	**87**	107
Cash and cash equivalents, end of period	**$ 147**	$ 106	**$ 147**	$ 106

Supplementary Information to Consolidated Statements of Cash Flows (Note 14)
See accompanying Notes to Interim Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Changes in Equity (Unaudited)
For the periods ended September 30
(in millions of Canadian dollars)

	Common Shares (Note 4)	Preference Shares	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Non-Controlling Interests	Total Equity
As at December 31, 2011	**$ 3,036**	**$ 912**	**$ 14**	**$ (95)**	**$ 868**	**$ 208**	**$ 4,943**
Net earnings	**-**	**-**	**-**	**-**	**262**	**7**	**269**
Other comprehensive income	**-**	**-**	**-**	**(2)**	**-**	**-**	**(2)**
Common share issues	**56**	**-**	**(1)**	**-**	**-**	**-**	**55**
Stock-based compensation	**-**	**-**	**2**	**-**	**-**	**-**	**2**
Advances from non-controlling interests	**-**	**-**	**-**	**-**	**-**	**83**	**83**
Foreign currency translation impacts	**-**	**-**	**-**	**-**	**-**	**(4)**	**(4)**
Subsidiary dividends paid to non-controlling interests	**-**	**-**	**-**	**-**	**-**	**(6)**	**(6)**
Dividends declared on common shares ($0.90 per share)	**-**	**-**	**-**	**-**	**(173)**	**-**	**(173)**
Dividends declared on preference shares	**-**	**-**	**-**	**-**	**(34)**	**-**	**(34)**
As at September 30, 2012	**$ 3,092**	**$ 912**	**$ 15**	**$ (97)**	**$ 923**	**$ 288**	**$ 5,133**
As at December 31, 2010	$ 2,575	$ 912	$ 12	$ (108)	$ 774	$ 162	$ 4,327
Net earnings	-	-	-	-	263	7	270
Other comprehensive income	-	-	-	23	-	-	23
Common share issues	395	-	(2)	-	-	-	393
Stock-based compensation	-	-	3	-	-	-	3
Advances from non-controlling interests	-	-	-	-	-	77	77
Foreign currency translation impacts	-	-	-	-	-	3	3
Subsidiary dividends paid to non-controlling interests	-	-	-	-	-	(6)	(6)
Expropriation of Belize Electricity (Notes 16, 17 and 19)	-	-	-	-	-	(38)	(38)
Dividends declared on common shares ($0.87 per share)	-	-	-	-	(159)	-	(159)
Dividends declared on preference shares	-	-	-	-	(34)	-	(34)
As at September 30, 2011	$ 2,970	$ 912	$ 13	$ (85)	$ 844	$ 205	$ 4,859

See accompanying Notes to Interim Consolidated Financial Statements

1. DESCRIPTION OF THE BUSINESS

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation assets, and commercial office and retail space and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following outlines each of the Corporation's reportable segments and is consistent with the basis of segmentation as disclosed in the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States ("US GAAP").

REGULATED UTILITIES

The Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility are as follows:

a. *Regulated Gas Utilities - Canadian:* Includes the FortisBC Energy companies, which is comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc.

b. *Regulated Electric Utilities - Canadian:* Includes FortisAlberta; FortisBC Electric; Newfoundland Power; and Other Canadian Electric Utilities, which includes Maritime Electric and FortisOntario. FortisOntario mainly includes Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company, Limited and Algoma Power Inc.

c. *Regulated Electric Utilities - Caribbean:* Includes Caribbean Utilities, in which Fortis holds an approximate 60% controlling ownership interest; three small wholly owned utilities in the Turks and Caicos Islands, which include Turks and Caicos Utilities Limited ("TCU"), acquired in August 2012, FortisTCI Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. (collectively "Fortis Turks and Caicos"); and the financial results of the Corporation's approximate 70% controlling interest in Belize Electricity up to June 20, 2011. Effective June 20, 2011, the Government of Belize ("GOB") expropriated the Corporation's investment in Belize Electricity. As a result of no longer controlling the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011 (Notes 16, 17 and 19).

NON-REGULATED - FORTIS GENERATION

Fortis Generation includes the financial results of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upstate New York. Effective July 1, 2012, the legal ownership of the six small non-regulated hydroelectric generating facilities in eastern Ontario, with a combined generating capacity of 8 megawatts ("MW"), was transferred from Fortis Properties to a limited partnership directly held by Fortis.

1. DESCRIPTION OF THE BUSINESS (cont'd)

NON-REGULATED - FORTIS PROPERTIES

Fortis Properties owns and operates 23 hotels, collectively representing more than 4,400 rooms, in eight Canadian provinces, including the acquisition of the StationPark All Suite Hotel in London, Ontario, which was acquired on October 1, 2012. Fortis Properties also owns and operates approximately 2.7 million square feet of commercial office and retail space primarily in Atlantic Canada.

CORPORATE AND OTHER

The Corporate and Other segment includes Fortis net corporate expenses and the net expenses of non-regulated FortisBC Holdings Inc. ("FHI") corporate-related activities. Also included in the Corporate and Other segment are the financial results of FHI's 30% ownership interest in CustomerWorks Limited Partnership ("CWLP") and of FHI's wholly owned subsidiary FortisBC Alternative Energy Services Inc. ("FAES"). CWLP provides billing and customer care services to utilities, municipalities and certain energy companies. The contracts between CWLP and the FortisBC Energy companies ended on December 31, 2011. FAES provides alternative energy solutions.

PENDING ACQUISITION

In February 2012 Fortis announced that it had entered into an agreement to acquire CH Energy Group, Inc. ("CH Energy Group") for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of approximately US$500 million of debt on closing. CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson Gas & Electric Corporation, is a regulated transmission and distribution utility serving approximately 300,000 electric and 75,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from the Federal Energy Regulatory Commission and the Committee on Foreign Investment in the United States in July 2012. In addition, the waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction.

The transaction remains subject to approval by the New York State Public Service Commission ("NYSPSC") and satisfaction of customary closing conditions. The application for approval of the transaction by the NYSPSC was jointly filed by Fortis and CH Energy Group in April 2012. The acquisition is expected to close by the end of the first quarter of 2013 and be immediately accretive to earnings per common share, excluding acquisition-related expenses (Notes 8 and 18).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These interim consolidated financial statements have been prepared in accordance with US GAAP for interim financial statements. As a result, these interim consolidated financial statements do not include all of the information and disclosures required in the annual consolidated financial statements and should be read in conjunction with the Corporation's 2011 annual audited consolidated financial statements prepared in accordance with US GAAP and voluntarily filed on the System for Electronic Document Analysis and Retrieval by Fortis on March 16, 2012 (the "Corporation's 2011 US GAAP annual audited consolidated financial statements"). In management's opinion, the interim consolidated financial statements include all adjustments that are of a recurring nature and necessary to present fairly the financial position of the Corporation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Because of natural gas consumption patterns, most of the annual earnings of the FortisBC Energy companies are realized in the first and fourth quarters. Given the diversified group of companies, seasonality may vary.

The preparation of financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. During the second quarter of 2012, the FortisBC Energy companies and FortisAlberta received revenue requirements decisions, effective January 1, 2012, the cumulative impacts of which, where such impacts were different from those estimated, were recorded in the second quarter of 2012. Similarly, FortisBC Electric recorded the cumulative impacts of its revenue requirements decision, effective January 1, 2012, in the third quarter of 2012 when the decision was received. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the three and nine months ended September 30, 2012, except as described further with respect to capital asset depreciation.

An evaluation of subsequent events through to October 31, 2012, the date these interim consolidated financial statements were approved by the Audit Committee of the Board of Directors, was completed to determine whether circumstances warranted recognition and disclosure of events or transactions in the interim consolidated financial statements as at September 30, 2012 (Note 21).

All amounts are presented in Canadian dollars unless otherwise stated.

These interim consolidated financial statements include the accounts of Fortis and its wholly owned subsidiaries and controlling ownership interests. All significant intercompany balances and transactions have been eliminated on consolidation.

These interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2011 US GAAP annual audited consolidated financial statements, except as described below.

Presentation of Comprehensive Income

Effective January 1, 2012, the Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income.* The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. Fortis continues to report the components of comprehensive income in a separate but consecutive statement.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Testing Goodwill for Impairment

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 350, *Goodwill.* The amended standard allows entities testing goodwill for impairment to have the option of performing a qualitative assessment before calculating the fair value of the reporting unit. If the qualitative factors indicate that the fair value of the reporting unit is more likely than not (i.e., greater than a 50% chance) to be greater than the carrying value, then the two-step impairment test, including the quantification of the fair value of the reporting unit, would not be required. In adopting the amendments, Fortis will perform a qualitative assessment before calculating the fair value of its reporting units when it performs its annual impairment test as of October 1.

Fair Value Measurement

Effective January 1, 2012, the Corporation adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amended standard improves comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with US GAAP. The amendment does not change what items are measured at fair value but instead makes various changes to the guidance pertaining to how fair value is measured. The above-noted changes did not materially impact the Corporation's interim consolidated financial statements for the three and nine months ended September 30, 2012.

New Accounting Policies

Effective January 1, 2012, the FortisBC Energy companies prospectively adopted the policy of accruing for non-asset retirement obligation ("non-ARO") removal costs in depreciation expense, as requested in their 2012-2013 Revenue Requirements Application ("RRA") and subsequently approved by the regulator in its April 2012 decision. The accrual of estimated non-ARO removal costs is included in depreciation expense and the provision balance is recognized as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. Non-ARO removal costs are direct costs incurred by the FortisBC Energy companies in taking assets out of service, whether through actual removal of the assets or through disconnection of the assets from the transmission or distribution system. Prior to 2012 estimated non-ARO removal costs, net of salvage proceeds, were recognized in operating expenses with variances between actual non-ARO removal costs and those forecasted for rate-setting purposes recorded in a regulatory deferral account for future recovery from, or refund to, customers in rates commencing in 2012. For the three and nine months ended September 30, 2012, non-ARO removal costs of approximately $5 million and $15 million, respectively, were accrued as part of depreciation expense. For the three and nine months ended September 30, 2011, non-ARO removal costs of approximately $4 million and $12 million, respectively, were recognized in operating expenses.

Prior to 2012 variances from forecast, adjusted for certain revenue and cost variances which flowed through to customers, for rate-setting purposes were shared equally between customers and FortisBC Electric. As applied for in FortisBC Electric's 2012-2013 RRA and approved by the regulator, prospectively from January 1, 2012 the above-noted sharing of positive or negative variances is no longer in effect. Beginning in 2012, variances between actual electricity revenue and purchased power costs and those forecasted in determining customer electricity rates are subject to full deferral account treatment, to be recovered from, or refunded to, customers in future rates and, therefore, do not impact net earnings in 2012. Effective January 1, 2012, however, the flow through treatment for finance charges, as was applied for in FortisBC Electric's 2012-2013 RRA, was denied by the regulator pursuant to its revenue requirements decision. As a result, a retroactive adjustment was recorded in the third quarter of 2012 to eliminate the flow through treatment. Variances between actual finance charges from those forecasted in determining customer electricity rates, therefore, have an impact on net earnings in 2012.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Effective January 1, 2012, as approved by the regulator, the FortisBC Energy companies are deferring variances between actual depreciation expense and that forecasted in determining customer gas rates.

Effective January 1, 2012, as approved by the regulator, FortisAlberta is no longer permitted to defer transmission volume variances associated with its Alberta Electric System Operator ("AESO") charges deferral account. For the three and nine months ended September 30, 2012, FortisAlberta recognized approximately \$3.5 million and \$6.5 million, respectively, of net transmission revenue as a result of this change.

Change in Estimates - Capital Asset Depreciation

Changes in regulator-approved depreciation rates at FortisAlberta and FortisBC Electric, in conjunction with approved depreciation studies and revenue requirements decisions received in 2012, have impacted consolidated depreciation expense. The composite depreciation rate for utility capital assets at FortisAlberta decreased to 4.0% for 2012 from 4.1% for 2011. FortisBC Electric's composite depreciation rate for utility capital assets decreased to 3.1% for 2012 from 3.2% for 2011. As required by the regulator, effective January 1, 2012, depreciation rates at the FortisBC Energy companies now include an amount allowed for regulatory purposes to accrue for estimated non-ARO removal costs, net of salvage proceeds. The impact of the above-noted changes in depreciation rates on depreciation expense has been reflected in the utilities' approved revenue requirements and resulting customer rates.

3. REGULATORY ASSETS AND LIABILITIES

A summary of the Corporation's regulatory assets and liabilities is provided below. A detailed description of the nature of the Corporation's regulatory assets and liabilities is provided in Note 7 to the Corporation's 2011 US GAAP annual audited consolidated financial statements.

	As at	
($ millions)	**September 30, 2012**	December 31, 2011
Regulatory assets		
Deferred income taxes	**683**	630
Employee future benefits	**406**	428
Deferred lease costs - FortisBC Electric	**81**	70
Rate stabilization accounts - electric utilities	**53**	55
Replacement energy deferral - Point Lepreau [(1)]	**47**	47
Deferred energy management costs	**43**	36
Rate stabilization accounts - FortisBC Energy companies	**31**	105
Deferred operating overhead costs	**30**	22
Customer Care Enhancement Project cost deferral	**25**	13
Deferred net losses on disposal of utility capital assets	**25**	23
Income taxes recoverable on other post-employment benefit ("OPEB") plans	**23**	22
Whistler pipeline contribution deferral	**16**	16
Pension cost variance deferral	**14**	10
Alternative energy projects cost deferral	**13**	8
Deferred development costs for capital	**10**	11
Deferred costs - smart meters	**8**	8
AESO charges deferral	**-**	44
Other regulatory assets	**83**	71
Total regulatory assets	**1,591**	1,619
Less: current portion	**(98)**	(219)
Long-term regulatory assets	**1,493**	1,400

[(1)] New Brunswick Power Point Lepreau Nuclear Generating Station

	As at	
($ millions)	**September 30, 2012**	December 31, 2011
Regulatory liabilities		
Non-ARO removal cost provision	**374**	354
Rate stabilization accounts - FortisBC Energy companies	**154**	127
Rate stabilization accounts - electric utilities	**36**	33
AESO charges deferral	**33**	12
Deferred income taxes	**15**	9
Deferred interest	**8**	10
Performance-based rate-setting incentive liabilities	**8**	7
Income tax variance deferral	**6**	12
Southern Crossing Pipeline deferral	**5**	8
Unrecognized net gains on disposal of utility capital assets	**-**	6
Other regulatory liabilities	**24**	20
Total regulatory liabilities	**663**	598
Less: current portion	**(75)**	(43)
Long-term regulatory liabilities	**588**	555

4. COMMON SHARES

Common shares issued during the period were as follows:

	Quarter Ended September 30, 2012		Year-to-Date September 30, 2012	
	Number of Shares *(in thousands)*	Amount *($ millions)*	Number of Shares *(in thousands)*	Amount *($ millions)*
Balance, beginning of period	189,967	3,071	188,828	3,036
Dividend Reinvestment Plan	460	15	1,355	43
Consumer Share Purchase Plan	8	-	32	1
Employee Share Purchase Plan	63	2	63	2
Stock Option Plans	160	4	380	10
Balance, end of period	190,658	3,092	190,658	3,092

Effective May 4, 2012, the Corporation's Board of Directors approved the 2012 Employee Share Purchase Plan (“2012 ESPP”). Under the 2012 ESPP, common shares may be issued from treasury, acquired in the open market or a combination from treasury and the open market, as determined by the Corporation. The first shares issued from treasury under the 2012 ESPP occurred in September 2012.

Subscription Receipts Offering

In June 2012, to finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18,500,000 Subscription Receipts at $32.50 each through a bought-deal offering underwritten by a syndicate of underwriters led by CIBC World Markets Inc., Scotia Capital Inc. and TD Securities Inc., realizing gross proceeds of approximately $601 million. The gross proceeds from the sale of the Subscription Receipts are being held by an escrow agent, pending satisfaction of closing conditions, including receipt of regulatory approvals, included in the agreement to acquire CH Energy Group (“Release Conditions”). The Subscription Receipts began trading on the Toronto Stock Exchange on June 27, 2012 under the symbol “FTS.R”.

Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of the Release Conditions, and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares to holders of record during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts.

If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition of CH Energy Group is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount (Note 18).

5. NON-CONTROLLING INTERESTS

	As at	
($ millions)	**September 30, 2012**	December 31, 2011
Waneta Expansion Limited Partnership ("Waneta Partnership")	**197**	128
Caribbean Utilities	**72**	73
Mount Hayes Limited Partnership (Note 18)	**12**	-
Preference shares of Newfoundland Power	**7**	7
	288	208

6. STOCK-BASED COMPENSATION PLANS

In January 2012 21,417 Deferred Share Units ("DSUs") were granted to the Corporation's Board of Directors, representing the equity component of the Directors' annual compensation and, where opted, their annual retainers in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

In March 2012 44,863 Performance Share Units ("PSUs") were paid out to the President and Chief Executive Officer ("CEO") of the Corporation at $32.40 per PSU, for a total of approximately $1.5 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2009 and the President and CEO satisfying the payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

In May 2012 62,000 PSUs were granted to the President and CEO of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation. The maturation period of the May 2012 PSU grant is three years, at which time a cash payment may be made to the President and CEO after evaluation by the Human Resources Committee of the Board of Directors of the achievement of payment requirements.

In May 2012 the 2012 Stock Option Plan ("2012 Plan") was approved at the Annual General Meeting of the Corporation's shareholders. The 2012 Plan will ultimately replace the 2002 Stock Option Plan ("2002 Plan") and the 2006 Stock Option Plan ("2006 Plan"). The 2002 Plan and 2006 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 Plan and 2006 Plan and all new options granted after 2011 will be made under the 2012 Plan.

In May 2012 the Corporation granted 789,220 options to purchase common shares under its 2012 Plan at the five-day volume weighted average trading price immediately preceding the date of grant of $34.27. The options vest evenly over a four-year period on each anniversary of the date of grant. The options expire 10 years after the date of grant. The fair value of each option granted was $4.21 per option.

The fair value was estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

Dividend yield (%)	3.67
Expected volatility (%)	22.2
Risk-free interest rate (%)	1.50
Weighted average expected life (years)	5.3

For the three and nine months ended September 30, 2012, stock-based compensation expense of approximately $2 million and $5 million, respectively, was recognized ($2 million and $5 million for the three and nine months ended September 30, 2011, respectively).

7. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans and defined contribution pension plans, including group registered retirement savings plans, for employees. The Corporation and certain subsidiaries also offer OPEB plans for qualifying employees. The net benefit cost of providing the defined benefit pension and OPEB plans is detailed in the following tables.

	Quarter Ended September 30			
	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2012**	2011	**2012**	2011
Components of net benefit cost:				
Service costs	**6**	5	**2**	1
Interest costs	**12**	12	**2**	3
Expected return on plan assets	**(12)**	(12)	**-**	-
Amortization of actuarial losses	**6**	5	**2**	1
Amortization of past service costs/plan amendments	**-**	-	**-**	(1)
Regulatory adjustments	**(2)**	(2)	**-**	1
Net benefit cost	**10**	8	**6**	5

	Year-to-Date September 30			
	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2012**	2011	**2012**	2011
Components of net benefit cost:				
Service costs	**20**	15	**5**	3
Interest costs	**35**	36	**8**	9
Expected return on plan assets	**(37)**	(36)	**-**	-
Amortization of actuarial losses	**19**	15	**4**	3
Amortization of past service costs/plan amendments	**-**	-	**(2)**	(3)
Amortization of transitional obligation	**1**	-	**1**	-
Regulatory adjustments	**(8)**	(6)	**1**	3
Net benefit cost	**30**	24	**17**	15

For the three and nine months ended September 30, 2012, the Corporation expensed $3 million and $10 million, respectively ($3 million and $11 million for the three and nine months ended September 30, 2011, respectively) related to defined contribution pension plans.

8. OTHER INCOME (EXPENSES), NET

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions)	**2012**	2011	**2012**	2011
Interest income	**2**	2	**4**	4
Equity component of allowance for funds used during construction	**1**	2	**4**	10
Foreign exchange (loss) gain	**(2)**	1	**(2)**	1
Acquisition-related expenses	**-**	-	**(8)**	-
Merger termination fee	**-**	17	**-**	17
Other income, net of expenses	**-**	-	**-**	2
	1	22	**(2)**	34

The foreign exchange loss for the three and nine months ended September 30, 2012 included approximately $3 million and $2.5 million, respectively, related to the translation of the Corporation's US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity (Notes 17 and 19).

8. OTHER INCOME (EXPENSES), NET (cont'd)

The foreign exchange gain for the three and nine months ended September 30, 2011 included a foreign exchange gain of $7 million associated with the translation of the above-noted US dollar-denominated long-term other asset, which was partially offset by a $5.5 million ($4.5 million after tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated long-term debt.

The acquisition-related expenses are associated with the pending acquisition of CH Energy Group (Notes 1 and 18).

The termination fee was paid to Fortis in July 2011 following the termination of a Merger Agreement between Fortis and Central Vermont Public Service Corporation.

9. FINANCE CHARGES

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions)	**2012**	2011	**2012**	2011
Interest:				
Long-term debt and finance and capital lease obligations	**95**	91	**282**	275
Short-term borrowings and other finance charges	**3**	1	**6**	10
Debt component of allowance for funds used during construction	**(5)**	(3)	**(12)**	(11)
	93	89	**276**	274

10. INCOME TAXES

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory income taxes to consolidated effective income taxes.

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions, except as noted)	**2012**	2011	**2012**	2011
Combined Canadian federal and provincial statutory income tax rate	**29.0%**	30.5%	**29.0%**	30.5%
Statutory income tax rate applied to earnings before income taxes	**19**	25	**91**	100
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(3)**	(4)	**(10)**	(9)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(1)**	(1)	**(9)**	(9)
Items capitalized for accounting purposes but expensed for income tax purposes	**(11)**	(11)	**(39)**	(39)
Difference between capital cost allowance and amounts claimed for accounting purposes	**3**	5	**7**	11
Non-deductible expenses	**2**	2	**5**	3
Part VI.1 tax - difference between enacted and substantively enacted tax rates and the effect of statute-barred reversals	**(1)**	-	**2**	2
Difference between employee future benefits paid and amounts expensed for accounting purposes	**-**	(1)	**1**	(1)
Other	**(1)**	(3)	**(4)**	1
Income taxes	**7**	12	**44**	59
Effective income tax rate	**10.6%**	14.6%	**14.1%**	17.9%

As at September 30, 2012, the Corporation had approximately $100 million (December 31, 2011 - $86 million) in non-capital and capital loss carryforwards, of which $8 million (December 31, 2011 - $13 million) has not been recognized in the consolidated financial statements. The non-capital loss carryforwards expire between 2014 and 2032.

11. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. Diluted EPS is calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

EPS were as follows:

	Quarter Ended September 30					
	2012			2011		
	Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**45**	**190.2**	**$ 0.24**	56	186.5	$ 0.30
Effect of potential dilutive securities:						
Stock Options	**-**	**0.9**		-	1.0	
Preference Shares	**4**	**10.3**		4	10.1	
Convertible Debentures	**-**	**-**		1	1.4	
	49	**201.4**		61	199.0	
Deduct anti-dilutive impacts:						
Preference Shares	**(4)**	**(10.3)**		(4)	(10.1)	
Convertible Debentures	**-**	**-**		(1)	(1.4)	
Diluted EPS	**45**	**191.1**	**$ 0.24**	56	187.5	$ 0.30

	Year-to-Date September 30					
	2012			2011		
	Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares *(in millions)***	**EPS**	Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(in millions)*	EPS
Basic EPS	**228**	**189.6**	**$ 1.20**	229	179.5	$ 1.28
Effect of potential dilutive securities:						
Stock Options	**-**	**0.9**		-	1.0	
Preference Shares	**12**	**10.3**		12	10.1	
Convertible Debentures	**-**	**-**		2	1.4	
	240	**200.8**		243	192.0	
Deduct anti-dilutive impacts:						
Preference Shares	**(5)**	**(3.9)**		(5)	(3.9)	
Diluted EPS	**235**	**196.9**	**$ 1.19**	238	188.1	$ 1.27

12. BUSINESS ACQUISITIONS

In April 2012 FortisOntario exercised its option, under the terms of a 10-year operating lease agreement with the City of Port Colborne that commenced in April 2002, to purchase the remaining assets of Port Colborne Hydro for approximately $7 million. Under the lease arrangement with the City of Port Colborne, and now through ownership of the previously leased assets, FortisOntario operates and maintains the City of Port Colborne's electricity distribution system for provision of electricity service to the residents of Port Colborne. Throughout the 10-year lease term, FortisOntario incurred approximately $17 million in capital expenditures in Port Colborne Hydro's electricity distribution system. The exercise of the purchase option, which qualifies as a business combination, provides ownership and legal title to all of the assets, including equipment, real property and distribution assets, which constitute the entire distribution system in Port Colborne. The purchase was approved by the Ontario Energy Board.

12. BUSINESS ACQUISITIONS (cont'd)

FortisOntario is regulated under traditional cost of service and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, fair market value approximates book value and no adjustments were recorded for the assets acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, $3 million of the purchase price was allocated to utility capital assets and $4 million was recognized as goodwill in the preliminary purchase price allocation.

In August 2012 Fortis Turks and Caicos acquired TCU for an aggregate purchase price of approximately $13 million (US$13 million), inclusive of debt assumed of $5 million (US$5 million). TCU is a regulated electric utility operating pursuant to a 50-year licence expiring in 2036. The utility serves more than 2,000 residential and commercial customers between Grand Turk and Salt Cay with a diesel-fired generating capacity of 9 MW. Fortis Turks and Caicos is regulated under traditional cost of service and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, fair market value approximates book value and no adjustments were recorded for the net assets acquired, because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, approximately $9 million of the purchase price was allocated to utility capital assets, $3 million to current net assets, $5 million to long-term debt and $1 million was recognized as goodwill in the preliminary purchase price allocation.

13. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Quarter Ended September 30, 2012 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**192**	117	71	100	91	**379**	**72**	**8**	**65**	**5**	**(7)**	**714**
Energy supply costs	**61**	-	16	54	59	**129**	**45**	**-**	**-**	**-**	**-**	**235**
Operating expenses	**64**	40	20	17	11	**88**	**7**	**2**	**42**	**2**	**(2)**	**203**
Depreciation and amortization	**40**	34	12	11	7	**64**	**8**	**1**	**5**	**-**	**-**	**118**
Operating income	**27**	43	23	18	14	**98**	**12**	**5**	**18**	**3**	**(5)**	**158**
Other income (expenses), net	**1**	-	1	1	-	**2**	**1**	**-**	**-**	**(3)**	**-**	**1**
Finance charges	**36**	17	9	9	5	**40**	**3**	**-**	**6**	**13**	**(5)**	**93**
Income tax (recovery) expense	**(2)**	-	2	1	3	**6**	**-**	**-**	**4**	**(1)**	**-**	**7**
Net (loss) earnings	**(6)**	26	13	9	6	**54**	**10**	**5**	**8**	**(12)**	**-**	**59**
Non-controlling interests	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**11**	**-**	**11**
Net (loss) earnings attributable to common equity shareholders	**(6)**	26	13	9	6	**54**	**7**	**5**	**8**	**(23)**	**-**	**45**
Goodwill	**913**	227	221	-	67	**515**	**138**	**-**	**-**	**-**	**-**	**1,566**
Identifiable assets	**4,503**	2,617	1,686	1,244	705	**6,252**	**735**	**686**	**623**	**498**	**(425)**	**12,872**
Total assets	**5,416**	2,844	1,907	1,244	772	**6,767**	**873**	**686**	**623**	**498**	**(425)**	**14,438**
Gross capital expenditures [(1)]	**66**	104	19	22	13	**158**	**11**	**39**	**9**	**-**	**-**	**283**

Quarter Ended September 30, 2011 *($ millions)*												
Revenue	**197**	103	67	101	87	**358**	**74**	**11**	**63**	**4**	**(8)**	**699**
Energy supply costs	**76**	-	15	52	56	**123**	**47**	**-**	**-**	**-**	**-**	**246**
Operating expenses	**65**	35	19	17	11	**82**	**9**	**2**	**40**	**4**	**(2)**	**200**
Depreciation and amortization	**29**	34	11	11	6	**62**	**7**	**1**	**5**	**-**	**-**	**104**
Operating income	**27**	34	22	21	14	**91**	**11**	**8**	**18**	**-**	**(6)**	**149**
Other income (expenses), net	**2**	-	-	-	-	**-**	**-**	**-**	**-**	**20**	**-**	**22**
Finance charges	**36**	15	10	9	5	**39**	**2**	**-**	**6**	**12**	**(6)**	**89**
Income tax (recovery) expense	**(3)**	-	2	4	3	**9**	**-**	**-**	**3**	**3**	**-**	**12**
Net (loss) earnings	**(4)**	19	10	8	6	**43**	**9**	**8**	**9**	**5**	**-**	**70**
Non-controlling interests	**-**	-	-	-	-	**-**	**3**	**-**	**-**	**-**	**-**	**3**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**11**	**-**	**11**
Net (loss) earnings attributable to common equity shareholders	**(4)**	19	10	8	6	**43**	**6**	**8**	**9**	**(6)**	**-**	**56**
Goodwill	**913**	227	221	-	63	**511**	**144**	**-**	**-**	**-**	**-**	**1,568**
Identifiable assets	**4,364**	2,345	1,626	1,232	670	**5,873**	**742**	**539**	**589**	**507**	**(434)**	**12,180**
Total assets	**5,277**	2,572	1,847	1,232	733	**6,384**	**886**	**539**	**589**	**507**	**(434)**	**13,748**
Gross capital expenditures [(1)]	**64**	82	25	24	14	**145**	**17**	**49**	**11**	**-**	**-**	**286**

[(1)] Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statements of cash flows

13. SEGMENTED INFORMATION (cont'd)

	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
Year-to-Date September 30, 2012 *($ millions)*	**FortisBC Energy Companies - Canadian**	Fortis Alberta	FortisBC Electric	Newfoundland Power	Other Canadian	**Total Electric Canadian**	**Electric Caribbean**	**Fortis Generation**	**Fortis Properties**	**Corporate and Other**	**Inter-segment eliminations**	**Consolidated**
Revenue	**1,004**	335	225	422	264	**1,246**	**202**	**26**	**181**	**18**	**(22)**	**2,655**
Energy supply costs	**472**	-	54	274	168	**496**	**124**	**1**	**-**	**-**	**(1)**	**1,092**
Operating expenses	**197**	116	62	54	35	**267**	**24**	**6**	**124**	**8**	**(5)**	**621**
Depreciation and amortization	**120**	99	36	33	20	**188**	**24**	**3**	**15**	**1**	**-**	**351**
Operating income	**215**	120	73	61	41	**295**	**30**	**16**	**42**	**9**	**(16)**	**591**
Other income (expenses), net	**2**	2	1	2	-	**5**	**2**	**1**	**-**	**(11)**	**(1)**	**(2)**
Finance charges	**107**	49	29	27	16	**121**	**10**	**1**	**18**	**36**	**(17)**	**276**
Income tax expense (recovery)	**20**	-	7	8	7	**22**	**-**	**1**	**7**	**(6)**	**-**	**44**
Net earnings (loss)	**90**	73	38	28	18	**157**	**22**	**15**	**17**	**(32)**	**-**	**269**
Non-controlling interests	**1**	-	-	-	-	**-**	**6**	**-**	**-**	**-**	**-**	**7**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**34**	**-**	**34**
Net earnings (loss) attributable to common equity shareholders	**89**	73	38	28	18	**157**	**16**	**15**	**17**	**(66)**	**-**	**228**
Goodwill	**913**	227	221	-	67	**515**	**138**	**-**	**-**	**-**	**-**	**1,566**
Identifiable assets	**4,503**	2,617	1,686	1,244	705	**6,252**	**735**	**686**	**623**	**498**	**(425)**	**12,872**
Total assets	**5,416**	2,844	1,907	1,244	772	**6,767**	**873**	**686**	**623**	**498**	**(425)**	**14,438**
Gross capital expenditures [(1)]	**144**	304	52	58	35	**449**	**33**	**144**	**24**	**-**	**-**	**794**
Year-to-Date September 30, 2011 *($ millions)*												
Revenue	**1,090**	306	215	417	256	**1,194**	**234**	**25**	**173**	**17**	**(29)**	**2,704**
Energy supply costs	**590**	-	49	266	163	**478**	**146**	**1**	**-**	**-**	**(8)**	**1,207**
Operating expenses	**209**	106	58	54	34	**252**	**31**	**6**	**117**	**9**	**(5)**	**619**
Depreciation and amortization	**83**	100	34	32	18	**184**	**24**	**3**	**14**	**1**	**-**	**309**
Operating income	**208**	100	74	65	41	**280**	**33**	**15**	**42**	**7**	**(16)**	**569**
Other income (expenses), net	**8**	3	1	-	-	**4**	**2**	**1**	**-**	**20**	**(1)**	**34**
Finance charges	**106**	44	29	27	16	**116**	**11**	**2**	**18**	**38**	**(17)**	**274**
Income tax expense (recovery)	**24**	1	8	14	7	**30**	**1**	**1**	**6**	**(3)**	**-**	**59**
Net earnings (loss)	**86**	58	38	24	18	**138**	**23**	**13**	**18**	**(8)**	**-**	**270**
Non-controlling interests	**-**	-	-	-	-	**-**	**7**	**-**	**-**	**-**	**-**	**7**
Preference share dividends	**-**	-	-	-	-	**-**	**-**	**-**	**-**	**34**	**-**	**34**
Net earnings (loss) attributable to common equity shareholders	**86**	58	38	24	18	**138**	**16**	**13**	**18**	**(42)**	**-**	**229**
Goodwill	**913**	227	221	-	63	**511**	**144**	**-**	**-**	**-**	**-**	**1,568**
Identifiable assets	**4,364**	2,345	1,626	1,232	670	**5,873**	**742**	**539**	**589**	**507**	**(434)**	**12,180**
Total assets	**5,277**	2,572	1,847	1,232	733	**6,384**	**886**	**539**	**589**	**507**	**(434)**	**13,748**
Gross capital expenditures [(1)]	**177**	253	78	55	33	**419**	**57**	**131**	**20**	**-**	**-**	**804**

[(1)] Relates to cash payments to acquire or construct utility capital assets, including amounts for AESO transmission-related capital projects, income producing properties and intangible assets, as reflected on the consolidated statements of cash flows

13. SEGMENTED INFORMATION (cont'd)

Related party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant related party inter-segment transactions primarily related to: (i) the sale of energy from Fortis Generation to Belize Electricity, up to June 20, 2011; (ii) electricity sales from Newfoundland Power to Fortis Properties; and (iii) finance charges on related party borrowings. The significant related party inter-segment transactions for the three and nine months ended September 30, 2012 and 2011 were as follows:

Significant Inter-Segment Transactions	**Quarter Ended September 30**		**Year-to-Date September 30**	
($ millions)	**2012**	2011	**2012**	2011
Sales from Fortis Generation to Regulated Electric Utilities - Caribbean	**-**	-	**-**	7
Sales from Fortis Generation to Other Canadian Electric Utilities	**-**	-	**-**	1
Sales from Newfoundland Power to Fortis Properties	**1**	1	**4**	3
Inter-segment finance charges on lending from:				
Fortis Generation to Other Canadian Electric Utilities	**-**	-	**1**	1
Corporate to Regulated Electric Utilities - Canadian	**-**	1	**-**	2
Corporate to Regulated Electric Utilities - Caribbean	**1**	1	**3**	3
Corporate to Fortis Generation	**-**	1	**1**	2
Corporate to Fortis Properties	**4**	3	**12**	9

The significant inter-segment asset balances were as follows:

	As at September 30	
($ millions)	**2012**	2011
Inter-segment lending from:		
Fortis Generation to Other Canadian Electric Utilities	**20**	20
Corporate to Regulated Electric Utilities - Canadian	**-**	50
Corporate to Regulated Electric Utilities - Caribbean	**84**	78
Corporate to Fortis Generation	**12**	32
Corporate to Fortis Properties	**284**	226
Other inter-segment assets	**25**	28
Total inter-segment eliminations	**425**	434

14. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	Quarter Ended September 30		**Year-to-Date September 30**	
($ millions)	**2012**	2011	**2012**	2011
Cash paid for:				
Interest	**84**	79	**269**	260
Income taxes	**12**	16	**63**	61
Change in non-cash operating working capital:				
Accounts receivable	**96**	115	**224**	184
Prepaid expenses	**(8)**	(8)	**(14)**	(15)
Inventories	**(48)**	(84)	**(21)**	(28)
Regulatory assets - current portion	**2**	(15)	**50**	(21)
Accounts payable and other current liabilities	**28**	4	**(39)**	(34)
Regulatory liabilities - current portion	**(13)**	(14)	**19**	18
	57	(2)	**219**	104
Non-cash investing and financing activities:				
Common share dividends reinvested	**15**	16	**43**	47
Exercise of stock options into common shares	**-**	-	**1**	2

15. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges. As at September 30, 2012, the Corporation's derivative contracts consisted of fuel option contracts, natural gas swap and option contracts, and gas purchase contract premiums. The fuel option contracts are held by Caribbean Utilities and the remaining derivative instruments are held by the FortisBC Energy companies.

Volume of Derivative Activity

As at September 30, 2012, the following notional volumes related to fuel option contracts and natural gas derivatives that are expected to be settled are outlined below.

	2012	2013	2014
Fuel option contracts *(millions of imperial gallons)*	4	3	-
Gas swaps and options *(petajoules)*	4	26	6
Gas purchase contract premiums *(petajoules)*	94	17	1

Presentation of Derivative Instruments in the Consolidated Financial Statements

In the Corporation's consolidated balance sheets, derivative instruments are presented on a net basis by counterparty, where the right of offset exists.

The Corporation's outstanding derivative balances were as follows:

	As at	
($ millions)	**September 30, 2012**	December 31, 2011
Gross derivatives balance [(1)]	**59**	136
Netting [(2)]	**-**	-
Cash collateral	**-**	-
Total derivative balances [(3)]	**59**	136

(1) Refer to Note 16 for a discussion of the valuation techniques used to calculate the fair value of the derivative instruments.
(2) Positions, by counterparty, are netted where the intent and legal right to offset exists.
(3) Unrealized losses of $34 million on commodity risk-related derivative instruments as at September 30, 2012 were recognized in current regulatory assets and $25 million were recognized as an offset to current regulatory liabilities (December 31, 2011 - $136 million recognized in current regulatory assets), which would otherwise be recognized on the consolidated statement of comprehensive income and in accumulated other comprehensive loss. These amounts exclude the impact of cash collateral postings.

Cash flows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's consolidated statements of cash flows.

The majority of the FortisBC Energy companies' risk-related derivative instruments contain collateral posting provisions tied to FEI's credit rating. A downgrade of FEI below investment grade by any of the major credit rating agencies could trigger margin calls and other cash requirements under FEI's gas purchase and swap and option contracts. Most of the existing natural gas derivative contracts are in liability positions and might be subject to margin calls and other cash requirements if FEI was downgraded below investment grade.

16. FAIR VALUE MEASUREMENTS

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except for those which qualify for the normal purchase and normal sale exception.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets
Level 2: Fair value determined using pricing inputs that are observable
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available

The fair values of the Corporation's financial instruments, including derivatives, reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows.

The following table details the estimated fair value measurements of the Corporation's financial instruments, all of which were measured using Level 2 inputs, except for certain long-term debt as noted.

	As at			
Asset (Liability)	**September 30, 2012**		December 31, 2011	
	Carrying	**Estimated**	Carrying	Estimated
($ millions)	**Value**	**Fair Value**	Value	Fair Value
Other asset - Belize Electricity [1]	**103**	**-** [2]	106	- [2]
Long-term debt, including current portion [3]	**(5,937)**	**(7,476)**	(5,788)	(7,172)
Waneta Partnership promissory note [4]	**(46)**	**(52)**	(45)	(49)
Foreign exchange forward contract [5]	**-**	**-**	-	-
Fuel option contracts [5]	**-**	**-**	(1)	(1)
Natural gas derivatives: [5]				
Swaps and options	**(60)**	**(60)**	(135)	(135)
Gas purchase contract premiums	**1**	**1**	-	-

(1) Included in long-term other assets on the consolidated balance sheet

(2) The fair value of the Corporation's expropriated investment in Belize Electricity determined under the GOB's valuation is significantly lower than the fair value determined under the Corporation's independent valuation of the utility. Due to uncertainty in the ultimate amount and ability of the GOB to pay appropriate fair value compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the long-term other asset at the carrying value of the Corporation's previous investment in Belize Electricity, including foreign exchange impacts (Notes 17 and 19).

(3) The Corporation's $200 million unsecured debentures due 2039 and consolidated credit facilities classified as long-term are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.

(4) Included in long-term other liabilities on the consolidated balance sheet

(5) The fair values of the derivatives were recorded in accounts payable and other current liabilities as at September 30, 2012 and December 31, 2011. The fair value of the fuel option contracts as at September 30, 2012 were less than $1 million. The foreign exchange forward contract held by FEI expired in April 2012. The fair value of the contract was less than $1 million as at December 31, 2011.

16. FAIR VALUE MEASUREMENTS (cont'd)

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The fuel option contracts are used by Caribbean Utilities to reduce the impact of volatility in fuel prices on customer rates, as approved by the regulator under the Company's Fuel Price Volatility Management Program. The fair value of the fuel option contracts reflects only the value of the heating oil derivative and not the offsetting change in the value of the underlying future purchases of heating oil and is calculated using published market prices for heating oil. The fuel option contracts mature in March 2013. In October 2012 Caribbean Utilities executed additional fuel option contracts covering the period from November 1, 2012 to October 31, 2013. With the execution of these new contracts, approximately 70% of the Company's annual diesel fuel requirements are under fuel hedging arrangements.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the FortisBC Energy companies have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the fuel option contracts and natural gas derivatives were estimates of the amounts that the utilities would have to receive or pay to terminate the outstanding contracts as at the balance sheet dates. As at September 30, 2012, none of the fuel option contracts or natural gas derivatives were designated as hedges of fuel purchases or natural gas supply contracts. However, any gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators.

17. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit Risk	Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity Risk	Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market Risk	Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and other long-term receivables, the Corporation's credit risk is limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

17. FINANCIAL RISK MANAGEMENT (cont'd)

Credit Risk (cont'd)

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at September 30, 2012, the utility's gross credit risk exposure was approximately $57 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to less than $1 million by obtaining from the retailers an acceptable form of prudential, which includes either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The FortisBC Energy companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. To help mitigate credit risk, the FortisBC Energy companies deal with reasonable credit-quality institutions in accordance with established credit-approval practices. The FortisBC Energy companies do not expect any counterparties to fail to meet their obligations. The counterparties with which the FortisBC Energy companies have significant derivative transactions are A-rated entities or better. The Company uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

The following table summarizes the FortisBC Energy companies' net credit risk exposure to its counterparties, as well as credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as it relates to its natural gas swaps and options.

	As at	
($ millions, except for number of customers)	**September 30, 2012**	December 31, 2011
Gross credit exposure before credit collateral [(1)]	**60**	136
Credit collateral	**-**	-
Net credit exposure [(2)]	**60**	136
Number of counterparties > 10%	**4**	4
Net exposure to counterparties > 10%	**53**	104

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported do not include adjustments for time value or liquidity.

(2) Net credit exposure is the gross credit exposure collateral minus credit collateral (cash deposits and letters of credit).

The Corporation is exposed to credit risk associated with the amount and timing of fair value compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. As at September 30, 2012, the Corporation had a long-term other asset of $103 million (December 31, 2011 - $106 million; September 30, 2011 - $103 million), including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 16 and 19).

Additionally, as at September 30, 2012, Belize Electricity owed Belize Electric Company Limited ("BECOL") approximately US$10 million for energy purchases of which US$6 million was overdue. In accordance with long-standing agreements, the GOB guarantees the payment of Belize Electricity's obligations to BECOL.

17. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's committed credit facility is available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at September 30, 2012, average annual consolidated long-term debt maturities and repayments over the next five years are expected to be approximately $295 million. The combination of available credit facilities and relatively low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at September 30, 2012, the Corporation and its subsidiaries had consolidated credit facilities of approximately $2.5 billion, of which $2.0 billion was unused. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $2.3 billion of the total credit facilities are committed credit facilities with maturities ranging from 2013 to 2017.

The following table outlines the credit facilities of the Corporation and its subsidiaries.

				As at	
($ millions)	Regulated Utilities	Fortis Properties	Corporate and Other	**September 30, 2012**	December 31, 2011
Total credit facilities	1,401	13	1,045	**2,459**	2,248
Credit facilities utilized:					
Short-term borrowings *(1)*	(97)	-	-	**(97)**	(159)
Long-term debt *(2)*	(63)	-	(236)	**(299)**	(74)
Letters of credit outstanding	(67)	-	(1)	**(68)**	(66)
Credit facilities unused	1,174	13	808	**1,995**	1,949

(1) The weighted average interest rate on short-term borrowings was approximately 2.2% as at September 30, 2012 (December 31, 2011 - 1.9%).

(2) As at September 30, 2012, credit facility borrowings classified as long term included $20 million (December 31, 2011 - $16 million) that was included in current installments of long-term debt on the consolidated balance sheet. The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 2.2% as at September 30, 2012 (December 31, 2011 - 2.2%).

As at September 30, 2012 and December 31, 2011, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

In March 2012 Newfoundland Power renegotiated and amended its $100 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility from August 2015 to August 2017. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

17. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk (cont'd)

In April 2012 FortisBC Electric renegotiated and amended its credit facility agreement resulting in an extension to the maturity of the Company's $150 million unsecured committed revolving credit facility with $100 million now maturing in May 2015 and $50 million now maturing in May 2013.

In May 2012 FHI extended its $30 million operating credit facility to mature in May 2013 from May 2012. The new agreement contains substantially similar terms and conditions as the previous credit facility agreement.

In May 2012 Fortis increased the amount available for borrowing under its unsecured committed revolving corporate credit facility from $800 million to $1 billion, as permitted under the credit facility agreement.

In May 2012 Caribbean Utilities renegotiated and increased the amount available for borrowing under its unsecured credit facilities to US$47 million from US$33 million.

In June 2012 FortisOntario entered into a new short-term credit facility agreement for $30 million, replacing two short-term credit facilities totaling $20 million. The new credit facility agreement reflects a decrease in pricing and improved terms and conditions. In July 2012 the former credit facilities were terminated.

In July 2012 FEI entered into a one-year extension of its $500 million unsecured committed revolving credit facility, extending the maturity date from August 2013 to August 2014. The amended credit facility agreement reflects an increase in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

In July 2012 FortisAlberta renegotiated and amended its $250 million unsecured committed revolving credit facility, obtaining an extension to the maturity of the facility from September 2015 to August 2016. The amended credit facility agreement reflects a decrease in pricing but, otherwise, contains substantially similar terms and conditions as the previous credit facility agreement.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at September 30, 2012, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A- (long-term corporate and unsecured debt credit rating)
DBRS	A (low) (unsecured debt credit rating)

In May 2012 and July 2012, S&P and DBRS, respectively, affirmed the Corporation's debt credit ratings. Due to the Corporation's financing plans for the pending acquisition of CH Energy Group and the expected completion of the Waneta Expansion hydroelectric generating facility on time and on budget, S&P and DBRS also removed the ratings from credit watch with negative implications and under review with developing implications, respectively, where the ratings had been placed in February 2012.

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level, the Corporation's reasonable credit metrics and its demonstrated ability and continued focus on acquiring and integrating stable regulated utility businesses financed on a conservative basis.

17. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk

Foreign Exchange Risk
The Corporation's earnings from, and net investment in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above-noted exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars. The reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. Belize Electricity's financial results were denominated in Belizean dollars, which are pegged to the US dollar.

As at September 30, 2012, the Corporation's corporately issued US$557 million (December 31, 2011 – US$550 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at September 30, 2012, the Corporation had approximately US$19 million (December 31, 2011 – US$6 million) in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar borrowings designated as effective hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded in other comprehensive income.

Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, during 2011, a portion of corporately issued debt that previously hedged the former investment in Belize Electricity was no longer an effective hedge. Effective from June 20, 2011, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity and the corporately issued US dollar-denominated debt that previously qualified as a hedge of the investment were recognized in earnings. The Corporation has recognized in earnings foreign exchange losses of approximately $3 million and $2.5 million during the three and nine months ended September 30, 2012, respectively. During the third quarter of 2011, a foreign exchange gain of $7 million associated with the translation of the above-noted US dollar-denominated long-term other asset was partially offset by a $5.5 million ($4.5 million after tax) foreign exchange loss associated with the translation of previously hedged US dollar-denominated long-term debt, resulting in a net foreign exchange gain of approximately $2.5 million after tax.

FEI's US dollar payments under a contract for the implementation of a customer care information system were exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI had entered into a foreign exchange forward contract to hedge this exposure. FEI had regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. FEI's foreign exchange forward contract expired in April 2012.

Interest Rate Risk
The Corporation and most of its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and the subsidiaries may enter into interest rate swap agreements to help reduce this risk.

17. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk (cont'd)

Commodity Price Risk
The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas and Caribbean Utilities is exposed to commodity price risk associated with changes in the market price for fuel (Note 16). The risks have been reduced by entering into natural gas derivatives and fuel option contracts that effectively fix the price of natural gas purchases and fuel purchases, respectively. The natural gas derivatives and fuel option contracts are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

The price risk-management strategy of the FortisBC Energy companies aims to improve the likelihood that natural gas prices remain competitive, to mitigate gas price volatility on customer rates and to reduce the risk of regional price discrepancies. As directed by the regulator in 2011, the FortisBC Energy companies have suspended their commodity hedging activities with the exception of certain limited swaps as permitted by the regulator. The existing hedging contracts will continue in effect through to their maturity and the FortisBC Energy companies' ability to fully recover the commodity cost of gas in customer rates remains unchanged. Any differences between the cost of natural gas purchased and the price of natural gas included in customer rates are recorded as regulatory deferrals and are recovered from, or refunded to, customers in future rates, subject to regulatory approval.

18. COMMITMENTS

There were no material changes in the nature and amount of the Corporation's commitments from the commitments disclosed in the Corporation's 2011 US GAAP annual audited consolidated financial statements, except as described as follows.

(a) Pending Acquisitions

In February 2012 Fortis entered into an agreement to acquire CH Energy Group for US$1.5 billion, including the assumption of approximately US$500 million in debt on closing. The transaction received CH Energy Group shareholder approval in June 2012 and regulatory approval from the Federal Energy Regulatory Commission and the Committee on Foreign Investment in the United States in July 2012. In addition, the waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976* expired in October 2012, satisfying another condition necessary for consummation of the transaction. The transaction remains subject to approval by the NYSPSC and satisfaction of customary closing conditions. The application for approval of the transaction by the NYSPSC was jointly filed by Fortis and CH Energy Group in April 2012 (Note 1). The acquisition is expected to close by the end of the first quarter of 2013 and be immediately accretive to earnings per common share, excluding acquisition-related expenses.

The agreement and plan of merger may be terminated by the Corporation or CH Energy Group at any time prior to closing in certain circumstances, including if the acquisition has not closed by February 20, 2013, provided, however, that if the only unsatisfied conditions to closing are the obtaining of the regulatory approvals as defined in the agreement and plan of merger, then such date shall be extended to August 20, 2013.

18. COMMITMENTS (cont'd)

FortisBC Electric has offered to purchase the City of Kelowna's electrical utility assets, which currently serve approximately 15,000 customers, for approximately $55 million. FortisBC Electric provides the City of Kelowna with electricity under a wholesale tariff and has operated and maintained the City of Kelowna's electrical utility assets since 2000. Closing of the transaction is subject to certain conditions and receipt of certain approvals, including regulatory approval. The parties are working towards closing the transaction by the end of the first quarter of 2013.

(b) Subscription Receipts Offering

In June 2012, to finance a portion of the pending acquisition of CH Energy Group, Fortis sold 18,500,000 Subscription Receipts at $32.50 each, realizing gross proceeds of approximately $601 million. Each Subscription Receipt will entitle the holder thereof to receive, on satisfaction of Release Conditions and without payment of additional consideration, one common share of Fortis and a cash payment equal to the dividends declared on Fortis common shares to holders of record during the period from June 27, 2012 to the date of issuance of the common shares in respect of the Subscription Receipts. If the Release Conditions are not satisfied by June 30, 2013, or if the agreement and plan of merger relating to the acquisition is terminated prior to such time, holders of Subscription Receipts shall be entitled to receive from the escrow agent an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned on such amount (Note 4).

(c) Other

In January 2012 two First Nations bands each invested approximately $6 million in equity in the Mount Hayes liquefied natural gas storage facility, representing a 15% equity interest in the Mount Hayes Limited Partnership, with FEVI holding the controlling 85% ownership interest (Note 5). The non-controlling interests hold put options, which, if exercised, would require FEVI to repurchase the 15% ownership interest for cash, in accordance with the terms of the partnership agreement.

In April 2012 the December 31, 2011 actuarial valuation of the defined benefit pension plan at Newfoundland Power was completed. As a result Newfoundland Power is required to fund a solvency deficiency of approximately $53 million, including interest, over five years beginning in 2012. The Company fulfilled its 2012 annual solvency deficit funding requirement during the second quarter of 2012. The increase in funding contributions is expected to be recovered from customers in future rates.

In September 2012 Caribbean Utilities entered into primary and secondary fuel supply contracts with two different suppliers and is committed to purchasing approximately 60% and 40% of the Company's diesel fuel requirements under each of the contracts, respectively, for the operation of Caribbean Utilities' diesel-powered generating plant. The approximate combined quantities under the contracts, expressed in millions of imperial gallons, on an annual basis by fiscal year are: 2012 - 10.8, 2013 - 32.4 and 2014 - 18.9. The contracts expire in July 2014 with the option to renew for two additional 18-month terms. The renewal options can be exercised only within six months of the expiry dates of the existing contracts.

19. EXPROPRIATED ASSETS

Belize Electricity

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. Consequent to the deprivation of control over the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment in the utility as a long-term other asset on the consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to the challenge of the legality of the expropriation of the Corporation's investment in Belize Electricity. Fortis commissioned an independent valuation of its expropriated investment in Belize Electricity and submitted its claim for compensation to the GOB in November 2011. The book value of the long-term other asset is below fair value as at the date of expropriation as determined under the Corporation's valuation. The GOB also commissioned a valuation of Belize Electricity and communicated the results of such valuation in its response to the Corporation's claim for compensation. The fair value of Belize Electricity determined under the GOB's valuation is significantly lower than both the fair value determined under the Corporation's valuation and the book value of the long-term other asset.

In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision on the appeal has been suspended pending the outcome of another related appeal in the Caribbean Court of Justice ("CCJ"). A possible outcome of the appeal could be the return to Fortis of the majority ownership interest in Belize Electricity. Alternatively, in the event that the Belize Court of Appeal decision confirms the trial judgment, Fortis could pursue an appeal of the case to the CCJ, the highest court of appeal available for judical matters in Belize.

Fortis believes it has a strong, well-positioned case before the Belize Courts and will continue to vigorously litigate the legality of the expropriation. There exists, however, a reasonable possibility that the outcome of the above-noted litigation may be unfavourable to the Corporation and the amount of compensation to be paid to Fortis could be lower than the book value of its expropriated investment in Belize Electricity, which was $103 million, including foreign exchange impacts, as at September 30, 2012 (December 31, 2011 - $106 million; September 30, 2011 - $103 million) and recorded in long-term other assets on the consolidated balance sheet. Based on presently available information, the outcome of the above is not determinable at this time. As such, the long-term other asset is not deemed impaired. Fortis will continue to assess for impairment each reporting period based on the outcomes of court proceedings and/or compensation settlement negotiations, if any. As well as continuing its legal actions, Fortis is also pursuing alternative options for obtaining fair compensation.

Exploits River Hydro Partnership

The Exploits River Hydro Partnership ("Exploits Partnership") is owned 51% by Fortis Properties and 49% by AbitibiBowater Inc. ("Abitibi"). The Exploits Partnership operated two non-regulated hydroelectric generating facilities in central Newfoundland with a combined capacity of approximately 36 MW. In December 2008 the Government of Newfoundland and Labrador expropriated Abitibi's hydroelectric assets and water rights in Newfoundland, including those of the Exploits Partnership. The newsprint mill in Grand Falls-Windsor closed on February 12, 2009, subsequent to which the day-to-day operations of the Exploits Partnership's hydroelectric generating facilities were assumed by Nalcor Energy as an agent for the Government of Newfoundland and Labrador with respect to expropriation matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi in the province. The loss of control over cash flows and operations required Fortis to cease consolidation of the Exploits Partnership, effective February 12, 2009. Discussions between Fortis Properties and Nalcor Energy with respect to expropriation matters are ongoing.

20. CONTINGENT LIABILITIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Fortis
In May 2012 CH Energy Group and Fortis entered into a proposed settlement agreement with counsel to plaintiff shareholders pertaining to several complaints, which named Fortis and other defendants, which were filed in, or transferred to, the Supreme Court of the State of New York, County of New York, relating to the proposed acquisition of CH Energy Group by Fortis. The complaints generally alleged that the directors of CH Energy Group breached their fiduciary duties in connection with the proposed acquisition and that CH Energy Group, Fortis, FortisUS Inc. and Cascade Acquisition Sub Inc. aided and abetted that breach. The settlement agreement is subject to court approval.

FHI
During 2007 and 2008, a non-regulated subsidiary of FHI received Notices of Assessment from Canada Revenue Agency for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. FHI is appealing these assessments.

In 2009 FHI was named, along with other defendants, in an action related to damages to property and chattels, including contamination to sewer lines and costs associated with remediation, related to the rupture in July 2007 of an oil pipeline owned and operated by Kinder Morgan, Inc. FHI filed a statement of defence. During the second quarter of 2010, FHI was added as a third party in all of the related actions. FHI was advised that all matters have now been settled and the action has been dismissed by consent.

FortisBC Electric
The Government of British Columbia has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC Electric dated August 2, 2005. The Government of British Columbia has now disclosed that its claim includes approximately $13.5 million in damages but that it has not fully quantified its damages. In addition, private landowners have filed separate writs and statements of claim dated August 19, 2005 and August 22, 2005 for undisclosed amounts in relation to the same matter. FortisBC Electric and its insurers are defending the claims. A date for mediation of this matter has been set for December 2012. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

The Government of British Columbia filed a claim in the British Columbia Supreme Court in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which includes FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $12 million. FortisBC Electric has not been served, however, has retained counsel and has contacted its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

21. SUBSEQUENT EVENT

In October 2012 FortisAlberta issued 40-year $125 million 3.98% unsecured debentures, the proceeds from which are being used to repay borrowings under the Company's credit facility, fund future capital expenditures, and for general corporate purposes.

22. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. The most significant change related to a decrease in current and long-term debt of $4 million and $120 million, respectively, and a corresponding increase in current and long-term capital lease and finance obligations associated with a change in the presentation of finance obligations.

Dates – Dividends* and Earnings

Expected Earnings Release Dates

February 7, 2013	May 7, 2013
August 1, 2013	November 1, 2013

Dividend Record Dates

November 16, 2012	February 14, 2013
May 17, 2013	August 16, 2013

Dividend Payment Dates

December 1, 2012	March 1, 2013
June 1, 2013	September 1, 2013

* *The declaration and payment of dividends are subject to Board of Directors' approval.*

Registrar and Transfer Agent

Computershare Trust Company of Canada
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514-982-7555 or 1-866-586-7638
F: 416-263-9394 or 1-888-453-0330
W: www.computershare.com/fortisinc

Share Listings

The Common Shares, First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; and Subscription Receipts of Fortis are traded on the Toronto Stock Exchange under the symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H and FTS.R, respectively.

Fortis Common Shares ($) Quarter Ended September 30		
	2012	**2011**
High	**34.03**	**33.78**
Low	**32.37**	**28.24**
Close	**33.53**	**32.93**

APPENDIX N

Affidavit of

William J. Daley

EB-2011-0140

IN THE MATTER OF sections 70 and 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

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 WILLIAM J. DALEY

I, William J. Daley, of the Community of Crystal Beach, within the Town of Fort Erie, in the Province of Ontario, **HEREBY MAKE OATH AND SAY AS FOLLOWS:**

1. I am President and Chief Executive Officer of Canadian Niagara Power Inc. ("CNPI") and, as such, have knowledge of CNPI's designation application in this proceeding.
2. In accordance with section 6.3 of the Board's Filing Requirements for the East-West Tie designation application, I confirm the following:
   - that the line will be designed to meet or exceed the existing NERC, NPCC and IESO reliability standards; and
   - that the line will be designed to meet or exceed the Board's Minimum Technical Requirements.

SWORN before me at the Town of)
Fort Erie, in the Province of Ontario)
Ontario, this 4th day of January, 2013)

Commissioner for taking affidavits

W. J. Daley

APPENDIX O

Environmental Assessment,
Scope of Work, Assumptions,
List of Permits

Scope of Work Outline Environmental Assessment

The following is a suggested Table of Contents for the Terms of Reference (ToR) and Individual Environmental Assessment (EA). Any assumptions with regard to methodologies for the environmental and engineering works are discussed below.

Terms of Reference

1.0 Introduction
- 1.1 Consultation with MOE
- 1.2 Consultation with CEAA
- 1.3 Consultation with other review agencies such as MNR, Ontario Parks, Parks Canada, DFO, AANDC
- 1.4 Introduction/Background on the Electricity Sector and Purpose of Undertaking

2.0 Environmental Assessment Framework
- 2.1 Outline of EA Framework and timelines
- 2.2 Identification of Other Approvals

3.0 Overview of EA Requirements for Proposed Project

4.0 Description of The Undertaking
- 4.1 Technical Overview
- 4.2 Description of Study Area

5.0 Existing Conditions
- 5.1 Background Review of Physical Characteristics
- 5.2 Background Review of Significant Areas/Wildlife/Habitat
- 5.3 Terrestrial Fieldwork Methodologies
- 5.4 Aquatic Fieldwork Methodologies
- 5.5 Socio-Economic Environment and Land Use/Planning/Community Profiles
- 5.6 Cultural Environment – Archaeology, Cultural Heritage, First nation and Metis, Traditional Ecological Knowledge and Traditional Land Use

6.0 Alternatives to

6.1 Brief discussion of potential alternatives to the undertaking and direction of the Ontario government.

7.0 Alternative Methods

7.1 Evaluation of Methods

7.2 Alternative Route Evaluation and scoping to potential preferred routes (for selected areas)

7.3 Effects Evaluation and Mitigation – Natural and Socio-Economic

7.4 Effects Evaluation and Mitigation – Cost and Technical Considerations

8.0 Commitments and Monitoring

8.1 Project Effects Monitoring Plan

8.2 EA Process Monitoring

9.0 Consultation

9.1 Stakeholder Consultation Plan

9.2 Public Consultation Plan

9.3 Aboriginal Consultation Plan

9.4 Agency Consultation Plan

9.5 Documentation and Issues Resolution

9.6 Public Information Centre to Review and Comment on ToR

10.0 Approval of ToR

Individual Environmental Assessment

1.0 Introduction

1.1 Background/Proponent/Document Outline

2.0 The Undertaking

2.1 Purpose of Undertaking/Description of Undertaking/Regulatory Framework

3.0 Description of the Existing Environment

3.1 Description of Study Area – Air Photo Interpretation/LiDAR/Topographic Survey/Base Plans

- 3.2 Description of Atmospheric/Geology/Physiographic/Soils/Surface Water/Groundwater Hydrology
- 3.3 Vegetation Assessment
- 3.4 Timber Evaluation
- 3.5 Environmentally Significant Areas
- 3.6 Wildlife and Habitat
- 3.7 Aquatic Assessment
- 3.8 Socio-Economic Assessment
- 3.9 Archaeological and Cultural Heritage Assessment
- 3.10 Visual Landscape Character
- 3.11 First Nations and Métis Traditional Use and Traditional Ecological Knowledge

4.0 Alternative Methods

- 4.1 Evaluation of Route Refinements
- 4.2 Evaluation of Alternative Methods (Project Design Considerations)

5.0 Effects Evaluation and Mitigation

- 5.1 Construction Effects and Mitigation – Natural Environment
- 5.2 Construction Effects and Mitigation – Socio-Economic and Cultural Environment
- 5.3 Operational Effects and Mitigation – Natural Environment
- 5.4 Operational Effects and Mitigation – Socio-Economic and Cultural Environment

6.0 Cumulative Effects

7.0 Environmental Management and Monitoring

- 7.1 Environmental Management System – Management Structure, Contract Documents, Change Management
- 7.2 Specific Management System Components – Construction Phase Environmental Specifications, Environmental Compliance and Effects Monitoring, Post Construction Monitoring and Documentation

8.0 Other Permits and Approvals

- 8.1 List of Permits/Approvals and Relevant Legislation

9.0 First Nations Consultation and Engagement

- 9.1 Identification of First Nations
- 9.2 Consultation/Engagement During EA and commitments to permitting, construction and in-service phases of project

10.0 Community and Stakeholder Consultation

- 10.1 Stakeholder Identification – Property Owners, General Public, Residents within 500 m, Agencies, Non-Government Organizations, Municipalities, Regional and County Staff
- 10.2 Notices, Newsletters, Website/Hotline
- 10.3 Public Information Centres
- 10.4 Meetings
- 10.5 Workshops

11.0 EA Preparation, Submission and Review

Permits

Required permits may include but are not be limited to the following:

- Federal
  - NWPA – Transport Canada
  - Fisheries Act – DFO
  - Aeronautical Act – Transport Canada
- Provincial
  - Provincial Highways Act – MTO
  - SAR Permit – MNR
  - Conservation Authorities Act – CA's
  - Public Lands Act – MNR
  - Permit to Take Water - MOE
- Municipal
  - Access/Use Permit from Municipal Roads and Heavy Load Transportation
  - Tree Clearing
- Other
  - Utilities – Pipelines, fiber optic telecommunications
  - Railway Work Permits or Construction Permits

Detailed Assumptions for the Development Process

Terms of Reference will take 18 months to submit and receive approval.

- Pukaskwa National Park and other areas may require alternate route evaluations at 5 locations along the line.
- Public Information Centres (PIC) will be required for ToR review
- Environmental Assessment will take approximately two and a half to three years to complete. MOE review and approval time is critical and is expected to add another year.

- Several route refinement areas may be required following public/stakeholder consultation, based on the number of First Nations and Municipalities, and Townships traversed by existing route.
- 5 Public Information Centres (PICs) will be required during EA (including ToR) (2 PIC's will be held in each of the following locations: Thunder Bay, Nipigon, Marathon, Schreiber or Terrace Bay and Wawa during the ToR development and 3 PIC's at the same locations during the EA development.)
- During the EA - 3 workshops will be required for municipal/agency staff – route refinement/biodiversity/effects mitigation – in Thunder Bay additional teleconferences are planned.
- During the EA - 5 route refinement workshops will be required with landowners (in addition to individual landowner meetings), these will be held in Thunder Bay, Nipigon, Terrace Bay or Schreiber, Marathon and Wawa
- Air photo interpretation/LiDAR and possibly 3-D technology will be used to virtually walk-through the study area and refine fieldwork efforts (this approach has been readily accepted by MNR)
- A detailed reconnaissance fly-over (helicopter) will be required with field teams with the aim of refining site access requirements and determining an appropriate fieldwork strategy
- A minimum of 4 field crews will be required for terrestrial and aquatic fieldwork (crews will be based in Thunder Bay, Marathon, Terrace Bay or Schreiber, and Wawa).
- Field guides will be utilized from First Nation communities
- First Nation communities may also provide people to assist with flora and fauna or archaeological surveys.
- Approximately 15 environmental permits required.
- Terrestrial
- The majority of vegetation along the proposed new Right of Way (ROW) will likely need to be cleared. The existing 230 kV line traverses through 9 parks/conservation lands. Fieldwork will be required within 120 m, or as indicated by approval agencies, each side of the proposed ROW. Efforts will

be focused in selected habitats by means of undertaking a virtual walk-through along the entire route. ATV's will be used to access the route. Helicopters will be utilized for in-accessible areas. Assume access is available along existing maintenance roads. Natural environment will be characterized by collecting data at 100 survey stations using the Ontario Parks Inventoryingand Monitoring Program Rapid Assessment plots Protocol. Survey stations will be identified through a desktop survey using FRI mapping. Lidar and other data sources to locate a suite of representative plots in locations throughout the study area and including plots in all park locations. Three seasons of fieldwork over at least one full year will be required as follows: 1) Spring surveys to identify breeding birds and preliminary ELC/FEC mapping (or equivalent), botanical lists, 2) Late summer/early fall surveys for aquatic habitat mapping, wildlife habitat identification and refinements to ELC/FEC mapping, 3) Additional visits to remote sites requiring fly-in access, 4) Winter aerial survey for wildlife habitat, Caribou habitat assessment and modeling will be undertaken (no tracking). The work program assumes only one bird survey at each survey station.

    - Parks/conservation lands (9) -Black Sturgeon River Provincial Park, Ruby Lake Provincial Park, Kama Cliffs Conservation Reserve, Kama Hills Provincial Nature Reserve, Gravel River Conservation Reserve, White Lake Provincial Park, Pukaskwa National Park, Pukaskwa River Provincial Park and Nimoosh Provincial Park
    - 32 wetlands located along the existing route

- Aquatic
  - The majority of watercourses can be spanned by the line, however crossings may be required for construction and maintenance. Some access road crossing will already exist as they will be utilized to maintain the existing 230 kV line. Improvements to these access roads may be required. Temporary crossings may also be required for clearing activities. We assume that aquatic habitat mapping will be

required at 100 of the 318 watercourse crossing. Mapping locations will be based on a desktop watershed analysis to identify representative watercourses and watercourses where a crossing may be required. Mapping will be undertaken in accordance with "Fisheries and Fish Habitat Technical Requirements for Environmental Impact Study and Environmental Protection and Mitigation (MTO 2009) Habitat assessment forms will be completed for each crossing. One season survey (summer) will be required

    - The following waterbodies/watercourses are located along the existing route - 86 waterbodies (lakes, ponds, wide river channels), 318 watercourses (streams, creeks, narrow river channels)

- Timber evaluation
    - Verify and update portions of the FRI obtained by MNR or the SFL holders along the route. Undertake basic "loss of use "valuations using a variety of benchmarks.
- Archaeology
    - A detailed terrain analysis will be undertaken using a variety of data sets. Localities of elevated heritage potential will be identified in fairly specific detail. A report will be produced including maps and geo-referenced map data (shape files). A Stage 1 report will be provided for approval to the Ministry of Tourism and Culture (MTC). Geo-referenced locations will be provided if a Stage 2 assessment is recommended.
- Cultural Heritage
    - A general background historical review and identification of potential cultural remains (and issues) will be undertaken. This study will focus on cultural heritage data sources outside FN and Metis traditional communities and will be integrated with the Archaeological work.
- FN and Metis Traditional land Use and Traditional Ecological Knowledge
    - Information on traditional land use for cultural activities (e.g. sacred ceremonial sites) and traditional ecological knowledge (e.g. use of

native medicinal plants) will be obtained through engagement with community elders. We have assumed aboriginal participation at engagement sessions/visits will be acknowledged throught the giving of of community appropriate medicine gifts (e.g. tobacco, sweetgrass, medicine blankets) or cash reimbursements.

- Hydrogeology – We have assumed that no construction camp will be required for this project.
    - Prior to site acquisition and construction regardless of the method of land acquisition, there will be a requirement to conduct a Phase I Environmental Site Assessment to evaluate the environmental liabilities of the lands being acquired. A Phase II Environmental Site Assessment may be required based upon the findings. All work would need to be done to the new O.Reg. 511/09 standards. If there are water wells (O.Reg. 903) or buildings (Occupational Health and Safety Act), they will need to be decommissioned in accordance with regulations. A review of the proposed route indicates that the only developed area located near the Right of way is the First Nation community of Pays Plat. The current ROW is within 300m of some of the residences, but the community uses a surface water treatment plant so there will be no concern with impacts to wells. There is a gravel pit located just east of Marathon which is within the current ROW. There appears to be a scrap yard on the portion of the property closest to the ROW. This site will require a Phase 1 ESA and likely a Phase 2.
    - During construction there will be blasting for tower construction and road access. A preconstruction review of all local water supply wells will be required within 500 m of any significant blasting and construction activities. A review of the current ROW did not indicate any wells likely to be nearby. There is a building in Marathon which appears to be a hydro facility. Potentially impacted wells must be

identified and mitigation measures developed, to limit impacts to residents, business, and municipal supply wells.

  - The Construction Plan will require a team to assist with spill response and environmental impacts from construction. The Neegan Burnside Hydrogeology Group will provide the expertise to assist. Again there are many unknowns. The greatest opportunity for spills is during equipment refueling. Given the length of the route there will likely be several equipment yards where refueling occurs

- Geotechnical

Assumes total length of 400 Km, 1335 structure locations. Accessibility is largely unknown. Benefits of existing information from the HONI parallel line is also unknown.

APPENDIX P

Press Release with LHATC

FOR IMMEDIATE RELEASE

St. John's, NL – February 2, 2011

FORTISONTARIO AND LAKE HURON ANISHINABEK FIRST NATIONS ANNOUNCE MEMORANDUM OF UNDERSTANDING TO DEVELOP TRANSMISSION PROJECTS IN ONTARIO

FortisOntario Inc. ("FortisOntario"), a wholly owned subsidiary of Fortis Inc. ("Fortis") (TSX:FTS) and First Nations' Lake Huron Anishinabek Transmission Company Inc. ("LHATC") announced today that FortisOntario and LHATC have entered into a memorandum of understanding for a joint venture to develop, construct and operate regulated electricity transmission projects in Ontario. LHATC represents First Nations who are signatories or are adherent to the Robinson-Huron Treaty of 1850. FortisOntario will hold a minimum 51% interest, with LHATC having the rights to acquire up to a 49% equity interest, in the joint venture.

The Ontario Energy Board recently issued a Framework for Transmission Project Development Plans (the "Framework"), which encourages competition for new transmission investment in Ontario through a formal competitive designation process for projects identified by the Ontario Power Authority, the transmission planner for the Province of Ontario. The Framework was issued in response to the significant investment required in Ontario's transmission system to build additional capacity to accommodate new renewable energy supply and upgrade the aging transmission infrastructure to ensure a safe, reliable and efficient system over the long term.

"This joint venture will leverage the combined strengths of LHATC and its unified group of First Nations communities with the expertise of the Fortis companies, thereby enabling us to compete successfully to construct, own and operate new transmission infrastructure in Ontario," says Bill Daley, President and Chief Executive Officer, FortisOntario.

"The Lake Huron Anishinabek First Nations are pleased to announce our new partnership with FortisOntario. By combining their existing capacity and expertise in electrical transmission with our key, strategic rights to the 1850 Robinson-Huron Treaty territory, we are confident that we are in a strong position to deliver high quality transmission services for the greatest public benefit to Ontario," says John Beaucage, Chief Executive Officer, LHATC.

"By sharing in the wealth of the resources within our treaty territory, we can now demonstrate a true measure of the Spirit and Intent of treaties in Canada. We have a strong partner in FortisOntario and this partnership marks a very significant change in Ontario where treaties are being recognized by investors as an opportunity to benefit from and to participate in First Nation economies," says Lake Huron Regional Grand Chief, Isadore Day, *Wiindawtegowinini*.

Fortis is the largest investor-owned distribution utility in Canada, with total assets of $12.5 billion and fiscal 2009 revenues totalling $3.6 billion. Fortis serves approximately 2,100,000 gas and electricity customers. Its regulated holdings include electric distribution utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis owns and operates non-regulated generation assets across Canada and in Belize and Upper New York State. It also owns hotels and commercial real estate across Canada. Fortis shares are listed on the Toronto Stock Exchange and trade under the symbol FTS.

Fortis includes forward-looking information in this media release within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on assumptions developed using information currently available to the Corporation's management. Although Fortis believes that these statements are based on information and assumptions which are current, reasonable and complete, these statements are necessarily subject to a variety of risks and uncertainties. For additional information on risk factors that have the potential to affect the Corporation, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the Management Discussion and Analysis for the three and nine months ended September 30, 2010 and for the year ended December 31, 2009. Except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

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APPENDIX Q

The Transmission Times

The Transmission Times

The LHATC- FortisOntario partnership will create jobs

Find out more on…
Page 2

An update on transmission projects actively being pursued

Find out more on…
Page 3

A message from Chief Paul Eshkakogan, Sagamok Anishinabek First Nation

Find out more on…
Page 4

Issue 1 **October 2011**

LHATC and FortisOntario are partnered to create a sustainable future for Ontario

Lake Huron Anishinabek Transmission Company (LHATC) and FortisOntario Inc. join forces to construct, own and operate transmission in Ontario

Ownership in transmission is one way we can bring our communities to the forefront in managing and sharing in the wealth of the natural resources that are part of our treaty lands. The development of energy sector knowledge and expertise will translate into a new resource that our people can leverage to develop transmission lines in other parts of the province and possibly beyond.

A Ministry of Energy Directive was the original catalyst for the Joint Venture. In 2009, the McGuinty government announced the new plan for 20 new transmission projects, worth $2.3 billion. Lake Huron Anishinabek First Nations were proactive and formed LHATC to pursue opportunities and in February 2011, the Joint Venture with FortisOntario was formed.

According to the government plan, transmission lines would be located east from Sault Ste Marie to Sudbury; also from Sudbury to the GTA and another line between Nipigon and Wawa.

This plan has attracted the attention of the Joint Venture partners because of the high project value and the projected creation of 20,000 jobs.

In recent years, First Nations have moved toward more of a business mindset and an ownership role in development projects. Sagamok First Nation Chief, recently noted – "...Our Treaty Rights have been promoted in Ontario's Green Energy Act… Sagamok intends to be prominent in exploring their options for opportunities…The new transmission lines that will be traversing our territory will provide for much needed revenue, employment and procurement opportunities".

The implementation of the government's transmission plan and competitive designation process are part of an overall Ontario government initiative to assess transmission infrastructure in the province and to ensure a managed approach to energy needs and resources. Besides the obvious business opportunities, this plan will assist in bringing transmission lines and power to more urban centres, assisting in furthering economic development.

The Joint Venture will create jobs through tailored training programs

The Joint Venture (JV) has agreed to develop a Skills Builder program which develops qualified First Nations participants to work during the construction phase of the transmission project. As well, there is sponsorship programs that will be available for linemen training once the construction is complete. For more information on this type of program, please go to : http://fortisbc.com/About/OurCommitments/GasUtility/NatGasAboriginalRelations/Pages/default.aspx

The Skills Builder Program will enable First Nations workers to acquire technologically advanced skills that are in high demand. The Joint Venture plans to implement a similar program to alleviate the 14 per cent First Nations unemployment rate in Ontario. The JV recognizes that this rate is significantly higher than the rates for Métis and non-Aboriginal people which are 10 per cent and six per cent respectively.

Currently in Ontario, only 63 per cent of First Nation people are in the labour force. The JV hopes that these training opportunities (and subsequent employment opportunities) will help to increase employment for First Nation youth.

First Nations to be leaders in the Ontario Government's Integrated Power System Plan

The creation of a new Integrated Power System Plan (IPSP II) is the job of the Ontario Power Authority. It was appointed in 2004 with the task of creating a 20-year plan to assist with managing energy use in the province.

In 2008, Minister George Smitherman decided that an IPSP was needed in light of the Green Energy Act.

In 2009 Minister Smitherman's Directive was for the development of the Sudbury-West and North-South Tie. The government has also provided various programs and funding to allow Aboriginal groups to participate in the development of renewable energy generation facilities, transmission systems and distribution systems. In light of these developments, an LHATC-Fortis partnership is important in giving real partnering opportunities to First Nation and highlighting Aboriginal concerns about energy needs and development in Ontario.

The provision of these programs and funding is important and a step in the right direction. But this points also to a bigger need for Aboriginal groups to step into a larger space in the Energy Industry in Ontario and claim a greater share of participation.

Not by simply participating in these programs or applying for funding, though these have merit, but by taking real ownership with our own Joint Venture to signal our strength and willingness to be a real player at the Energy Table.

Ross Assinewe
Interim CEO, LHATC

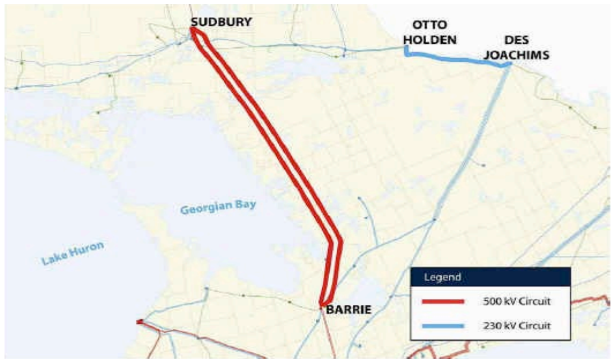
I believe that when our Grandfathers signed the "Robinson Huron Treaty of 1850", their visions included that the Anishinabek will retain the benefits on the management of the natural resources provided by our lands.

The Lake Huron Anishinabek People are the Stewards of this territory and their objectives include the Protection of our Treaty Rights, Protection of the Environment and Investment Opportunities.

This Partnership between the Lake Huron Anishinabek Transmission Company and FortisOntario will achieve those objectives and the visions of our Grandfathers."

Status of the Projects: The Sudbury-West Line, the North-South Line and the East-West Tie

The Sudbury West and North South Line



While the 2009 Ministry Directive placed high priority on a new $450M, 220 km, 500 kV line from Sudbury to Sault Ste. Marie (the "Sudbury West"), and a new $900M, 280 km, 500 kV line from Sudbury to GTA (the "North South Tie"), more recently the government has put these lines on the back burner indicating that they will not be required until beyond 2018.

The Joint Venture has been actively engaging stakeholders to reconsider these projects and put them back onto the priority list. These stakeholders include: the Ontario Ministry of Energy, the Ministry of Aboriginal Affairs, the Ontario Power Authority, and the Ontario Energy Board. The Joint Venture remains committed to these projects and to creating awareness of the importance of these lines.

The East West Tie – OEB Competitive Designation

The Ontario Energy Board (the "OEB") recently announced a new competitive process to develop electricity transmission projects and the Joint Venture has submitted a notice of its intention to participate in this process for a new line called the East West Tie; a new 400 km, double-circuit kV transmission line from Thunder Bay to Wawa. The first project for this process was announced through a 2011 Ministry of Energy Directive,

The Joint Venture will be vigilant to ensure that this process remains transparent, and competitive and that its application for designation is prepared and filed with the OEB.

CHIEF'S CORNER

Chief Paul Eshkakogan, Sagamok First Nation, speaks about the increasing opportunities that exists for First Nations, especially in Transmission Development

The Sagamok Anishnawbek is located along the north shore of Lake Huron and is home to an on-reserve population of approximately 1,700 Ojibway and a total of 2,400 members. Sagamok is one of a few First Nation communities in Ontario that has greater than 50% of the registered population living on-reserve.

The Sagamok Anishnawbek has been accessing the economic development opportunities on the developments within our territory. There have been a lot of activities going on in the Mining and Power Development industries. The Base Metals and Precious Metals make the Sudbury Basin area a hot bed for exploration and mining development. Our Treaty Rights have been promoted in Ontario's Green Energy and Mining Act and Sagamok intends to be prominent in exploring their options for opportunities. The new transmission lines that will be traversing our territory will provide for much needed revenue, employment and procurement opportunities.

The Sagamok Anishnawbek are very encouraged that the LHATC, a Treaty based organization, will be seeking out ownership and construction opportunities for our communities.

I want to congratulate LHATC and FortisOntario for their accomplishments in the Energy Sector and look forward to participating in the procurement strategy. I want to take this opportunity to express our sincere wishes to the success of the LHATC and look forward to additional economic opportunities.

The Joint Venture is working with First Nations to ensure the highest level of consultation and accommodation is being met

The partnership developed between Lake Huron Anishinabek Transmission Company and industry experts FortisOntario sets the standard of what defines First Nations partnership in many ways.

First, the very core principles of the Joint Venture mirror those of the goals identified in the Northern Growth Plan and will help both the Federal and Provincial governments achieve their development goals such as bringing sustained growth to the region, retaining youth by offering significant employment opportunities and significantly improving infrastructure networks.

Second, this partnership is not simply a case of an industry partner obtaining a band council resolution. The Joint Venture is working together to jointly pursue business opportunities as equal partners; here, the highest level of consultation and accommodation has been achieved. The Joint Venture is committed to working with partners to help to build the economic and social fabric that brings hope to the people in Ontario's North.

DEFINING THE PLAYERS

Ontario Power Authority: Assesses the long-term adequacy of electricity resources

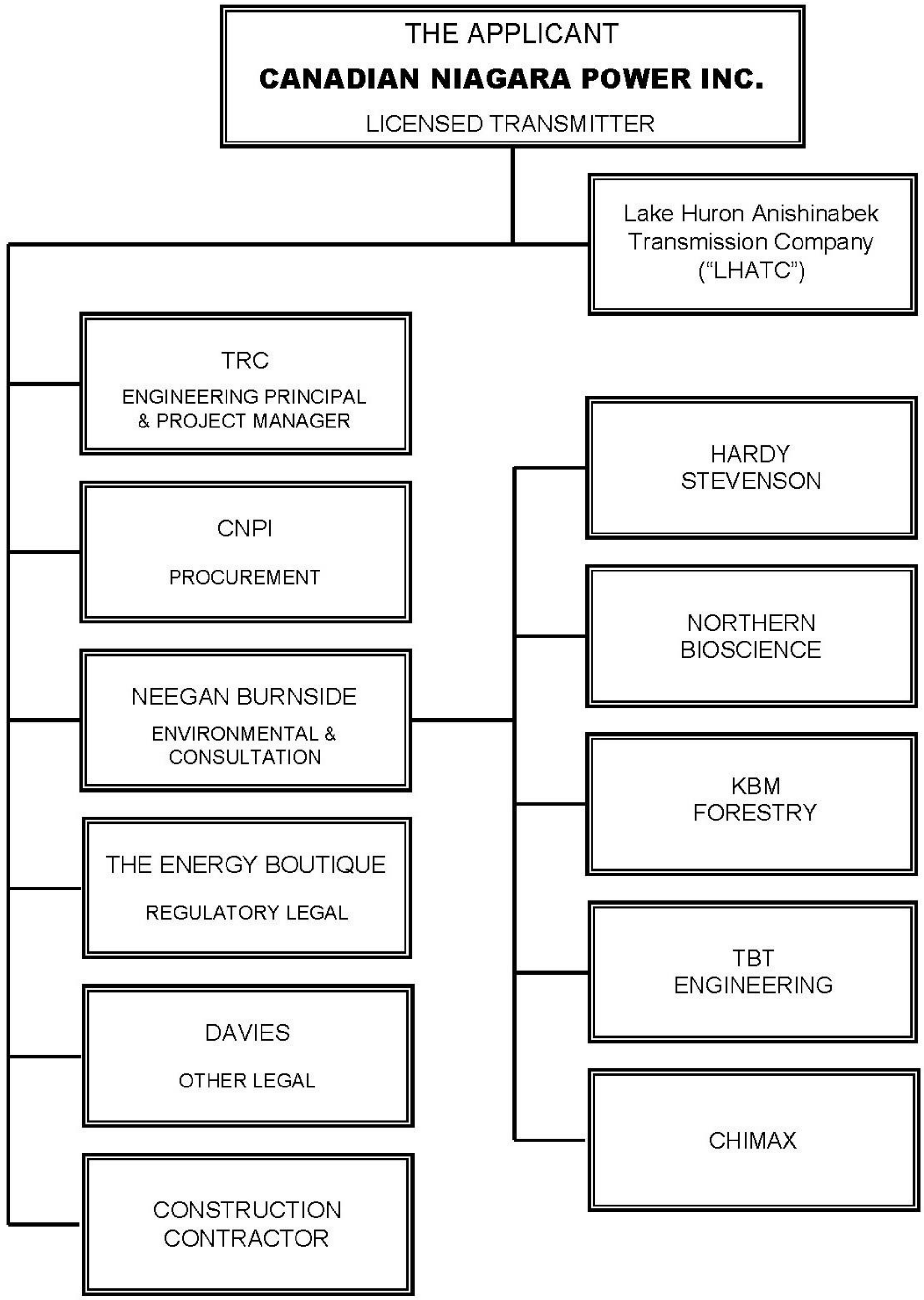
Ministry of Energy: Responsible for ensuring Ontario's electricity system functions reliably

Ontario Energy Board: Regulates natural gas and electricity utilities in the province

Please direct all questions to:
LHATC: Ross Assinewe, Interim CEO (tel) 1.705.671.6045 (email) ross.assinewe@sympatico.ca
FortisOntario: Scott Hawkes, Vice President (tel) 905.871.0330 (email) scott.hawkes@fortisontario.com

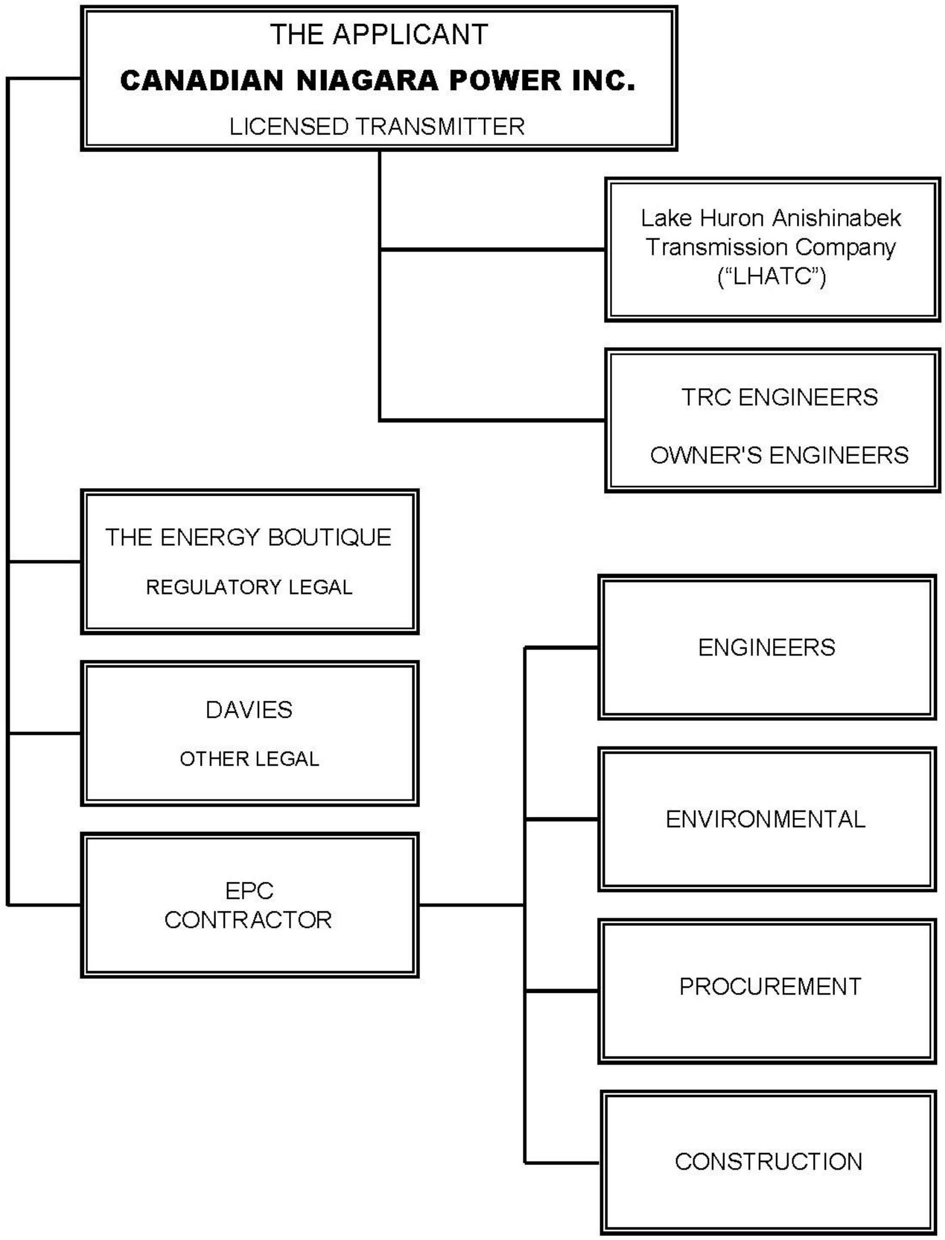
APPENDIX R

Charts for Utility Contract Models



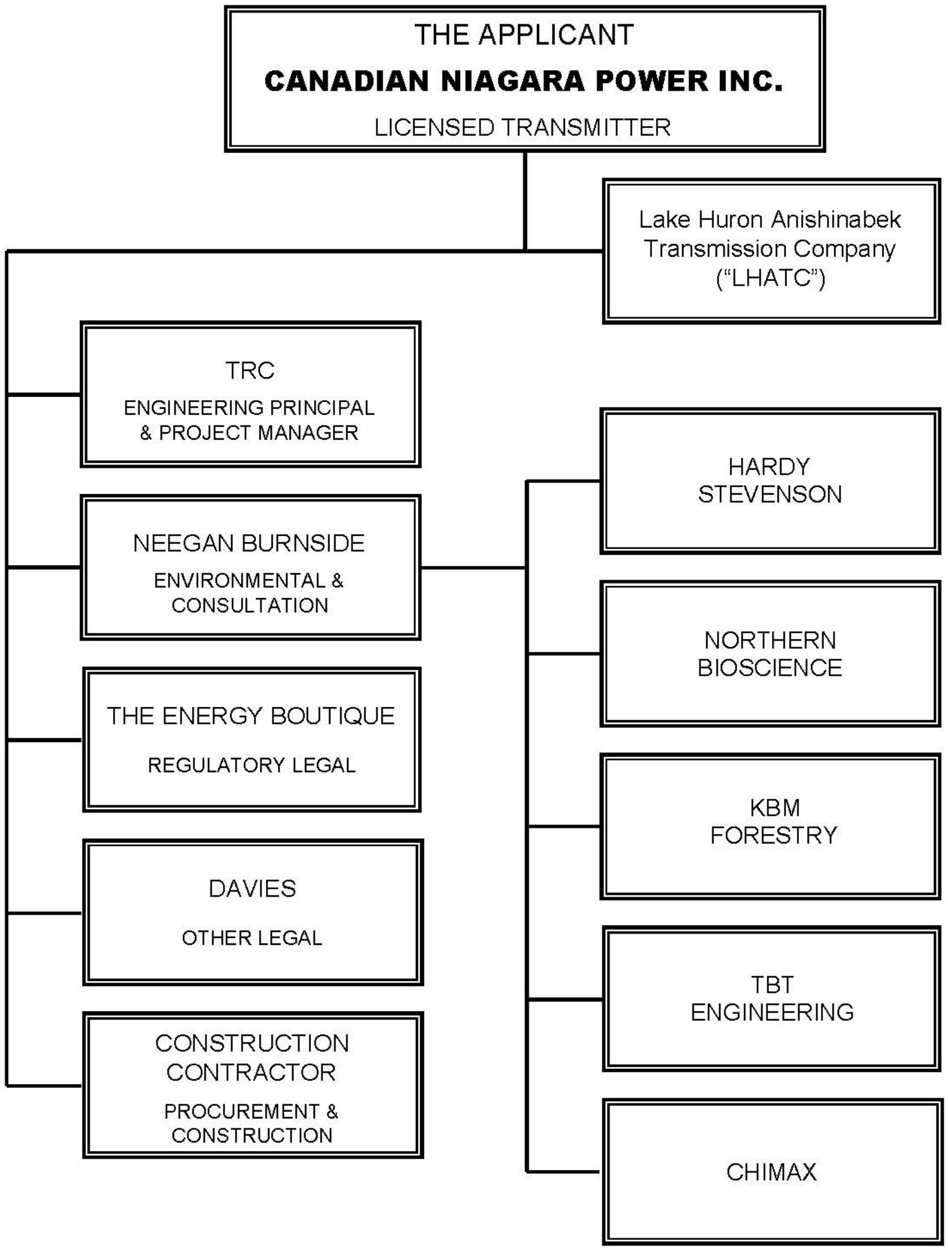
TRADITIONAL UTILITY MODEL

APPLICANT = ENGINEERING, PROCUREMENT & CONSTRUCT



FULL EPC

APPLICANT = OWNER
CONTRACTOR = ENGINEERING, PROCUREMENT & CONSTRUCT



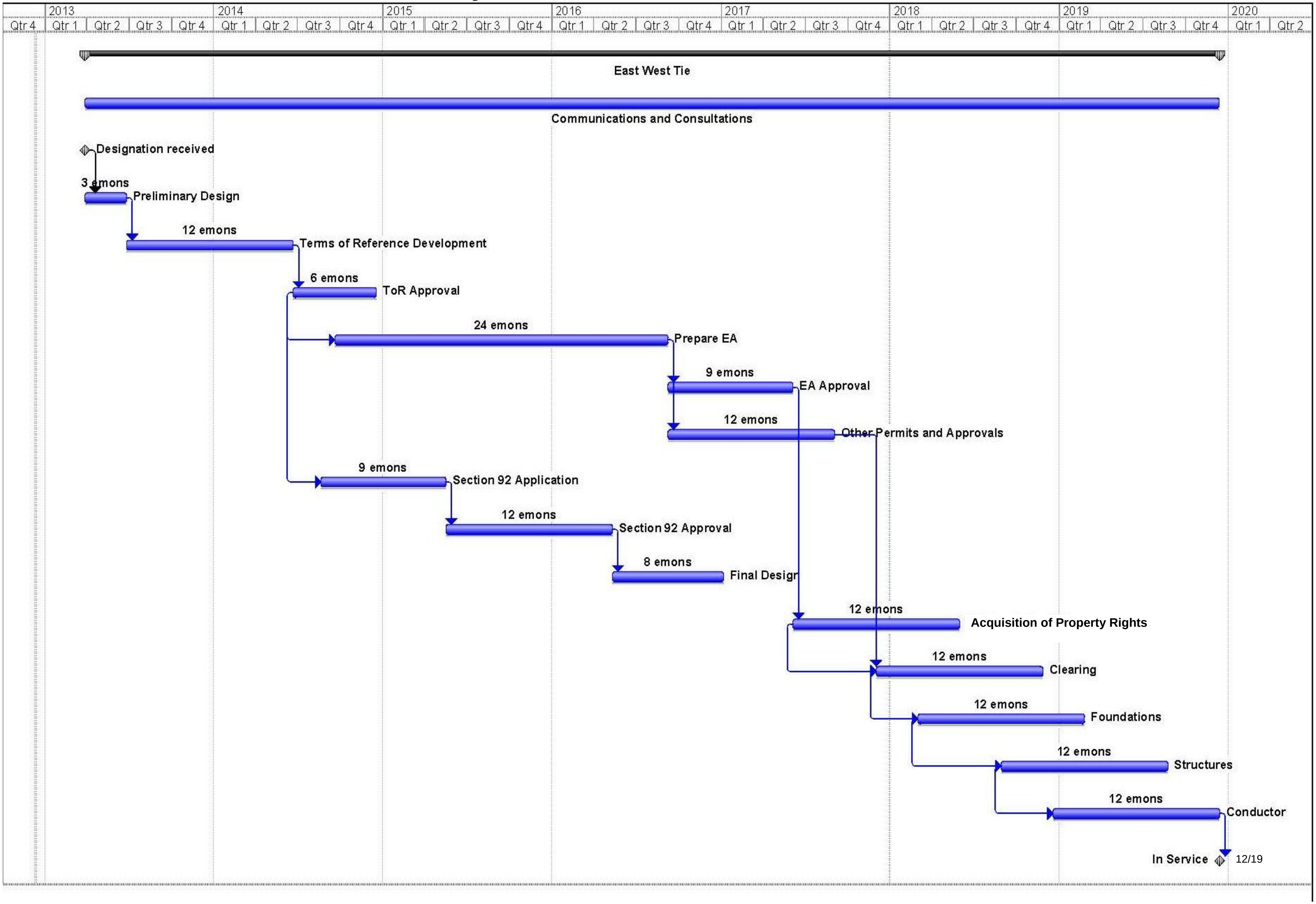
MODIFIED EPC

APPLICANT = ENGINEERING
CONTRACTOR = PROCUREMENT & CONSTRUCT

APPENDIX S

Project Execution Chart

Project Execution Chart



APPENDIX T

Photos of Proposed and Alternate Routes

Photos of Existing Lakehead to Wawa 230 kV Line

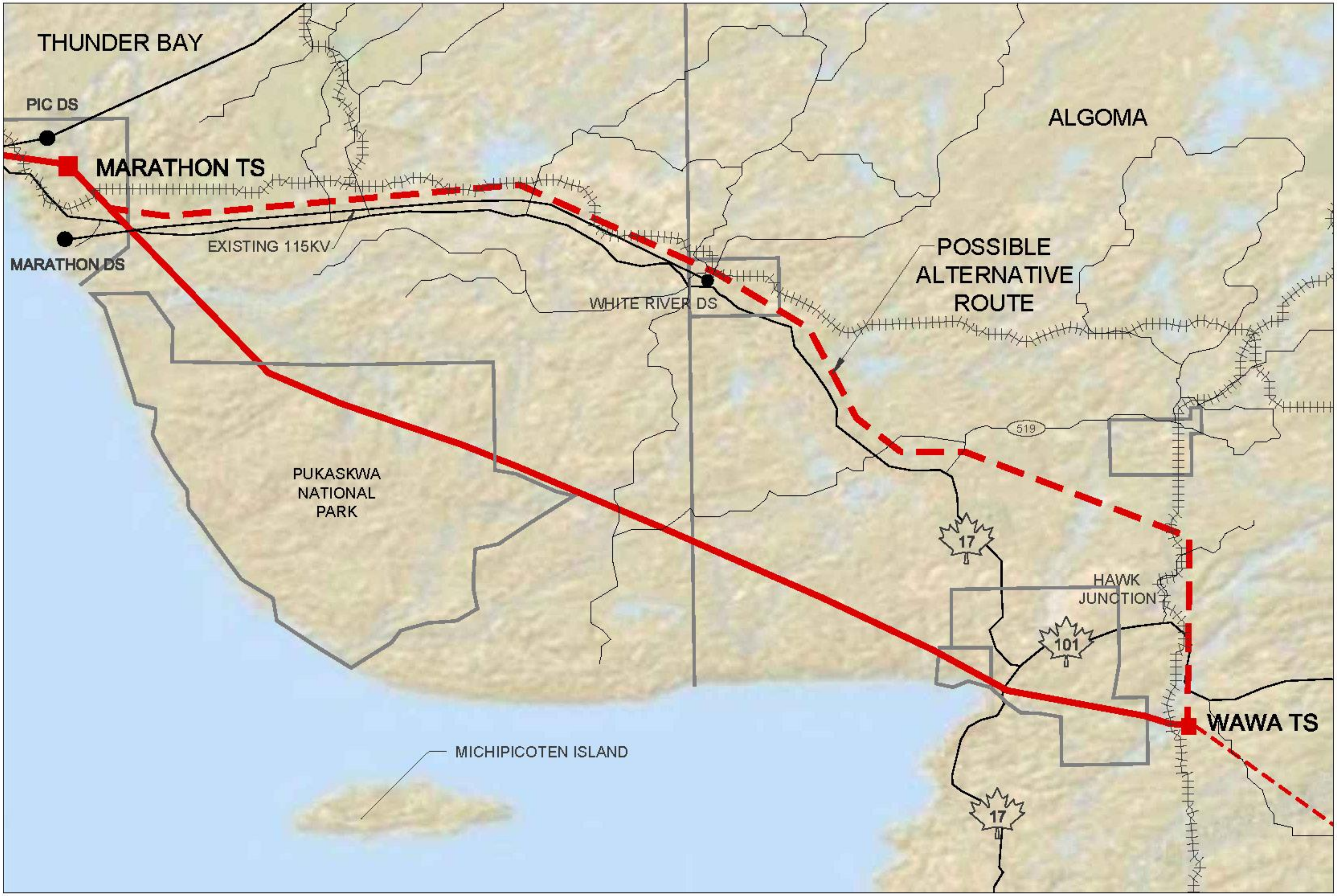
(Proposed Parallel Route)


Photos of Alternate Route

APPENDIX U

Map of Possible Alternate Route

Map of Possible Alternate Route



APPENDIX V

Skill Builder Presentation

Skill Builder
An Aboriginal Training Initiative

Presentation for the CANDO Conference

Wednesday, October 8th 2009

Skill Builder

A BC Industry Aboriginal Training Initiative

Agenda

- How it began and why it makes sense
- Skill Builder Vision and Goals
- Utility Construction Boot Camps
- Benefits and challenges for participants
- Benefits and challenges for industry
- Wrap-up and questions

Skill Builder

A BC Industry Aboriginal Training Initiative

How It Began: Construction of Terasen’s Liquid Natural Gas Facility

“We've had significant involvement from local First Nations. The Chemainus First Nations people have taken on major chunks of the work, giving their input and contributing to construction.”

- Guy Wassick; Project Director

Skill Builder

A BC Industry Aboriginal Training Initiative

Why It Makes Sense

- Providing job opportunities addresses labour force shortages by tapping into the fastest growing demographic in Canada
- BC's unique political and legal environment
- It's the right thing to do and everyone benefits

Skill Builder
A BC Industry Aboriginal Training Initiative

Skill Builder Vision

An industry collaboration supporting initiatives to promote meaningful employment for Aboriginal peoples

Kinder Morgan Canada Inc.

BC Transmission Corporation — Building Connections with Aboriginal Peoples

Terasen Gas

Spectra Energy

BC hydro FOR GENERATIONS

corix Utilities

TransCanada In business to deliver

Skill Builder — A BC Industry Aboriginal Training Initiative

About our logo:

The raven represents creation and knowledge and is known as the Bringer of the Light, and the Catalyst of Change

Enbridge Northern Gateway Pipelines

Goals

- To promote coordination of Aboriginal relations and employment initiatives
- To support and promote programs that emphasize transferable skills
- To develop a common foundation for skills training in the utility sector
- To provide a forum for sharing best practices

Skill Builder

A BC Industry Aboriginal Training Initiative

First Bootcamp Chemainus First Nation

- Seven graduates
- All secured work on Terasen's Natural Gas Storage Project
- Two pursuing further education in the industry field

Skill Builder

A BC Industry Aboriginal Training Initiative

Second Bootcamp
Seabird Island First Nation

- Collaborative planning with First Nation and industry partners
- Six week program designed to meet community and industry needs

Skill Builder
A BC Industry Aboriginal Training Initiative

Second Bootcamp
Seabird Island First Nation

Skill Builder

A BC Industry Aboriginal Training Initiative

Second Bootcamp
Seabird Island First Nation

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A BC Industry Aboriginal Training Initiative

Second Bootcamp
Seabird Island First Nation

Skill Builder
A BC Industry Aboriginal Training Initiative

Participant Benefits

- Increased awareness about utility infrastructure in the community
- Provides an overview of many utilities
- Opens doors for possible funding for further training
- Experience is useful before working on a job site
- Local training / employment
- Certification recognized by industry
- Peer support

Skill Builder
A BC Industry Aboriginal Training Initiative

Participant Challenges

- Skill Builders provides an overview of the utility sector
- Specific circumstances

Skill Builder

A BC Industry Aboriginal Training Initiative

Industry Benefits

- Relationship development / maintenance
- Assists in meeting regulatory / legal obligations
- Improved interest in trades generally
- Future local employees and contractors
- Flexible formula
- Allows sharing of best practices

Skill Builder
A BC Industry Aboriginal Training Initiative

Industry Challenges

- Managing expectations that participants will be ‘job ready’
- Continuous improvement of boot camps
- Working with diverse agencies
- Procurement strategy refinement
- Keeping Skill Builders momentum

Skill Builder

A BC Industry Aboriginal Training Initiative

Wrap-up and Questions

Skill Builder

A BC Industry Aboriginal Training Initiative

APPENDIX W

Statement of Principles for Aboriginal Relations

STATEMENT OF PRINCIPLES
ABORIGINAL RELATIONS

FortisOntario Inc. and its operating subsidiaries are committed to building effective relationships with Aboriginal communities for mutual benefit and to ensure we have the structures, resources and skills necessary to maintain these relationships. In order to meet this commitment, the actions of FortisOntario and its employees will be guided by the following key principles.

We will endeavour to:

❖ Acknowledge, respect and understand that Aboriginal people have unique histories, cultures, protocols, values, beliefs and governments.

❖ Support fair and equal access to employment and business opportunities within FortisOntario companies for Aboriginal people provided they meet FortisOntario's performance standards.

❖ Commit to dialogue through clear and open communication with Aboriginal communities on an ongoing and timely basis for the mutual interest and benefit of both parties.

❖ Encourage awareness and understanding of Aboriginal issues within its work force, industry and communities where it operates.

❖ Ensure that when interacting with Aboriginal peoples, our employees, consultants and contractors demonstrate respect and understanding of Aboriginal peoples culture, values and beliefs.

To give effect to these principles, each of FortisOntario's business units will develop, in dialogue with Aboriginal communities, plans in line with the intent of these principles specific to their circumstances.

Date: December 19, 2012

Approved By: W. J. Daley
President and Chief Executive Officer



APPENDIX X

Summary of Total Costs

Summary of Total Costs

Project Name:	**East West 230kV Tie Line**	***Date of Estimate:***		**1/4/13**
Project Location:	**Ontario, Canada**	***Proposed Service Date:***		**12/12/19**
Line Length:	**400 km**			

		Material	Labour	Total
Development:				
Environmental Assessment, Regulatory approvals			3,996,000	3,996,000
Section 92 Application				
Preliminary Engineering and Design			7,420,000	7,420,000
Consultations and Participation			5,760,000	5,760,000
R/W research and options			2,995,000	2,995,000
Financing, Legal			960,000	960,000
Project Managenment			1,440,000	1,440,000
Subtotal			22,571,000	22,571,000
Contingency	10%			2,257,000
Total Development				24,828,000
Construction:		Material	Labour	Total
Development				
Final Engineering and Design			3,741,000	3,741,000
Permits			1,408,000	1,408,000
LiDAR			1,780,000	1,780,000
Subsurface investigations		-	6,400,000	6,400,000
Subtotal		-	13,329,000	13,329,000
Construction				
Purchase R/W		18,212,000	540,000	18,752,000
Project Management		-	8,640,000	8,640,000
Consultations		-	1,900,000	1,900,000
Surveys		80,000	802,000	882,000
Clearing		455,000	9,105,000	9,560,000
Environmental		534,000	2,670,000	3,204,000
Roads		935,000	10,605,000	11,540,000
Foundations		27,570,000	41,910,000	69,480,000
Steel Structures		136,748,000	80,100,000	216,848,000
Structures assemblies		8,474,000	24,030,000	32,504,000
Conductor & Shield Wire		28,050,000	28,340,000	56,390,000
Stations (3 stations)		-	-	-
Inspection		-	3,600,000	3,600,000
Subtotal		221,058,000	212,242,000	433,300,000
Contingency (Risk acceptance)	20%			86,660,000
Total Construction				533,289,000
Interest during construction				50,680,000
Grand Total Construction				583,969,000
Total Development and Construction				608,797,000