2011 ANNUAL REPORT

Energy *matters*

ENBRIDGE INC.

Forward-Looking Information: This Annual Report includes references to forward-looking information. By its nature this information applies certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect every business, including ours. The more significant factors and risks that might affect future outcomes for Enbridge are listed and discussed in the “Forward-Looking Information” section on page 36 of this annual report and also in the risk sections of our public disclosure filings, including Management’s Discussion and Analysis, available on both the SEDAR and EDGAR systems at www.sedar.com and www.sec.gov/edgar.shtml.

There is a growing dialogue around energy issues. It's an important discussion for us all to be a part of.

PAT DANIEL
Chief Executive Officer

Most North Americans enjoy easy access to affordable energy, but many take for granted the vast infrastructure that enables this access.

Society needs a secure and reliable supply of energy. We need energy to heat and light our homes, businesses, schools and hospitals. We need energy to move people, goods and information. Energy literally drives economies around the world.

As North America moves towards energy self-sufficiency, through growing production of oil, gas and renewable energy, there is a need to develop new infrastructure to deliver the energy to where people need it.

This is where Enbridge fits into the discussion.

We recognize there's a range of perspectives on energy matters—about everything from security of supply and diversity of markets, to the overall environmental impact of energy production and consumption.

These are important issues—not just for Enbridge shareholders, but for all our stakeholders, including employees, partners, customers, governments, Aboriginal groups, communities in which we operate and the general public, all of whom are inextricably linked to our business.

Enbridge's number one social responsibility is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible.


While we can’t promise to have all the answers, we can promise an openness to discussing energy matters with you.
So let’s start the discussion.

Energy supply and demand

“WHY DO WE NEED MORE PIPELINES?”

People need energy for nearly everything we do, and with new sources of supply emerging, we need new infrastructure to meet growing demand.

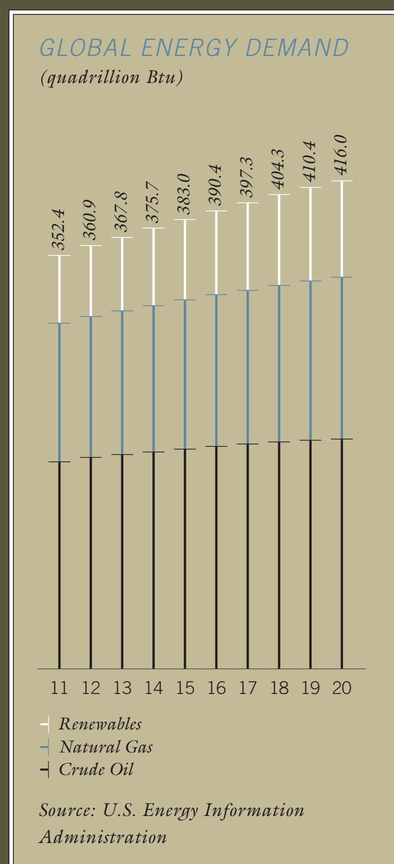
Even as society moves towards a lower impact energy future, the supply of and demand for oil and gas are growing.

Evolving technology has opened up vast new energy resources in North America.

At the same time, demand for crude oil is rising globally, and there are tremendous opportunities to deliver domestically produced crude oil into existing and developing markets.

Demand for natural gas is also growing, driven by an increasing number of gas-fired power plants and consumers’ demand for this cleaner burning fuel.

Whether it’s crude oil or natural gas, pipelines are the safest and most efficient way to deliver the energy society needs.



STEVE WUORI
President, Liquids Pipelines

Steve is responsible for all of Enbridge's crude oil and liquids pipeline operations in North America, and oversees Enbridge's many opportunities for new pipelines to transport growing crude oil production. Steve is also responsible for the Major Projects unit at Enbridge, which manages the engineering, procurement and construction of growth projects across the Company.

"We are on the cusp of the next wave of crude oil pipeline development in North America. Our already expansive network positions us well for these new market extension opportunities."

"WHAT'S ENBRIDGE DOING TO KEEP PACE WITH EVOLVING ENERGY SUPPLY AND DEMAND?"

We're continually monitoring changes in supply and demand, optimizing our existing systems and identifying new opportunities on an ongoing basis.

From the Alberta oil sands and the Bakken formation, to unconventional gas and renewable energy, Enbridge's existing systems and operations position us well to offer new and innovative solutions to connect these growing and developing sources of energy supply to the places where energy is needed. We work closely with our customers to understand their needs and develop solutions that meet the changing supply and demand landscape. In doing so, we're playing a key role in the delivery of secure and reliable energy that supports economic stability and growth.

Exiting 2011, we had over $13 billion in commercially secured projects, all of which are expected to be in service by the end of 2015. We've so far identified $48 billion in individual projects for development between 2011 and 2020.

We have enormous opportunities in front of us. Here's what we're doing today.

CRUDE OIL

North American crude oil supply is growing at a rapid pace and producers need greater access to new and existing markets. We're providing that access.

CONNECTING CANADA'S OIL SANDS: We have an extensive pipeline network in the oil sands region, one of the largest proven oil resources in the world. To connect growing oil sands production to upgraders and

Energy matters

60% OF THE U.S.-BOUND CRUDE OIL THAT COMES FROM WESTERN CANADA IS TRANSPORTED BY ENBRIDGE, DELIVERING APPROXIMATELY 13% OF THE UNITED STATES' DAILY CRUDE OIL IMPORTS.

JANET HOLDER
Executive Vice President, Western Access

Janet provides overall leadership for the Northern Gateway Pipeline Project, providing oversight as the project advances through the regulatory phase. Previously, Janet was President, Gas Distribution, a role she held since January 2008.

> ***"Gateway is the link between the third-largest petroleum reserves and the fastest-growing markets for energy in the world and it will have a truly transformative positive impact on Canada's economy."***

refineries, we're expanding our Alberta regional infrastructure, including a $1.2-billion twinning of our Athabasca Pipeline, which will add approximately 450,000 barrels per day (bpd) of capacity by 2015.

GROWING IN THE BAKKEN: The Bakken region of southern Saskatchewan and northern North Dakota is one of the most prolific new resource plays in North America. We're expanding our crude oil transportation systems there to provide producers greater access out of the region.

ENABLING MARKET ACCESS: We're extending our network off our mainline system to provide Canadian and U.S. crude oil producers access to new markets, including the U.S. Gulf Coast (in 2011, we acquired 50% of the Seaway Pipeline System and announced the twinning of our Spearhead Pipeline), as well as refineries in Ontario and potentially Quebec (through our Line 5 expansion and Line 9 reversal projects). Moreover, to help Canadian producers meet growing Asian demand, we're also proposing to build the Enbridge Northern Gateway Project, a crude oil export pipeline and condensate import pipeline between Edmonton, Alberta, and a proposed new marine terminal in Kitimat, British Columbia. Public hearings on Northern Gateway began in January 2012.

NATURAL GAS

Large unconventional gas resource plays in both Canada and the United States are providing a major new source of natural gas supply. We're helping to link these new sources of supply to consumers and capturing new natural gas transportation and processing opportunities—from northeast British Columbia to offshore Gulf of Mexico.

ONSHORE PIPELINES: Alliance Pipeline is expanding its infrastructure in northeast British Columbia and the Bakken region to facilitate movement of those regions' high-energy, liquids-rich natural gas to the Aux Sable natural gas liquids (NGL) processing facilities in Illinois. Also, Enbridge Energy Partners (EEP) is participating in a joint venture to build the 280,000-bpd Texas Express Pipeline to enhance access for mid-continent NGL to the Gulf Coast market.

OFFSHORE PIPELINES: We're expanding our footprint in the Gulf of Mexico with the $400-million Walker Ridge Gas Gathering System, $200-million Big Foot Oil Pipeline and $150-million Venice expansion, all of which are scheduled to be in service for our customers by 2014.

AL MONACO
President, Enbridge Inc.

Prior to his appointment as President of Enbridge Inc. on February 27, 2012, Al served as President, Gas Pipelines, Green Energy & International, which included responsibility for the growth and operations of Enbridge's gas pipelines and gas gathering and processing operations.

"With the explosive growth in unconventional resource development, producers require new energy infrastructure to capitalize on the value of natural gas liquids. Our strong position in some of the most prolific shale gas plays in North America allows us to capture these opportunities."

PROCESSING: Enbridge took an important initial step into the Canadian Midstream natural gas business in 2011 with our $1.1-billion investment in the development of the Cabin Gas Plant, a natural gas processing facility in the prolific Horn River Basin natural gas play in northeast British Columbia. Also in 2011, EEP, which is already one of the largest gas processors in Texas, placed a new gas plant into service, upgraded two others and started construction of a 150-million-cubic-feet-per-day (mmcf/d) cryogenic processing plant.

GAS DISTRIBUTION

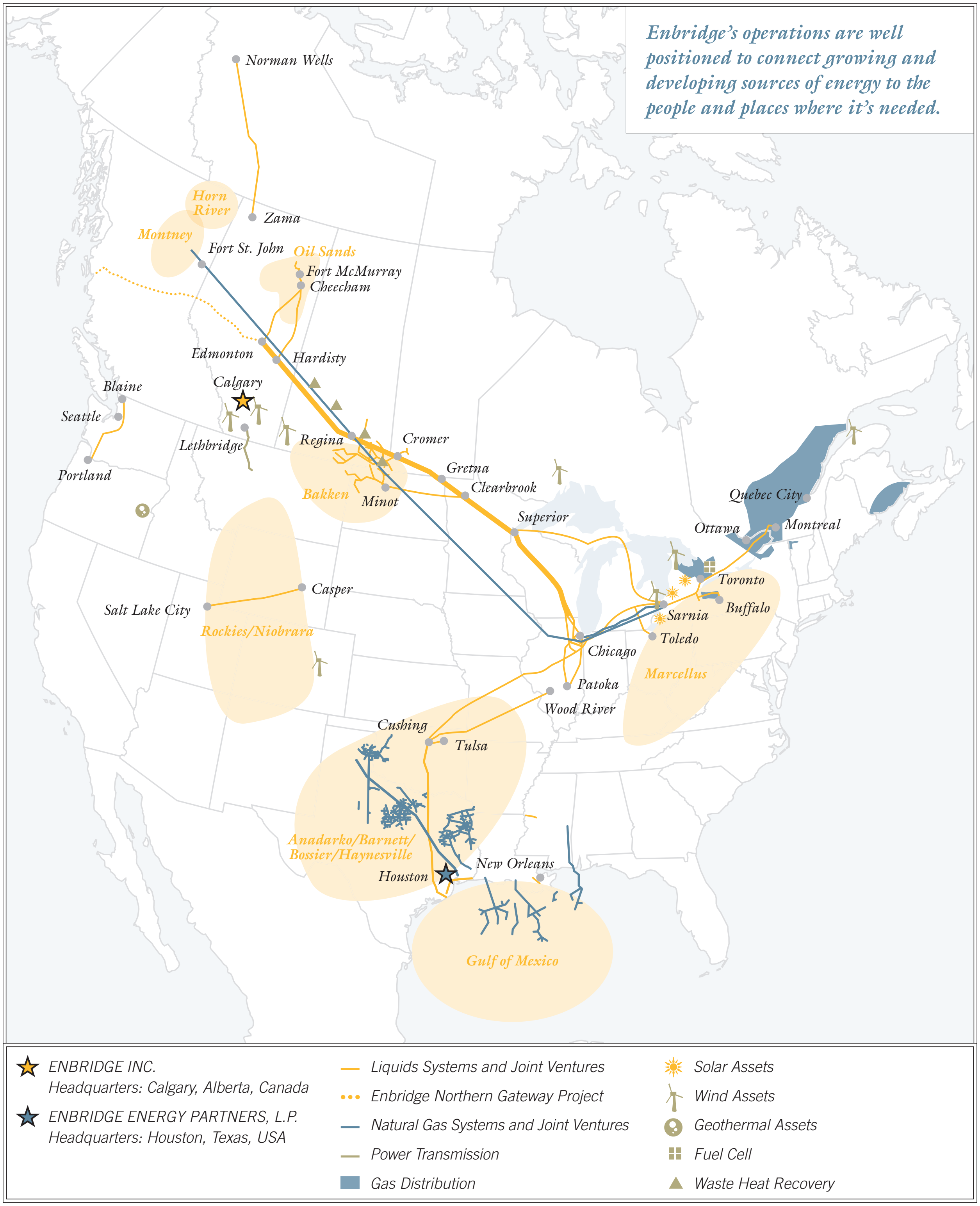
Enbridge Gas Distribution (EGD), which has been delivering clean-burning natural gas to consumers for over 160 years, expects to welcome its two millionth customer in Ontario in 2012. EGD is the largest gas distribution franchise in Canada and one of the fastest growing in North America, adding about 35,000 new customers each year. Enbridge's gas distribution business also includes Enbridge Gas New Brunswick and interests in natural gas utilities in Quebec and upstate New York.

GREEN ENERGY

We're continuing our substantial investment in renewable energy and alternative technologies to support society's desire for a lower impact energy future. In 2011, we placed into service approximately 370 megawatts (MW) of new wind and solar generating capacity, including our first U.S. wind farm, the 250-MW Cedar Point Wind Energy Project in Colorado. We also entered the large and growing Quebec wind energy market through our $330-million investment in the 300-MW Lac Alfred Wind Project. As a result, we now have interests in close to 1,000 MW of renewable and alternative energy projects—including eight wind farms, three solar farms, a geothermal facility, four waste heat recovery facilities, and a fuel cell power plant. These have enough capacity to supply the power needs of over 270,000 homes and avoid approximately 1.4 million tonnes of greenhouse gas emissions each year.

POWER TRANSMISSION

We successfully entered the power transmission business in 2011 with our acquisition of the 300-MW Montana-Alberta Tie-Line (MATL) project, a 345-kilometre transmission line that will connect the prolific wind energy resource regime of Montana with the growing demand centre of Alberta.


Enbridge's operations are well positioned to connect growing and developing sources of energy to the people and places where it's needed.
Norman Wells
Horn River
Zama
Montney
Fort St. John
Oil Sands
Fort McMurray
Cheecham
Edmonton
Hardisty
Blaine
Calgary
Seattle
Lethbridge
Regina
Cromer
Portland
Gretna
Clearbrook
Bakken
Minot
Superior
Quebec City
Ottawa
Montreal
Toronto
Casper
Salt Lake City
Buffalo
Sarnia
Rockies/Niobrara
Toledo
Chicago
Marcellus
Patoka
Wood River
Cushing
Tulsa
Anadarko/Barnett/
Bossier/Haynesville
New Orleans
Houston
Gulf of Mexico
ENBRIDGE INC.
Headquarters: Calgary, Alberta, Canada
ENBRIDGE ENERGY PARTNERS, L.P.
Headquarters: Houston, Texas, USA
Liquids Systems and Joint Ventures
Enbridge Northern Gateway Project
Natural Gas Systems and Joint Ventures
Power Transmission
Gas Distribution
Solar Assets
Wind Assets
Geothermal Assets
Fuel Cell
Waste Heat Recovery


Responsible
energy
development

"HOW ARE YOU ADDRESSING DIFFERING VIEWS ABOUT ENERGY PROJECTS?"

Public concerns are a valid part of the conversation, and we're committed to transparent and open consultation about our projects.

We fully understand there are alternate points of view about energy development. We also understand that energy is essential for our society and our economy.

Energy at any cost isn't energy worth having—or delivering. That's why we consult openly and communicate frequently with communities located near our planned projects to build public awareness and understanding, gather comments and suggestions, and answer questions. It's also why we build and operate our infrastructure the way we do—with safety and integrity as our first priority and with respect for the people and the environment that our infrastructure impacts.

We're confident that we can continue to deliver the energy that powers our lives safely, reliably and efficiently—just as we've done for decades.

Energy *matters*

BY THE 2010 INVENTORY YEAR, WE HAD REDUCED OUR DIRECT GREENHOUSE GAS EMISSIONS BY

21%

BELOW 1990 LEVELS, WHILE INCREASING PIPELINE THROUGHPUT BY

47%

LEON ZUPAN
President, Gas Pipelines

Leon is responsible for the overall leadership of Enbridge's gas pipelines and processing businesses in Canada and the U.S., and prior to that was Senior Vice President, Operations overseeing Enbridge's Canadian and U.S. liquids pipelines.

"Public awareness of our buried facilities and maintenance activities is a vital element of pipeline safety. We're committed to open, transparent and ongoing consultation with the people who live along our pipeline rights-of-way and those who may become neighbours as our pipeline network grows."

"WHAT ARE YOU DOING ABOUT PIPELINE SAFETY?"

We'll never compromise on the safety and reliability of our pipelines and facilities. Safety is our top priority—for people, communities, the environment—and we're aiming to be the best.

In July 2010, Enbridge experienced the worst spill in our history near Marshall, Michigan. That incident has only strengthened our resolve to achieve our goal of zero spill incidents. We have and will continue to apply our learnings from that experience to our operations, and to share those learnings with industry to enhance pipeline safety for all.

Our ability to consistently provide safe and reliable operations and service is of paramount importance to us, our customers and the communities we serve. It's also a prerequisite for us in maintaining our social license to build and operate our infrastructure within the communities along our rights-of-way. In other words, it provides us with the foundation for our future growth.

Even though pipelines have been proven to be by far the safest and most efficient way of transporting oil and gas, we're working constantly to ensure safety by increasing the reliability of our pipelines and facilities.

We're reinforcing a high level of safety and operational integrity across the Company by investing in six program areas:

- integrity management;
- third-party damage avoidance and detection;
- leak detection capability and control systems;
- incident response capacity;
- worker and contractor occupational safety; and
- public safety and environmental protection.

We will strive to remain at or attain at least top-quartile performance in all of these critical program areas in the near term, with being best in class as our ultimate objective.

DAVID ROBOTTOM

Executive Vice President & Chief Legal Officer

David is responsible for Enbridge's legal teams, supporting the Company's businesses, growth initiatives and financial transactions.

"Building energy infrastructure involves thorough regulatory review processes that touch on all aspects of a project—from stakeholder consultation to economic benefits to engineering and construction. Enbridge has the in-house expertise to ensure we provide regulators—and our stakeholders—all of the information they need to make decisions on our projects."

"HOW CAN YOU DELIVER HYDROCARBONS AND STILL BE ENVIRONMENTALLY RESPONSIBLE?"

We recognize that our relationship with hydrocarbons comes with great responsibilities. These include reducing our own use of these fuels, minimizing their environmental impact, and investing in the development of alternative energy technologies for the future.

Just as we take great pride in meeting our primary social responsibility of safely and reliably delivering energy to people, we're also committed to conducting our business in an environmentally sustainable way.

For example, we set targets to lower our Canadian direct greenhouse gas (GHG) emissions. For the 2010 inventory year, we had reduced GHG emissions by 21% below 1990 levels, primarily through upgrading facilities and equipment. We achieved these reductions at the same time as increasing pipeline throughput by 47%. EGD in Ontario has also undertaken many initiatives to reduce GHG emissions, including the operation of 550 natural gas vehicles—the largest fleet in Canada.

Enbridge has formally committed to stabilizing its environmental footprint through our Neutral Footprint initiative. As of 2009, we're counteracting our environmental impacts within five years of their occurrence—planting a tree for every tree we remove; conserving an acre of natural habitat for every acre we permanently impact; and generating a kilowatt of renewable energy for every kilowatt of power our operations consume.

Energy matters

FOR THE FOURTH CONSECUTIVE YEAR, ENBRIDGE HAS BEEN RECOGNIZED AS ONE OF THE GLOBAL 100 MOST SUSTAINABLE CORPORATIONS IN THE WORLD. AMONG CANADIAN COMPANIES IN 2012, WE'RE RANKED

No.2

GUY JARVIS
President, Enbridge Gas Distribution

Guy is responsible for the overall leadership and operations of Enbridge Gas Distribution, Canada's largest natural gas utility, as well as Enbridge Gas New Brunswick, Gazifère and St. Lawrence Gas.

"Through our demand-side management programs and our incentive regulation sharing model, we're helping consumers make informed decisions about energy use and helping them get good value for every energy dollar they spend."

Between January 2009 and the end of 2011, we had made significant progress on these commitments. We had removed 589,850 trees and planted approximately 250,000. Over the same time period, we had disturbed almost 1,600 acres of natural habitat and through our work with the Nature Conservancy of Canada had conserved approximately 3,950 acres. Regarding our kilowatt-for-a-kilowatt commitment, we forecast our electricity consumption will increase in the future as new projects come on stream. However, at the same time Enbridge's electricity generation from renewable sources will also increase over time and we're on track to honour this commitment as well.

We're investing in a wide array of low-environmental-impact energy sources—both renewables (wind, solar and geothermal) and alternative technologies (fuel cell and waste heat recovery). These investments complement our core operations today and may one day form part of a sustainable energy future.

We're also helping our customers use energy wisely. EGD has a broad portfolio of demand-side management (DSM) programs that encourage our residential, commercial and industrial customers to adopt energy-saving equipment and reduce consumption of natural gas. Since 1995, EGD's DSM programs have cumulatively delivered approximately 6.1 billion cubic metres of natural gas savings (the equivalent of enough gas to supply approximately 1.9 million homes for one year) and net savings to customers of about $1.9 billion. Through these DSM activities, EGD has helped its customers avoid cumulatively approximately 11.5 million tonnes of carbon dioxide emissions.

Energy *matters*

WE NOW HAVE INTERESTS IN NEARLY

1,000 megawatts

OF RENEWABLE AND ALTERNATIVE ENERGY PROJECTS, WHICH HAVE THE CAPACITY TO POWER OVER 270,000 HOMES.

KAREN RADFORD

Executive Vice President, People & Partners

Karen leads Enbridge's Human Resources and Public & Government Affairs teams.

"We're passionate about supporting initiatives that deliver real, tangible benefits to the communities where we operate. For example, 11,000 riders made a commitment toward a cancer-free future by participating in our 2011 Enbridge Ride to Conquer Cancer in British Columbia, Alberta, Ontario and Quebec, which raised nearly $44 million to support cancer research, treatment and care."

"WHAT IMPACT DO YOU HAVE ON THE COMMUNITIES WHERE YOU OPERATE?"

Along with delivering the energy people count on, we deliver significant economic and social benefits to communities across North America.

We believe our success is rooted in treating people well, and we work hard every day to demonstrate to all of our stakeholders that we'll always live up to our core values of integrity, safety, and respect.

Across Canada and the United States, our business operations provide thousands of jobs and contracting opportunities. Over the years, we've also paid hundreds of millions of dollars in taxes that have ultimately been used in part to fund and operate public services and infrastructure, both locally and nationally.

We work with Aboriginal communities to ensure they achieve sustainable benefits from our projects and operations, including opportunities in equity partnership, training and education, employment, procurement, business development and community investment.

We also invest significantly in hundreds of charitable, non-profit and community organizations every year to help make communities better places to live. Through our dollars, partnerships and employees' initiatives, we support organizations that contribute to the economic and social development of communities near the Company's operations. We believe that these investments are essential to being a good neighbour and are a contributing factor in maintaining the Company's social license to operate.

Energy matters

ENBRIDGE'S SCHOOL PLUS PROGRAM PROVIDES FUNDING FOR EXTRACURRICULAR PROGRAMMING AT FIRST NATIONS SCHOOLS. SINCE 2009, THE PROGRAM HAS ENRICHED THE EDUCATION OF OVER

8,500

youth in over 50 schools.


Reliable
energy
investments

“IN THESE GLOBAL ECONOMIC CONDITIONS, WHY SHOULD I INVEST IN ENBRIDGE?”

Our unique combination of growth, dividends and reliability has delivered consistently great returns for our shareholders over the long term.

Enbridge’s growth has been strong and steady over the long term, and has been based on a wide range of business opportunities which have provided highly predictable earnings and cash flows.

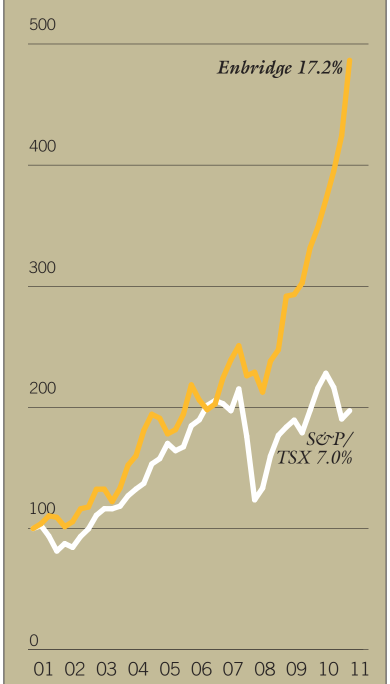
The demand for new energy infrastructure that continues to fuel Enbridge’s growth has also resulted in significant value creation for our shareholders.

In 2011 alone, our total shareholder return (TSR) reached 40% and we were the single largest positive contributor to the S&P/TSX Composite Index.

Looking back 10 years, Enbridge’s TSR has increased on average 17% per year, significantly outperforming the TSX Composite Index. While historical performance is not necessarily an indicator of future results, our formula for success remains unchanged going forward.

TOTAL SHAREHOLDER RETURN

Total Return Index December 2001=100



RICHARD BIRD

Executive Vice President, Chief Financial Officer & Corporate Development

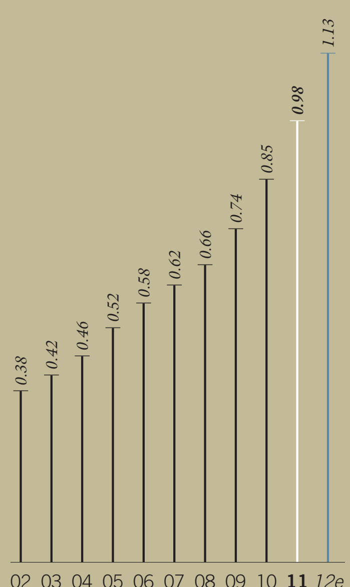
Richard is responsible for all financial affairs of the Company as well as corporate planning, mergers, acquisitions and corporate development. Richard is also responsible for Enbridge's green energy, international and energy services businesses.

"To support our growth plans, we place a very high priority on financial strength and flexibility, ensuring that we have access to capital when we need it and at the lowest possible cost."

DIVIDENDS

(Canadian dollars per share)

We have increased the dividend in each of the last 17 years and grown it by about 11% a year over the past decade.



VISIBLE GROWTH

Enbridge's growth is fueled by the ongoing need for new energy infrastructure development. In 2011 alone, we secured $8 billion in new growth projects across all of our business segments. As a result, by year-end we had $13 billion in secured growth projects, all of which we expect will be in service by 2015. These form part of the $48 billion in new opportunities that we have identified for development between 2011 and 2020.

We've achieved close to 10% average annual adjusted earnings per share (EPS) growth over the past decade, grew EPS 11% in 2011, and we're confident in achieving 10% average annual EPS growth from 2010 through the middle of this decade.

RELIABLE BUSINESS MODEL

Enbridge's business model produces adjusted earnings you can count on. That's because a substantial amount of Enbridge's earnings come from fees paid by customers for essential energy delivery services.

GROWING INCOME STREAM

Our shareholders place a great deal of value on the growing dividend that we provide, especially in the current low-interest rate environment. We've increased the dividend in each of the last 17 years, grown the dividend by more than 11% a year over the past decade, and we've never cut the dividend in our almost 60-year history as a publicly traded company. In 2010, 2011 and again in 2012, we increased the dividend by 15%. Looking ahead, we expect dividend growth will continue to track or exceed our strong EPS growth rate.

Whether it's delivering energy or delivering returns for our investors, we hold ourselves to very high standards.

FINANCIAL HIGHLIGHTS

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings per common share [1]	**1.32**	1.30	2.13
Adjusted earnings per common share [1]	**1.48**	1.33	1.17
Dividends paid per common share [1]	**0.98**	0.85	0.74
Common share dividends declared	**759**	648	555
Return on average shareholders' equity	**12.0%**	12.9%	22.2%
Debt to debt plus shareholders' equity	**64.6%**	66.7%	66.2%

OPERATING HIGHLIGHTS

Liquids Pipelines – Average deliveries *(thousands of barrels per day)*			
Canadian Mainline [2]	**1,554**	1,537	1,562
Regional Oil Sands System [3]	**329**	291	259
Spearhead Pipeline	**82**	144	121
Gas Pipelines, Processing and Energy Services – Average throughput volume *(millions of cubic feet per day)*			
Alliance Pipeline US	**1,564**	1,600	1,601
Vector Pipeline	**1,525**	1,456	1,334
Enbridge Offshore Pipelines	**1,595**	1,962	2,037
Gas Distribution – Enbridge Gas Distribution			
Volumes *(billions of cubic feet)*	**426**	409	408
Number of active customers *(thousands)* [4]	**1,997**	1,963	1,937

1 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

2 Canadian Mainline includes deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.

3 Volumes are for the Athabasca mainline and the Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.

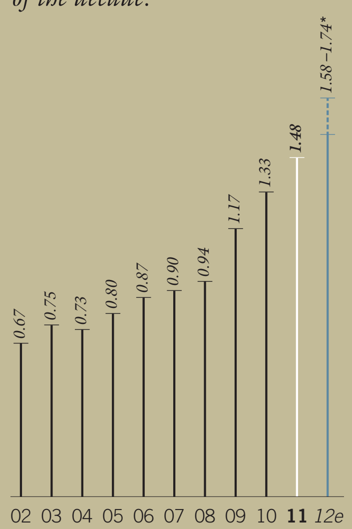
4 Number of active customers is the number of natural gas consuming EGD customers at the end of the period.

PAT DANIEL
Chief Executive Officer

DAVID ARLEDGE
Chair of the Board

ADJUSTED EARNINGS PER SHARE
(Canadian dollars per share)

We're confident we can achieve 10% in average annual EPS growth through the middle of the decade.



** 2012 earnings guidance announced December 7, 2011 of $1.58 to $1.74.*

Because energy matters to North Americans, Enbridge is constantly growing and expanding, all of which is translating into significant value creation for our shareholders.

Enbridge made tremendous progress on many fronts in 2011, with new projects continuing to be the main driver of our very impressive growth story.

We achieved significant cash flow growth in 2011 as we reaped the benefits of the many energy infrastructure projects we completed and placed into service over the past year.

Adjusted earnings per share rose 11% in 2011 to $1.48 per common share, building on a 14% increase in 2010.

Enbridge has outperformed the stock market over the last 50+ years. And while many investors may not be looking at an investment of 50 years, we run the Company as if they are.

Strides taken in 2011 will have a positive impact on Enbridge's future growth. We reached agreement with our Liquids Pipelines shippers on a 10-year Competitive Toll Settlement (CTS). We secured over $8 billion in attractive new growth projects across our existing businesses, including liquids pipelines, gas pipelines and distribution, green energy, and our new platforms of power transmission and the Canadian midstream gas sector.

On that basis, we are confident we can deliver a 10% average annual growth rate in adjusted earnings per share through the middle of this decade, based on conservative assumptions about throughput on our crude oil mainline system and future growth investments.

$48 BILLION IN OPPORTUNITIES

Enbridge today has a much larger and more broadly based suite of opportunities than we have ever had. Over $48 billion worth of individually identified opportunities are before us over the next 10 years. We plan to have invested $20 billion of this amount by the middle of the decade, $13 billion of which is already commercially secured.

Underpinning our growth story is our strong balance sheet and financial flexibility, together with an uncompromising focus on operational safety and integrity across all of our operations and assets.

The Board has increased the 2012 dividend by 15%. This follows similar increases in 2010 and 2011. Enbridge has increased its dividend by an average of 11% per year over the past decade, and we have never reduced the dividend to shareholders in our almost 60 years as a publicly traded company.

Looking ahead, our ability to continue to grow the dividend is supported by our ongoing success in securing new business development projects. All of our projects—whether they are within our liquids pipelines, gas pipelines and processing, green energy or gas distribution businesses—are aligned with our reliable business model, with long-term contracts or regulatory structures that allow us to be confident in our earnings and cash-flow growth targets into the future.

LIQUIDS PIPELINES

The new CTS on our mainline system that went into effect in 2011 is a win-win, providing shippers a competitive, stable and predictable toll while also providing the opportunity for better returns for Enbridge. Already, CTS is acting as a catalyst for advancing Enbridge's business development opportunities to extend our traditional market reach.

Enbridge's network is hard-wired into one of the largest reserves of crude oil in the world—Canada's oil sands—and we deliver into one the best markets for crude oil in the world—the U.S. Midwest. Those two anchors make our Liquids Pipelines business segment one of the strongest utility franchises in the world, and, as a strategic priority, we are moving ahead with expanding and extending our network to make it even stronger.

To connect growing oil sands production to upgraders and refineries, we are expanding our Alberta regional infrastructure, including a $1.2-billion twinning of our Athabasca Pipeline, which will add approximately 450,000 bpd of capacity to that line by 2015.

Simultaneously, we are broadening market access to the U.S. Gulf Coast for Canadian and U.S. crude oil production through two major initiatives:

- our acquisition in 2011 of a 50% interest in the Seaway Pipeline System and the reversal and twinning of that system, which will provide U.S. and Canadian producers new and timely options to transport crude oil from the oversupplied hub in Cushing, Oklahoma, to the U.S. Gulf Coast; and
- our program to twin our Spearhead Pipeline from Flanagan, Illinois, to Cushing, from where crude oil will move to Houston and Port Arthur, Texas, on the Seaway Pipeline System.

And we are continuing to expand our already extensive crude oil transportation systems in the Bakken region of southern Saskatchewan and northern North Dakota, which is one of the most prolific energy plays in North America. Our significant investments there are enabling Bakken producers to access multiple markets.

We are also working to broaden western Canadian shippers' access to markets by extending our network both east and west.

We are providing shippers of light crude oil produced in western Canada and the U.S. access to eastern refiners through the expansion of EEP's Line 5 light crude oil pipeline between Superior, Wisconsin, and Sarnia, Ontario, and by reversing a portion of Enbridge's Line 9 in western Ontario to permit crude oil movements eastbound to refineries in central Ontario and potentially to Montreal.

In the west, community hearings got underway in January 2012 for the Enbridge Northern Gateway Pipeline Project, a proposed crude oil export pipeline and condensate import

EXECUTIVE LEADERSHIP TEAM

(left to right)

D. GUY JARVIS
President, Enbridge Gas Distribution

LEON A. ZUPAN
President, Gas Pipelines

DAVID T. ROBOTTOM
Executive Vice President & Chief Legal Officer

JANET A. HOLDER
Executive Vice President, Western Access

J. RICHARD BIRD
Executive Vice President, Chief Financial Officer & Corporate Development

KAREN L. RADFORD
Executive Vice President, People & Partners

AL MONACO
President

STEPHEN J. WUORI
President, Liquids Pipelines

PATRICK D. DANIEL
Chief Executive Officer

pipeline running between Edmonton, Alberta and a proposed new marine terminal in Kitimat, British Columbia. This will be a very thorough and extensive regulatory process, conducted by the National Energy Board and the Canadian Environmental Assessment Agency.

We believe strongly that Northern Gateway is a tremendous opportunity for Canada. It will contribute significantly to Canada's national prosperity, and the strong commercial support we have received for the project from both Canadian oil producers and Asian markets reinforces the international importance of the project for Canada. There may never have been an energy project more in Canada's national interest than Northern Gateway, and we believe the sooner we are able to get the project in service, the better it will be for Canada and its trading partners.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

The strategic positioning of our natural gas assets is excellent, with exposure to many of the major North American gas plays—from northeast British Columbia to offshore Gulf of Mexico.

In 2011, we took a substantial initial step in the execution of our strategy to establish a strong position in the Canadian Midstream natural gas business with our $1.1-billion investment in the development of the Cabin Gas Plant, a natural gas processing facility in the prolific Horn River Basin natural gas play in northeast British Columbia. Midstream gas infrastructure in western Canada is an area of excellent growth potential. The Cabin investment aligns very well with Enbridge's reliable business model. The investment also comes with growth potential from future development.

In the United States, EEP is participating in a joint venture to build the 280,000-bpd Texas Express Pipeline. This pipeline will help producers in west and central Texas, the Rocky Mountains, southern Oklahoma and the mid-continent maximize the value of their natural gas production by providing additional NGL takeaway capacity and enhanced access to the Gulf Coast market.

In 2011, EEP further strengthened its competitive position in the prolific, liquids-rich Granite Wash area, which is primarily located in the Texas Panhandle region, placing its 150-mmcf/d Allison Gas Plant into service, upgrading its Sweetwater and Nine Mile gas plants, and starting construction of the 150-mmcf/d Ajax cryogenic processing plant.

Alliance Pipeline bolstered its strong position in the Bakken region in 2011, developing a natural gas pipeline lateral and associated facilities to facilitate movement of the region's high-energy, liquids-rich natural gas to the Aux Sable NGL processing facilities in Illinois. In addition, an affiliate of Aux Sable acquired two key assets in the Bakken region—the Palermo Conditioning Plant and the Prairie Rose Pipeline.

In the Gulf of Mexico, we have several very good new projects underway, with the $400-million Walker Ridge Gas Gathering System, $200-million Big Foot Oil Pipeline and $150-million Venice expansion all scheduled to be in service by 2014. Our strategy going forward is to optimize and grow our offshore business.

GAS DISTRIBUTION

EGD's customer base continues to grow solidly. Already the largest gas distribution franchise in Canada and one of the fastest growing in North America, EGD is adding approximately 35,000 new customers each year and expects to welcome its two millionth customer in Ontario this year. 2012 is the final year of EGD's current Incentive Regulation (IR) settlement and we expect to file our next generation IR plan for 2014 through 2018 later this year.

In 2011, Enbridge invested $144 million to acquire an additional interest in Noverco, bringing its total interest to 38.9%. Noverco holds a majority interest in Gaz Métro Limited Partnership, which owns gas distribution and gas pipelines assets in Quebec and gas and electric power distribution and transmission assets in Vermont.

GREEN ENERGY

In 2011, we advanced our strategy to invest in renewable energy sources that complement our core operations, generate solid returns and stable cash flow, and benefit the environment.

We celebrated the opening, ahead of schedule and under budget, of the Company's first U.S. wind farm, the 250-MW Cedar Point Wind Energy Project in Colorado. In Ontario, we placed into operation the 99-MW Greenwich Wind Project and the 5-MW Tilbury and 15-MW Amherstburg II solar projects.

In November, Enbridge announced it will invest $330 million in a 50% interest in the development of the 300-MW Lac Alfred Wind Project, marking our entry into the growing Quebec wind energy market, which is the second largest in Canada.

We also transferred a portfolio of Enbridge's renewable energy assets to Enbridge Income Fund (the Fund) for $1.2 billion, which both enhanced the distributable cash flow of the Fund and provided Enbridge with additional capital to reinvest into new growth opportunities.

The Company's interests in renewable and alternative generating capacity now total close to 1,000 MW.

POWER TRANSMISSION

Power transmission represents an attractive opportunity for Enbridge, with strong industry fundamentals and growth potential, and our acquisition in 2011 of the 300-MW MATL project was an excellent entry point for us.

The 345-kilometre transmission line from Great Falls, Montana, to Lethbridge, Alberta, is designed to take advantage of a growing supply of electric power in Montana, including green power production, and the buoyant power demand of Alberta. MATL has great fundamentals in terms of the Montana-to-Alberta power price differential, is fully contracted and has low-cost expansion potential.

We plan to build on this initial base to continue to grow within the power transmission sector, as well as potentially expanding into other electric platforms such as gas-fired power generation.

INTERNATIONAL

We continue to be very interested in international opportunities to support the Company's long-term growth.

We are currently evaluating a liquids pipeline project in Colombia, and while this will be a main focus for our international activities in 2012, we are also examining other opportunities elsewhere in the world that would fit within the Company's reliable business model.

SAFETY AND PIPELINE INTEGRITY

We made good progress in 2011 in further reinforcing the safety and operational integrity across all our business units, including the implementation of an Operations and Integrity Committee as the most senior committee in the Company.

Our Operational Risk Management Plan, which is a companion to our strategic business plan, focuses on six program areas—integrity management; third-party damage avoidance and detection; leak detection capability and control systems; incident response capacity; worker and contractor occupational safety; and public safety and environmental protection. Our ultimate objective is to be best in class in each of these six areas.

The safety and reliability of our existing assets provides us with the foundation for our future growth.

MANAGEMENT CHANGES

On February 27, 2012, the Board of Directors announced that Pat Daniel will retire on or before the end of 2012. The Board also announced the appointment of Al Monaco to the Board of Directors and to the position of President effective immediately. Pat will continue as CEO and a member of the Board until his retirement.

The Board wishes to recognize Pat's tremendous contribution to Enbridge over his tenure with the Company. Under his leadership, Enbridge's share price has grown by 250% and the average annual total shareholder return has been 15.8%. The market capitalization of the Company has grown from $6.8 billion in January 2001 to over $30 billion today. Enbridge's success is testament to Pat's keen sense of the needs of Enbridge's many stakeholders, his ability to successfully navigate through challenges, and his consistent, thorough and disciplined leadership style.

The Board places very high priority on succession planning and on developing people to ensure the Company's continuing success. Over his 30 years of experience in the energy industry, Al Monaco has demonstrated exceptional leadership capabilities across the range of Enbridge's businesses. The Board looks forward to working with both Al and Pat over the coming months as they transition leadership responsibilities.

With Al's appointment as President and our ongoing focus on broadening the experience of our senior management talent pool, the Company also announced several organizational changes. Leon Zupan has been appointed President, Gas Pipelines. Richard Bird has broadened his responsibilities to include Enbridge's green energy, international and energy services businesses. Steve Wuori has expanded his responsibilities to include the major projects group.

Also, in 2011, Janet Holder, who previously ran EGD, relocated to Prince George, British Columbia, as Executive Vice President, Western Access, with primary responsibility for the Northern Gateway Project. Guy Jarvis joined the executive management team as President of EGD. We also welcomed Karen Radford to the team as Executive Vice President, People and Partners, a new title that highlights our strong commitment to our employees and the communities in which we work.

Enbridge has an outstanding management team, and it will remain focused on the sustainability of profitable growth, on adding value for our customers, and on safe operations, the environment and our people.

Behind our many successes in 2011 and our continuing growth story are our 6,900 employees. We wish to thank each of them for their exceptional efforts in helping to establish Enbridge as a North American leader in the safe and reliable delivery of energy.

IN CONCLUSION

Few major corporations in North America have had the quarter-over-quarter, year-over-year success that Enbridge has achieved.

Our success is based on our ability to create strong and respectful relationships by adhering to our core values of safety, integrity, and respect for every single stakeholder who is linked to our business.

Energy matters to all of us. Across North America, we will continue to deliver the energy people count on every day, and we are fully committed to doing so safely and reliably well into the future.

DAVID A. ARLEDGE
Chair of the Board of Directors

PATRICK D. DANIEL
Chief Executive Officer

March 2, 2012

Corporate Governance

BOARD OF DIRECTORS

(left to right)

DAVID A. LESLIE
*Corporate Director,
Toronto, Ontario*

CHARLES W. FISCHER
*Corporate Director,
Calgary, Alberta*

PATRICK D. DANIEL
*Chief Executive Officer,
Enbridge Inc.,
Calgary, Alberta*

CHARLES E. SHULTZ
*Chair & Chief Executive Officer,
Dauntless Energy Inc.,
Calgary, Alberta*

J. HERB ENGLAND
*Chairman & Chief Executive Officer,
Stahlman-England Irrigation Inc.,
Naples, Florida*

CATHERINE L. WILLIAMS
*Corporate Director,
Calgary, Alberta*

GEORGE K. PETTY
*Corporate Director,
San Luis Obispo, California*

DAVID A. ARLEDGE
*Chair of the Board, Enbridge Inc.,
Naples, Florida*

J. LORNE BRAITHWAITE
*President & Chief Executive Officer,
Build Toronto,
Thornhill, Ontario*

V. MAUREEN KEMPSTON DARKES
*Corporate Director,
Lauderdale-by-the-Sea, Florida*

DAN C. TUTCHER
*Corporate Director,
Houston, Texas*

JAMES J. BLANCHARD
*Senior Partner, DLA Piper U.S., LLP,
Beverly Hills, Michigan*

AL MONACO
*President, Enbridge Inc.,
Calgary, Alberta*

At Enbridge, corporate governance means that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance with respect to the strategic plan of the Company and monitors implementation.

The Board approves all significant decisions that affect the Company and reviews its results. The Board also oversees identification of the Company's principal risks on an annual basis, monitors risk management programs, reviews succession planning and seeks assurance that internal control systems and management information systems are in place and operating effectively.

2011 Awards and Recognition

By focusing on our core values of Integrity, Safety and Respect, Enbridge has received local and international recognition for the way we run our business.

Listed below are some of the awards and recognition we received in 2011:

Corporate Knights Global 100 Most Sustainable Corporations in the World The Global 100 Most Sustainable Corporations in the World is an annual project initiated by *Corporate Knights* magazine with results announced at the World Economic Forum in Davos, Switzerland. The aim is to highlight the global corporations that have been most proactive in managing environmental, social and governance issues. Enbridge was named to the Global 100 in 2010, 2011, and again in January 2012.

Corporate Knights Best 50 Corporate Citizens in Canada
Corporate Knights magazine recognized Enbridge as being one of Canada's Best 50 Corporate Citizens, the ninth year in a row the Company has been recognized. Enbridge also made it onto the highly prestigious top 10 list, earning the number 10 spot overall. The ranking is the longest running of its kind and is determined based on a thorough analysis of contenders' environmental, social and governance indicators found in the public domain.

Canada's Top 100 Employers
Canada's Top 100 Employers project is a national competition to determine which employers lead their industries in offering exceptional workplaces for their employees. Enbridge was recognized for being an industry leader in attracting and retaining employees. This is the seventh consecutive year Enbridge has been on the list, and tenth since the list's inception 12 years ago.

Canada's Greenest Employers
Launched in 2007, this special designation recognizes the employers that lead the nation in creating a culture of environmental awareness in their organizations.

Canada's Top Employers for Young People This special designation recognizes the employers that offer the nation's best benefits for younger workers.

Alberta's Top Employers
Alberta's Top Employers is an annual competition organized by the editors of Canada's Top 100 Employers in partnership with the Human Resources Institute of Alberta. The award recognizes companies for best practices in recruitment and retention.

Carbon Disclosure Project
The Carbon Disclosure Project (CDP) ranked Enbridge in the top 15% of companies globally for GHG disclosure and management. The CDP is an independent not-for-profit organization working to drive GHG reduction and sustainable water use by business and cities.

Gold Champion Level Reporter (Canadian Standards Association's GHG Registry) The Canadian Standards Association awarded Enbridge Gold Champion Level Reporter status for its GHG emissions reporting.

Canadian Institute of Chartered Accountants Corporate Reporting Award The Corporate Reporting Awards, presented annually by the Canadian Institute of Chartered Accountants, showcase the best reporting models in the country. Enbridge received the 2011 Award of Excellence for Corporate Reporting in the Utilities & Pipelines/Real Estate industry sector and was recognized for both its financial and sustainable development reporting.

FINANCIAL RESULTS

Management's Discussion and Analysis

Consolidated Financial Statements

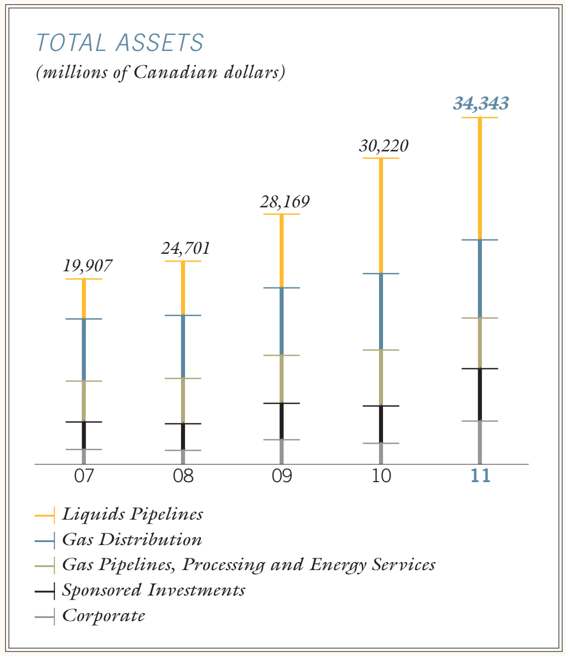
Notes to the Consolidated Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 21, 2012 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2011, prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

Overview

Enbridge is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has significant involvement in the natural gas transmission and midstream businesses. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a clean energy generator, Enbridge is expanding its interests in renewable and green energy technologies, including wind, solar and geothermal energy, as well as hybrid fuel cells. Enbridge employs approximately 6,900 people, primarily in Canada and the United States.



The Company's activities are carried out through five business segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines and processing facilities, green energy projects, Canadian midstream businesses, the Company's energy services businesses and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business and an interest in the development of Cabin Gas Plant (Cabin) in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico system. The energy services businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, corporate investments and financing costs not allocated to the business segments.

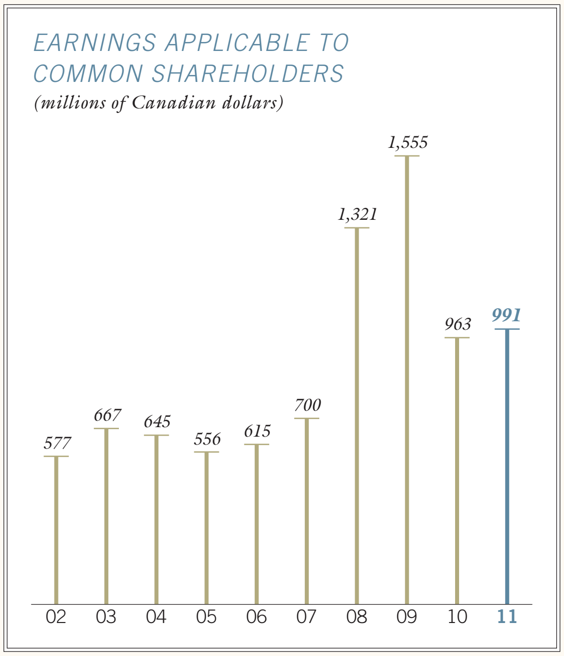
Performance Overview

	Three Months Ended December 31,		Year Ended December 31,		
	2011	2010	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)					
Earnings attributable to common shareholders					
Liquids Pipelines	**203**	117	**505**	512	445
Gas Distribution	**34**	60	**176**	155	186
Gas Pipelines, Processing and Energy Services	**157**	32	**293**	121	428
Sponsored Investments	**159**	56	**344**	137	141
Corporate	**(218)**	61	**(327)**	38	355
	335	326	**991**	963	1,555
Earnings per common share [1]	**0.44**	0.44	**1.32**	1.30	2.14
Diluted earnings per common share [1]	**0.44**	0.43	**1.30**	1.29	2.12
Adjusted earnings [2]					
Liquids Pipelines	**126**	117	**536**	512	454
Gas Distribution	**46**	54	**175**	167	154
Gas Pipelines, Processing and Energy Services	**41**	31	**163**	123	116
Sponsored Investments	**78**	48	**253**	209	151
Corporate	**(16)**	(12)	**(17)**	(27)	(20)
	275	238	**1,110**	984	855
Adjusted earnings per common share [1,2]	**0.37**	0.32	**1.48**	1.33	1.17
Cash flow data					
Cash provided by operating activities	**452**	375	**2,703**	1,851	2,017
Cash used in investing activities	**(2,179)**	(746)	**(4,017)**	(2,674)	(3,306)
Cash provided by financing activities	**1,221**	60	**1,380**	766	1,082
Dividends					
Common share dividends declared	**190**	163	**759**	648	555
Dividends paid per common share [1]	**0.2450**	0.2125	**0.98**	0.85	0.74
Revenues					
Commodity sales	**4,132**	3,280	**15,676**	11,990	9,720
Transportation and other services	**1,304**	863	**3,726**	3,137	2,746
	5,436	4,143	**19,402**	15,127	12,466
Total assets	**34,343**	30,220	**34,343**	30,220	28,169
Total long-term liabilities	**19,796**	18,542	**19,796**	18,542	16,392

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

2 *Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see pages 37 and 114.*

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS



Earnings attributable to common shareholders were $991 million, or $1.32 per common share, for the year ended December 31, 2011, compared with $963 million, or $1.30 per common share, for the year ended December 31, 2010. Earnings for 2011 reflected strong earnings growth from substantially all of the Company's business segments and also included the effect of non-cash, unrealized fair value derivative and foreign exchange gains and losses. Earnings for 2011 were also negatively impacted by non-recurring income taxes of $98 million incurred on an intercompany gain on sale to the Fund, not eliminated for accounting purposes.

Significant contributors to increased earnings included, within Liquids Pipelines, the Regional Oil Sands System which realized an increase in earnings in 2011 relative to prior year due to higher shipped volumes, increased tolls, the continued positive impact of terminal infrastructure additions and lower depreciation expense. Similarly, the Canadian Mainline delivered year-over-year growth on increasing volumes and favourable operating performance. Effective July 1, 2011, tolls on the mainline system are governed by the Competitive Toll Settlement (CTS), under which earnings are now subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms.

Within the Gas Pipelines, Processing and Energy Services segment, Energy Services benefited from favourable market conditions, as did Aux Sable which realized stronger fractionation margins compared with prior years. Also within this segment, earnings contributions were realized from newly sanctioned renewable energy projects including the Sarnia Solar and Talbot Wind projects, later transferred to the Fund, within Sponsored Investments, in the fourth quarter of the year, and the Cedar Point and Greenwich wind projects.

EEP earnings, within Sponsored Investments, increased for the year ended December 31, 2011, largely due to higher volumes both within EEP's liquids business and its natural gas business, which was bolstered by the addition of the Elk City Gathering and Processing System (Elk City System) acquired in September 2010, and higher incentive income.

Offsetting these increases in earnings were lower contributions from Southern Lights Pipeline and Spearhead Pipeline, which is experiencing lower volumes due to market pricing dynamics at Cushing, Oklahoma, and higher Corporate costs. Enbridge Offshore Pipelines (Offshore) earnings declined $30 million in 2011 relative to the prior year due to a slower regulatory permitting process and delayed drilling programs by producers in the Gulf of Mexico.

Earnings attributable to common shareholders were $963 million, or $1.30 per common share, for the year ended December 31, 2010, compared with $1,555 million, or $2.14 per common share, for the year ended December 31, 2009. The Company's earnings for 2010 included the positive impacts of projects coming into service in 2010, including Alberta Clipper, Southern Lights Pipeline and the Sarnia Solar Project. Compared with 2009, earnings have increased further due to customer growth in Gas Distribution and improved contributions from green energy, partially offset by less favourable weather conditions in the Company's gas distribution franchise areas. In 2009, significant one-time favourable items impacted earnings, including a $329 million gain on the disposal of Oleoducto Central S.A. (OCENSA) and unrealized derivative and intercompany foreign exchange gains.

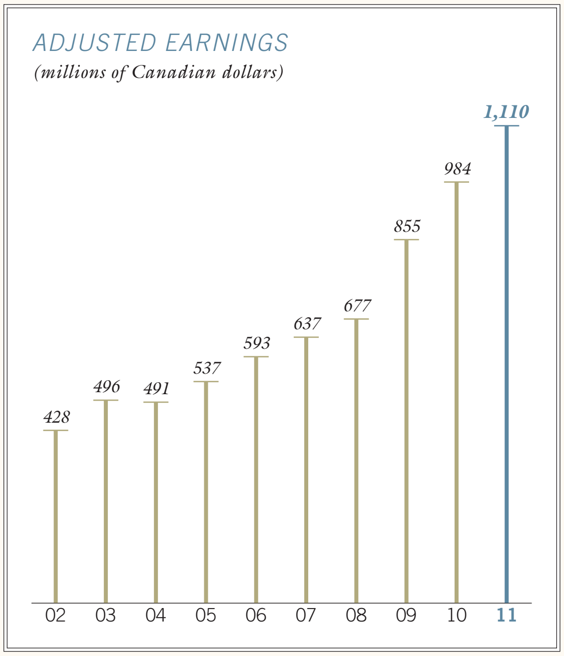
Additionally, 2011 and 2010 results were impacted by the 2010 Line 6A and 6B crude oil releases. Earnings for the year ended December 31, 2011 and 2010 included the Company's share of EEP's costs, before insurance recoveries and excluding fines and penalties, of $33 million and $103 million, respectively, related to these incidents. Lost revenue associated with downtime on both Line 6A and 6B of $3 million (net to Enbridge) further contributed to the decrease in earnings in 2010 compared with 2009. Earnings for the year ended December 31, 2011 included insurance recoveries of $50 million (net to Enbridge) related to the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners – EEP Lakehead System Line 6A and 6B Crude Oil Releases.*

Comparability of earnings attributable to common shareholders for the year ended December 31, 2011 with the prior years is impacted by the effect of unrealized derivative and intercompany foreign exchange gains and losses which totaled a loss of $132 million in 2011, a gain of $59 million in 2010 and a gain of $305 million in 2009. Further, earnings for the year ended December 31, 2009 reflected gains on the disposition of investments, including OCENSA, of $354 million, whereas no dispositions occurred in 2010 or 2011.

Earnings attributable to common shareholders for the three months ended December 31, 2011 were $335 million compared with $326 million for the fourth quarter of 2010. Fourth quarter earnings drivers are largely consistent with year-to-date trends and continued to include non-cash, unrealized fair value derivative and foreign exchange gains and losses. Unique to the fourth quarter of 2011 are reduced earnings from Gas Distribution due to warmer than normal weather, leak insurance recoveries of $29 million (net to Enbridge) and $98 million of income taxes on the intercompany gain on sale to the Fund not eliminated for accounting purposes.

ADJUSTED EARNINGS

Adjusted earnings for the year ended December 31, 2011 were $1,110 million, or $1.48 per common share, compared with $984 million, or $1.33 per common share, for the year ended December 31, 2010, an increase of 11% in adjusted earnings per common share. Adjusted earnings, which excludes the impact of non-recurring or non-operating items, for the year ended December 31, 2011 surpassed $1.0 billion for the first time in the Company's history, with higher contributions from substantially all of the Company's business segments driving strong overall earnings growth in the year. Significant drivers of the increase in adjusted earnings included increased volumes on the Company's liquids pipelines assets both in Canada and the United States, supported by robust activity in the oil sands region of Alberta, favourable fractionation margins and market conditions benefiting the Aux Sable and Energy Services businesses and increased contributions from a growing portfolio of renewable power generation assets. Areas of the Company's operations which realized year-over-year declines in adjusted earnings included Offshore, due to a slower regulatory permitting process and delayed drilling programs by producers in the Gulf of Mexico, and Spearhead Pipeline, which experienced lower volumes due to market pricing dynamics at Cushing, Oklahoma.



Adjusted earnings were $984 million, or $1.33 per common share, for the year ended December 31, 2010, compared with $855 million, or $1.17 per common share, for the year ended December 31, 2009. The increase in adjusted earnings primarily reflected contributions from projects coming into service, including the Alberta Clipper Project, the Southern Lights Pipeline and the Sarnia Solar Project, as well as strong performance from the Company's existing liquids and natural gas assets. The Company also realized improved adjusted earnings from Gas Distribution due to customer growth and favourable operating performance. Sponsored Investments further contributed to year-over-year increases in adjusted earnings, benefiting from higher contributions from EEP as a result of expansions and the acquisition of the Elk City System completed in 2010.

Adjusted earnings were $275 million, or $0.37 per common share, for the three months ended December 31, 2011, compared with $238 million, or $0.32 per common share, for the three months ended December 31, 2010. Positive contributors to increased adjusted earnings in the quarter included Gas Pipelines, Processing and Energy Services, whose Aux Sable and Energy Services businesses continued to benefit from favourable margins in the period, and Regional Oil Sands System which realized higher shipped volumes. Adjusted earnings from Sponsored Investments increased in the fourth quarter of 2011 due to strong results from EEP's natural gas business and higher general partner incentive income. Partially offsetting these items are lower adjusted earnings from Gas Distribution owing to lower other income. Commencing the fourth quarter of 2011, adjusted earnings from the Ontario Wind, Sarnia Solar and Talbot Wind projects are included within Sponsored Investments following the transfer of these assets to the Fund. These assets were previously reported under Gas Pipelines, Processing and Energy Services.

CASH FLOWS

The Company's strong operating results from its core assets and stable cash flow generation from growth projects placed into service in recent years resulted in cash provided by operating activities of $2,703 million for the year ended December 31, 2011, an increase over $1,851 million generated in the prior year. Operating cash flow, together with cash provided by financing activities, funded the Company's ongoing growth initiatives in 2011, including capital expenditures of $2,516 million and the strategic acquisition of a 50% interest in the Seaway Pipeline for $1.2 billion.

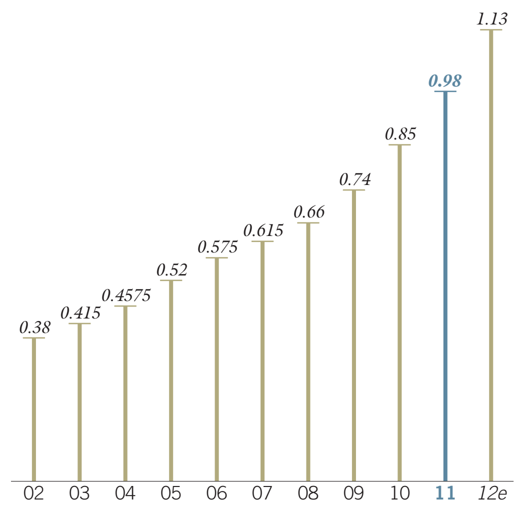
Financing activities for 2011 included normal course short-term borrowings and term note issuances, as well as the issuance of $926 million of preference shares. The partial monetization of Enbridge's interest in several renewable power generation assets through a transfer to the Fund generated net cash proceeds of $210 million that will be reinvested in further growth projects. These transactions are in keeping with the Company's strategy to diversify its funding sources and derive greater value for its investors through maintaining a low cost of capital.

DIVIDENDS

The Company has paid common share dividends since its public inception in 1953. Based on estimated 2012 dividends, the annual rate of increase has averaged 11.5% since 2002 and 10.2% since inception. In December 2011, the Company announced a 15% increase in its quarterly dividend to $0.2825 per common share, or $1.13 annualized, effective March 1, 2012. The Company continues to target a payout of approximately 60% to 70% of adjusted earnings as dividends and, with the most recent dividend increase, the 2012 payout is expected to be near the upper end of the range. In 2011, dividends paid per share were 66% of adjusted earnings per share (2010 – 64%; 2009 – 63%).

The chart shows dividends per common share for the last 10 years, as well as estimated dividends for 2012, based on the quarterly dividend of $0.2825 per common share declared by the Board of Directors on December 7, 2011.

DIVIDENDS PER COMMON SHARE
(millions of Canadian dollars)



REVENUES

The Company generates revenue from two primary sources: commodity sales and transportation and other services.

Commodity sales revenue of $15,676 million (2010 – $11,990 million; 2009 – $9,720 million) is earned through the Company's natural gas distribution and energy services activities. While revenues generated by the natural gas distribution business vary with the price of natural gas, earnings are not affected due to the pass through nature of these costs. Similarly, the impact of commodity prices on revenues derived from the Company's energy services activities do not directly impact earnings since such earnings reflect a margin or percentage of revenue which depends more on differences in commodity prices between locations and points in time than on the absolute level of prices. The period-over-period variances in commodity sales are primarily driven by natural gas and crude oil commodity prices and similar trends were experienced in commodity costs over these periods.

Transportation services revenue has increased from $2,746 million in 2009 to $3,137 million in 2010 and $3,726 million in 2011. This increasing trend reflects contributions from the Company's growth projects placed into service in recent years as well as increasing volumes within the Company's core liquids and natural gas businesses. Significant growth projects placed in service over this time period include the initial phase of the Sarnia Solar Project in December 2009 followed by an expansion in 2010, Alberta Clipper in April 2010 and the Southern Lights Pipeline in July 2010. The Talbot Wind Energy Project commenced operations near the end of 2010, as did several Bakken-area expansion projects completed by the Company's Sponsored Investments.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings or adjusted earnings; expected earnings or adjusted earnings per share; expected costs related to projects under construction; expected in-service dates for projects under construction; expected tariffs for pipelines; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and NGLs; prices of crude oil, natural gas and NGLs; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas and NGLs, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings or adjusted earnings and associated per share amounts, or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company's dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by Canadian GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

Corporate Vision

Enbridge's vision is to be the leading energy delivery company in North America. The Company transports, generates and distributes energy. By doing so, we deliver value to shareholders. The Company's objective is to generate superior economic value for shareholders through securing, constructing and operating energy infrastructure projects that are consistent with its investment value proposition: visible growth, a reliable business model and a growing income stream. Consistently applied, such stewardship should continue to generate attractive returns on invested capital and, in turn, provide for growing dividend distributions and capital appreciation to its shareholders.

At Enbridge, we integrate our core values into our daily activities, helping us work toward achieving our collective vision. Our values include integrity, safety and respect.

Corporate Strategy

In support of its long-term vision, the Company employs six key strategies that guide decision making across the enterprise:

1. Focusing on Operations and System Integrity;
2. Strengthening Our Core Businesses;
3. Developing New Platforms for Growth and Diversification;
4. Developing People;
5. Responding to Environmental Priorities; and
6. Preserving Financial Strength and Flexibility.

Enbridge's strategies are reviewed annually with direction from its Board of Directors and incorporate perspectives on macroeconomic conditions in North America and globally, evolving energy supply and demand fundamentals, changing customer demands, stakeholder expectations and competitor behaviors.

1. FOCUSING ON OPERATIONS AND SYSTEM INTEGRITY

Effective management of operations and project execution is the foundation of Enbridge's strategic plan. The overarching objective and priority of the business is to ensure the safety and reliability of our delivery systems for our customers, the public and our employees. To support this objective and to emphasize the operational focus of our business, the Company has organized its operations along functional lines and has substantially increased the amount of capital that will be directed towards maintenance and integrity programs.

Timely and cost-effective execution of an existing slate of $13 billion commercially secured projects continues to be a key priority for Enbridge. Project execution is a core competency at Enbridge and the Company continues to build upon its project management skills and processes, primarily through the Major Projects support team which was established in early 2008. Major Projects focuses on project execution success factors such as cost estimation, regulatory permitting, material and labour sourcing and project governance.

2. STRENGTHENING OUR CORE BUSINESSES

The Company has an established history of serving the transportation needs of key North American crude oil and natural gas markets and our Liquids Pipelines and natural gas segments will continue to be central to delivering our value proposition to investors. However, faced with evolving supply and demand fundamentals and increased competition, strategies to strengthen the Company's core businesses and to expand and extend our asset base in these areas are critical to meet the Company's long-term objectives.

Within the Liquids Pipelines segment, strategies are focused on maintaining the competitiveness of mainline assets, pursuing new market access opportunities and strengthening the Company's position in the Alberta oil sands and Bakken regions. The 10-year CTS reached with shippers in 2011 was an important first step in executing this broader strategy. The CTS provides a stable and competitive toll to shippers and preserves and enhances throughput on the Canadian mainline system for Enbridge. The CTS provides the foundation to support further extensions off the mainline system and the Company continues to pursue opportunities to provide its customers broader market access for Canadian bitumen and synthetic crude oil, including expansion initiatives to the Texas Gulf Coast. In late 2011, the Company announced it had acquired a 50% interest in the Seaway Pipeline system and that it was proceeding with the Gulf Coast Access initiative, which will offer shippers access to the Gulf Coast refining complex. The Company's efforts to expand market access and provide the highest netback for producers also include eastern market access opportunities and development of the proposed Northern Gateway pipeline, which would provide access to markets off the Pacific coast of Canada.

Regional liquids pipeline development involves projects which connect new oil sands production to existing hubs on the Canadian mainline. Enbridge, the largest pipeline operator in the oil sands region of Alberta, is currently is developing close to $3.4 billion in commercially secured regional oil sands transportation facilities that are being placed into service between 2011 and 2015. The Company also has $0.8 billion of secured system expansion projects in Saskatchewan and North Dakota where the Company is strategically located to capture increased production from the Bakken play.

The fundamentals of the natural gas market in North America have been altered significantly in recent years with the emergence of unconventional shale gas plays. The Company's natural gas strategies include leveraging the competitive advantages of existing assets and expanding its footprint in these emerging areas, including establishment of a Canadian midstream position. Alliance Pipeline is well positioned to service developing regions in northeast British Columbia and the Bakken play, and is continuously evaluating opportunities to expand its service offerings in those areas as well as strategies to attract liquids rich gas onto the system. Development of the Montney and Horn River shale plays is also creating the need for additional Canadian midstream infrastructure; an opportunity which fits with the Company's investment value proposition and which can leverage existing operational expertise. The Company made a significant investment in the Canadian midstream business in October 2011 with the acquisition of a majority stake in Cabin in the Horn River basin. Within the United States, strategic priorities include expanding gathering and processing capacity, particularly in the Granite Wash area, and seeking opportunities to expand its service offerings, including NGL transportation. In addition to these onshore strategies, the Company continues to pursue crude oil and natural gas gathering expansion opportunities for ultra-deep projects in the Gulf of Mexico.

3. DEVELOPING NEW PLATFORMS FOR GROWTH AND DIVERSIFICATION

The development of new platforms to diversify and sustain long-term growth is an important strategy for Enbridge. Renewable energy is a source of new growth as government initiatives and changing social beliefs focused on lower carbon emissions are creating opportunities to deliver green energy solutions with risk and return characteristics consistent with Enbridge's investment value proposition. Renewable energy is also an important part of Enbridge's environmental and corporate social responsibility (CSR) strategies. Enbridge has advanced its green energy strategy over the last several years and has interests in a renewable energy portfolio of close to 1,000-megawatts (MW). Near term priorities will focus on expansion of existing sites and pursuit of relationships with existing developers that have a suite of development projects. The Company is also assessing opportunities to invest in gas-fired generation which is projected to grow significantly over the long-term based on natural gas supply fundamentals.

Power transmission is also an attractive growth opportunity for the Company and a complement to its renewable energy strategy. Substantial transmission needs exist in North America with risk and return profiles that fit Enbridge's investment value proposition. The Company's strategy in this area is to establish an initial base of assets and an experienced management team. Enbridge's first step in this regard was achieved in late 2011 with the acquisition of the Montana-Alberta Tie-Line (MATL) transmission project and integration of the project development management team into Enbridge.

Internationally, there is a growing need for energy infrastructure which provides further opportunities for Enbridge to grow and diversify. Enbridge's international business development strategy focuses on select regions with strong supply and demand fundamentals and favourable investment climates.

Enbridge's Alternative and Emerging Technology program continues to identaqify early stage energy technologies that complement the Company's core businesses and provide potential for further growth.

4. DEVELOPING PEOPLE

Attracting, developing and retaining high performing and effective employees and leaders continue to be strategic priorities for Enbridge. Key priorities related to building and improving Enbridge's organizational and workforce capabilities include:

- Developing workforce optimization strategies and determining optimal staffing models;
- Ensuring leadership continuity and readiness with an increased focus on succession management, leadership development and mentorship;
- Refreshing Enbridge's core values and embedding them within all talent management practices;
- Implementing an enterprise wide change management approach and building change management capability within the organization; and
- Standardizing processes and systems.

5. RESPONDING TO ENVIRONMENTAL PRIORITIES

Enbridge believes it must have effective strategies to respond to environmental and other corporate responsibilities. Enbridge adheres to a strong set of corporate values, has adopted a number of corporate responsibility policies and practices and has made significant investments in renewable and alternative energy technologies.

Enbridge defines CSR as conducting business in an ethical and responsible manner, protecting the environment and the safety of people, providing economic and other benefits to the communities in which we operate, supporting universal human rights and employing a variety of policies, programs and practices to manage corporate governance and ensure fair, full and timely disclosure. Enbridge's 2011 CSR Report can be found at *http://csr.enbridge.com/*. None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.

The Company's Neutral Footprint plan includes commitments to counteract the environmental impact of Enbridge's operations since January 2009 within five years of their occurrence. Enbridge Neutral Footprint commitments include:

- planting a tree for every tree we remove to build new facilities;
- conserving an acre of land for every acre of wilderness we permanently impact; and
- generating a kilowatt of renewable energy for every kilowatt our operations consume.

To achieve its Neutral Footprint goal, Enbridge is working with the Nature Conservancy of Canada, The Conservation Fund in the United States and others. As reported in Enbridge's 2011 CSR Report, progress on the Company's Neutral Footprint initiatives (which are subject to change based on changes in the Company's operations) includes:

- 589,850 trees removed; 246,000 tree seedlings planted;
- 1,598 acres disturbed; 3,955 acres conserved through the Nature Conservancy of Canada;
- forecasted growth in power consumption (from 2008 to 2015) is 1,852 gigawatts per hour (GWh); power currently generated from renewable sources is approximately 1,900 GWh.

6. PRESERVING FINANCIAL STRENGTH AND FLEXIBILITY

The maintenance of adequate financial strength and flexibility is fundamental to Enbridge's growth strategy. Enbridge's financial strategies are designed to ensure the Company has sufficient liquidity to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain or improve Enbridge's credit ratings, diversify its funding sources and maintain substantial bank credit facilities and ready access to capital markets in both Canada and the United States.

A key tenet of the Company's reliable business model is mitigation of exposure to market price risks. The Company has robust risk management processes which ensure earnings volatility from market price risk is managed within the parameters of its earnings-at-risk policy. Enbridge will continue to proactively hedge interest rate, foreign exchange and commodity price exposures. Management of counterparty credit risk also remains an ongoing priority.

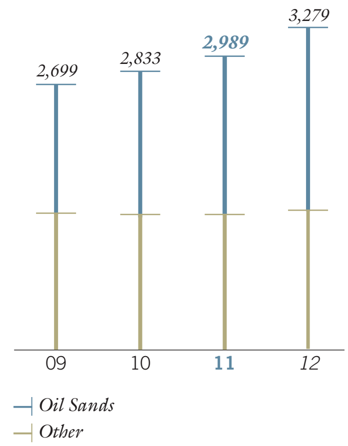
Enbridge's strategy is reviewed annually with direction from its Board of Directors. The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial benchmarks before being pursued.

Industry Fundamentals

SUPPLY AND DEMAND FOR LIQUIDS

Canadian crude oil exports to the United States continue to grow, further solidifying Canada as its number one supplier. Combined conventional and oil sands established reserves of approximately 173 billion barrels suggest that this trend will continue, albeit against growing concern over the environmental footprint of oil sands crude. The National Energy Board (NEB) estimates that total Western Canadian Sedimentary Basin (WCSB) production averaged approximately 2.8 million barrels per day (bpd) in 2011 (2010 – 2.6 million bpd; 2009 – 2.4 million bpd).

CANADIAN CRUDE OIL PRODUCTION
(thousands of barrels per day)



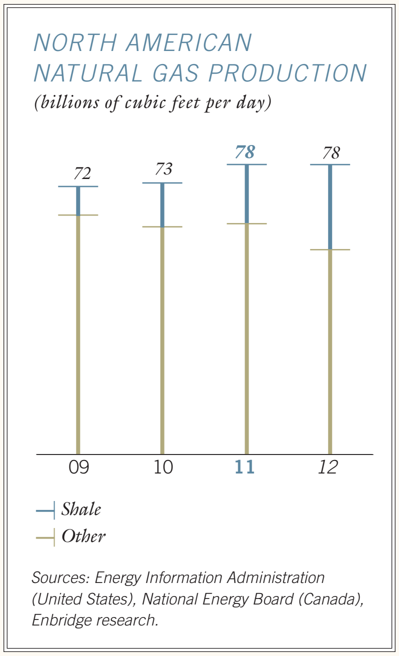
Sources: National Energy Board, Canadian Association of Petroleum Producers.

Other than the WCSB, significant growth is forecasted to come from the Bakken Play in North Dakota and eastern Montana. Despite production problems as a result of severe weather in early 2011, production from this area grew from 371 thousand barrels per day (kbpd) in 2010 to an estimated 466 kbpd in 2011. Starting in July 2011, with the reversal of the Portal Link connecting EEP's North Dakota System with the Saskatchewan System, the Canadian Mainline began to receive up to 25 kbpd of United States Bakken crude at Cromer, Manitoba. This volume will increase to a maximum of 145 kbpd with the completion of the Bakken Expansion program in 2013.

Sustained oil prices have led to a resurgence in oil sands project announcements that had slowed during the economic downturn. These announcements provide optimism for oil sands production growth in the medium term. The question remains whether industry can avoid the capital cost inflation which overwhelmed projects during the most recent boom as companies competed for resources. The Canadian Association of Petroleum Producers' June 2011 growth case estimates indicate that future WCSB production is expected to steadily increase by 5.3% annually to approximately 4.6 million bpd by 2025. This forecasted growth is largely attributed to increased oil sands production in Alberta.

World crude oil demand was approximately 700 kbpd higher in 2011 relative to 2010, with China being the major contributor of demand growth. Although North American demand growth remains relatively flat, and is projected to remain that way in the near future, Canadian crude exports to the United States Midwest are growing while United States overall crude imports from other countries have declined relative to past years. Planned reconfiguration of refineries in the Midwest will increase the demand for Canadian crude in one of Enbridge's key markets. Further, the Company's planned incremental pipeline capacity into the Texas Gulf Coast refining complex will serve to expand market access and improve netbacks for Canadian producers. While improved Gulf Coast access is an important step to diversify markets for Canadian crude, an industry solution to efficiently access growing Asian markets off the west coast of Canada is needed and is currently under development by Enbridge with industry support.

With the expected increase in heavy oil production in western Canada, there is an increasing requirement for condensate to be used as a blending agent in order to transport these high viscosity volumes to market. Condensate is a light hydrocarbon which is conventionally a byproduct of natural gas production. Production of this commodity is decreasing in western Canada but, with the increasing demand for diluents from heavy oil producers, there is an increasing need to import condensate. Currently, volumes are transported via Enbridge's Southern Lights condensate pipeline, via rail to Alberta from the United States and from international sources via tankers and rail from the West Coast.



SUPPLY AND DEMAND FOR NATURAL GAS

Evolving drilling and completion technologies have unlocked vast gas resources from unconventional reservoirs, primarily shale plays, and have led to oversupplied markets in North America. Recent estimates of gas resources for the United States and Canada total approximately 2,600 trillion cubic feet (tcf). With current combined annual gas production of approximately 27 tcf, the United States and Canada have almost 100 years of gas supply. Moreover, as producers continue to improve well productivity and drilling efficiency for unconventional gas, the average unit cost of developing gas supply has fallen over the past few years. Considering the abundant resource base and lower development costs, North America is expected to experience a relatively low gas price environment for the foreseeable future.

With the expectation of weak gas prices over the near-term, producers are expected to continue their shift in focus away from dry gas to more competitive liquids-rich gas and oil targets. The Marcellus, Eagle Ford and Granite Wash rich-gas plays remain prime targets in the United States. As well, activity is picking up in the offshore Gulf of Mexico as an increasing number of drilling permits are issued focused on oil production, which would lead to additional associated gas production. In Canada, drilling strategies are similar with the focus on liquids-rich gas plays in northeast British Columbia and the Alberta Deep Basin.

Gas supply is expected to continue to outpace demand growth as the North American economy struggles to advance. In contrast to low gas prices, oil prices are expected to be strong, driven by demand growth in developing countries. As such, the wide disparity between gas and oil prices should continue to support the extraction of NGL with favorable fractionation spreads.

Growth in industrial gas demand has been sluggish as the economic recovery has been slow. While economic growth is expected to continue to be weak over the next few years, low gas prices should enable a larger amount of coal-fired generation to be displaced by more competitive gas units. Further, proposed environmental regulations in the Lower 48 would cause the retirement of some older, less efficient coal generators and potentially increase gas-fired generation's share of the overall power production portfolio. Growth in gas-fired generation is expected to lead overall gas demand in North America. Canadian gas demand will also be driven by the development of oil sands projects. The United States Energy Information Administration (EIA) and the NEB estimate North American gas demand to be approximately 31 tcf in 2035; a 15% increase from 2010.

The prospect of relatively low domestic gas prices continuing over the longer-term have spurred the progress of multiple projects to export liquefied natural gas from North America to higher-priced global markets, which are primarily linked to oil prices. Export authorization has been granted to several Canadian and United States projects with first deliveries occurring as early as mid-decade.

SUPPLY AND DEMAND FOR GREEN ENERGY

Traditional forms of energy are expected to represent the major source of future North American energy supply; however, a shift to a lower carbon intensive economy, prompted mainly by government policy, exists. As overall North American energy needs continue to grow, particularly the need for electricity to meet industrial and residential demand, opportunities arise for renewable energy projects to capture a significant portion of incremental and replacement generation capacity over the next 25 years.

Growth in North American electricity demand is expected to average approximately 1% annually. The EIA forecasts that new United States generating capacity of over 200 gigawatts (GW) will be required by 2035, with renewable sources playing an increasing role. Growth in nuclear and coal-fired generation is expected to be limited due to permitting challenges, long lead times, capital cost and uncertainty of environmental regulations, leaving opportunity for renewable sources to meet a critical portion of the incremental demand.

The United States National Renewable Energy Laboratory reports that North America has significant wind and solar resources, with wind alone having the potential for over 10,000 GW of power generation. Solar resources in south western states such as Arizona, California, Colorado and Nevada are the best in the world for large-scale solar plants. In Canada, Environment Canada reports an abundance of wind resources, particularly in the north eastern regions.

Expanding renewable energy infrastructure in North America is not without challenges. Projects are typically capital intensive and renewable technology is in the early stages relative to mature energy sources. Further, renewable projects must balance the benefit of reduced carbon emissions with land disturbances and project aesthetics. High quality wind and solar resources are often found in regions at long distances from high demand markets, introducing the need for new transmission capacity.

Many factors will impact the pace of future development in renewable energy, including, but not limited to, the pace of economic recovery; technological advances; future energy or climate change regulations; and continued government support. The forecasted increase in power generation arising from renewable sources is in part supported by government incentives. The continuing ability to obtain tax or other government incentives and the ability to secure long-term power purchase agreements through government or investor-owned power authorities is required to support project economics, based on current costs and technologies. Alternative energy sources are expected to play an increasingly important role in meeting future North American energy demand with a continued drive to develop and promote green energy.

Growth Projects

In 2010, Enbridge was successful in placing almost $7 billion of new growth projects into service, including the $3.5 billion Alberta Clipper project, the largest liquids pipeline project in the Company's history, as well as the $2.3 billion Southern Lights Pipeline. In 2011, the Company was very successful in re-stocking its growth project inventory by securing close to $8 billion in new infrastructure growth projects across many of its businesses, including Liquids Pipelines, Canadian gas midstream, Texas gathering and processing, offshore Gulf of Mexico gas processing, renewable power generation and power transmission. The Company now has approximately $13 billion in commercially secured growth projects that have or are expected to come into service between 2011 and 2015. Further, the Company has identified an additional $35 billion of potential opportunities for development over the 2011 – 2020 time horizon.

The table below summarizes the current status of the Company's commercially secured projects, separated into the Company's business segments. This inventory of growth projects provides confidence to Enbridge management that the Company will be able to achieve an average annual earnings per share growth of 10% through the middle of this decade, based on conservative assumptions.

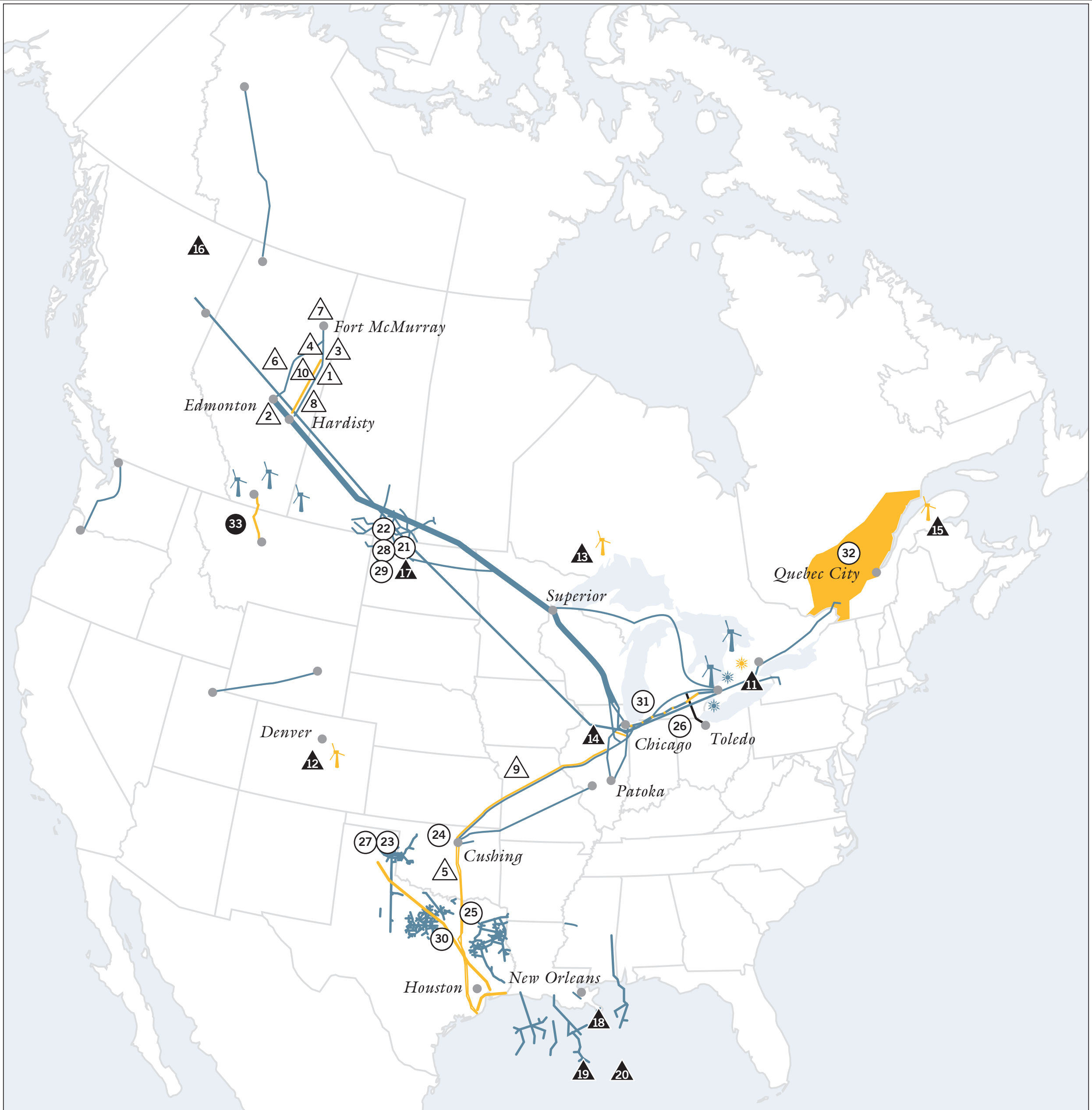
	Actual/Estimated Capital Cost [1]	Expenditures to Date	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
Liquids Pipelines				
1. Christina Lake Lateral Project	$0.2 billion	$0.2 billion	2011	Substantially complete
2. Edmonton Terminal Expansion	$0.3 billion	$0.1 billion	2012	Under construction
3. Woodland Pipeline	$0.3 billion	$0.2 billion	2012	Under construction
4. Wood Buffalo Pipeline	$0.4 billion	$0.2 billion	2012	Under construction
5. Seaway Crude Pipeline System (including reversal and extension)	US$1.5 billion	US$1.2 billion	2012 – 2013 (in phases)	Pre-construction
6. Waupisoo Pipeline Capacity Expansion	$0.4 billion	$0.1 billion	2012 – 2013 (in phases)	Under construction
7. Norealis Pipeline	$0.5 billion	No significant expenditures to date	2013	Under construction
8. Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.1 billion	2013 – 2014 (in phases)	Pre-construction
9. Flanagan South Pipeline Project	US$1.9 billion	No significant expenditures to date	2014	Pre-construction
10. Athabasca Pipeline Twinning	$1.2 billion	No significant expenditures to date	2015	Pre-construction
Gas Pipelines, Processing and Energy Services				
11. Amherstburg Solar Project	$0.1 billion	$0.1 billion	2011	Complete
12. Cedar Point Wind Energy Project [2]	US$0.5 billion	US$0.5 billion	2011	Complete
13. Greenwich Wind Energy Project	$0.3 billion	$0.3 billion	2011	Complete
14. Prairie Rose Pipeline and Palermo Conditioning Plant	US$0.1 billion	US$0.1 billion	2011	Complete
15. Lac Alfred Wind Project	$0.3 billion	$0.1 billion	2012 – 2013 (in phases)	Under construction
16. Cabin Gas Plant	$1.1 billion	$0.4 billion	2012 – 2014 (in phases)	Under construction
17. Tioga Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
18. Venice Condensate Stabilization Facility	US$0.2 billion	No significant expenditures to date	2013	Pre-construction
19. Walker Ridge Gas Gathering System	US$0.4 billion	No significant expenditures to date	2014	Pre-construction
20. Big Foot Oil Pipeline	US$0.2 billion	No significant expenditures to date	2014	Pre-construction

		Actual/Estimated Capital Cost [1]	Expenditures to Date	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)					
Sponsored Investments					
21.	EEP – Bakken Expansion Program	US$0.4 billion	US$0.1 billion	2013	Under construction
22.	The Fund – Bakken Expansion Program	$0.2 billion	No significant expenditures to date	2013	Pre-construction
23.	EEP – Allison Cryogenic Processing Plant	US$0.1 billion	US$0.1 billion	2011	Complete
24.	EEP – Cushing Terminal Storage Expansion Project	US$0.1 billion	No significant expenditures to date	2011 – 2012 (in stages)	Under construction
25.	EEP – South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+	Under construction
26.	EEP – Eastern Market Expansion	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
27.	EEP – Ajax Cryogenic Processing Plant	US$0.2 billion	No significant expenditures to date	2013	Under construction
28.	EEP – Bakken Access Program	US$0.1 billion	No significant expenditures to date	2013	Under construction
29.	EEP – Berthold Rail Project	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
30.	EEP – Texas Express Pipeline	US$0.4 billion	No significant expenditures to date	2013	Pre-construction
31.	EEP – Line Replacement Program	US$0.3 billion	No significant expenditures to date	2013	Pre-construction
Corporate					
32.	Noverco	$0.1 billion	$0.1 billion	2011	Complete
33.	Montana-Alberta Tie-Line	US$0.3 billion	US$0.2 billion	2012 – 2013 (in stages)	Under construction

1 *These amounts are estimates only and subject to upward or downward adjustment based on various factors. As appropriate, the amounts reflect Enbridge's share of joint venture projects.*

2 *Expenditures to date reflected total expenditures before receipt of US$0.1 billion payment from the United States Treasury. See Growth Projects – Gas Pipelines, Processing and Energy Services – Cedar Point Wind Energy Project.*

Risks related to the development and completion of growth projects are described under *Risk Management and Financial Instruments*.



△ Liquids Pipelines

1 Christina Lake Lateral Project
2 Edmonton Terminal Expansion
3 Woodland Pipeline
4 Wood Buffalo Pipeline
5 Seaway Crude Pipeline System (including reversal and extension)
6 Waupisoo Pipeline Capacity Expansion
7 Norealis Pipeline
8 Athabasca Pipeline Capacity Expansion
9 Flanagan South Pipeline Project
10 Athabasca Pipeline Twinning

▲ Gas Pipelines, Processing and Energy Services

11 Amherstburg Solar Project
12 Cedar Point Wind Energy Project
13 Greenwich Wind Energy Project
14 Prairie Rose Pipeline and Palermo Conditioning Plant
15 Lac Alfred Wind Project
16 Cabin Gas Plant
17 Tioga Lateral Pipeline
18 Venice Condensate Stabilization Facility
19 Walker Ridge Gas Gathering System
20 Big Foot Oil Pipeline

○ Sponsored Investments

21 EEP – Bakken Expansion Program
22 The Fund – Bakken Expansion Program
23 EEP – Allison Cryogenic Processing Plant
24 EEP – Cushing Terminal Storage Expansion Project
25 EEP – South Haynesville Shale Expansion
26 EEP – Eastern Market Expansion
27 EEP – Ajax Cryogenic Processing Plant
28 EEP – Bakken Access Program
29 EEP – Berthold Rail Project
30 EEP – Texas Express Pipeline
31 EEP – Line Replacement Program

● Corporate

32 Noverco
33 Montana-Alberta Tie-Line

Current Assets
Growth Opportunities

LIQUIDS PIPELINES

CHRISTINA LAKE LATERAL PROJECT

The Christina Lake Lateral Project includes a new pipeline terminal and blended products pipeline, which will allow the Cenovus and ConocoPhillips partnership to deliver increased Christina Lake production volumes directly into the Athabasca Pipeline. Upon substantial completion in August 2011, the expansion project added two 375,000 barrel tanks and 26 kilometres (16 miles) of 30-inch diameter pipeline to the existing Christina Lake lateral and terminal facilities, which include two eight-inch lateral lines and 240,000 barrels of tankage, that connect to the Athabasca Pipeline. The final cost of the additional facilities is approximately $0.2 billion.

EDMONTON TERMINAL EXPANSION

The Edmonton Terminal Expansion Project involves expanding the tankage of the mainline terminal at Edmonton, Alberta by one million barrels at an estimated cost of $0.3 billion, with expenditures to date of approximately $0.1 billion. The expansion is required to accommodate growing oil sands production receipts both from Enbridge's Waupisoo Pipeline and other non-Enbridge pipelines. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of three booster pumps and related infrastructure. Regulatory approval was received in the first quarter of 2011 and, subject to receipt of other approvals, the expansion is expected to be completed in 2012.

WOODLAND PIPELINE

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties to provide for the transportation of blended bitumen from the Kearl oil sands mine to crude oil hubs in the Edmonton, Alberta area. The project will be phased with the mine expansion, with the first phase involving construction of a new 140-kilometre (87-mile) 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on Enbridge's existing Waupisoo Pipeline from Cheecham to the Edmonton area. The new Woodland Pipeline may be extended from Cheecham to Edmonton as part of future industry expansions. Regulatory approval for the Phase I facilities was received in June 2010 and construction is underway. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, with expenditures to date of approximately $0.2 billion. Enbridge expects the pipeline will come into service in late 2012.

WOOD BUFFALO PIPELINE

Enbridge entered into an agreement with Suncor Energy Inc. (Suncor) to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal adjacent to Suncor's oil sands plant to the Cheecham Terminal, which is the origin point of Enbridge's Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to the Edmonton mainline hub. The new Wood Buffalo Pipeline will parallel the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion. With regulatory approval received in the first quarter of 2011, the new pipeline is expected to be in service by late 2012.

SEAWAY CRUDE PIPELINE SYSTEM

In December 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Pipeline system at a cost of approximately US$1.2 billion. The 1,078-kilometre (670-mile) Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter Freeport, Texas to Cushing, Oklahoma long-haul system, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and four import docks at two locations. The other 50% interest in the Seaway Pipeline system is owned by Enterprise Products Partners L.P. (Enterprise).

Enbridge and Enterprise have announced plans to reverse the flow direction of the 805-kilometre (500-mile) 30-inch diameter Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the U.S. Gulf Coast. The initial 150,000 bpd of capacity on the reversed system is expected to be available by the second quarter of 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, capacity would increase to 400,000 bpd assuming a mix of light and heavy grades of crude oil.

In addition, a proposed 137-kilometre (85-mile) pipeline is expected to be built from Enterprise's ECHO crude oil terminal southeast of Houston to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities. This lateral could offer incremental capacity in excess of 400,000 bpd and is expected to be available in early 2014. Enbridge's investment in the joint venture, including its share of reversal expenditures and the Port Arthur lateral, is expected to be approximately US$1.5 billion. Open Seasons were held from January 4, 2012 through February 10, 2012 to solicit capacity commitments from shippers for potential expansion of the Seaway Pipeline through looping or twining, and for service on the Port Arthur lateral.

WAUPISOO PIPELINE CAPACITY EXPANSION

The Waupisoo Pipeline Capacity Expansion, which received regulatory approval in November 2010, is expected to provide 65,000 bpd of additional capacity in the second half of 2012 and an estimated 190,000 bpd of additional capacity in the second half of 2013 when the expansion is fully in service. The project is expected to accommodate additional shipper commitments of 229,000 bpd. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion.

NOREALIS PIPELINE

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company will construct a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed Norealis Terminal to the Cheecham Terminal, and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5 billion. With regulatory approval received in the second quarter of 2011, the facilities are expected to be in service in late 2013.

ATHABASCA PIPELINE CAPACITY EXPANSION

The Company will undertake an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including production from the Christina Lake Oilsands Project operated by Cenovus. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on type of crude oil. The estimated cost of full expansion is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion and an expected in service date of 2013 for an initial 430,000 bpd of capacity. The balance of additional capacity is expected to be available by early 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

FLANAGAN SOUTH PIPELINE PROJECT

The Flanagan South Pipeline will transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. The common carrier pipeline is expected to have an initial annual capacity of 350,000 bpd at an expected cost of approximately US$1.9 billion and is designed to be expandable to 540,000 bpd. A binding Open Season that was held in the fourth quarter of 2011 resulted in sufficient customer commitment to move forward with this project. A second Open Season was held concurrent with that for Seaway Pipeline, and commitments from that Open Season will determine the final design scope and capacity. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. Both the Seaway and Flanagan South pipelines are included in the Company's Gulf Coast Access initiative to offer crude oil transportation from its terminal at Flanagan to the United States Gulf Coast.

ATHABASCA PIPELINE TWINNING

In September 2011, Enbridge announced plans to twin the southern section of its Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to accommodate the need for additional capacity to serve Kirby Lake area expected oil sands growth. The expansion project, with an estimated cost of approximately $1.2 billion, will include 345 kilometres (210 miles) of 36-inch pipeline within the existing Athabasca Pipeline right-of-way. The initial annual capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. The line is expected to enter service in 2015.

NORTHERN GATEWAY PROJECT

The Northern Gateway Project involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine and tank terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to import condensate and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

Northern Gateway submitted an application to the NEB on May 27, 2010. The Joint Review Panel (JRP) established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act, has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest. The JRP conducted sessions with the public, including Aboriginal groups, to receive comments on the draft List of Issues, additional information which Northern Gateway should be required to file and locations for the oral hearings. The JRP decided to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. In January 2011, the JRP issued a decision requiring Northern Gateway to provide certain additional information on the design and risk assessment of the pipelines before it would issue a Hearing Order. This information, together with other updates regarding the project, was provided to the JRP in March 2011. The JRP subsequently issued a Hearing Order outlining the procedures to be followed and accordingly, hearings started in January 2012.

In June 2011, Northern Gateway filed additional materials with the JRP including, but not limited to, details of its extensive program of consultation with over 40 Aboriginal communities between December 2009 and March 2011. The update summarized the information provided to Aboriginal groups, the engagement activities that have occurred, the interests and concerns that have been expressed to Northern Gateway, commitments and mitigation measures in response to those concerns and an update on the status of Aboriginal Traditional Knowledge study programs. In August 2011, Northern Gateway filed commercial agreements with the NEB which provide for committed long-term service and capacity on both the proposed crude oil export and condensate import pipelines. Capacity has also been reserved for use by uncommitted shippers.

In a Procedural Direction issued in December 2011, the JRP indicated it expects to hold final hearings in September and October 2012 where Northern Gateway, intervenors, government participants and the JRP will question those who have presented oral or written evidence. Based on this projected schedule, the JRP would anticipate releasing the Environmental Assessment in the fall of 2013 and its final decision on this project near the end of 2013. Subject to continued commercial support, regulatory and other approvals, and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service by 2017 at the earliest, at an estimated cost of $5.5 billion. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.2 billion, including $0.1 billion in funding secured from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

The JRP posts public filings related to Northern Gateway on its website at *http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html* and Enbridge also maintains a Northern Gateway Project website in addition to information available on *www.enbridge.com*. The full regulatory application submitted to the NEB and the 2010 Enbridge Northern Gateway CSR Report are available on *www.northerngateway.ca*. None of the information contained on, or connected to, the JRP website, the Northern Gateway Project website or Enbridge's website is incorporated in or otherwise part of this MD&A.

FORT HILLS PIPELINE SYSTEM

In late 2008, Fort Hills Energy L.P. (FHELP) announced that its final investment decision for the mining portion of its project was being deferred until costs could be reduced, and commodity prices and financial markets strengthened. It also announced that the Fort Hills upgrader was put on hold and that a decision to proceed with the upgrader would be made at a later date. FHELP has now completed its re-evaluation and while it is proceeding with the mining portion of the project, FHELP has decided not to proceed with the original pipeline project. Expenditures incurred to date under the original contractual arrangement of approximately $0.1 billion have been substantially collected from FHELP. Discussions on a new pipeline project to meet the new needs of the mining project are ongoing, with no commitments currently in place.

GAS DISTRIBUTION

NEXUS PROJECT

The Nexus Project is a 4.5 billion cubic feet expansion of EGD's unregulated natural gas storage facility near Sarnia, Ontario. The project, which has received regulatory approval for construction, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and was completed in 2011 at an approximate capital cost of $34 million. Additional remediation and close-out activities are expected to be performed in 2012 to bring the total capital cost to approximately $38 million.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

AMHERSTBURG SOLAR PROJECT

The Amherstburg II Solar Project, located in Amherstburg, Ontario, consists of both a 10-MW facility and a 5-MW facility. First Solar constructed both facilities for Enbridge under fixed price engineering, procurement and construction contracts. The Amherstburg II Solar Project was completed in the third quarter of 2011 at a cost of approximately $0.1 billion, at which time commercial operations commenced. Power output from the facilities is sold to the Ontario Power Authority (OPA) pursuant to 20-year power purchase agreements.

CEDAR POINT WIND ENERGY PROJECT

Enbridge developed the 250-MW Cedar Point Wind Energy Project near Denver, Colorado with Renewable Energy Systems America Inc. (RES Americas), at a cost of approximately US$0.5 billion. RES Americas constructed the wind project under a fixed price, turnkey, engineering, procurement and construction agreement. The project is comprised of 139 Vestas V90 1.8-MW wind turbines on 20,000 acres of leased private land. The Cedar Point Wind Energy Project delivers electricity into the Public Service Company of Colorado grid under a 20-year, fixed price power purchase agreement. Project construction was completed in September 2011 and commercial operation began in November 2011. In December 2011, the Company received a US$0.1 billion payment from the United States Treasury under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property.

GREENWICH WIND ENERGY PROJECT

The Company developed the 99-MW Greenwich Wind Energy Project on the northern shore of Lake Superior in Ontario with Renewable Energy Systems Canada Inc. (RES Canada). Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada constructed the project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens provides operations and maintenance services for the wind turbines. The Greenwich Wind Energy Project delivers energy to the OPA under a 20-year power purchase agreement. The project was completed and commenced commercial operations in October 2011 with expenditures of approximately $0.3 billion.

PRAIRIE ROSE PIPELINE AND PALERMO CONDITIONING PLANT

In July 2011, an affiliate of Aux Sable acquired the Prairie Rose Pipeline and the Palermo Conditioning Plant for US$0.2 billion. The Palermo Conditioning Plant removes condensate and will have a capacity of 80 mmcf/d. The 12-inch diameter, 134-kilometre (83-mile) Prairie Rose Pipeline, with an estimated capacity of 110 mmcf/d, connects the plant to the Alliance Pipeline, which then delivers high energy content gas to Aux Sable's Channahon, Illinois plant for further processing. Enbridge has a 42.7% equity interest in Aux Sable and a 50% interest in Alliance Pipeline US.

LAC ALFRED WIND PROJECT

In December 2011, Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred). The project, located 400 kilometres (250 miles) northeast of Quebec City in Quebec's Bas-Saint-Laurent region, will consist of 150 wind turbines. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1, which began construction in June 2011, is expected to be completed in December 2012; while Phase 2 is expected to be completed in December 2013. Hydro-Quebec will purchase the power under a 20-year power purchase agreement and will construct the 30-kilometre transmission line to connect Lac Alfred to the grid under an interconnection agreement. The Company's total investment in the project is expected to be approximately $0.3 billion.

CABIN GAS PLANT

In December 2011, the Company secured a 71% interest in the development of Cabin, located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. The Company's total investment in phases 1 and 2 of Cabin is expected to be approximately $1.1 billion.

Phase 1 of the development is to have 400 million cubic feet per day (mmcf/d) of processing capacity. The plant is currently under construction and is expected to be in-service in late 2012. Phase 2, which is to provide an additional 400 mmcf/d of capacity, has been sanctioned by the producers and has also received regulatory approval. Phase 2 is expected to be ready for service in the third quarter of 2014. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. These producers can request the Company to expand Cabin up to an additional four phases, under agreed terms.

TIOGA LATERAL PIPELINE

In September 2011, Alliance Pipeline US announced plans to develop a natural gas pipeline lateral and associated facilities to connect production from the Hess Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. Through its 50% ownership interest in Alliance Pipeline US, Enbridge's expected cost related to the project is approximately US$0.1 billion. Alliance Pipeline US has executed a precedent agreement with Hess Corporation (Hess) as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products and Hess have reached a concurrent agreement for the provision of NGL services. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of high-energy, liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of the Alliance mainline system. The pipeline will have an initial design capacity of approximately 120 mmcf/d, which can be expanded based on shipper demand. Subject to regulatory and other required approvals, the pipeline is expected to be in service by the third quarter of 2013.

VENICE CONDENSATE STABILIZATION FACILITY

In January 2011, the Company announced plans for an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within its Offshore business. The expanded condensate processing capacity will be required to accommodate additional natural gas production from the recently sanctioned Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge's onshore facility at Venice via Enbridge's Mississippi Canyon offshore pipeline where it will be processed to separate and stabilize the condensate. The expansion, which is expected to more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

WALKER RIDGE GAS GATHERING SYSTEM

The Company executed definitive agreements in the last quarter of 2010 with Chevron USA, Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deepwater developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 0.1 billion cubic feet per day (bcf/d). WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion.

BIG FOOT OIL PIPELINE

The Company executed definitive agreements in March 2011 with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the proposed Big Foot ultra-deepwater development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline (Big Foot), which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion and it is expected to be in service in 2014.

SPONSORED INVESTMENTS

BAKKEN EXPANSION PROGRAM

A joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. The Bakken Expansion Program is expected to increase takeaway capacity from the Bakken area by an initial 145,000 bpd, which can be expanded to 325,000 bpd. The Bakken Expansion Program will involve United States projects undertaken by EEP at a cost of approximately US$0.4 billion and Canadian projects undertaken by the Fund at a cost of approximately $0.2 billion. Regulatory approval has been received and construction commenced in July 2011 on the United States portion of the project, with expenditures to date of approximately US$0.1 billion. In Canada, NEB approval was secured in December 2011. Subject to other approvals in respect of the Canadian portion, the Bakken Expansion Program is expected to be completed in the first quarter of 2013.

ENBRIDGE ENERGY PARTNERS, L.P.

ALLISON CRYOGENIC PROCESSING PLANT

In April 2010, EEP announced plans to construct a cryogenic processing plant and other facilities on its Anadarko System. The Allison Plant has a capacity of 150 mmcf/d and is intended to accommodate the resurgence of horizontal drilling activity that exists in the Granite Wash formation in the Texas Panhandle, where the Anadarko System is located. The Allison Plant was constructed at an approximate capital cost of US$0.1 billion and placed into service in November 2011. EEP is awaiting the completion of additional third party NGL takeaway capacity to the Allison Plant, expected to be in place during the first quarter of 2012, which will allow EEP to fully utilize its capacity.

CUSHING TERMINAL STORAGE EXPANSION PROJECT

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.2 million barrels. The total estimated cost of the expansion is approximately US$0.1 billion. Five tanks went into service in December 2011 and the remaining tanks are expected to come into service by December 2012.

SOUTH HAYNESVILLE SHALE EXPANSION

EEP is expanding its East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage. The expansion, with an estimated cost of approximately US$0.1 billion, is expected to increase capacity of EEP's East Texas system by 900 mmcf/d once completed in the first quarter of 2012.

In April 2011, EEP announced plans to invest an additional US$0.2 billion to expand its East Texas system, including the construction of gathering and related treating facilities. EEP has signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services. Completion of the additional expansion is dependent on drilling plans of these producers. In light of weak gas prices and lower levels of producer activity, EEP is evaluating deferral of portions of its Haynesville natural gas expansion.

EASTERN MARKET EXPANSION

In October 2011, Enbridge and EEP announced two projects that will provide increased access to refineries in the United States upper mid-west and in Ontario for light crude oil produced in western Canada and the United States. The project involves the expansion of EEP's Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 bpd, at a cost of approximately US$0.1 billion. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of its Line 9 in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a cost of approximately $20 million. Subject to regulatory and other approvals, the Line 5 expansion is targeted to be in service during the first quarter of 2013, while the Line 9 reversal is targeted to be in service in late 2013.

AJAX CRYOGENIC PROCESSING PLANT

EEP is constructing an additional processing plant and other facilities on its Anadarko System at an approximate cost of US$0.2 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013. The Ajax Plant, when operational, in addition to the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

BAKKEN ACCESS PROGRAM

In October 2011, EEP announced the Bakken Access Program, a series of projects totaling approximately US$0.1 billion, which represents an upstream expansion that will further complement its Bakken expansion. This expansion program will enhance gathering capabilities on the North Dakota System by 100,000 bpd. The program, which involves increasing pipeline capacities, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

BERTHOLD RAIL PROJECT

In December 2011, EEP announced that it will be proceeding with the Berthold Rail Project, a US$0.1 billion investment that will provide an interim solution to shipper needs in the Bakken region. The project is expected to expand capacity into the Berthold Terminal by 80,000 bpd and includes the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. Conditional approval was received in early December subject to securing remaining shipper commitments. A regulatory filing is in progress and detailed design is proceeding to enable construction to commence in April 2012 with an expected in-service date by early 2013.

TEXAS EXPRESS PIPELINE

In September 2011, EEP announced a joint venture with Enterprise and Anadarko Petroleum Corporation to design and construct a new NGL pipeline, as well as two new NGL gathering systems which EEP will build and operate. EEP will invest approximately US$0.4 billion in the Texas Express Pipeline (TEP), which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. One of the new NGL gathering systems will connect TEP to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma, while the second will connect TEP to central Texas Barnett Shale processing plants. Subject to regulatory approvals and finalization of commercial terms, the pipeline and portions of the gathering systems are expected to begin service in mid-2013.

LINE REPLACEMENT PROGRAM

In May 2011, EEP announced plans to replace 120 kilometres (75 miles) of non-contiguous sections of Line 6B of its Lakehead System at an estimated cost of US$286 million. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through EEP's tariff surcharge that is part of the system-wide rates of the Lakehead System. EEP subsequently revised the scope of this project to increase the cost by approximately US$30 million, which will bring the total capital for this replacement program to an estimated cost of US$316 million. The US$30 million of additional costs do not currently have recovery under the tariff surcharge.

CORPORATE

MONTANA-ALBERTA TIE-LINE

In October 2011, Enbridge acquired all outstanding common shares of Tonbridge Power Inc. (Tonbridge) for $20 million and assumed long-term debt of $182 million incurred by Tonbridge in the development of the MATL project that was repaid by Enbridge. The Company will also inject further funding to complete the first 300-MW phase of MATL and an expansion between 550-MW and 600-MW. The total expected cost for both phases of MATL is approximately US$0.3 billion, of which approximately half will be funded through a 30-year loan from the Western Area Power Administration of the United States Department of Energy. Expenditures to date are approximately US$0.2 billion.

MATL is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and the buoyant power demand in Alberta. While the permits required for construction have been obtained, the approval in Canada is currently being updated to reflect a number of design modifications which require further consultation with land owners. Subject to these approvals, the system's north-bound capacity, which is fully contracted, is expected to be in-service in the fourth quarter of 2012.

NOVERCO

On June 30, 2011, the Company completed the acquisition of an additional 6.8% interest in Noverco for $144 million. Following the completion of the transaction, Enbridge and Trencap, a partnership managed by the Caisse de Depot et Placement du Quebec, became the sole shareholders of Noverco.

NEAL HOT SPRINGS GEOTHERMAL PROJECT

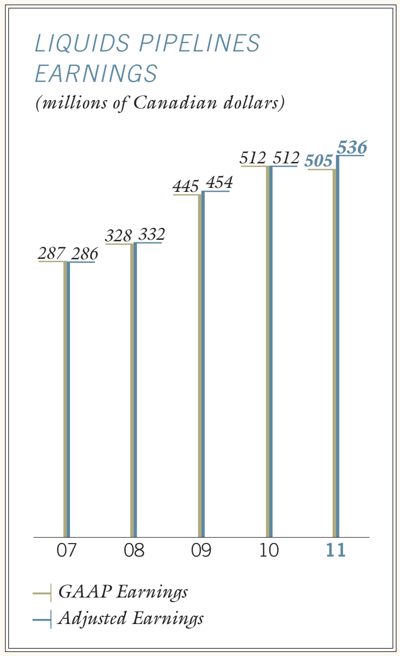
The Company has partnered with U.S. Geothermal Inc. to develop the 35-MW Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. The project is anticipated to be completed in the second quarter of 2012 and will deliver electricity to the Idaho Power grid under a 25-year power purchase agreement. Construction on the project has commenced and Enbridge will invest up to approximately $27 million for a 29% interest in the project.

Liquids Pipelines

EARNINGS

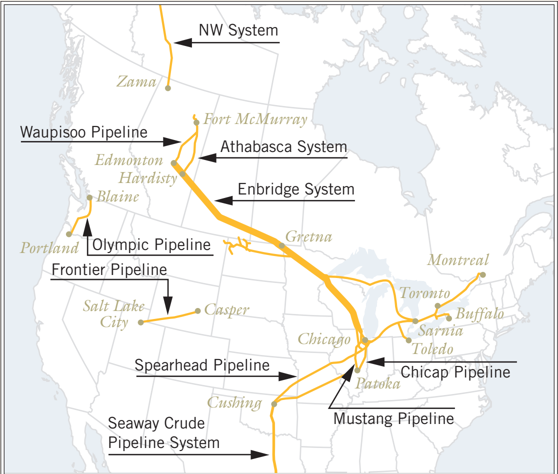
	2011	2010	2009
(millions of Canadian dollars)			
Canadian Mainline	**337**	327	295
Regional Oil Sands System	**110**	73	72
Southern Lights Pipeline	**75**	82	58
Spearhead Pipeline	**17**	29	17
Feeder Pipelines and Other	**(3)**	1	12
Adjusted earnings	**536**	512	454
Canadian Mainline – shipper dispute settlement	**14**	–	–
Canadian Mainline – Line 9 tolling adjustment	**10**	–	–
Canadian Mainline – unrealized derivative fair value loss	**(48)**	–	–
Regional Oil Sands System – asset impairment write-off	**(8)**	–	–
Regional Oil Sands System – leak remediation costs	**–**	–	(9)
Spearhead Pipeline – unrealized derivative fair value gains	**1**	–	–
Earnings	**505**	512	445

Liquids Pipelines adjusted earnings were $536 million in 2011 compared with adjusted earnings of $512 million in 2010 and $454 million in 2009. The Company continued to realize earnings growth on the Canadian Mainline, primarily due to the CTS and the related change in tolling methodology, as well as on the Regional Oil Sands System; however, in 2011 such growth was partially offset by lower contributions from its Southern Lights and Spearhead pipelines as well as Feeder Pipelines and Other.



Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting items.

- Canadian Mainline earnings for 2011 included $14 million from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- Canadian Mainline earnings for 2011 included a Line 9 tolling adjustment related to services provided in prior periods.
- Canadian Mainline earnings for 2011 reflected unrealized fair value losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Regional Oil Sands System earnings for 2011 included the write-off of development expenditures on certain project assets.
- Cleanup and remediation costs related to a valve leak within the Enbridge Cheecham Terminal on the Regional Oil Sands System in January 2009.
- Spearhead Pipeline earnings included unrealized fair value gains on derivative financial instruments used to manage exposures to allowance oil commodity prices.



LIQUIDS PIPELINES

CANADIAN MAINLINE

The mainline system is comprised of Canadian Mainline and Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through six adjacent pipelines with a combined capacity of approximately 2.5 million bpd, the system transports various grades of crude oil and diluted bitumen from western Canada to the midwest region of the United States and eastern Canada. Also included within the Canadian Mainline and located in eastern Canada are two crude oil pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd.

COMPETITIVE TOLL SETTLEMENT

On June 24, 2011, the NEB approved the 10-year CTS reached between Enbridge and shippers on its mainline system. The CTS, which took effect on July 1, 2011, covers local tolls, denominated in United States dollars, to be charged for service on the mainline system (with the exception of Lines 8 and 9). Under the terms of the CTS, the initial Canadian Local Toll (CLT), applicable to deliveries within western Canada, is based on the 2011 Incentive Tolling Settlement (ITS) toll and will be subsequently adjusted by 75% of the Canada Gross Domestic Product at Market Price Index, effective July 1st, for each of the remaining nine years of the settlement. The CTS also provides for an International Joint Tariff (IJT) for crude oil shipments originating in Canada on the mainline system and delivered in the United States off the Lakehead System and into eastern Canada. The IJT, which is based on a fixed toll for the term of the settlement that was negotiated between Enbridge and shippers, will be adjusted annually by the same factor as the CLT. In other limited circumstances the shippers or Enbridge may elect to renegotiate the toll, including a shipper option to renegotiate if TransCanada's Keystone XL pipeline project does not receive the required United States presidential permit by January 1, 2013. If a renegotiation of the toll is triggered, Enbridge and the shippers will meet and use reasonable efforts to agree on how the CTS can be amended to accommodate the event. Local tolls for service on the Lakehead System will not be affected by the CTS and will continue to be established by EEP's existing toll agreements. To the extent the sum of the CLT and the Lakehead System local toll exceeds the IJT, the CLT will be adjusted to ensure the IJT is maintained. The IJT is designed to provide mainline shippers with a stable and competitive long-term toll, preserving and enhancing throughput on both the Canadian Mainline and Lakehead System. Although the Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues and commodity price risk resulting from exposure to variable crude oil and power prices, earnings under the CTS are subject to variability in volume throughput, as well as capital and operating costs.

With NEB approval of the CTS, shippers who initiated the Alberta Clipper hearing request with the NEB formally withdrew their complaints and the hearing proceedings were terminated on July 7, 2011.

INCENTIVE TOLLING

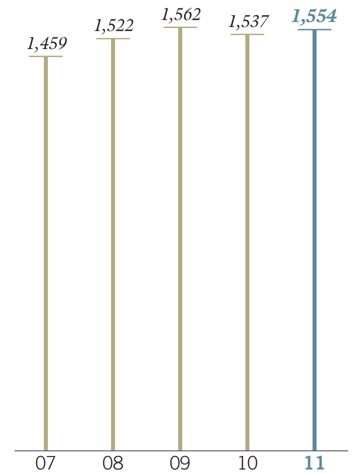
Prior to the CTS taking effect, tolls on Canadian Mainline were governed by various agreements which were subject to NEB approval. These agreements included both the 2011 and 2010 ITS applicable to the Canadian Mainline (excluding Lines 8 and 9), the Terrace agreement, the SEP II Risk Sharing agreement, the Alberta Clipper agreement and the Southern Access Expansion agreement which were recovered via the Mainline Expansion Toll.

RESULTS OF OPERATIONS

Canadian Mainline adjusted earnings were $337 million for the year ended December 31, 2011 compared with $327 million for the year ended December 31, 2010.

As noted previously, effective July 1, 2011, Canadian Mainline earnings are governed by the CTS (with the exception of Lines 8 and 9) whereas earnings for the first six months of 2011 and for the year ended December 31, 2010 were governed by a series of agreements, the most significant being the ITS applicable to the mainline system and the Terrace and Alberta Clipper agreements. Earnings under the CTS are subject to variability in volume throughput and operating costs. Canadian Mainline volumes during the second half of 2011, for which the CTS was in effect, were higher than expected contributing to an increase in full year earnings relative to the prior year. The increased earnings contribution from volumes was partially offset by higher operating costs.

CANADIAN MAINLINE—
AVERAGE DELIVERIES
(thousands of barrels per day)



Supplemental information on Canadian Mainline adjusted earnings for the period from July 1, 2011, the date the CTS became effective, to December 31, 2011 is as follows.

	Six months ended December 31, 2011
(millions of Canadian dollars, unless otherwise noted)	
Revenues	**618**
Expenses	
Operating and administrative	**189**
Power	**54**
Depreciation and amortization	**104**
	347
	271
Other income	**5**
Interest expense	**(66)**
	210
Income taxes	**(32)**
Adjusted earnings	**178**
IJT Benchmark Toll [1] *(US dollars per barrel)*	**$ 3.85**
Lakehead System Local Toll [2] *(US dollars per barrel)*	**$ 2.01**
Canadian Mainline IJT Residual Benchmark Toll [3] *(US dollars per barrel)*	**$ 1.84**
Effective United States dollar to Canadian dollar exchange rate [4]	**0.97**

1 *The benchmark toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil.*

2 *Per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois.*

3 *Per barrel of heavy crude oil transported from Hardisty to Gretna. The Canadian Mainline IJT residual toll for any shipment is the difference between the IJT toll for that shipment and the Lakehead System local toll for that shipment.*

4 *Inclusive of realized gains or losses on foreign exchange derivative financial instruments.*

THROUGHPUT VOLUME [1]

2011					2010				
Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Total
1,602	**1,457**	**1,565**	**1,594**	**1,554**	1,515	1,629	1,468	1,537	1,537

1 *Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.*

Canadian Mainline revenues included the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Line 8 and Line 9 are currently tolled on a separate basis and comprise a relatively small proportion of total Canadian Mainline revenues. CTS revenues include transportation revenues, the largest component, as well as allowance oil and revenues from receipt and delivery charges. Transportation revenues include revenues for volumes delivered off the Canadian Mainline at Gretna and on to the Lakehead System, to which Canadian Mainline IJT residual benchmark tolls apply, and revenues for volumes delivered to other western Canada delivery points, to which the CLT applies. Despite the many factors which affect Canadian Mainline revenues, the primary determinants of those revenues will be throughput volume ex-Gretna, the United States dollar Canadian Mainline IJT residual benchmark toll applicable to those volumes and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. The Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues. The exact relationship between the primary determinants and actual Canadian Mainline revenues will vary somewhat from quarter to quarter but is expected to be relatively stable on average for a year, absent a systematic shift in receipt and delivery point mix or in crude oil type mix.

The largest components of operating and administrative expenses are employee related costs, pipeline integrity, repairs and maintenance, rents and leases and property taxes. Operating and administrative costs are relatively insensitive to throughput volumes. The primary drivers of future increases in operating costs are expected to be normal escalation in wage rates, prices for purchased services and tax rates, addition of new facilities and more extensive integrity and maintenance programs.

Power is the most significant variable operating cost and is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements. However, the primary determinants of power cost are the level of power prices in various jurisdictions and throughput volume. The relationship of power consumption to throughput volume is expected to be roughly proportional over a moderate range of volumes. The Company may utilize derivative financial instruments to hedge power prices.

Depreciation and amortization expense will adjust over time as a result of changes in estimated depreciation rates and of additions to property, plant and equipment due to new facilities, as well as maintenance and integrity capital expenditures.

Canadian Mainline income taxes reflected current income taxes only. Under the CTS the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to future income taxes is recognized as incurred.

The preceding financial overview includes expectations regarding future events and operating conditions that the Company believes are reasonable based on currently available information; however, such statements are not guarantees of future performance and are subject to change.

Prior to the implementation of the CTS, revenue on the Canadian Mainline was recognized in a manner consistent with the underlying agreements as approved by the regulator, in accordance with rate-regulated accounting. The Company discontinued the application of rate-regulated accounting to its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis commencing July 1, 2011. The regulatory asset balance at the date of discontinuance related to tolling deferrals recognized in prior periods is being recovered through a surcharge to the CLT and IJT. While the CTS is based on previous tolling settlements and cost-of-service principles, earnings are subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset of approximately $470 million related to future income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the date of discontinuance and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred.

Canadian Mainline adjusted earnings were $327 million for the year ended December 31, 2010 compared with $295 million for the year ended December 31, 2009. The increase in adjusted earnings resulted from a higher Alberta Clipper contribution since entering service on April 1, 2010 and favourable operating performance. These positive factors were partially offset by higher taxes in the Terrace component.

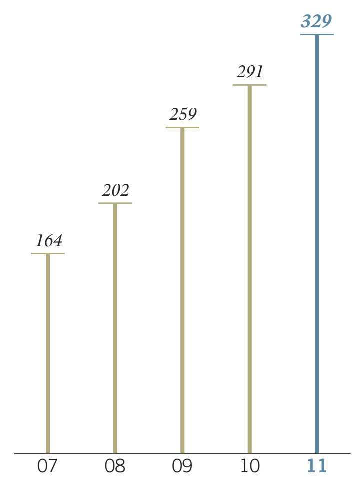
REGIONAL OIL SANDS SYSTEM

Regional Oil Sands System includes two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline, as well as a variety of other facilities including the MacKay River, Christina Lake, Surmont and Long Lake facilities. It also includes Hardisty Caverns Limited Partnership (Hardisty Caverns), which provides storage service, and two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located 95 kilometres (59 miles) south of Fort McMurray where the Waupisoo Pipeline initiates.

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline, built in 1999, that links the Athabasca oil sands in the Fort McMurray, Alberta region to a pipeline hub at Hardisty, Alberta. The Athabasca Pipeline has an ultimate design capacity of approximately 570,000 bpd, dependent on the viscosity of crude being shipped. It is currently configured to transport approximately 345,000 bpd.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca Pipeline which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected.

REGIONAL OIL SANDS SYSTEM—AVERAGE DELIVERIES
(thousands of barrels per day)



The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered into service on May 31, 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline initiates at Enbridge's Cheecham Terminal and terminates at its Edmonton Mainline Terminal. The pipeline currently has a design capacity, dependent on crude slate, of up to 350,000 bpd, which can ultimately be expanded to 600,000 bpd.

REGIONAL OIL SANDS SYSTEM

Enbridge has a long-term (25-year) take-or-pay commitment with the four founding shippers on the Waupisoo Pipeline who collectively have contracted for approximately one-third of the initial capacity on the line. The associated revenues provide for a base return on equity (ROE) with significant upside potential as incremental founders and third party volumes are added.

In June 2010, the Company acquired the remaining 50% of Hardisty Caverns previously owned by CCS Corporation for $52 million. The Hardisty Caverns facility, now wholly owned by Enbridge, also includes four salt caverns totaling 3.1 million barrels of capacity. The capacity at the facility is fully subscribed under long-term contracts that generate revenues from storage and terminaling fees.

RESULTS OF OPERATIONS

Adjusted earnings for the year ended December 31, 2011 were $110 million compared with $73 million for the year ended December 31, 2010 and $72 million for the year ended December 31, 2009. The increase in Regional Oil Sands System adjusted earnings reflected higher shipped volumes, increased tolls and the continued positive impact of terminal infrastructure additions. Adjusted earnings for 2011 also reflected lower depreciation expense due to extended estimated useful lives of certain assets reflecting increased probable reservoir supply and commercial viability.

SOUTHERN LIGHTS PIPELINE

The 180,000 bpd, 20-inch diameter Southern Lights Pipeline was placed into service on July 1, 2010 transporting diluent from Chicago, Illinois to Edmonton, Alberta. Enbridge receives tariff revenues under long-term (15-year) contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs plus a ROE of 10%. Uncommitted volumes, up to a specified amount, provide for tariff revenues that are fully credited to all shippers. Enbridge retains 25% of uncommitted tariff revenues on volumes above the specified amount, with the remainder being credited to shippers.

Both the Canadian and United States portions of the 2010, 2011 and 2012 rates for uncommitted shippers on Southern Lights Pipeline have been challenged. The Canadian Southern Lights toll hearing was held before NEB panel members in November 2011. On February 9, 2012, the NEB issued its decision rejecting the challenge from uncommitted shippers stating that tolls in place are just and reasonable. A Federal Energy Regulatory Commission (FERC) hearing was held in January 2012. Briefs will be filed February 27 and March 28, 2012 and an initial decision is expected on or before June 5, 2012. No material financial impact to the Company is anticipated to result from the FERC proceeding.

RESULTS OF OPERATIONS

Earnings for the year ended December 31, 2011 were $75 million compared with $82 million for the year ended December 31, 2010. Southern Lights Pipeline earnings for 2011 reflected a full year of in-service earnings. The decrease was primarily due to a decrease in leasing income from a pipeline which was transferred to the mainline system effective May 1, 2010.

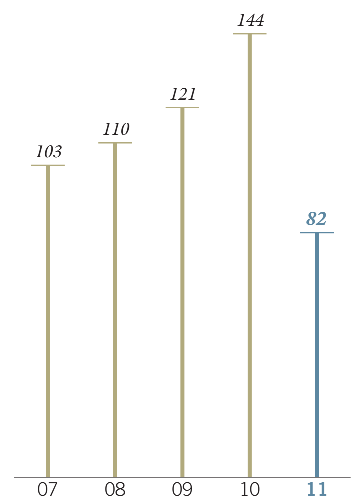
Earnings for the year ended December 31, 2010 were $82 million compared with $58 million for the year ended December 31, 2009. Southern Lights Pipeline earnings for 2010 reflected operating earnings from its in-service date of July 1, 2010 in addition to allowance for equity funds used during construction (AEDC) recognized on a growing capital base while the project was under construction during the first six months of the year. The increase in 2010 earnings was partially offset by a decrease in earnings from the new light sour pipeline, which became operational during the first quarter of 2009 and was subsequently transferred to the mainline system effective May 1, 2010.

SPEARHEAD PIPELINE

Spearhead Pipeline delivers crude oil from Chicago, Illinois to Cushing, Oklahoma. The pipeline was originally placed into service in March 2006 and the Spearhead Pipeline Expansion was completed in May 2009. The expansion increased the capacity to Cushing from 125,000 bpd to 193,300 bpd from the new initiating point at Flanagan, Illinois.

Initial committed shippers and expansion shippers currently account for more than 70% of the 193,300 bpd capacity on Spearhead. Both the initial committed shippers and expansion shippers were required to enter into 10-year shipping commitments at negotiated rates that were offered during the open season process. The balance of the capacity is currently available to uncommitted shippers on a spot basis at FERC approved rates.

SPEARHEAD PIPELINE—AVERAGE DELIVERIES
(thousands of barrels per day)



RESULTS OF OPERATIONS

Spearhead Pipeline adjusted earnings were $17 million for the year ended December 31, 2011 compared with $29 million for the year ended December 31, 2010. The decrease in Spearhead Pipeline adjusted earnings primarily reflected lower throughput volumes as a result of current market pricing dynamics at Cushing, Oklahoma, partially offset by the recognition of make-up rights which expired in the period.

Spearhead Pipeline adjusted earnings were $29 million for the year ended December 31, 2010 compared with $17 million for the year ended December 31, 2009. The earnings increase was due to a full year of higher volumes resulting from the expansion completed in May 2009. Earnings during 2010 were also positively impacted by the recognition of make-up rights which expired in the period, and lower operating costs.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the Company's 85% interest in Olympic Pipe Line Company (Olympic Pipeline), the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. It also includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories (NWT) to Zama, Alberta; interests in a number of liquids pipelines in the United States; contract tankage facilities, including the Hardisty Contract Terminal, which is comprised of 19 tanks with a working capacity of approximately 7.5 million barrels of storage; and business development costs related to Liquids Pipelines activities.

RESULTS OF OPERATIONS

In 2011, Feeder Pipelines and Other incurred a loss of $3 million compared with earnings of $1 million in 2010 and earnings of $12 million in 2009. Earnings in 2011 primarily reflected an increase in business development costs which more than offset a higher contribution from Olympic Pipeline due to the Company's increased ownership interest percentage, as well as a tariff increase and higher volumes.

The decrease in earnings from 2009 to 2010 was due to a number of small factors including a decrease in earnings from Toledo Pipeline due to the Line 6B shutdown and a decrease in earnings from Olympic Pipeline, as well as an increase in business development costs.

NORMAN WELLS PIPELINE CRUDE OIL RELEASE

The Norman Wells Pipeline is a 12-inch, 39,400 bpd line transporting sweet crude oil that stretches 869 kilometres (540 miles) from Norman Wells, NWT to Zama, Alberta. On May 9, 2011, Enbridge reported a crude oil release from the Norman Wells Pipeline approximately 50 kilometres (31 miles) south of the community of Wrigley, NWT. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing necessary repairs. Excavation of all contaminated soils from the spill site was completed in late November 2011. Based on the volume of contaminated materials removed from the site, the current estimate of volume released is approximately 1,600 barrels. Site reclamation work is anticipated to be completed in the summer of 2012. Monitoring of surface water and groundwater at the site will continue until remediation and reclamation goals have been achieved in accordance with plans filed with the regulator. Currently, Management does not believe this incident will have a material impact on the Company's consolidated financial position or result of operations.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

SUPPLY AND DEMAND

The profitability of the Company's liquids pipelines depends to some extent on the volume of products transported on its pipeline systems. The volume of shipments depends primarily on the supply of, and demand for, crude oil and other liquid hydrocarbons from western Canada. Investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, United States demand and availability of markets for produced crude oil. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing levels, alternative energy sources and global supply disruptions. Crude oil prices have been sustained at such levels that oil sands producers have recommenced projects that had been previously cancelled or deferred, creating increased demand in the WCSB for new pipeline infrastructure.

VOLUME RISK

A decrease in volumes transported by certain of the Company's liquids pipelines, including the Company's mainline system and the base Lakehead System owned by EEP, can directly and adversely affect revenues and results of operations. Shippers are not required to enter into long-term shipping commitments on Enbridge's Canadian Mainline; rather, monthly volume nominations are accepted. A decline in volumes transported can be influenced by factors beyond the Company's control, including competition, regulatory action, weather, storage levels, alternative energy sources, decreased demand, fluctuations in commodity prices, economic conditions, supply disruptions, availability of supply connected to the systems and adequacy of infrastructure to move supply into and out of the systems. The Company's existing right-of-way for the Canadian Mainline provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines. In addition, the CTS includes certain minimum threshold volumes to mitigate volume risk.

MARKET PRICE RISK

The replacement of the ITS agreement with the CTS agreement for the Company's Canadian Mainline increases exposure to foreign exchange rates, commodity prices and interest rates. The most significant of these risks is foreign exchange as the Company's International Joint Tolls under the CTS are charged in United States dollars. These risks have been substantially managed through the Company's hedging program by using financial contracts to fix the prices of United States dollars, commodities and interest rates. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, the Company's earnings are exposed to associated mark-to-market valuation changes.

COMPETITION

Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other competing carriers are available to ship western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition also arises from new pipeline proposals that provide access to market areas currently served by the Company's liquids pipelines. One such competing project began commercial operations in early 2010 and serves markets at Wood River, Illinois and Cushing, Oklahoma. This pipeline has an initial capacity of 435,000 bpd and an ultimate stated capacity of 591,000 bpd. Commercial support has also been announced for the construction of additional ex-Alberta capacity of 500,000 bpd to Nederland, Texas, with an in-service date during 2015. Competing alternatives for delivering western Canadian liquid hydrocarbons into the United States or other markets could erode shipper support for current or future expansion. However, the Company believes that its liquids pipelines provide attractive options to producers in the WCSB due to its competitive tolls and multiple delivery and storage points. Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

POTENTIAL PRESSURE RESTRICTIONS

The Company's liquids systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of a pipeline is indefinitely long; however, as pipelines age the level of expenditures required for inspection and maintenance may increase. Pressure restrictions may from time to time be established on the Company's pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. Certain of the Company's liquids pipelines, including the Company's Canadian Mainline, would be adversely affected by any pressure restrictions that do reduce volumes transported. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs.

REGULATION

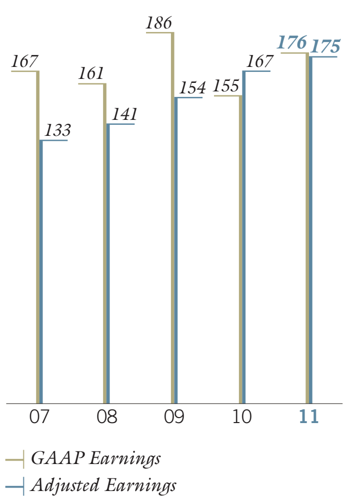
The Canadian Mainline and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from those operations. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the CTS, which govern the majority of the segment's assets.

Gas Distribution

EARNINGS

	2011	2010	2009
(millions of Canadian dollars)			
Enbridge Gas Distribution (EGD)	**137**	135	129
Other Gas Distribution and Storage	**38**	32	25
Adjusted earnings	**175**	167	154
EGD – colder/(warmer) than normal weather	**1**	(12)	17
EGD – impact of tax rate changes	**–**	–	21
EGD – interest income on GST refund	**–**	–	7
Other Gas Distribution and Storage – asset impairment loss	**–**	–	(10)
Other Gas Distribution and Storage – adoption of new accounting standard	**–**	–	(3)
Earnings	**176**	155	186

GAS DISTRIBUTION EARNINGS
(millions of Canadian dollars)

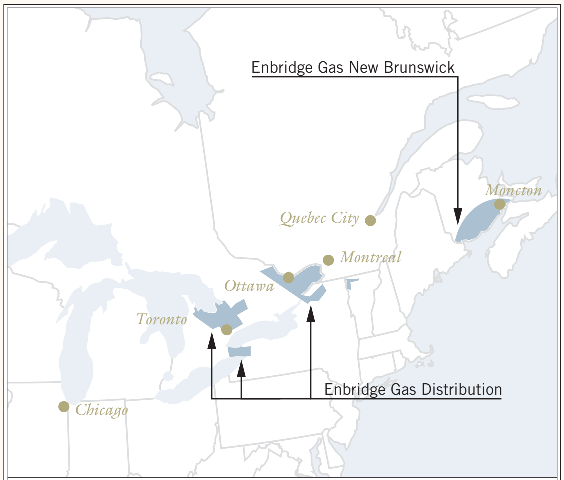


Adjusted earnings from Gas Distribution were $175 million for the year ended December 31, 2011 compared with $167 million for 2010 and $154 million for 2009. The increase in Gas Distribution adjusted earnings primarily resulted from continuing higher contributions from EGD under its Incentive Regulation (IR) arrangement and further growth in the Company's other gas distribution businesses.

Gas Distribution earnings were impacted by the following non-recurring or non-operating adjusting items.

- EGD earnings are adjusted to reflect the impact of weather.
- In 2009, earnings from EGD reflected the impact of favourable tax rate changes.
- Earnings from EGD for 2009 included interest income related to the recovery of excess GST remitted to Canada Revenue Agency.
- Other Gas Distribution and Storage earnings for 2009 were impacted by an asset impairment loss which included goodwill.
- Other Gas Distribution and Storage earnings for 2009 reflected the write-off of deferred development costs as a result of adopting a change in accounting standards, effective January 1, 2009.

ENBRIDGE GAS DISTRIBUTION



GAS DISTRIBUTION

EGD is Canada's largest natural gas distribution company and has been in operation for more than 160 years. It serves approximately 2 million customers in central and eastern Ontario and parts of northern New York State. EGD's utility operations are regulated by the Ontario Energy Board (OEB) and by the New York State Public Service Commission.

INCENTIVE REGULATION

In 2007, the Company filed a rate application with the OEB requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the IR Settlement Agreement (the Settlement) with customer representatives.

The objectives of the Settlement are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to its customers.

Under the Settlement, EGD is allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps must be shared with customers on an equal basis. EGD estimates the customer portion of 2011 earnings over the allowed threshold to be $14 million (2010 – $19 million). In preparation for the conclusion of the current IR term at the end of 2012, EGD filed a 2013 cost of service application, which they expect will be addressed by the OEB in 2012.

RATE ADJUSTMENT APPLICATIONS

In September of each year, EGD files an application with the OEB to adjust rates for the next calendar year. Each of the 2012, 2011 and 2010 rate applications were filed pursuant to the approved IR formula. Out of the total distribution revenue applied for in the 2012 rate application, 98% was approved for recovery with the rate adjustment being effective January 1, 2012. The hearing with respect to the remaining 2% and related issues was held by the OEB in January 2012 with a decision expected in April 2012.

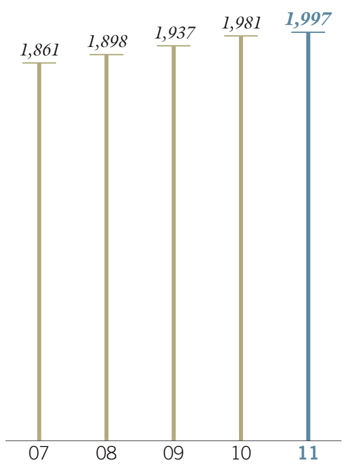
The total distribution revenue applied for in the 2011 rate application was approved by the OEB and the rate adjustment was effective January 1, 2011. In September 2009, EGD filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Subsequent to filing a settlement agreement with ratepayer groups with the OEB, in March 2010, EGD received approval of a fiscal 2010 final rate order from the OEB. The 2010 final rate order approved the implementation of a rate change effective April 1, 2010, which enabled EGD to recover the approved revenues as if rates were effective January 1, 2010.

RESULTS OF OPERATIONS

Adjusted earnings for the year ended December 31, 2011 were $137 million compared with $135 million for the year ended December 31, 2010. The increase in EGD's adjusted earnings was primarily due to customer growth, lower interest expense and lower taxes. These positive impacts were partially offset by higher customer support costs, as well as an increase in system integrity and employee related expenses. Depreciation expense also increased due to a higher overall asset base.

Adjusted earnings for the year ended December 31, 2010 were $135 million compared with $129 million for the year ended December 31, 2009. The increase in EGD adjusted earnings was primarily a result of continued favourable performance under IR, reflecting customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation expense. Depreciation expense increased due to a higher overall asset base, including the implementation of a new customer billing system in late 2009.

ENBRIDGE GAS DISTRIBUTION—NUMBER OF ACTIVE CUSTOMERS
(thousands)



BUSINESS RISKS

The risks identified below are specific to EGD. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

REGULATORY RISK

The utility operations of EGD are regulated by the OEB. To the extent that the Regulator's future actions are different from EGD's current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

The IR Framework permits EGD to recover, with OEB approval, certain costs that are beyond management control, but that are necessary for the maintenance of its services. The IR Framework also includes a mechanism to reassess the IR plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the settlement mitigate EGD's risk to factors beyond management's control. The current IR Framework term expires after the rate year 2012.

NATURAL GAS COST RISK

EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow EGD to recover or refund the natural gas cost differential. EGD has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB. However, the cost of natural gas does affect the amount of EGD's investment in gas in storage.

VOLUME RISK

Since customers are billed on both a fixed charge and volumetric basis, EGD's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current Settlement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. For the years ended December 31, 2011, 2010 and 2009, colder/(warmer) than normal weather resulted in an increase to earnings of $1 million, a reduction to earnings of $12 million and an increase to earnings of $17 million, respectively.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and small commercial sectors account for approximately 80% (2010 – 80%; 2009 – 81%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for customers other than large volume transportation customers is mitigated by the average use true-up variance account that was established under the IR Framework. This variance account enables recovery from or repayment to customers of amounts representing variances in the actual and forecast average use by general service customers. EGD remains at risk from the variability of distribution volumes for large volume contract commercial and industrial customers.

OTHER GAS DISTRIBUTION AND STORAGE

Other Gas Distribution includes natural gas distribution utility operations in Quebec and New Brunswick, the most significant being Enbridge Gas New Brunswick (EGNB) (100% owned and operated by the Company), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 11,000 customers. Approximately 790 kilometres (490 miles) of distribution main has been installed with the capability of attaching approximately 30,000 customers.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The EUB had previously approved the deferral of the shortfall between distribution revenues and the cost of service during the development period for recovery in future rates. The recovery period is expected to commence at the end of the development period in 2013 and end no sooner than 2040. On December 31, 2011, the regulatory deferral asset was $180 million (2010 – $171 million).

ENBRIDGE GAS NEW BRUNSWICK – REGULATORY MATTERS

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 – $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

RESULTS OF OPERATIONS

Other Gas Distribution and Storage adjusted earnings were $38 million for the year ended December 31, 2011 compared with $32 million for the year ended December 31, 2010 and $25 million for the year ended December 31, 2009, primarily due to an increased contribution from Enbridge's Ontario unregulated gas storage business.

Gas Pipelines, Processing and Energy Services

EARNINGS

	2011	2010	2009
(millions of Canadian dollars)			
Enbridge Offshore Pipelines (Offshore)	**(7)**	23	29
Alliance Pipeline US	**26**	25	27
Vector Pipeline	**18**	15	16
Aux Sable	**55**	37	26
Energy Services	**55**	20	29
Other	**16**	3	(11)
Adjusted earnings	**163**	123	116
Offshore – property insurance recoveries from hurricanes	**–**	2	4
Aux Sable – unrealized derivative fair value gains/(loss)	**(7)**	7	(36)
Aux Sable – loan forgiveness	**–**	–	7
Energy Services – unrealized derivative fair value gains/(loss)	**113**	(12)	3
Energy Services – Lehman and SemGroup credit recovery	**–**	1	1
Other – unrealized derivative fair value gains	**24**	–	–
Other – gain on sale of investments	**–**	–	329
Other – impact of tax rate changes	**–**	–	4
Earnings	**293**	121	428

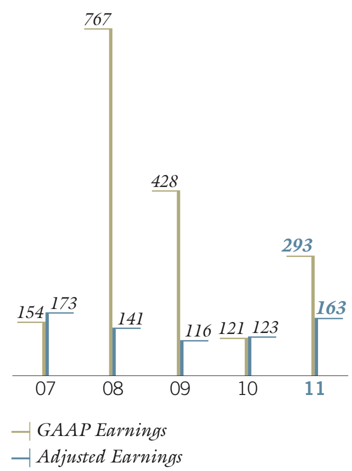
Adjusted earnings from Gas Pipelines, Processing and Energy Services were $163 million for the year ended December 31, 2011 compared with $123 million for the year ended December 31, 2010. The increase was primarily due to higher adjusted earnings from Aux Sable, Energy Services and Other, which includes the Company's green energy projects, partially offset by losses in Offshore.

Adjusted earnings were $123 million for the year ended December 31, 2010 compared with $116 million for the year ended December 31, 2009. The increase resulted from improved contributions from Aux Sable and new green energy investments.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items.

- Offshore earnings for 2010 and 2009 included insurance proceeds related to the replacement of damaged infrastructure as a result of a 2008 hurricane.
- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company's forward gas processing risk management position.
- Earnings for the year ended December 31, 2009 from Aux Sable reflected a gain from a loan forgiveness related to a negotiated settlement with a counterparty in bankruptcy proceedings.
- Energy Services earnings for each period reflected unrealized fair value gains and losses related to the revaluation of inventory and the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions.
- Energy Services earnings for 2010 and 2009 included partial recoveries from the sale of its receivable from Lehman Brothers and from SemGroup.
- Other earnings for 2011 reflected unrealized fair value changes on derivative financial instruments.
- In March 2009, the Company sold its investment in OCENSA, a crude oil export pipeline in Colombia, for proceeds of $512 million, resulting in a gain of $329 million.
- Other earnings for 2009 reflected the impact of favourable tax rate changes.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES EARNINGS
(millions of Canadian dollars)



ENBRIDGE OFFSHORE PIPELINES

ENBRIDGE OFFSHORE PIPELINES

Offshore is comprised of 13 natural gas gathering and FERC-regulated transmission pipelines and one oil pipeline with a capacity of 60,000 bpd, in five major corridors in the Gulf of Mexico, extending to deepwater developments. These pipelines include almost 2,400 kilometres (1,500 miles) of underwater pipe and onshore facilities with total capacity of approximately 7.2 bcf/d. Offshore currently moves approximately 40% of offshore deepwater gas production through its systems in the Gulf of Mexico.

TRANSPORTATION CONTRACTS

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current delivery expectations. The majority of long-term transport rates are market-based, with revenue generation directly tied to actual production deliveries. Some of the systems operate under a cost-of-service methodology while others have minimum take-or-pay obligations.

The business model utilized on a go forward basis and included in the WRGGS, Big Foot and Venice commercially secured projects differs from the historic model. These new projects have a base level return which is locked in through take or pay commitments. If volumes reach producer anticipated levels the return on these projects will increase. In addition, Enbridge has minimal capital cost risk on these projects and commercial agreements continue to contain life-of-lease commitments. The WRGGS and Big Foot project agreements provide for recovery of actual capital costs to complete the project in fees payable by producers over the contract term. The Venice project provides for a capital cost risk sharing mechanism, whereby Enbridge is exposed to a portion of the capital costs in excess of an agreed upon target. Conversely, Enbridge can recover in fees from producers a portion of the capital cost savings below the agreed upon target.

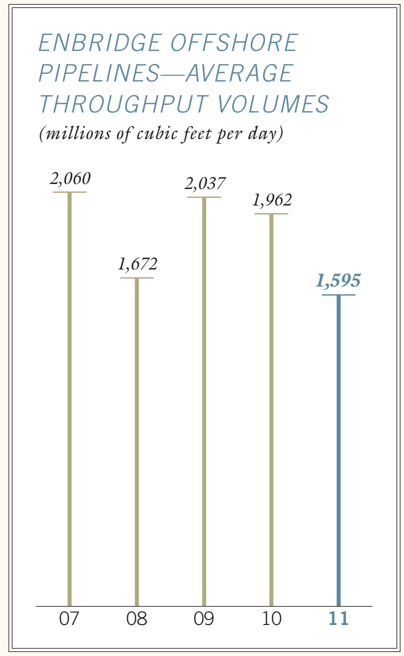
RESULTS OF OPERATIONS

For the year ended December 31, 2011, Offshore incurred a loss of $7 million compared with adjusted earnings of $23 million for the year ended December 31, 2010. The decrease in Offshore adjusted earnings reflected continued volume declines due to the slower regulatory permitting process and delayed drilling programs by producers. Increased operating and administrative costs, including higher insurance premiums and employee benefits, as well as increased depreciation expense also contributed to the decrease in earnings from the prior year.

Adjusted earnings from Offshore for the year ended December 31, 2010 were $23 million compared with $29 million for the year ended December 31, 2009. The Company experienced volume declines due to the slower regulatory permitting process. In July 2010, the Secretary of the Interior suspended deepwater drilling in the Gulf of Mexico. Subsequently, in October 2010, the deepwater drilling suspension was lifted, allowing a return to deepwater drilling, but subject to increased regulation and approval. Other factors contributing to the adjusted earnings decrease were higher operating and administrative costs, including insurance and higher depreciation expense.

BUSINESS RISKS

The risks identified below are specific to Offshore. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*



WEATHER

Adverse weather, such as hurricanes, may impact Offshore's financial performance directly or indirectly. Direct impacts may include damage to Offshore facilities resulting in lower throughput, as well as inspection and repair costs. Indirect impacts may include damage to third party production platforms, onshore processing plants and pipelines that may decrease throughput on Offshore systems. Effective June 2011, Offshore's insurance policy includes specific coverage related to named windstorms, such as hurricanes, for all systems. The occurrence of hurricanes in the United States Gulf Coast increases the cost and availability of insurance coverage, so Enbridge may not be able, or may choose not, to insure against this risk in the future.

COMPETITION

There is competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities, allowing it to more fully utilize existing capacity. Offshore's gas pipelines serve a majority of the strategically located deepwater host platforms, positioning it favourably to make incremental investments for new platform connections and receive additional transportation volumes from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining gas production, as demonstrated with the Neptune crude oil lateral and the planned Big Foot. Given rates of decline, offshore pipelines typically have available capacity, resulting in significant competition for new developments in the Gulf of Mexico.

SUPPLY AND DEMAND

Low natural gas prices, in part due to the prevalence of shale gas, have resulted in reduced investment in exploration activities and producing infrastructure. Offshore diversifies its risk of declining gas production through the construction of crude oil pipelines as noted above.

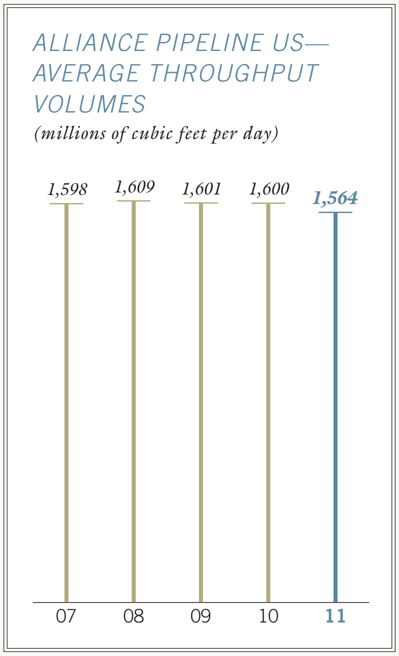
REGULATION

The transportation rates on many of Offshore's transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates are subject to challenge from time-to-time.

The Macondo oil spill in 2010 has altered the offshore regulatory environment. Although the moratorium on deepwater drilling was lifted, future deepwater drilling activity will be subject to heightened regulation and oversight. Increased regulation may impact the levels and timing of future exploration and drilling activity in the region and the resultant production volumes available to ship on the Offshore system. The shifting business environment could result in increases in available capacity, resulting in heightened competition.

OTHER RISKS

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing, changes in plans by shippers and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners or through cost of service tolling arrangements or other pre-arranged terms in commercial agreements. Start-up delays are mitigated by the right to collect stand-by fees.



ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and United States portions of the pipeline system, consists of an approximately 3,000-kilometre (1,864-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (454-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to Channahon, Illinois. Alliance Pipeline US and Alliance Pipeline Canada have firm service shipping contract capacity to deliver 1.405 bcf/d and 1.325 bcf/d, respectively. Enbridge owns 50% of Alliance Pipeline US, while the Fund, described under *Sponsored Investments*, owns 50% of Alliance Pipeline Canada.

Alliance connects with Aux Sable, (of which Enbridge owns 42.7%), an NGL extraction and fractionation facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the midwestern and northeastern United States and eastern Canada. Alliance Pipeline US is adjacent to the Bakken oil formation in North Dakota which offers new incremental sources of liquids-rich natural gas for delivery to downstream markets. In February 2010, a new receipt point on the pipeline near Towner, North Dakota was placed into service. The receipt point connects to the Prairie Rose Pipeline, which initially provided access to a shipper operating out of the Bakken formation with a firm transportation contract for an initial contract capacity of 40 mmcf/d under a 10-year contract. An additional 40 mmcf/d of firm transportation capacity at this same receipt point became effective February 2011. The Prairie Rose Pipeline was acquired by Aux Sable in 2011.

TRANSPORTATION CONTRACTS

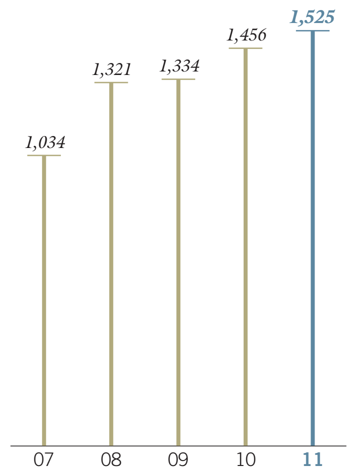
Alliance Pipeline US has long-term, take-or-pay contracts to transport substantially all its 1.405 bcf/d of natural gas capacity with terms ending on December 1, 2015. A small percentage of natural gas is being contracted on a short-term basis with an annual renewal option. These contracts permit Alliance Pipeline US, whose operations are regulated by the FERC, to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed ROE of 10.88%.

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense under Canadian GAAP is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the Canadian GAAP amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue, which began being recovered from shippers starting in 2009 for Alliance Pipeline US and in 2012 for Alliance Pipeline Canada. As at December 31, 2011, $103 million (US$101 million) (2010 – $122 million (US$123 million)) was recorded as Enbridge's share of deferred transportation revenue for Alliance Pipeline US.

RESULTS OF OPERATIONS

Alliance Pipeline US earnings were $26 million for the year ended December 31, 2011 comparable with $25 million for the year ended December 31, 2010 and $27 million for the year ended December 31, 2009.

VECTOR PIPELINE—
AVERAGE THROUGHPUT
VOLUMES
(millions of cubic feet per day)



VECTOR PIPELINE

The Vector Pipeline (Vector) system, which includes both the Canadian and United States portions of the pipeline system, consists of 560 kilometres (348 miles) of mainline natural gas transmission pipeline between the Chicago, Illinois hub and the storage complex at Dawn, Ontario. Vector's primary sources of supply are through interconnections with Alliance and the Northern Border Pipeline in Joliet, Illinois. Vector has the capacity to deliver a nominal 1.3 bcf/d and is operating at or near capacity. The Company provides operating services to and holds a 60% joint venture interest in Vector.

TRANSPORTATION CONTRACTS

The total long haul capacity of Vector is approximately 87% committed through 2015. Approximately 55% of the long haul capacity is committed through firm transportation contracts at rates negotiated with the shippers and approved by the FERC, while the remaining committed capacity is sold at market rates. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service. Vector is an interstate natural gas pipeline with FERC and NEB approved tariffs that establish the rates, terms and conditions governing its service to customers. On the United States portion of Vector, tariff rates are determined using a cost of service methodology and tariff changes may only be implemented upon approval by the FERC. For 2011, the FERC approved maximum tariff rates include an underlying weighted average after-tax ROE component of 11.18% (2010 – 11.18%; 2009 – 11.07%). On the Canadian portion, Vector is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2011, maximum tariff tolls include a ROE component of 10.48% after-tax.

Depreciation expense prescribed in the negotiated transportation contracts is different than the depreciation expense used for financial statement purposes. Negotiated depreciation expense is less than the financial statement amount at the beginning of the contract and higher than the financial statement amount in the later years of the negotiated transportation contracts. This difference results in the recognition of a long-term receivable, referred to as unbilled transportation revenue, which began to be recovered from shippers in 2008 for Vector US and 2006 for Vector Canada. As at December 31, 2011 $21 million (US$21 million) (2010 – $27 million (US$27 million)) was recorded as Enbridge's share of unbilled transportation revenue for Vector.

RESULTS OF OPERATIONS

Vector Pipeline earnings were $18 million for the year ended December 31, 2011 comparable with $15 million for the year ended December 31, 2010 and $16 million for the year ended December 31, 2009.

BUSINESS RISKS

The risks identified below are specific to both Alliance Pipeline US and Vector. General risks that affect the entire Company are described under *Risk Management and Financial Instruments.*

NATURAL GAS PIPELINES

SUPPLY AND DEMAND

Currently, natural gas pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending primarily to 2015; however, excess capacity could negatively impact re-contracting beyond this term. Re-contracting risk is mitigated to some extent as Alliance Pipeline US is well positioned to deliver incremental liquids-rich gas production from new developments in the Montney and Bakken regions. Alliance Pipeline US is also engaged with market participants in developing new receipt facilities and services to expand its reach in transporting liquids-rich gas to premium markets. In addition, Aux Sable, through its participation in midstream businesses upstream of Alliance Pipeline US, attracts liquids-rich gas to Alliance Pipeline US by offering incremental value for producers' NGL. Vector's interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago, Illinois and Dawn, Ontario relative to the transportation toll.

COMPETITION

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB and the Bakken to natural gas markets in the midwestern United States. In addition, there are several proposals to upgrade existing pipelines or to build new pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by Alliance Pipeline US because of location, facilities or other factors. In addition, these pipelines could charge rates or provide transportation services to locations that result in greater net profit for shippers, with the effect of forcing Alliance Pipeline US to realize lower revenues and cash flows. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance the competitive position of Alliance Pipeline US.

Vector faces competition for pipeline transportation services to its delivery points from new supply sources and traditional low cost pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector has mitigated this risk by entering into long-term firm transportation contracts, which expire starting in November 2015, for approximately 87% of its capacity. The remaining contracts expire at various times starting in April 2012. Certain long-term firm contracts (55% of capacity) provide for additional compensation to Vector if shippers do not extend their contracts beyond the initial term ending November 2015. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Vector and Alliance pipelines also face potential competition from new sources of natural gas such as the Marcellus shale formation, which is among the largest gas play in North America. The Marcellus shale formation is in close proximity to the Chicago Hub. The development of the Marcellus shale formation could provide an alternate source of gas to the Chicago Hub as well as decrease the northeastern region of the United States' reliance on natural gas imports from Canada.

REGULATION

Both the United States portion of Vector and Alliance Pipeline US operations are subject to regulation by the FERC. If tariff rates are protested, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position could be different from the amounts that are eventually recovered or refunded. In addition, future profitability of the entities could be negatively impacted. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

FERC has intensified its oversight of financial reporting, risk standards and affiliate rules and has issued new standards on managing gas pipeline integrity. The Company continues ongoing dialogue with regulatory agencies and participates in industry lobby groups to ensure it is informed of emerging issues in a timely manner.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, an NGL extraction and fractionation business, which owns and operates a plant near Chicago, Illinois at the terminus of Alliance. The plant extracts NGLs from the liquids-rich natural gas transported on Alliance, as necessary to meet gas quality specifications of downstream transmission and distribution companies and to take advantage of positive fractionation spreads.

Aux Sable sells its NGL production to BP under a long-term contract. BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel gas requirements of the Aux Sable plant and pays market rates for the capacity on the Alliance Pipeline held by an Aux Sable affiliate. The BP agreement is for an initial term of 20 years, expiring March 31, 2026, and may be extended by mutual agreement for 10-year terms.

Aux Sable also owns and operates facilities upstream of the Alliance Pipeline that deliver liquids-rich gas volumes into the pipeline for further processing at the Aux Sable plant. These facilities include the Prairie Rose Pipeline and the Palermo Conditioning Plant in the Bakken area of North Dakota and the Septimus Gas Plant and the Septimus Pipeline in the Montney area of British Columbia.

RESULTS OF OPERATIONS

Aux Sable adjusted earnings were $55 million for the year ended December 31, 2011 compared with $37 million for the year ended December 31, 2010. Aux Sable adjusted earnings increased primarily due to stronger realized fractionation margins which resulted in higher contributions from the upside sharing mechanism in its production sales agreement, as well as increased earnings contribution from new assets including Septimus Pipeline and Gas Plant, Prairie Rose Pipeline and Palermo Conditioning Plant.

Aux Sable adjusted earnings increased from $26 million in 2009 to $37 million in 2010 primarily due to enhanced plant performance and stronger fractionation margins.

ENERGY SERVICES

Energy Services provides energy supply and marketing services to North American refiners, producers and other customers. Crude oil and NGL marketing services are provided by Tidal Energy. This business transacts at many North American market hubs and provides its customers with various services, including transportation, storage, supply management, flexible pricing, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities can create commodity exposures. Any residual open positions created from this physical business are closely monitored and must comply with the Company's formal risk management policies.

Natural gas marketing services are provided by Tidal Energy and Gas Services. Tidal Energy markets natural gas to optimize Enbridge's commitments on the Alliance and Vector pipelines. Capacity commitments at December 31, 2011 and 2010 were 30 mmcf/d on Alliance and 156 mmcf/d on Vector. Earnings from these commitments are dependent upon the basis (location) differentials between Alberta and Chicago, Illinois for Alliance, and between Chicago and Dawn, Ontario for Vector. To the extent transportation costs exceed the basis (location) differential, earnings will be negatively affected. Tidal Energy also provides fee-for-service arrangements for third parties, leveraging its natural gas marketing expertise and access to transportation capacity. Gas Services markets natural gas to commercial and industrial customers in the upper mid-west area of the United States.

RESULTS OF OPERATIONS

Energy Services adjusted earnings were $55 million for the year ended December 31, 2011 compared with $20 million for the year ended December 31, 2010. This increase was primarily attributable to crude oil marketing strategies designed to capture basis (location) differentials and tank management revenue when opportunities arise. Energy Services employs such strategies in compliance with and under the oversight of the Company's formal risk management policies and procedures. Partially offsetting positive earnings contributions from crude oil services were declines in natural gas marketing due to narrower natural gas basis (location) spreads, which impact the Company's merchant capacity on certain natural gas pipelines. Earnings from Energy Services are dependent on market conditions, including, but not limited to, location and grade basis spreads, and may not be indicative of results to be achieved in future periods.

Energy Services adjusted earnings decreased to $20 million for the year ended December 31, 2010 from $29 million in 2009 as a result of reduced volume and margin opportunities in liquids marketing.

OTHER

Other includes operating results from the Company's investments in green energy projects, net of business development expenses associated with international and Canadian gas activities.

In October 2011, ownership of the Sarnia Solar, Ontario Wind and Talbot Wind energy projects was transferred to the Fund. Effective October 21, 2011, earnings contributions from these assets, net of noncontrolling interest, will be reflected within the Sponsored Investments segment. Green energy projects remaining in the Gas Pipelines, Processing and Energy Services segment include Greenwich Wind Energy, Cedar Point Wind Energy, Amherstburg Solar and Tilbury Solar.

In 2009, the Company sold its 24.7% interest in OCENSA, a crude oil export pipeline in Colombia. This investment was sold at a very attractive price and proceeds were utilized in the funding of the North American expansion projects discussed earlier. There are currently minimal operations in International; however, Enbridge continues to actively monitor the international business environment to identify potential new investment opportunities.

RESULTS OF OPERATIONS

Other adjusted earnings for the year ended December 31, 2011 were $16 million compared with $3 million for the year ended December 31, 2010 and an adjusted loss of $11 million for the year ended December 31, 2009. The increase reflected strong contributions primarily from the Sarnia Solar expansion and Talbot Wind Energy Project, both of which were completed in the latter part of 2010. In addition, adjusted earnings from 2011 reflected several newly constructed green energy projects, including Cedar Point Wind Energy, Greenwich Wind Energy and Amherstburg Solar.

Sponsored Investments

EARNINGS

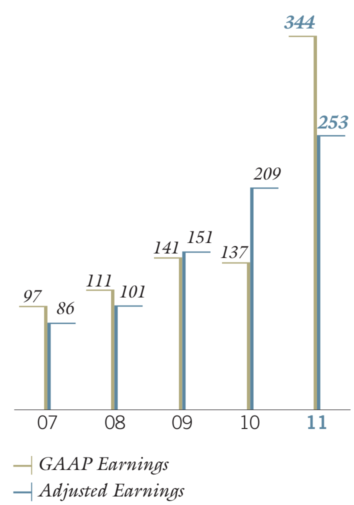
	2011	2010	2009
(millions of Canadian dollars)			
Enbridge Energy Partners (EEP)	**152**	122	99
Enbridge Energy, Limited Partnership – Alberta Clipper US (EELP)	**42**	42	7
Enbridge Income Fund (the Fund)	**59**	45	45
Adjusted earnings	**253**	209	151
EEP – leak insurance recoveries	**50**	–	–
EEP – leak remediation costs and lost revenue	**(33)**	(106)	–
EEP – unrealized derivative fair value gains/(loss)	**3**	(1)	(2)
EEP – NGL trucking and marketing prior period adjustment	**(3)**	–	–
EEP – shipper dispute settlement	**8**	–	–
EEP – lawsuit settlement	**1**	–	–
EEP – impact of unusual weather conditions	**(1)**	–	–
EEP – Lakehead System billing correction	**–**	1	4
EEP – dilution gain on Class A unit issuance	**66**	36	–
EEP – asset impairment loss	**–**	(2)	(12)
Earnings	**344**	137	141

Adjusted earnings from Sponsored Investments were $253 million for the year ended December 31, 2011 compared with $209 million for the year ended December 31, 2010. The increase in adjusted earnings resulted from increased contributions from both EEP and the Fund.

Adjusted earnings from Sponsored Investments were $209 million for the year ended December 31, 2010 compared with $151 million in 2009. The increase in adjusted earnings resulted primarily from increased contributions from EEP as a result of positive operating factors, including growth projects, as well as the Company's investment in EELP.

SPONSORED INVESTMENTS EARNINGS

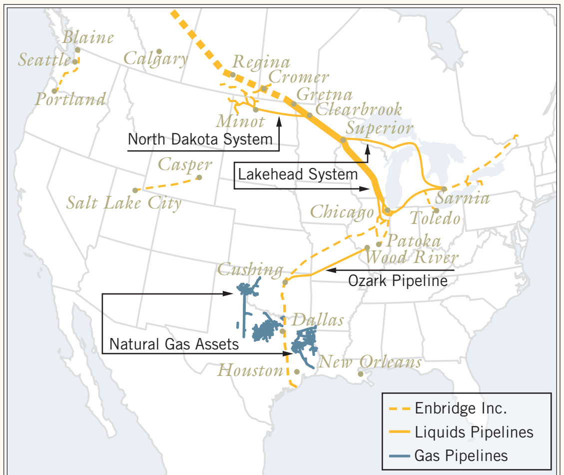
(millions of Canadian dollars)



Sponsored Investments earnings were impacted by the following non-recurring or non-operating adjusting items.

- EEP 2011 earnings included insurance recoveries associated with the Line 6B crude oil release. See *EEP Lakehead System Line 6A and 6B Crude Oil Releases.*
- Earnings from EEP for 2011 and 2010 included a charge related to estimated costs, before insurance recoveries, associated with the Line 6A and 6B crude oil releases. EEP earnings from 2010 also included a charge of $3 million (net to Enbridge) related to lost revenue as a result of the crude oil releases. See *EEP Lakehead System Line 6A and 6B Crude Oil Releases.*
- Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.
- Earnings from EEP included an unfavourable prior period adjustment related to NGL trucking and marketing.
- EEP earnings for 2011 included proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- EEP earnings for 2011 included proceeds related to the settlement of a lawsuit during the first quarter.

- EEP earnings for 2011 included an unfavourable effect related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations.
- EEP earnings for 2010 and 2009 included Lakehead System billing corrections.
- EEP 2011 and 2010 earnings included dilution gains (after tax and noncontrolling interest) as Enbridge did not fully participate in EEP's issuances of Class A units.
- EEP earnings for 2010 and 2009 included charges related to asset impairment losses.



ENBRIDGE ENERGY PARTNERS

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transportation and storage assets and natural gas and NGL gathering, treating, processing, transportation and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Canadian Mainline in the United States, the Mid-Continent crude oil system consisting of an interstate crude oil pipeline and storage facilities, a crude oil gathering system and interstate pipeline system in North Dakota and natural gas assets located primarily in Texas. Subsidiaries of Enbridge provide services to EEP in connection with the operation of its liquids assets, including the Lakehead System.

In September 2010, EEP acquired the entities that comprise the Elk City System from Atlas Pipeline Partners for US$686 million. The Elk City System extends from southwestern Oklahoma to Hemphill County in the Texas Panhandle and consists of approximately 1,290 kilometres (800 miles) of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 mmcf/d and a combined NGL production capability of 20,000 bpd. The acquisition of the Elk City System complements EEP's existing Anadarko natural gas system by providing additional processing capacity and expansion capability.

OWNERSHIP INTEREST

Enbridge's ownership interest in EEP is impacted by EEP's issuance and sale of its Class A common units. To the extent Enbridge does not fully participate in these offerings, the Company's ownership interest in EEP is reduced. At December 31, 2011, Enbridge's ownership interest in EEP was 23.0% (2010 – 25.5%; 2009 – 27.0%). The Company's average ownership interest in EEP during 2011 was 24.4% (2010 – 26.7%; 2009 – 27.0%).

DISTRIBUTIONS

EEP makes quarterly distributions of its available cash to its common unitholders. Under the Partnership Agreement, Enbridge Energy Company, Inc. (EECI), a wholly owned subsidiary of Enbridge, as general partner (GP), receives incremental incentive cash distributions, which represent incentive income on the portion of cash distributions (on a per unit basis) that exceed certain target thresholds as follows.

	Unitholders including Enbridge	GP Interest
Quarterly cash distributions per unit [1]		
Up to $0.295 per unit	98%	2%
First target – $0.295 per unit up to $0.350 per unit	85%	15%
Second target – $0.350 per unit up to $0.495 per unit	75%	25%
Over second target – cash distributions greater than $0.495 per unit	50%	50%

1 *Distributions restated to reflect EEP's two-for-one stock split which was effective April 2011.*

In 2009, EEP paid a quarterly distribution of $0.495 per unit to its common unitholders. This quarterly distribution remained in effect through the first quarter of 2010 when, effective April 2010, EEP increased it to $0.50125 per unit. In July 2010, EEP further increased its quarterly distribution to $0.51375 per unit and in July 2011 the quarterly distribution was increased to $0.5325. Of the $152 million Enbridge recognized as adjusted earnings from EEP during 2011, $46 million (2010 – $33 million; 2009 – $27 million) were GP incentive earnings, while the remainder was Enbridge's limited partner share of EEP's earnings.

RESULTS OF OPERATIONS

After adjusting EEP earnings for non-recurring or non-operating items, including the impact of the 2010 Line 6A and Line 6B crude oil releases, EEP adjusted earnings increased to $152 million for the year ended December 31, 2011 compared with $122 million for the year ended December 31, 2010. The increase was primarily attributable to strong results from its natural gas business as a result of higher natural gas and NGL volumes, including those associated with the acquisition of the Elk City System in September 2010, as well as higher general partner incentive income. Increased volumes in liquids pipelines and a full year contribution from Alberta Clipper also drove higher earnings in 2011. These positive factors were partially offset by an increase in operating and administrative costs and higher financing costs.

EEP adjusted earnings were $122 million for the year ended December 31, 2010 compared with $99 million for the year ended December 31, 2009. The increase was largely attributable to strong results from the liquids business as well as higher incentive income. The liquids improvement was generated largely from higher delivered volumes and increased average transportation rates, partially offset by increased operating costs.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

LINE 6B CRUDE OIL RELEASE

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas—a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The change in estimate was primarily based on a review of costs and commitments incurred, and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations, and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

LINE 6A CRUDE OIL RELEASE

A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

INSURANCE RECOVERIES

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) in insurance recoveries for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

LINE 6B PIPELINE INTEGRITY PLAN

In connection with the restart of Line 6B, EEP committed to accelerate a process initiated prior to the crude oil release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), EEP completed remediation of those pipeline anomalies it identified between 2007 and 2009 that were scheduled for refurbishment, and anomalies identified for action in a July 2010 PHMSA notification, on schedule within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, EEP also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

In February 2011, EEP filed a tariff supplement with the FERC, which became effective on April 1, 2011, for recovery of US$175 million of capital costs and US$5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30-year period, while operating costs will be recovered through EEP's annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

LEGAL AND REGULATORY PROCEEDINGS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP – ALBERTA CLIPPER US

In July 2009, the Company committed to fund 66.7% of the cost to construct the United States segment of the Alberta Clipper Project. The Company funded 66.7% of the project's equity requirements through EELP, while 66.7% of the debt funding was made through EEP. EELP – Alberta Clipper US earnings are the Company's earnings from its investment in EELP which undertook the project. The Alberta Clipper Project was placed into service on April 1, 2010.

RESULTS OF OPERATIONS

Adjusted earnings from EELP – Alberta Clipper US were $42 million for the year ended December 31, 2011 compared with $42 million for the year ended December 31, 2010 and $7 million for the year ended December 31, 2009. These earnings represent the Company's earnings from its 66.7% investment in a series of equity within EELP which owns the United States segment of Alberta Clipper. In 2010, earnings were favourably impacted by lower operating costs, predominantly property tax rates applicable during the construction phase relative to the deemed recovery permitted in tolls. Earnings for 2009 and for the first quarter of 2010, in advance of the in service date of April 1, 2010, were attributable to AEDC recognized while the project was under construction.

BUSINESS RISKS

The risks identified below are specific to EEP and EELP. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

COMPETITION

EEP's Lakehead System, the United States portion of the Liquids Pipelines mainline, is a major crude oil export conduit from the WCSB. Other existing competing carriers and pipeline proposals to ship western Canadian liquids hydrocarbons to markets in the United States represent competition for the Lakehead System. Further details on such competing projects are described within Business Risks under *Liquids Pipelines.* EEP's Mid-Continent and North Dakota systems also face competition from existing competing pipelines, proposed future pipelines and alternative gathering facilities (being predominately rail), available to producers or the ability of the producers to build such gathering facilities. Competition for EEP's storage facilities includes large integrated oil companies and other midstream energy partnerships.

Other interstate and intrastate natural gas pipelines (or their affiliates) and other midstream businesses that gather, treat, process and market natural gas or NGLs represent competition to EEP's natural gas segment. The level of competition varies depending on the location of the gathering, treating and processing facilities. However, most natural gas producers and owners have alternate gathering, treating and processing facilities available to them, including those owned by competitors that are substantially larger than EEP.

EEP's marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and natural gas producers, independent aggregators and regional marketing companies.

SUPPLY AND DEMAND

The profitability of EEP depends to some extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and eastern Canada. Investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, United States demand and availability of markets for produced crude oil. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing levels, alternative energy sources and global supply disruptions. Crude oil prices have been sustained at such levels that oil sands producers have recommenced projects that had been previously cancelled or deferred, creating increased demand in the WCSB for new pipeline infrastructure.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Supply for the marketing segment depends to a large extent on the natural gas reserves and rate of drilling within the areas served by the natural gas business. Demand is typically driven by weather-related factors, with respect to power plant and utility customers, and industrial demand. EEP's marketing business uses third party storage to balance supply and demand factors.

VOLUME RISK

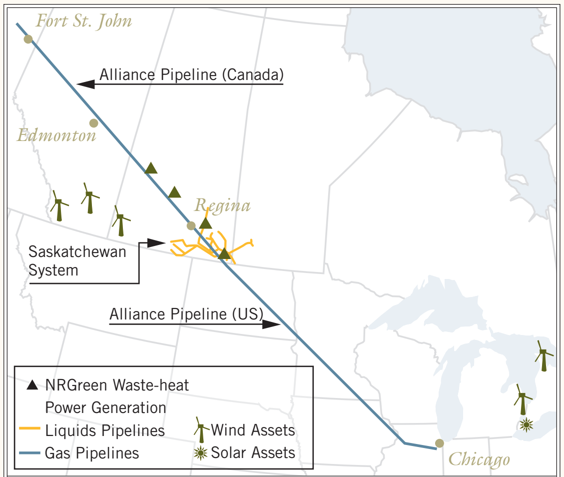
A decrease in volumes transported by EEP's systems can directly and adversely affect revenues and results of operations. A decline in volumes transported can be influenced by factors beyond EEP's control including competition, regulatory actions, government actions, weather, storage levels, alternative energy sources, decreased demand, fluctuations in commodity prices, economic conditions, supply disruptions, availability of supply connected to the systems and adequacy of infrastructure to move supply into and out of the systems.

REGULATION

In the United States, the interstate oil pipelines owned and operated by EEP and certain activities of EEP's intrastate natural gas pipelines are subject to regulation by the FERC or state regulators and its financial condition and results of operations could worsen if tariff rates were protested. While gas gathering pipelines are not currently subject to active rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

MARKET PRICE RISK

EEP's gas processing business is subject to commodity price risk arising from movements in natural gas and NGL prices and differentials. These risks have been managed by using physical and financial contracts to fix the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, EEP's earnings are exposed to associated mark-to-market valuation changes.



ENBRIDGE INCOME FUND

ENBRIDGE INCOME FUND

The Fund is involved in the generation and transportation of energy through its 50% interest in Alliance Pipeline Canada, its crude oil and liquids pipelines business in Saskatchewan (the Saskatchewan System) and interests in more than 400 MW of renewable power generation capacity. The Saskatchewan System operates a crude oil gathering system and trunkline pipeline in southern Saskatchewan and southwestern Manitoba, connecting to Enbridge's mainline pipeline to the United States. The Fund's renewable power portfolio includes the 190-MW Ontario Wind Project, the 99-MW Talbot Wind Project and the 80-MW Sarnia Solar Project, which were acquired from a wholly-owned subsidiary of Enbridge in October 2011, as well as interests in three wind power joint ventures and a business that operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

CORPORATE RESTRUCTURING

On December 17, 2010, a plan of arrangement (the Plan) to restructure the Fund took effect. Under the Plan all publicly held trust units and five million units held by Enbridge were exchanged on a one-for-one basis for shares of a taxable Canadian corporation, ENF. The business of ENF is generally limited to investment in the Fund. Following completion of the Plan, the Company retained its overall 72% economic interest in the Fund and remained the primary beneficiary of the Fund both before and after the Plan through a combined direct and indirect investment in the Fund voting units and a non-voting preferred unit investment. As such, Enbridge continues to consolidate the Fund under variable interest entity accounting rules.

RENEWABLE ENERGY ASSETS TRANSFER

In October 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for an aggregate price of approximately $1.2 billion. The transaction was financed by the Fund through a combination of debt and equity, including the issuance of additional ordinary trust units of the Fund to ENF and preferred units to Enbridge. ENF in turn issued additional common shares to the public and to Enbridge. Enbridge's overall economic interest in the Fund was reduced from 72% to 69% upon completion of the transaction and associated financing.

As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer has been eliminated from the consolidated financial statements of Enbridge, although cash income taxes incurred of $98 million remain as a charge to consolidated earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.

Through this transaction, which essentially resulted in a partial monetization of these assets by Enbridge through sale to non-controlling interests (being ENF's public shareholders), Enbridge realized a source of funds of $210 million, as presented within Financing Activities on the Consolidated Statement of Cash Flows for the year ended December 31, 2011.

SASKATCHEWAN SYSTEM SHIPPER COMPLAINT

On December 17, 2010, the Saskatchewan System filed amended Westspur tariffs with the NEB with an effective date of February 1, 2011. In January 2011, a shipper on the Westspur System requested the NEB make the tolls "interim" effective February 1, 2011 pending discussions between the shipper and the Saskatchewan System on information requests put forward by the shipper. Subsequently, the shipper filed a complaint with the NEB on the basis the information provided by the Fund was not adequate to allow an assessment to be made of the reasonableness of the tolls. Six parties have filed letters with the NEB supporting the shipper's complaint. The NEB directed additional discussion among the parties and, as of February 6, 2012, the Fund continues to discuss the reasonableness of its Westspur tolls with shippers.

INCENTIVE AND MANAGEMENT FEES

Enbridge receives an annual base management fee for administrative and management services it provides to the Fund, plus incentive fees. Incentive fees are paid to Enbridge based on cash distributions by the Fund that exceed a base distribution amount. In 2011, the Company received intercompany incentive fees of $10 million (2010 – $8 million; 2009 – $8 million) before income taxes. Enbridge also provides management services to ENF. No additional fee is charged to ENF for these services provided the Fund is paying a fee to Enbridge.

RESULTS OF OPERATIONS

Earnings from the Fund totaled $59 million for the year ended December 31, 2011 compared with $45 million for the year ended December 31, 2010. The increased earnings from the Fund reflected continued increased contributions from the Saskatchewan System following substantial completion of its Phase II expansion project in December 2010, as well as contribution from the renewable assets acquired by the Fund in October 2011. These positive impacts were partially offset by higher operating and administrative costs as a result of the asset acquisition and an increase in interest expense and taxes.

Earnings from the Fund were $45 million for both the years ended December 31, 2010 and 2009. Earnings for both years reflected growth attributable to Phase II of the Saskatchewan System Capacity Expansion, which was placed into service in December 2010, offset by a reduced contribution from the wind power assets and increased corporate costs related to the corporate restructuring completed in December 2010. The Fund's interest in Alliance Pipeline Canada continued to contribute stable adjusted earnings in both 2010 and 2009.

BUSINESS RISKS

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Gas Pipelines, Processing and Energy Services segment. The following risks generally relate to the Saskatchewan System and the wind and solar business, as indicated. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments.*

COMPETITION

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably trucking. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers and thereby potentially reduce shipping on the Saskatchewan System or result in possible toll reductions. The Saskatchewan System manages exposure to loss of shippers by ensuring the shipping rates are competitive and by providing a high level of service. Furthermore, the Saskatchewan System's right-of-way and expansion efforts have created a competitive advantage. The Saskatchewan System will continue to focus on increasing efficiencies through its expansion projects in order to meet its shippers' growing demand.

REGULATION

The Fund's 50% interest in Alliance Pipeline Canada and certain pipelines within the Saskatchewan System are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays. Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of the Fund.

VOLUME RISK

Operations and tolls for the Saskatchewan Gathering and the Westspur Systems are, in general, based on volumes transported and are on terms similar to a common carrier basis with no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls.

WIND AND SOLAR RESOURCES

There is risk that the wind or solar resource at specific locations is lower than expected leading to lower than expected power generation revenue. Extensive long term wind studies were completed prior to committing capital to the selected sites in order to mitigate this risk.

Corporate

EARNINGS

	2011	2010	2009
(millions of Canadian dollars)			
Noverco	**24**	21	19
Other Corporate	**(41)**	(48)	(39)
Adjusted loss	**(17)**	(27)	(20)
Noverco – impact of tax rate changes	**–**	–	6
Other Corporate – unrealized derivative fair value gains/(loss)	**(87)**	25	207
Other Corporate – unrealized foreign exchange gains/(loss) on translation of intercompany balances, net	**(131)**	40	133
Other Corporate – impact of tax rate changes	**6**	–	4
Other Corporate – gain on sale of investment in NetThruPut (NTP)	**–**	–	25
Other Corporate – tax on intercompany gain on sale	**(98)**	–	–
Earnings/(loss)	**(327)**	38	355

Total adjusted loss from Corporate was $17 million for the year ended December 31, 2011 compared with $27 million for the year ended December 31, 2010. The decrease in adjusted loss was due to both an increase in adjusted earnings from the Company's investment in Noverco and a decrease in adjusted loss from Other Corporate.

Total adjusted loss from Corporate was $27 million for the year ended December 31, 2010 compared with $20 million for the year ended December 31, 2009. The increase in adjusted loss was primarily due to the Company recording foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances in 2009, whereas no similar gains occurred in 2010. Other factors contributing to the increased adjusted loss included higher administrative costs and higher interest costs, partially offset by an increased corporate income tax recovery.

Corporate earnings/(loss) was impacted by the following non-recurring or non-operating adjusting items.

- Noverco earnings for 2009 included a benefit related to favourable tax rate changes.
- Earnings/(loss) for each year included a change in the unrealized fair value gains and losses on derivative financial instruments related to forward foreign exchange risk management positions.
- Earnings/(loss) included net unrealized foreign exchange gains or losses on the translation of foreign-denominated intercompany balances.
- Earnings/(loss) for the 2011 and 2009 were impacted by tax rate changes.
- In May 2009, the Company sold its investment in NTP, an internet-based crude oil trading and clearing platform, for proceeds of $32 million, resulting in a gain of $25 million.
- Earnings/(loss) for 2011 were impacted by tax on an intercompany gain on sale.

NOVERCO

At December 31, 2011, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2010 – 32.1%; 2009 – 32.1%) of its common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71% of Gaz Metro Limited Partnership (Gaz Metro), a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the state of Vermont. Effective September 2010, Gaz Metro became a privately held limited partnership as a result of a reorganization of its publicly held partnership units, which were exchanged on a one-for-one basis for common shares in Valener Inc., a new publicly listed corporation.

Noverco also holds, directly and indirectly, an investment in Enbridge common shares aggregating 69.4 million shares. The substantial increase in the value of these shares over the last decade has resulted in a significant shift in the balance of Noverco's asset mix. The board of directors of Noverco has authorized the Caisse De Depot et Placement de Quebec, as manager of Noverco, to rebalance Noverco's asset mix through the sale of up to 22.5 million Enbridge shares, by way of private placement, secondary offering or stock market sales, from time to time as market conditions permit, and to distribute the proceeds to shareholders, subject to compliance with restrictions under applicable law and credit facilities. Enbridge's share of such proceeds would be up to approximately $300 million, which would be applied to the funding of Enbridge's growth program.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investments which are based on the yield of 10-year Government of Canada bonds plus a weighted average spread of approximately 4.38%.

RESULTS OF OPERATIONS

Noverco adjusted earnings were $24 million for the year ended December 31, 2011 compared with $21 million for the year ended December 31, 2010 and $19 million for the year ended December 31, 2009. Noverco earnings for each year reflected contributions from the Company's increased preferred share investment and Noverco's underlying gas distribution investments.

OTHER CORPORATE

Corporate also consists of the new business development activities, general corporate investments and financing costs not allocated to the business segments.

RESULTS OF OPERATIONS

Other Corporate adjusted loss was $41 million for the year ended December 31, 2011 compared with $48 million for the year ended December 31, 2010. The decreased adjusted loss reflected an increase in preference share dividends following the issuance of 38 million preference shares during the year and higher tax expense, which were more than offset by lower interest expense.

Adjusted loss from Corporate was $48 million for the year ended December 31, 2010 compared with $39 million for the year ended December 31, 2009. The increase was primarily due to the Company recording foreign exchange gains realized on hedge settlements and on residual United States dollar cash balances in 2009, whereas no similar gains occurred in 2010. Other factors contributing to the increase included higher administrative costs and higher interest costs, partially offset by an increased income tax recovery.

Liquidity and Capital Resources

The Company expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. At December 31, 2011, excluding the Southern Lights project financing, the Company had $7,170 million of committed credit facilities of which $3,682 million were drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $77 million, the Company had net available liquidity at December 31, 2011 of $3,565 million. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2011.

	Maturity Dates [1]	Total Facilities	Credit Facility Draws [2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012 – 2013	**717**	**556**	**161**
Sponsored Investments	2013	**500**	**268**	**232**
Corporate [4]	2012 – 2016	**5,653**	**2,832**	**2,821**
		7,170	**3,682**	**3,488**
Southern Lights project financing [3]	2013 – 2014	**1,576**	**1,466**	**110**
Total credit facilities		**8,746**	**5,148**	**3,598**

1 *Total facilities include $30 million in demand facilities with no maturity date.*

2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

3 *Total facilities inclusive of $61 million for debt service reserve letters of credit.*

4 *In January 2012, the Company secured additional revolving facilities of US$1.3 billion with a maturity date of 2015.*

The Company's credit facility agreements include standard default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As in prior years, the Company expects to continue to comply with these provisions and therefore not trigger any early repayments. As at December 31, 2011, the Company was in compliance with all debt covenants.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The Company's debt to capitalization ratio at December 31, 2011, including short-term borrowings but excluding non-recourse debt, was 63.2%, compared with 65.1% at the end of 2010. Including all debt, the debt to capitalization ratio was 64.7% at December 31, 2011 compared with 66.9% at December 31, 2010.

The Company invests its surplus cash in short-term investment grade instruments with credit worthy counterparties. Short-term investments were $77 million at December 31, 2011 (2010 – $99 million).

Excluding current maturities of long-term debt, the Company has a negative working capital position, compared with a positive position at December 31, 2010. Working capital includes the current portion of unrealized fair value derivative gains and losses related to the Company's risk management activities. Of the $821 million change in working capital in 2011 compared with the prior year, $573 million relates to an increase in current derivative liabilities. Actual cash outflows to be incurred to settle these liabilities depend on foreign exchange rates, interest rates or commodity prices in effect when derivative contracts outstanding mature; therefore, working capital at a point in time may not be representative of actual future cash flows. The Company maintains adequate liquidity at all times, through committed credit facilities and other sources, to fund liabilities as they come due. Further, working capital will fluctuate from time to time due to changes in natural gas inventory and borrowing levels at EGD, as well as activity levels within, among others, the Company's Energy Services businesses.

	2011	2010
(millions of Canadian dollars)		
Cash and cash equivalents [1]	**420**	342
Accounts receivable and other	**3,136**	2,706
Inventory	**739**	813
Bank indebtedness	**(102)**	(100)
Short-term borrowings	**(548)**	(326)
Accounts payable and other	**(3,722)**	(2,688)
Interest payable	**(114)**	(117)
Working capital	**(191)**	630

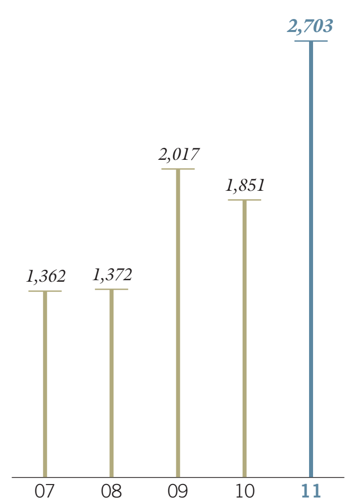
1 *Includes short-term investments, restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.*

Changes in commodity prices impact accounts receivable and other, inventory and accounts payable and other within Energy Services and EGD.

OPERATING ACTIVITIES

Cash provided by operating activities for the year ended December 31, 2011 was $2,703 million compared with $1,851 million for the year ended December 31, 2010. The growth in cash from operating activities represented favourable operating performance from the Company's core liquids and natural gas assets, increased contributions from a growing portfolio of renewable power generation assets and increased cash flow generated by the Energy Services and Aux Sable business. Also contributing to the increase in cash from operating activities was a variance of $544 million in changes in operating assets and liabilities due to increased transaction volume in the Energy Services business.

CASH PROVIDED BY OPERATING ACTIVITES
(millions of Canadian dollars)



Cash provided by operating activities for the year ended December 31, 2010 was $1,851 million compared with $2,017 million for the year ended December 31, 2009. Cash from operating activities was positively impacted in 2010 by contributions from growth projects placed in service, including Alberta Clipper and Southern Lights Pipeline. Alberta Clipper includes contributions from both the Canadian portion as well as cash distributions received on the Company's 66.7% equity investment in EELP which owns the United States segment of Alberta Clipper. Variances in working capital balances, primarily due to changes in commodity prices and sales volumes within Energy Services, as well as changes in natural gas prices at EGD, resulted in the decline in cash from operating activities in 2010 compared with 2009.

There are no material restrictions on the Company's cash with the exception of proportionately consolidated joint venture cash of $224 million, which cannot be accessed until distributed to the Company, restricted cash of $7 million related to Southern Lights project financing and cash in trust of $10 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities was $4,017 million for the year ended December 31, 2011 compared with $2,674 million for 2010, an increase of $1,343 million. Cash used in investing activities included $2,516 million (2010 – $2,357 million) of additions to property, plant and equipment for the year ended December 31, 2011. Capital expenditures on growth projects included Cabin, Athabasca Pipeline Capacity Expansion and Cedar Point Wind Energy Project, as well as a number of other projects under construction. Investing activities also includes several acquisitions, including a 50% interest in Seaway Pipeline for $1.2 billion (US$1.2 billion).

In 2010, cash used for investing activities was $2,674 million compared with $3,306 million in 2009, a decrease of $632 million. Cash used in investing activities included $2,357 million of additions to property, plant and equipment for the year ended December 31, 2010 and $3,225 million of additions to property, plant and equipment for the year ended December 31, 2009. Additions to property, plant and equipment declined compared with 2009 given the completion of several significant projects – Alberta Clipper, Southern Lights Pipeline and Hardisty Contract Terminal, among others. The Company also completed three acquisitions in 2010 resulting in a use of cash of $116 million.

Investing activities also include long-term investments and affiliate lending, which in 2009 and 2010 consisted primarily of the Company's investing in and funding of EELP which holds the Company's interest in the United States segment of Alberta Clipper. The higher use of cash used in investing activities reported in 2009 was partially offset by proceeds received on the sale of the Company's investments in OCENSA and NTP.

CAPITAL EXPENDITURES AND INVESTMENTS

	Expected 2012	**Actual 2011**	Actual 2010
(millions of Canadian dollars)			
Liquids Pipelines	2,080	**977**	765
Gas Distribution	480	**483**	387
Gas Pipelines, Processing and Energy Services	910	**953**	1,153
Sponsored Investments [1]	–	**122**	253
Corporate	250	**33**	–
	3,720	**2,568**	2,558

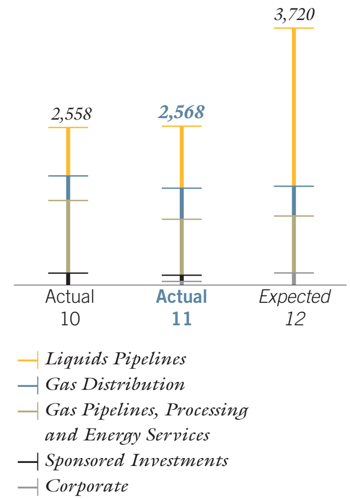
1 *Includes the Company's investment in sponsored vehicles.*

The Company's capital expansion initiatives are described in *Growth Projects*. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $3,720 million during 2012 on maintenance and growth capital projects which are substantially secured, including increased spending on integrity programs. The Company expects to finance these expenditures through cash from operating activities and available liquidity. The Company may also raise capital through the monetization or disposition of selected assets, or through accessing capital markets as required.

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued by the Company to finance business acquisitions, investments in subsidiaries and long-term investments. Funds for debt retirements are generated through cash provided from operating activities as well as through the issuance of replacement debt.

CAPITAL EXPENDITURES AND INVESTMENTS

(millions of Canadian dollars)



FINANCING ACTIVITIES

In 2011, cash provided by financing activities was $1,380 million compared with $766 million and $1,082 million in 2010 and 2009, respectively. Significant financing activities included an increase in short term borrowings, issuances and repayment of debentures and term notes, and issuances of preference shares.

Short-term borrowings are primarily used to finance near term working capital requirements, including gas inventories at EGD. In 2011, short-term borrowings increased to also fund long-term debt repayments and increased investing activities. In 2010, EGD had lower net repayments of short-term borrowings compared with 2009.

Medium-term note issuances included the following:

- Enbridge – $600 million (2010 – $800 million; 2009 – $1,000 million)
- Enbridge Pipelines Inc. – nil (2010 – $900 million; 2009 – $500 million)
- EGD – $100 million (2010 – $400 million; 2009 – nil)
- The Fund – $125 million (2010 – $200 million; 2009 – nil)

Contributions from noncontrolling interests increased to $214 million in 2011 compared with distributions of $1 million in 2010 and $33 million in 2009. The increase of contributions from noncontrolling interests was primarily a result of the share issuances at ENF and EEM. In 2011, Enbridge transferred three renewable energy assets to the Fund at an aggregate price of $1.2 billion. To acquire those assets, the Fund issued additional trust units to ENF, which in turn issued equity of $220 million to public shareholders.

In 2011, the proceeds from these term note issuances were used in part to fund term note repayments of $203 million (2010 – $600 million; 2009 – $616 million). In 2010, the proceeds from the issuance of term notes were also used to fund the repayment of commercial paper and credit facility of $347 million.

In 2011, the Company issued redeemable preference shares. Net proceeds from the issuance of Series B and Series D preference shares were $926 million (2010 and 2009 – nil).

In 2008, the Company secured financing that is non-recourse to the Company specific to the Canadian and United States segments of the Southern Lights Pipeline. In 2011, the repayment of Southern Lights Pipeline project financing was $62 million. For the years ended December 31, 2010 and 2009, the net proceeds on Southern Lights financing were $14 million and $343 million, respectively.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the year ended December 31, 2011, dividends declared were $759 million (2010 – $648 million), of which $530 million (2010 – $426 million) were paid in cash and reflected in financing activities. The remaining $229 million of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the years ended December 31, 2011 and 2010, 30% and 34%, respectively, of total dividends declared were reinvested.

OUTSTANDING SHARE DATA [1]

	Number
Preference Shares, Series A (non-voting equity shares)	5,000,000
Preference Shares, Series B (non-voting equity shares) [2]	20,000,000
Preference Shares, Series D (non-voting equity shares) [3]	18,000,000
Preference Shares, Series F (non-voting equity shares) [4]	20,000,000
Common Shares – issued and outstanding (voting equity shares)	782,270,762
Total issued and outstanding stock options (18,269,393 vested)	30,973,891

1 *Outstanding share data information is provided as at February 15, 2012.*

2 *On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series B will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series B into an equal number of Cumulative Redeemable Preference Shares, Series C.*

3 *On March 1, 2018, and on March 1 every five years thereafter, the holders of Preference Shares, Series D will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series D into an equal number of Cumulative Redeemable Preference Shares, Series E.*

4 *On June 1, 2018, and on June 1 every five years thereafter, the holders of Preference Shares, Series F will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series F into an equal number of Cumulative Redeemable Preference Shares, Series G.*

Effective May 25, 2011, a two-for-one stock split of the Company's common shares was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, adjusted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,120 million which are expected to be paid over the next five years.

CONTRACTUAL OBLIGATIONS

Payments due for contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1 – 3 years	3 – 5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt [1]	14,495	251	1,347	1,615	11,282
Non-recourse long-term debt [1]	1,048	120	154	143	631
Capital and operating leases	147	20	37	37	53
Long-term contracts [2,3]	4,318	2,247	1,515	361	195
Pension obligations [4]	105	105	–	–	–
Total contractual obligations	20,113	2,743	3,053	2,156	12,161

1 *Excludes interest. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements.*

2 *Approximately $2,776 million of these contracts are commitments for materials related to the construction of growth projects. Changes to the planned funding requirements, including cancellation, are dependent on changes to the related projects.*

3 *Contracts totaling $62 million are within proportionately consolidated joint venture entities and contracts totaling $125 million are between the Company and proportionately consolidated joint venture entities.*

4 *Assumes only required payments will be made into the pension plans in 2012. Contributions are made in accordance with the independent actuarial valuations as at December 31, 2011. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

UNITED STATES LEGAL AND REGULATORY PROCEEDINGS – LINE 6A AND 6B INCIDENTS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases; however, currently no penalties or fines have been assessed against EEP in connection with the incidents. In addition, a number of actions or claims have been filed against Enbridge, EEP or their affiliates in the United States federal and state courts in connection with these incidents. See *Sponsored Investments – Enbridge Energy Partners – EEP Lakehead System Line A and 6B Crude Oil Releases.*

ENBRIDGE GAS DISTRIBUTION INC.

BLOOR STREET INCIDENT

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

ENBRIDGE GAS NEW BRUNSWICK INC.

REGULATORY MATTERS

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 – $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LEGAL AND REGULATORY PROCEEDINGS

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

Quarterly Financial Information [1]

2011	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**4,713**	**4,981**	**4,272**	**5,436**	**19,402**
Earnings attributable to common shareholders	**393**	**259**	**4**	**335**	**991**
Earnings per common share [2]	**0.52**	**0.35**	**0.01**	**0.44**	**1.32**
Diluted earnings per common share [2]	**0.52**	**0.34**	**0.01**	**0.44**	**1.30**
Dividends per common share [2]	**0.2450**	**0.2450**	**0.2450**	**0.2450**	**0.98**
EGD – warmer/(colder) than normal weather	**(11)**	**(2)**	**–**	**12**	**(1)**
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	**(43)**	**27**	**235**	**(87)**	**132**

2010	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	3,977	3,505	3,502	4,143	15,127
Earnings attributable to common shareholders	342	138	157	326	963
Earnings per common share [2]	0.47	0.19	0.21	0.44	1.30
Diluted earnings per common share [2]	0.46	0.18	0.21	0.43	1.29
Dividends per common share [2]	0.2125	0.2125	0.2125	0.2125	0.85
EGD – warmer/(colder) than normal weather	8	10	–	(6)	12
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	(30)	87	(45)	(71)	(59)

1 *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

2 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

Several factors impact comparability of the Company's financial results on a quarterly basis, including, but not limited to, seasonality in the Company's gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company's other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market price risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, unrealized fair value gains and losses on these instruments will impact earnings. In 2011, Corporate earnings were impacted by unrealized derivative fair value changes of a $16 million gain, a $65 million loss, $83 million loss and a $45 million gain in the first, second, third and fourth quarters, respectively. Most comparably, earnings were positively impacted by unrealized derivative fair value gains of $26 million, $39 million and $48 million in the first, third and fourth quarters of 2010, respectively, and negatively impacted by an unrealized derivative fair value loss of $88 million in the second quarter of 2010. The revaluation of foreign-denominated intercompany loans impacts earnings each quarter, with most notable impacts being the recognition of gains of $68 million and $50 million in the second and third quarters of 2009.

Reflected in 2011 earnings are the Company's share of leak remediation costs and lost revenue associated with the Line 6A and Line 6B crude oil releases in the amounts of $6 million, $21 million (2010 – $85 million) and $6 million (2010 – $21 million) in the second, third and fourth quarters, respectively. Earnings for 2011 also reflected insurance recoveries associated with the Line 6B crude oil release of $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters, respectively.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company's capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects*.

Related Party Transactions

All related party transactions are undertaken in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, for the year ended December 31, 2011 are $380 million (2010 – $332 million; 2009 – $342 million) to EEP and $6 million (2010 – $7 million; 2009 – $6 million) to Vector. At December 31, 2011, the Company has accounts receivable of $35 million (2010 – $29 million) from EEP and nil (2010 – nil) from Vector.

The Company had previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principle amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty.

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance and Vector. EGD is charged market prices for these services. For the year ended December 31, 2011, EGD was charged $42 million (2010 – $42 million; 2009 – $42 million) for services from Alliance and $25 million (2010 – $28 million; 2009 – $29 million) from Vector.

Tidal Energy Marketing (US) L.L.C., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. For the year ended December 31, 2011, amounts purchased were $1 million (2010 – $2 million; 2009 – $16 million) and sales were nil (2010 – nil; 2009 – $6 million).

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C, subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector. For the year ended December 31, 2011, amounts paid to Alliance Pipeline Canada were $17 million (2010 – $13 million; 2009 – $9 million), amounts paid to Alliance Pipeline US were $11 million (2010 – $9 million; 2009 – $7 million) and amounts paid to Vector were $11 million (2010 – $10 million; 2009 – $16 million).

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP. For the year ended December 31, 2011, amounts purchased were $122 million (2010 – $151 million; 2009 – $80 million) and sales were $4 million (2010 – $3 million; 2009 – $7 million).

ALBERTA CLIPPER PROJECT

The Company funded 66.7% of the United States segment of Alberta Clipper's equity requirements through EELP, an equity investee. The Company also provided a $348 million (US$342 million) (2010 – $346 million (US$347 million) loan to EEP for debt financing related to the construction. At December 31, 2011, $336 million (2010 – $334 million) is included in Deferred amounts and other assets with the remaining $12 million (2010 – $12 million) included in Accounts receivable and other. The loan, denominated in United States dollars, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. Semi-annual payments of principal and accrued interest are required. Semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period.

During the year the Board of Directors of Enbridge Energy Management, L.L.C. declared distributions of $74 million (US$76 million) (2010 – $40 million (US$39 million)) payable to the Company relating to its Series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE

In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which was effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 – $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE

An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million.

LAKEHEAD LINE 6B CRUDE OIL RELEASE

In connection with the Lakehead Line 6B crude oil release, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $6 million for the year ended December 31, 2011 (2010 – $18 million).

Risk Management and Financial Instruments

Enbridge's proven investment value proposition is based on maintaining a reliable business model. More than 90% of the Company's revenues come from investment grade customers. Other risks, such as capital cost and inflation, are generally transferred to customers through contractual arrangements. In addition to contractually reducing the majority of its business risk, the Company has formal risk management policies, procedures and systems designed to mitigate any residual risks, such as market price risk, credit risk and operational risk. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

MARKET PRICE RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Market Price Risk Management Policy which outlines a risk management governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its businesses will exceed a defined tolerance.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk sensitivity at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The philosophy behind this metric is to identify the potential risk to the Company's annual earnings target, taking into account the illiquidity of certain exposure positions. The Company's policy is to limit EaR to a maximum of 5% of the next 12 months of forecasted earnings. Earnings exposure to market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with the EaR limits are reported to the CFRMC and variances are remediated as necessary.

Various hedging programs have been put into place to help ensure that the residual market price risks remain within policy limits, and thus help provide the Company with a general stability of earnings over a short and medium term horizon. The following section summarizes the primary types of market price risks to which the Company is exposed, and outlines the financial derivative hedging programs implemented.

The following table summarizes the EaR as a percentage of forecast earnings from the main groups of market price risk after impact of the Company's hedging programs. These EaR numbers are based on business conditions and hedging programs as of December 31, 2011 and may not be applicable to other periods.

Risk	EaR
(% of forecast 12 month forward earnings)	
Foreign exchange	0.8%
Interest rate	0.2%
Commodity	1.5%
Total EaR	2.5%

FOREIGN EXCHANGE RISK

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from the performance of its United States dollar denominated subsidiaries and investments, and certain revenues and expenses denominated in United States dollars. The Company has implemented a policy where it must hedge a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company currently has economically hedged over 85% of its forecast adjusted earnings through 2016 at an average rate of approximately $1.05C$/US$. The Company may also use foreign exchange forward contracts to hedge anticipated foreign currency denominated purchases or sales and foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries.

INTEREST RATE RISK

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate the volatility to variable rate interest expense through 2016 at an average swap rate of 2.27%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates on future fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a hedging program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2015. A total of $5,200 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure the consolidated portfolio of debt stays within the Board of Directors' approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding.

COMMODITY PRICE RISK

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGLs. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arises from physical transactions involving these commodities.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and its indirect ownership of the gathering and processing business held by EEP.

EQUITY PRICE RISK

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, Restricted Share Units.

CREDIT RISK

The Company's earnings and cash flows could be exposed to the risk of payment default by its shippers or other counterparties. Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Counterparty Credit Risk Policy outlining a governance framework and specific exposure limits to minimize the likelihood that adverse earnings fluctuations arise from counterparty defaults across any of its businesses.

Further initiatives to mitigate credit exposure include ensuring that all counterparties shipping on the regulated oil pipelines that have credit ratings below investment grade provide the carrier with a form of credit assurance, for example, a creditworthy parental guarantee, letter of credit or cash.

Credit risk in the Gas Distribution segment is mitigated by its large and diversified customer base and its ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due. The Company minimizes credit risk applicable to derivatives counterparties by entering into risk management transactions only with institutions that possess investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company's credit criteria to provide collateral. During 2010 and 2011, despite challenging market conditions, the Company did not suffer any material credit losses.

FINANCING RISK

The Company's financing risk relates to the price volatility and availability of debt to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and United States financial market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian and United States public capital markets by maintaining current shelf prospectuses with the securities regulators.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as access to capital markets. The Company maintains current shelf prospectuses with the securities regulators, which enable, subject to market conditions, ready access to either the Canadian or United States public capital markets.

MATURITIES OF DERIVATIVE FINANCIAL INSTRUMENTS

For the years ending December 31, 2012 through 2016, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its derivative instruments based on the valuations at the balance sheet date:

	2012	2013	2014	2015	2016	Thereafter
(millions of Canadian dollars)						
Cash inflows	440	213	180	69	74	105
Cash outflows	(401)	(133)	(124)	(77)	(65)	(610)
Net cash flows	39	80	56	(8)	9	(505)

The maturity profile of non-derivative financial liabilities is presented in *Liquidity and Capital Resources*.

FINANCIAL INSTRUMENTS

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**420**	–	–	–	–	–	–	**420**	**420**
Accounts receivable and other	**443**	–	**2,392**	–	–	**22**	**279**	**3,136**	**2,857**
Long-term investments	–	**56**	–	**285**	–	–	**2,199**	**2,540**	**285**
Deferred amounts and other assets	**450**	–	**4**	–	–	**99**	**2,667**	**3,220**	**553**
Liabilities									
Bank indebtedness	**102**	–	–	–	–	–	–	**102**	**102**
Short-term borrowings	–	–	–	–	**548**	–	–	**548**	**548**
Accounts payable and other	**365**	–	–	–	**2,728**	**346**	**283**	**3,722**	**3,439**
Interest payable	–	–	–	–	**114**	–	–	**114**	**114**
Long-term debt	–	–	–	–	**14,509**	–	–	**14,509**	**16,772**
Non-recourse long-term debt	–	–	–	–	**1,073**	–	–	**1,073**	**1,248**
Other long-term liabilities	**88**	–	–	–	–	**345**	**1,459**	**1,892**	**433**

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [1]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	342	–	–	–	–	–	–	342	342
Accounts receivable and other	145	–	2,113	–	–	25	423	2,706	2,283
Long-term investments	–	54	339	181	–	–	1,624	2,198	520
Deferred amounts and other assets	277	–	334	–	–	185	2,090	2,886	462
Liabilities									
Bank indebtedness	100	–	–	–	–	–	–	100	100
Short-term borrowings	–	–	–	–	326	–	–	326	326
Accounts payable and other	62	–	–	–	2,393	76	157	2,688	2,531
Interest payable	–	–	–	–	117	–	–	117	117
Long-term debt	–	–	–	–	13,715	–	–	13,715	14,770
Non-recourse long-term debt	–	–	–	–	1,131	–	–	1,131	1,298
Other long-term liabilities	6	–	–	–	–	127	1,340	1,473	133

1 Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating interest rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

DERIVATIVE INSTRUMENTS

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

	2011		2010	
December 31,	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards – purchase *(millions of United States dollars)*	2012 – 2020	**1,281**	2011 – 2020	1,185
U.S. dollar forwards – sell *(millions of United States dollars)*	2012 – 2020	**10,866**	2011 – 2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	2012 – 2029	**16,540**	2011 – 2029	10,772
Commodity contracts – energy *(bcfe)*	2012 – 2013	**2**	2011 – 2013	41
Commodity contracts – power *(MW/H)*	2012 – 2024	**53**	2011 – 2024	2
Equity contracts *(millions of shares)*	2011 – 2013	**2**	2011 – 2012	1

The Company has also designated a US$300 million (2010 – US$300 million) medium-term note and US$15 million (2010 – US$15 million) of commercial paper as hedges of certain United States dollar investments.

The following table summarizes the fair value of the Company's derivative instruments.

December 31, 2011	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other				
Foreign exchange contracts	**4**	**15**	**315**	**334**
Interest rate contracts	**–**	**–**	**7**	**7**
Commodity contracts	**–**	**–**	**114**	**114**
Equity contracts	**3**	**–**	**7**	**10**
	7	**15**	**443**	**465**
Deferred amounts and other				
Foreign exchange contracts	**15**	**79**	**203**	**297**
Interest rate contracts	**1**	**–**	**22**	**23**
Commodity contracts	**1**	**–**	**223**	**224**
Equity contracts	**3**	**–**	**2**	**5**
	20	**79**	**450**	**549**
Accounts payable and other				
Foreign exchange contracts	**(4)**	**–**	**(275)**	**(279)**
Interest rate contracts	**(341)**	**–**	**(3)**	**(344)**
Commodity contracts	**(1)**	**–**	**(87)**	**(88)**
	(346)	**–**	**(365)**	**(711)**
Other long-term liabilities				
Foreign exchange contracts	**(35)**	**(5)**	**(51)**	**(91)**
Interest rate contracts	**(303)**	**–**	**(18)**	**(321)**
Commodity contracts	**(2)**	**–**	**(19)**	**(21)**
	(340)	**(5)**	**(88)**	**(433)**
Total net derivative asset/(liability)				
Foreign exchange contracts	**(20)**	**89**	**192**	**261**
Interest rate contracts	**(643)**	**–**	**8**	**(635)**
Commodity contracts	**(2)**	**–**	**231**	**229**
Equity contracts	**6**	**–**	**9**	**15**
	(659)	**89**	**440**	**(130)**

December 31, 2010	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other				
Foreign exchange contracts	4	15	111	130
Interest rate contracts	6	–	–	6
Commodity contracts	–	–	33	33
Equity contracts	–	–	1	1
	10	15	145	170
Deferred amounts and other				
Foreign exchange contracts	18	100	275	393
Interest rate contracts	67	–	–	67
Commodity contracts	–	–	2	2
	85	100	277	462
Accounts payable and other				
Foreign exchange contracts	(4)	–	(11)	(15)
Interest rate contracts	(72)	–	–	(72)
Commodity contracts	–	–	(51)	(51)
	(76)	–	(62)	(138)
Other long-term liabilities				
Foreign exchange contracts	(47)	–	(3)	(50)
Interest rate contracts	(80)	–	–	(80)
Commodity contracts	–	–	(3)	(3)
	(127)	–	(6)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	(29)	115	372	458
Interest rate contracts	(79)	–	–	(79)
Commodity contracts	–	–	(19)	(19)
Equity contracts	–	–	1	1
	(108)	115	354	361

The fair value of derivative instruments has primarily been estimated using models or other industry standard valuation techniques derived from observable market information. This market information includes published market prices for commodities, interest rate yield curves, foreign exchange rates and equity prices. When possible, financial instruments are valued using quoted market prices.

An unrealized fair value loss of $593 million (2010 – $82 million) related to derivative instruments used as cash flow and net investment hedges was recognized in OCI for the year ended December 31, 2011. An unrealized fair value gain related to non-qualifying derivative instruments of $78 million (2010 – $26 million) was recognized in transportation revenues, commodity costs, other investment income and interest expense for the year ended December 31, 2011.

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 23 and 24 of the 2011 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

STRATEGY AND EXECUTION RISKS

PROJECT EXECUTION

The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, inadequate resources and in-service delays (collectively, Execution Risk). Customer trends are toward expecting the Company to assume more risk and accept lower returns. Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation and environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to regulatory delays, contractor or supplier non-performance and weather conditions may impact project development.

The Company has a centralized and clearly defined governance structure and process for all major projects with dedicated resources organized to lead and execute each major project. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. Early stage project risks are mitigated by early assessment of stakeholder issues to develop proactive relationships and specific action plans. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors.

INVESTMENT ANALYSIS

The Company evaluates the value proposition for expansion projects, new acquisitions or divestitures on an ongoing basis. Investment analysis may be ineffective in terms of earnings projections, cost estimates, project scoping, and risk assessment resulting in a loss in profits for the Company. Large scale acquisitions may involve significant pricing and integration risk.

A centralized corporate development group which is appropriately staffed rigorously evaluates all major investment proposals with consistent due diligence processes including a thorough review of the asset quality, systems and financial performance of the assets being assessed.

REPUTATION RISK

The Company's reputation is one of its most valuable assets. Reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action, increased regulatory oversight and costs.

Reputation risk often arises as a consequence of some other risk event, such as in connection with operational, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;

- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's CSR Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company's commitment to Green Energy).

OPERATIONAL RISKS

SYSTEM INTEGRITY

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating and insuring the Company's assets or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required and are supported by operating and capital budgets directed to pipeline integrity. Emergency response plans, operator training and landowner education programs are included in the Company's response preparedness. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company feels the level of insurance is adequate, it may not be sufficient to cover all potential losses.

ENVIRONMENTAL, HEALTH AND SAFETY RISK

The Company's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment and the investigation and remediation of contamination. The Company's facilities, or facilities to which it provides operating services, could experience incidents, malfunctions or other unplanned events that result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company's upstream customers' ability to produce crude oil and natural gas. The Company could be targeted, along with the oil sands industry, by environmental groups attempting to draw attention to GHG emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Ongoing training is provided to ensure employee and contractor competency as well as to enhance the safety culture at Enbridge. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

INFORMATION SYSTEMS

The Company's infrastructure, applications and data are becoming more integrated, creating increased risk that a failure in one system could lead to a failure of another system. Major systems development involves project management risks including implementation delays, scope creep, cost overruns or failure of systems to meet original project requirements. Disruption to business operations due to inadequate information security safeguards is also a risk.

The Company has a centralized information office which supports the development of standardized systems, use of industry proven packages where feasible, use of an information security risk management strategy and disaster recovery plans for critical operations. Back-up computers are installed in business units for enterprise-wide fail protection. Project management risks are mitigated through both a strict value proposition evaluation and a robust pre-implementation testing process with high quality requirements.

BUSINESS ENVIRONMENT RISKS

ABORIGINAL RELATIONS

Canadian judicial decisions have recognized that Aboriginal rights and treaty rights exist in proximity to the Company's operations and future project developments. The courts have also confirmed that the Crown has a duty to consult with Aboriginal peoples when its decisions or actions may adversely affect Aboriginal rights and interests or treaty rights. Crown consultation has the potential to delay regulatory approval processes and construction, which may affect project economics. In some cases, respecting Aboriginal rights may mean regulatory approval is denied or made economically challenging.

Given this environment and the breadth of relationships across the Company's geographic span, Enbridge has implemented the Aboriginal and Native American Policy. This Policy promotes the achievement of participative and mutually beneficial relationships with Aboriginal and Native American groups affected by the Company's projects and operations. Specifically, the Policy sets out principles governing the Company's relationships with Aboriginal and Native American peoples and makes commitments to work with Aboriginal peoples and Native Americans so they may realize benefits from the Company's projects and operations. Notwithstanding the Company's efforts to this end, the issues are complex and the impact of Aboriginal relations on Enbridge's operations and development initiatives is uncertain.

SPECIAL INTEREST GROUPS INCLUDING NON-GOVERNMENTAL ORGANIZATIONS

The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups, including non-governmental organizations. Recent Supreme Court decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, the Company and others in the energy and pipeline businesses are facing opposition from organizations opposed to oil sands development and shipment of production from oil sands regions.

The Company works proactively with special interest groups and non-governmental organizations to identify and develop appropriate responses to their concerns regarding its projects. The Company is investing significant resources in these areas. Its CSR program also reports on the Company's responsiveness to environmental and community issues. Please see Enbridge's annual CSR report, available online at csr.enbridge.com for further details regarding the CSR program. None of the information contained on, or connected to, Enbridge's website is incorporated in or otherwise part of this MD&A.

REGULATORY AND COMPLIANCE RISKS

UNFAVOURABLE RULINGS

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers. Recently shippers have challenged toll increases on various pipelines owned by Enbridge and some of Enbridge's competitors. Enbridge retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

CLIMATE CHANGE LEGISLATION

Uncertainty continues with respect to GHG regulations in Canada and the United States. The federal governments of both countries have signaled their intention to develop sector specific carbon related regulations but are reluctant to implement measures that might slow economic recovery. As a result, it is uncertain how climate legislation could affect the industry.

Enbridge has voluntarily reported its GHG emissions for over ten years. The Company is on track to deploy a new emissions data management system to ensure compliance with reporting requirements mandated in Canada and the United States. The Company will continue to monitor GHG regulatory developments and publicly report its GHG emissions as well as develop internal procedures to reduce these emissions.

RENEWABLE ENERGY

Enbridge has significant interests in wind, solar and geothermal power generation and is well positioned to expand this portfolio. Many programs to encourage and advance renewable energy exist in Canada and the United States as well as individual provinces and states. Enbridge continues to assess and advance renewable energy opportunities and monitor potential changes to government policies and incentives that may positively or negatively impact existing or future renewable energy projects.

Critical Accounting Estimates

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2011 of $22,623 million (2010 – $20,332 million), or 66% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the Energy Resources Conservation Board and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2011, the Company's significant regulatory assets totaled $1,337 million (2010 – $1,368 million) and significant regulatory liabilities totaled $931 million (2010 – $1,014 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. See *Gas Distribution – Other Gas Distribution and Storage – Enbridge Gas New Brunswick Regulatory Matters.*

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and post-employment benefits other than pensions (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the universal method. This method involves complex actuarial calculations using several assumptions including discount rates which were determined using the discount rate curve developed by the Canadian Institute of Actuaries, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The Company remains able to pay the current benefit obligations using cash from operations, reflecting strong capital market performance recovery. The shortfall from expected return on plan assets was $76 million for the year ended December 31, 2011 (2010 – $47 million excess) as disclosed in Note 27 to the 2011 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2011 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	126	14	18	1
Decrease in expected return on assets	–	6	–	–
Decrease in rate of salary increase	(25)	(5)	–	–

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments, including EGD and EECI, are detailed in the *Commitments and Contingencies* section of this report and are disclosed in Note 31 of the 2011 Annual Consolidated Financial Statements. In addition, any unasserted claims that later may become evident could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin setting aside funds for abandonment no later than January 1, 2015. Since then, the NEB has issued several revised "base case assumptions" based on feedback from member companies. Companies have the option to follow the base case assumptions or to submit pipeline specific applications.

On November 29, 2011, as required by NEB, the Company filed the applications for its regulated pipelines systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc., and Vector Pipelines Limited Partnership (Group 2 companies). The Company is seeking NEB approval of its preliminary calculations, which were largely based on the base case assumptions issued by NEB specifically for the purpose of this filing. The NEB is also requiring regulated pipeline companies to file a proposed process for collecting and setting aside the funds for abandonment by November 30, 2012 for Group 1 companies and by March 31, 2013 for Group 2 companies.

Both of the required submissions will require NEB approval and will result in increases to transportation tolls and regulatory liabilities, the amount of which is uncertain at this time. Currently, for certain of the Company's assets, there is insufficient data or information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation (ARO). In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

Changes in Accounting Policies

BUSINESS COMBINATIONS

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The application of this standard decreased Earnings attributable to Enbridge Inc. by $37 million, net of income taxes of $5 million for dilution gains for subsidiaries, which are now recognized in equity for the year ended December 31, 2011. The application of this standard had no material impact to the Company's cash flows for the year ended December 31, 2011.

CONSOLIDATED FINANCIAL STATEMENTS AND NONCONTROLLING INTERESTS

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only there was no impact to the Company's earnings or cash flows for the current or prior periods presented.

FUTURE ACCOUNTING POLICIES

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (U.S. GAAP)

First-time adoption of Part I – International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and presented its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

As a rate regulated accounting standard model has not been finalized by the International Accounting Standards Board, the Company does not intend to adopt IFRS in 2012 but rather U.S. GAAP. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

In preparation for the U.S. GAAP conversion, Enbridge has formed a U.S. GAAP project team and developed a transition plan and governance structure to monitor the progress of the transition. The Company has engaged a public accounting firm to assist with the project and to provide technical accounting advice on the interpretation and application of U.S. GAAP to its primary financial statements. Management reports regularly to the Audit, Finance and Risk Committee of the Board of Directors on the advancement of the conversion to U.S. GAAP.

ACCOUNTING AND REPORTING

The Company is in the process of integrating known U.S. GAAP differences into its primary financial statements. The most significant U.S. GAAP differences impact the following areas:

- consolidation of EEP;
- equity accounting treatment of joint ventures;
- inventory valuation;
- common control transactions;
- classification and valuation of redeemable noncontrolling interests;
- pensions and OPEB; and
- presentation differences, including the presentation of deferred financing costs.

Under U.S. GAAP the Company is deemed to control EEP and will therefore consolidate its interest in the partnership. The Company will commence reporting using U.S. GAAP as its primary basis of accounting in the first quarter of 2012. To facilitate users understanding of the transition, subsequent to filing its Canadian GAAP financial statements for the year ended December 31, 2011 and before filing its first interim report under U.S. GAAP, the Company will provide, for information purposes, its 2011 financial statements restated under U.S. GAAP along with comparative periods and related note disclosures.

TRAINING

As an SEC registrant, the Company has experience reporting under U.S. GAAP and has reconciled its financial statements to U.S. GAAP for many years. Further, two of the Company's affiliates, EEM and EEP are also registered with the SEC and currently prepare and file U.S. GAAP financial statements. The Company has provided supplemental U.S. GAAP training to internal personnel impacted by the conversion. U.S. GAAP training will continue into and beyond 2012 as a regular business activity.

INFORMATION SYSTEMS AND BUSINESS PROCESSES

The Company has completed testing system changes necessary to support the conversion to U.S. GAAP and to sustain U.S. GAAP reporting in 2012 and beyond. Implementation of these changes will take place in the first quarter of 2012. Impacts to internal controls over financial reporting and disclosures have been evaluated and no significant impacts were noted.

BUSINESS ACTIVITIES

The Company has reviewed the effect of the U.S. GAAP conversion on its debt covenants, compensation agreements and hedging activities and does not expect the conversion to U.S. GAAP to significantly impact these activities or requirements.

The detailed project plan and the expected timing of key activities identified above may change prior to the U.S. GAAP conversion date due to economic conditions or other factors.

FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2012. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

FAIR VALUE MEASUREMENT

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on fair value measurement under U.S. GAAP as part of the FASB's joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

STATEMENT OF COMPREHENSIVE INCOME

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of net income and OCI either in one continuous statement, referred to as the Statement of Comprehensive Income, or in two separate but consecutive statements of net income and OCI. The adoption of this pronouncement does not affect the Company's presentation of comprehensive income, and will not have an impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

GOODWILL IMPAIRMENT

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

BALANCE SHEET OFFSETTING

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As of the year ended December 31, 2011, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Enbridge is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with Canadian GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2011.

During the year ended December 31, 2011, there has been no material change in the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

Non-GAAP Reconciliations

	2011	2010	2009
(millions of Canadian dollars)			
GAAP earnings as reported	**991**	963	1,555
Significant after-tax non-recurring or non-operating factors and variances:			
Liquids Pipelines			
Canadian Mainline – shipper dispute settlement	**(14)**	–	–
Canadian Mainline – Line 9 tolling adjustment	**(10)**	–	–
Canadian Mainline – unrealized derivative fair value loss	**48**	–	–
Regional Oil Sands System – asset impairment loss	**8**	–	–
Regional Oil Sands System – leak remediation costs	**–**	–	9
Spearhead Pipeline – unrealized derivative fair value gains	**(1)**	–	–
Gas Distribution			
EGD – warmer/(colder) than normal weather	**(1)**	12	(17)
EGD – impact of tax rate changes	**–**	–	(21)
EGD – interest income on GST refund	**–**	–	(7)
Other Gas Distribution and Storage – asset impairment loss	**–**	–	10
Other Gas Distribution and Storage – adoption of new accounting standard	**–**	–	3
Gas Pipelines, Processing and Energy Services			
Offshore – property insurance recovery from hurricanes	**–**	(2)	(4)
Aux Sable – unrealized derivative fair value (gains)/loss	**7**	(7)	36
Aux Sable – loan forgiveness	**–**	–	(7)
Energy Services – unrealized derivative fair value (gains)/loss	**(113)**	12	(3)
Energy Services – Lehman and SemGroup credit recovery	**–**	(1)	(1)
Other – unrealized derivative fair value gains	**(24)**	–	–
Other – gain on sale of investments	**–**	–	(329)
Other – impact of tax rate changes	**–**	–	(4)
Sponsored Investments			
EEP – leak insurance recoveries	**(50)**	–	–
EEP – leak remediation costs and lost revenue	**33**	106	–
EEP – unrealized derivative fair value (gains)/loss	**(3)**	1	2
EEP – NGL trucking and marketing prior period adjustment	**3**	–	–
EEP – shipper dispute settlement	**(8)**	–	–
EEP – lawsuit settlement	**(1)**	–	–
EEP – impact of unusual weather conditions	**1**	–	–
EEP – Lakehead System billing correction	**–**	(1)	(4)
EEP – dilution gain on Class A unit issuance	**(66)**	(36)	–
EEP – asset impairment loss	**–**	2	12
Corporate			
Noverco – impact of tax rate changes	**–**	–	(6)
Other Corporate – unrealized derivative fair value (gains)/loss	**87**	(25)	(207)
Other Corporate – unrealized foreign exchange (gains)/loss on translation of intercompany balances, net	**131**	(40)	(133)
Other Corporate – impact of tax rate changes	**(6)**	–	(4)
Other Corporate – tax on intercompany gain on sale	**98**	–	–
Other Corporate – gain on sale of investment in NTP	**–**	–	(25)
Adjusted earnings	**1,110**	984	855

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

FINANCIAL REPORTING

Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States).

PATRICK D. DANIEL
President & Chief Executive Officer

J. RICHARD BIRD
Executive Vice President &
Chief Financial Officer

February 21, 2012

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2011, 2010 and 2009 consolidated financial statements and its internal control over financial reporting as at December 31, 2011. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2011 and December 31, 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in accordance with Canadian generally accepted accounting principles.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2011, based on the criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

DEFINITION OF INTERNAL CONTROL OVER FINANCIAL REPORTING

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

INHERENT LIMITATIONS

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

OPINION

In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2011 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 21, 2012

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**15,676**	11,990	9,720
Transportation and other services	**3,726**	3,137	2,746
	19,402	15,127	12,466
Expenses			
Commodity costs	**14,854**	11,291	9,011
Operating and administrative	**1,720**	1,466	1,430
Depreciation and amortization	**937**	864	764
	17,511	13,621	11,205
	1,891	1,506	1,261
Income from equity investments	**336**	38	198
Other income *(Note 28)*	**112**	374	678
Interest expense *(Note 16)*	**(711)**	(687)	(597)
Gain on sale of investments *(Note 6)*	**–**	–	365
	1,628	1,231	1,905
Income taxes *(Note 26)*	**(568)**	(251)	(306)
Earnings	**1,060**	980	1,599
Earnings attributable to noncontrolling interests	**(56)**	(10)	(37)
Earnings attributable to Enbridge Inc.	**1,004**	970	1,562
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	**991**	963	1,555
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*	**1.32**	1.30	2.14
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*	**1.30**	1.29	2.12

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings	**1,060**	980	1,599
Other comprehensive income/(loss)			
Change in unrealized loss on cash flow hedges, net of tax	**(427)**	(113)	(54)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**(19)**	51	151
Reclassification to earnings of realized cash flow hedges, net of tax	**32**	(25)	114
Reclassification to earnings of unrealized cash flow hedges, net of tax *(Note 23)*	**8**	–	(20)
Other comprehensive loss from equity investees, net of tax	**(61)**	(11)	(24)
Change in foreign currency translation adjustment	**242**	(274)	(815)
Other comprehensive loss	**(225)**	(372)	(648)
Comprehensive income	**835**	608	951
Comprehensive (income)/loss attributable to noncontrolling interests	**(43)**	23	35
Comprehensive income attributable to Enbridge Inc.	**792**	631	986
Preference share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders	**779**	624	979

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**125**	125	125
Preference shares issued	**931**	–	–
Balance at end of year	**1,056**	125	125
Common shares *(Note 20)*			
Balance at beginning of year	**3,683**	3,379	3,194
Common shares issued	**–**	–	4
Dividend reinvestment and share purchase plan	**229**	224	143
Shares issued on exercise of stock options	**57**	80	38
Balance at end of year	**3,969**	3,683	3,379
Contributed surplus			
Balance at beginning of year	**59**	54	38
Stock-based compensation	**18**	13	19
Options exercised	**(7)**	(8)	(3)
Dilution gains and other *(Note 19)*	**36**	–	–
Balance at end of year	**106**	59	54
Retained earnings			
Balance at beginning of year	**4,734**	4,400	3,383
Earnings attributable to Enbridge Inc. common shareholders	**991**	963	1,555
Common share dividends declared	**(759)**	(648)	(555)
Dividends paid to reciprocal shareholder	**25**	19	17
Balance at end of year	**4,991**	4,734	4,400
Accumulated other comprehensive income/(loss) *(Note 22)*			
Balance at beginning of year	**(882)**	(543)	33
Other comprehensive loss	**(212)**	(339)	(576)
Balance at end of year	**(1,094)**	(882)	(543)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(154)**	(154)	(154)
Acquisition of equity investment	**(33)**	–	–
Balance at end of year	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	7,565	7,261
Noncontrolling interests			
Balance at beginning of year	**658**	727	797
Earnings attributable to noncontrolling interests	**56**	10	37
Other comprehensive income/(loss) attributable to noncontrolling interests			
Change in unrealized income/(loss) on cash flow hedges, net of tax	**(7)**	(9)	4
Other comprehensive loss from equity investees, net of tax	**(15)**	(3)	(5)
Change in foreign currency translation adjustment	**9**	(21)	(71)
	(13)	(33)	(72)
Comprehensive income/(loss) attributable to noncontrolling interests	**43**	(23)	(35)
Distributions	**(37)**	(30)	(33)
Contributions *(Note 19)*	**208**	29	–
Acquisitions *(Notes 10 and 19)*	**(27)**	(45)	–
Other	**1**	–	(2)
Balance at end of year	**846**	658	727
Total shareholders' equity	**9,687**	8,223	7,988
Dividends paid per common share	**0.98**	0.85	0.74

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Operating activities			
Earnings attributable to Enbridge Inc.	**1,004**	970	1,562
Depreciation and amortization	**937**	864	764
Unrealized gains on derivative instruments	**(13)**	(10)	(204)
Allowance for equity funds used during construction	**(3)**	(80)	(135)
Cash distributions (less than)/in excess of equity earnings	**(42)**	214	(9)
Gain on reduction of ownership interest	**(141)**	(81)	–
Gain on sale of investments *(Note 6)*	**–**	–	(365)
Future income taxes *(Note 26)*	**415**	238	218
Goodwill and asset impairment losses	**11**	–	11
Noncontrolling interests	**56**	10	37
Other	**150**	(11)	(105)
Changes in regulatory assets and liabilities	**78**	30	11
Changes in operating assets and liabilities *(Note 29)*	**251**	(293)	232
	2,703	1,851	2,017
Investing activities			
Additions to property, plant and equipment	**(2,516)**	(2,357)	(3,225)
Government grant	**145**	–	–
Additions to intangible assets	**(165)**	(50)	(95)
Change in construction payable	**(66)**	27	(110)
Long-term investments	**(217)**	(121)	(359)
Affiliate loans, net	**10**	(80)	(145)
Acquisitions *(Notes 6 and 19)*	**(1,208)**	(116)	–
Proceeds on sale of investments *(Note 6)*	**–**	23	535
Sale of property, plant and equipment	**–**	–	87
Settlement of hedges *(Note 6)*	**–**	–	6
	(4,017)	(2,674)	(3,306)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**224**	(165)	(393)
Net change in commercial paper and credit facility draws	**11**	(347)	736
Debenture and term note issues	**825**	2,300	1,500
Debenture and term note repayments	**(203)**	(600)	(616)
Net change in Southern Lights project financing	**(62)**	14	343
Non-recourse debt issues	**17**	5	60
Non-recourse debt repayments	**(81)**	(73)	(130)
Contributions from/(distributions to) noncontrolling interests, net	**214**	(1)	(33)
Preference shares issued	**926**	–	–
Common shares issued	**46**	66	36
Preference share dividends	**(7)**	(7)	(7)
Common share dividends	**(530)**	(426)	(414)
	1,380	766	1,082
Effect of translation of foreign denominated cash and cash equivalents	**12**	(11)	(35)
Increase/(decrease) in cash and cash equivalents	**78**	(68)	(242)
Cash and cash equivalents at beginning of year	**342**	410	652
Cash and cash equivalents at end of year [1]	**420**	342	410
Supplementary cash flow information			
Income taxes paid/(received) *(Note 26)*	**(35)**	108	205
Interest paid *(Note 16)*	**749**	711	656

The accompanying notes are an integral part of these consolidated financial statements.

1 *Cash and cash equivalents consists of $343 million (2010 – $243 million; 2009 – $267 million) of cash and $77 million (2010 – $99 million; 2009 – $143 million) of short-term investments and includes restricted cash of $17 million (2010 – $12 million; 2009 – $7 million), and joint-venture cash which is not readily accessible by the Company of $224 million (2010 – $48 million; 2009 – $52 million).*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2011**	2010
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**420**	342
Accounts receivable and other *(Note 7)*	**3,136**	2,706
Inventory *(Note 8)*	**739**	813
	4,295	3,861
Property, plant and equipment, net *(Note 9)*	**22,623**	20,332
Long-term investments *(Note 11)*	**2,540**	2,198
Deferred amounts and other assets *(Note 12)*	**3,220**	2,886
Intangible assets *(Note 13)*	**600**	478
Goodwill *(Note 14)*	**1,024**	385
Future income taxes *(Note 26)*	**41**	80
	34,343	30,220
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**102**	100
Short-term borrowings *(Note 16)*	**548**	326
Accounts payable and other *(Note 15)*	**3,722**	2,688
Interest payable	**114**	117
Current maturities of long-term debt *(Note 16)*	**252**	154
Current maturities of non-recourse long-term debt *(Note 17)*	**122**	70
	4,860	3,455
Long-term debt *(Note 16)*	**14,257**	13,561
Non-recourse long-term debt *(Note 17)*	**951**	1,061
Other long-term liabilities *(Note 18)*	**1,892**	1,473
Future income taxes *(Note 26)*	**2,696**	2,447
	24,656	21,997
Equity		
Share capital		
Preference shares *(Note 20)*	**1,056**	125
Common shares *(Note 20)*	**3,969**	3,683
Contributed surplus	**106**	59
Retained earnings	**4,991**	4,734
Accumulated other comprehensive loss *(Note 22)*	**(1,094)**	(882)
Reciprocal shareholding *(Note 11)*	**(187)**	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	7,565
Noncontrolling interests *(Note 19)*	**846**	658
	9,687	8,223
Commitments and contingencies *(Note 31)*		
	34,343	30,220

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

DAVID A. ARLEDGE
Chair

DAVID A. LESLIE
Director

1. General Business Description

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Distribution, Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including the Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines and processing facilities, green energy projects, Canadian midstream businesses, the Company's energy services businesses and international activities.

Investments in natural gas pipelines include the Company's interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business, an interest in the development of Cabin Gas Plant in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico System. The energy services businesses manage the Company's volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, corporate investments and financing costs not allocated to the business segments.

2. Summary of Significant Accounting Policies

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's consolidated financial statements are described in Note 33. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Notes 23 and 24)*; income taxes *(Note 26)*; post-employment benefits *(Note 27)*; commitments and contingencies *(Note 31)*; and fair value of asset retirement obligations (AROs). Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and its proportionate share of the accounts of various joint ventures. The Fund is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of the Fund through the combination of a total direct and indirect 35.4% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as Held to maturity, Loans and receivables or Available for sale (see *Financial Instruments*).

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing and the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed and the amount of revenue can be reliably measured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue was recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Effective July 1, 2011, Canadian Mainline earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective July 1, 2011, the Company discontinued the application of rate-regulated accounting for its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis, with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period.

For rate-regulated operations in Sponsored Investments and rate-regulated operations in natural gas pipelines included in Gas Pipelines, Processing and Energy Services, transportation revenues include amounts related to expenses recognized that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to a regulatory asset or liability.

FINANCIAL INSTRUMENTS

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, held to maturity, other financial liabilities or derivatives in qualifying hedging relationships. All financial instruments are initially recorded at fair value on the Consolidated Statements of Financial Position. Subsequent measurement of the financial instrument is based on its classification.

HELD FOR TRADING

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenue, Commodity costs, Other income and Interest expense. The Company has classified Cash and cash equivalents, bank indebtedness and its non-qualifying derivative instruments as held for trading.

AVAILABLE FOR SALE

Financial assets that are available for sale are measured at fair value, with changes in those fair values recorded in Other comprehensive income/(loss) (OCI) unless actively quoted prices are not available for fair value measurement, in which case available for sale assets are measured at cost. Generally, the Company classifies equity investments in other entities that do not trade on an actively quoted market as available for sale. Dividends received from available for sale financial assets are recognized in earnings when the right to receive payment is established.

LOANS AND RECEIVABLES

Loans and receivables, which include Accounts receivable and other and affiliate long-term notes receivable, are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

HELD TO MATURITY

The Company has classified certain investments which are non-derivative financial assets as held to maturity. Held to maturity investments are measured at amortized cost using the effective interest rate method.

OTHER FINANCIAL LIABILITIES

Other financial liabilities are recorded at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Interest payable, Long-term debt and Non-recourse long-term debt.

DERIVATIVES IN QUALIFYING HEDGING RELATIONSHIPS

The Company uses derivative financial instruments to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

CASH FLOW HEDGES

The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

FAIR VALUE HEDGES

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges outstanding at December 31, 2011 or December 31, 2010.

NET INVESTMENT HEDGES

The Company uses net investment hedges to manage the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated other comprehensive income/(loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment.

CLASSIFICATION OF DERIVATIVES

The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current or long-term depending on the timing of the settlements and the resulting cash flows associated with the instruments. The fair value related to cash flows occurring beyond one year are classified as non-current.

BALANCE SHEET OFFSET

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

TRANSACTION COSTS

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

EQUITY INVESTMENTS

Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees.

NONCONTROLLING INTERESTS

Noncontrolling interests represent the outstanding ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and variable interest entities. The portion of the entities not owned by the Company is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES

The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a future income tax liability is recognized with a corresponding regulatory asset. Any interest and/or penalty incurred related to tax is reflected in income taxes.

FOREIGN CURRENCY TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates. Transactions denominated in foreign currencies are translated into Canadian dollars using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The Company's foreign operations are primarily self-sustaining. The financial statements of self-sustaining foreign operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of these operations are included in the cumulative translation adjustment component of AOCI and are recognized in earnings when there is a disposal of all or part of the foreign operation.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased. Cash and cash equivalents include restricted cash of amounts in trust and proportionately consolidated cash from joint ventures.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at fair value as measured at the spot price less costs to sell.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

The Company uses the group method of depreciation for all property, plant and equipment, except for the non rate-regulated assets in Canada, which are depreciated on a single asset basis. Depreciation is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. Under the group method, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system, is sold, a gain or loss is recognized in the Consolidated Statements of Earnings for the difference between the cash received and the net book value of the assets sold.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including future income taxes, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts, long-term power purchase agreements and certain software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangibles are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually in the fourth quarter of each year, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. Potential impairment is identified when the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value. Goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the assets and liabilities of the reporting unit.

IMPAIRMENT

The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

ASSET RETIREMENT OBLIGATIONS

AROs associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors. Pension cost is charged to earnings as services are rendered and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the initial net transitional asset, prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses, in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

Certain regulated operations of the Company recover pension and OPEB expense based on amounts paid in accordance with the methodology accepted by the regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. In the absence of rate regulation, these balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Contributed surplus. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Bloomberg barrier option valuation model and is recognized on a straight-line basis with a corresponding credit to Contributed surplus. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's financial statement presentation.

3. Changes in Accounting Policies

BUSINESS COMBINATIONS

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations*, which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The application of this standard decreased Earnings attributable to Enbridge Inc. by $37 million, net of income taxes of $5 million for dilution gains for subsidiaries, which are now recognized in equity for the year ended December 31, 2011. The application of this standard had no material impact to the Company's cash flows for the year ended December 31, 2011.

CONSOLIDATED FINANCIAL STATEMENTS AND NONCONTROLLING INTERESTS

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements* and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there was no impact to the Company's earnings or cash flow for the current or prior periods presented.

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

First-time adoption of Part I – International Financial Reporting Standards (Part I or IFRS) of the CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and presented its financial statements in accordance with Part V of the CICA Handbook during the 2011 deferral period.

As a rate regulated accounting standard model has not been finalized by the International Accounting Standards Board, the Company does not intend to adopt IFRS in 2012 but rather U.S. GAAP. As a United States Securities and Exchange Commission (SEC) registrant, Enbridge is permitted by Canadian securities regulation to prepare its financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual financial statements beginning on January 1, 2012.

4. Segmented Information

Year ended December 31, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**1,959**	**2,574**	**14,476**	**393**	**–**	**19,402**
Commodity costs	**–**	**(1,354)**	**(13,500)**	**–**	**–**	**(14,854)**
Operating and administrative	**(760)**	**(492)**	**(295)**	**(137)**	**(36)**	**(1,720)**
Depreciation and amortization	**(327)**	**(320)**	**(167)**	**(111)**	**(12)**	**(937)**
	872	**408**	**514**	**145**	**(48)**	**1,891**
Income/(loss) from equity investments	**–**	**–**	**–**	**342**	**(6)**	**336**
Other income/(expense)	**31**	**(11)**	**38**	**202**	**(148)**	**112**
Interest expense	**(256)**	**(166)**	**(97)**	**(74)**	**(118)**	**(711)**
Income taxes recovery/(expense)	**(139)**	**(55)**	**(161)**	**(219)**	**6**	**(568)**
Earnings/(loss)	**508**	**176**	**294**	**396**	**(314)**	**1,060**
Earnings attributable to noncontrolling interests	**(3)**	**–**	**(1)**	**(52)**	**–**	**(56)**
Preference share dividends	**–**	**–**	**–**	**–**	**(13)**	**(13)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**505**	**176**	**293**	**344**	**(327)**	**991**
Additions to property, plant and equipment [1]	**977**	**483**	**953**	**73**	**33**	**2,519**
Total assets	**12,366**	**7,713**	**4,968**	**5,245**	**4,051**	**34,343**

Year ended December 31, 2010	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,672	2,611	10,518	326	–	15,127
Commodity costs	–	(1,384)	(9,907)	–	–	(11,291)
Operating and administrative	(603)	(497)	(215)	(120)	(31)	(1,466)
Depreciation and amortization	(312)	(310)	(144)	(88)	(10)	(864)
	757	420	252	118	(41)	1,506
Income from equity investments	–	–	–	32	6	38
Other income/(expense)	115	(17)	30	114	132	374
Interest expense	(223)	(179)	(96)	(58)	(131)	(687)
Income taxes recovery/(expense)	(135)	(64)	(65)	(66)	79	(251)
Earnings	514	160	121	140	45	980
Earnings attributable to noncontrolling interests	(2)	(5)	–	(3)	–	(10)
Preference share dividends	–	–	–	–	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	512	155	121	137	38	963
Additions to property, plant and equipment [1]	765	387	1,153	132	–	2,437
Total assets	11,508	7,594	5,536	3,833	1,749	30,220

Year ended December 31, 2009	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,333	2,992	7,823	313	5	12,466
Commodity costs	–	(1,757)	(7,254)	–	–	(9,011)
Operating and administrative	(565)	(495)	(226)	(113)	(31)	(1,430)
Depreciation and amortization	(230)	(298)	(140)	(88)	(8)	(764)
	538	442	203	112	(34)	1,261
Income from equity investments	–	–	–	188	10	198
Other income/(expense) and gain on sale of investments	161	(12)	366	13	515	1,043
Interest expense	(144)	(188)	(87)	(56)	(122)	(597)
Income taxes	(108)	(50)	(54)	(88)	(6)	(306)
Earnings	447	192	428	169	363	1,599
Earnings attributable to noncontrolling interests	(2)	(6)	–	(28)	(1)	(37)
Preference share dividends	–	–	–	–	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	445	186	428	141	355	1,555
Additions to property, plant and equipment [1]	2,662	326	321	41	10	3,360

1 *Includes allowance for equity funds used during construction (AEDC).*

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

GEOGRAPHIC INFORMATION

REVENUES [1]

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Canada	**12,591**	9,876	9,503
United States	**6,811**	5,251	2,963
	19,402	15,127	12,466

1 *Revenues are based on the country of origin of the product or services sold.*

PROPERTY, PLANT AND EQUIPMENT

December 31,	**2011**	2010
(millions of Canadian dollars)		
Canada	**17,843**	16,095
United States	**4,780**	4,237
	22,623	20,332

5. Financial Statement Effects of Rate Regulation

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation whereby the rates approved by the regulator are designed to recover the costs of providing products and services to customers, referred to as the cost of service toll methodology. The Company's significant regulated businesses and related accounting impacts are described below.

CANADIAN MAINLINE

The Canadian Mainline includes the Canadian portion of the mainline system. The primary business activities of the Canadian Mainline are subject to regulation by the NEB. Prior to July 1, 2011, the incentive tolling settlement (ITS) defined the methodology for calculation of tolls and the revenue requirement on the core component of the Canadian Mainline. Toll adjustments, for variances from requirements defined in the ITS, were filed annually with the regulator for approval. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

Effective July 1, 2011, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the ten year term of the CTS. As a result, the Company discontinued the application of rate-regulated accounting to its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost of service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment.

The regulatory asset of approximately $470 million related to future income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of future income taxes incurred subsequent to the discontinuance of rate-regulated accounting, and, as such, regulatory assets related to future income taxes will continue to be recognized as incurred. The regulatory asset of approximately $70 million related to tolling deferrals recorded at the date of discontinuance is being recovered through a toll surcharge over a period of two years.

SOUTHERN LIGHTS

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

ENBRIDGE GAS DISTRIBUTION

EGD's gas distribution operations are regulated by the OEB. EGD's rates are based on a revenue per customer cap incentive regulation methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD's after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2011, 2010 and 2009 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

ENBRIDGE GAS NEW BRUNSWICK

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB's after-tax ROE for the year ended December 31, 2011 was 10.90% (2010 – 13.00%; 2009 – 13.00%) based on equity which is capped at 45%.

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

VECTOR PIPELINE

Vector Pipeline is an interstate natural gas pipeline in the United States with a FERC approved tariff that establishes rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls for the year ended December 31, 2011 included an after-tax ROE component of 11.18% (2010 – 11.18%; 2009 – 11.07%).

ALLIANCE PIPELINE

The Alliance Pipeline US is regulated by the FERC and Alliance Pipeline Canada is regulated by the NEB. Transportation service agreements with shippers are in place for substantially all of the pipeline capacity until December 2015 under a cost of service methodology. Toll adjustments are filed annually with the regulators. Tolls for the years ended December 31, 2011, 2010 and 2009 included an after-tax ROE component of 10.88% for Alliance Pipeline US and 11.26% (2010 – 11.26%; 2009 – 11.26%) for Alliance Pipeline Canada. Alliance Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	2011	2010	Estimated Settlement Period *(years)*	Earnings Impact [1] 2011	2010	2009
(millions of Canadian dollars)						
Regulatory assets/(liabilities)						
Liquids Pipelines						
Future income taxes [2]	**527**	479	–	**36**	55	49
Tolling deferrals [3]	**14**	132	1	**(3)**	19	(16)
Deferred transportation revenue [8]	**84**	32	29	**34**	21	–
Gas Distribution						
Future income taxes [2]	**224**	211	–	**9**	(12)	(11)
EGNB regulatory deferral [4]	**180**	171	30	**9**	18	15
Future removal and site restoration reserves [5]	**(836)**	(773)	–	**–**	–	6
Purchased gas variance [6]	**–**	(144)	1	**–**	–	–
Pension plans and OPEB, net [7]	**(95)**	(97)	–	**(2)**	–	(2)
Gas Pipelines, Processing and Energy Services						
Future income taxes [2]	**1**	1	–	**–**	–	–
Deferred transportation revenue [8]	**124**	150	13 – 15	**(18)**	(17)	(6)
Sponsored Investments						
Future income taxes [2]	**83**	94	–	**(8)**	(3)	(11)
Deferred transportation revenue [8]	**100**	98	15	**1**	5	5

1 *The effect of a number of the Company's businesses being subject to rate regulation increased/(decreased) after-tax reported earnings by the identified amounts.*

2 *The asset represents the regulatory offset to future income tax liabilities to the extent that future income taxes are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3 *Tolls for regulated pipelines under a cost of service methodology are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline result in an under or over collection of the annual revenue requirement, a regulatory asset or liability is recognized and incorporated into tolls in the subsequent year or in accordance with the related agreement.*

4 *A regulatory deferral account captures the cumulative difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance is expected to be amortized over a recovery period approved by the EUB expected to commence at the end of the development period in 2013 and end no sooner than 2040. The impact of legislative changes passed by the Government of New Brunswick in December 2011 (the specific details of which remain dependent upon regulations which have not yet been published) is not determinable as of February 21, 2012.*

5 *The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company's businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

6 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.*

7 *The pension plan balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement periods for these balances are not determinable. EGD continues to record and recover pension and OPEB expenditures through rates on a cash basis. In the absence of rate regulation, these regulatory balances would not be recorded and pension and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

8 *Deferred transportation revenue is related to the cumulative difference between Canadian GAAP depreciation expense for Southern Lights, Alliance and Vector Pipelines and the negotiated depreciation rates included in the regulated transportation tolls. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed Canadian GAAP depreciation rates: for Southern Lights after 2020, for Alliance Pipeline US beginning in 2009, for Alliance Pipeline Canada beginning in 2012 and for Vector Pipeline beginning in 2008. This regulatory asset is not included in the rate base.*

OTHER ITEMS AFFECTED BY RATE REGULATION

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AND OTHER CAPITALIZED COSTS

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

OPERATING COST CAPITALIZATION

With the approval of regulators, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, cumulative costs relating to this consulting contract of $133 million (2010 – $124 million) were included in property plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. Acquisitions and Dispositions

ACQUISITIONS

SEAWAY CRUDE PIPELINE COMPANY

On December 20, 2011, Enbridge acquired 50% of the outstanding common units in Seaway Pipeline, a partnership engaged in the crude oil pipeline business in Texas, for cash consideration of $1.2 billion (US$1.2 billion). The Company's investment in Seaway Pipeline is accounted for as a joint venture interest *(Note 10)*.

December 20,	2011
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**536**
Goodwill	**638**
Current liabilities	**(4)**
	1,175
Purchase Price:	
Cash (net of $9 million cash acquired)	**1,175**

A net loss of $1 million related to transaction costs was recognized in Earnings for the year ended December 31, 2011. Had the acquisition occurred on January 1, 2011, an unaudited proforma net loss of $2 million, including $1 million of transaction costs, would have been recognized as earnings. The entire amount of acquired goodwill is expected to be tax deductible for United States income tax purposes.

TONBRIDGE POWER INC.

On October 13, 2011, Enbridge acquired 100% of the 36 million outstanding common shares of Tonbridge Power Inc. (Tonbridge), an independent company engaged in constructing an electric transmission line between Montana and Alberta, for $20 million in cash at a price of $0.54 per share.

October 13,	2011
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Working capital deficiency	**(5)**
Property, plant and equipment	**196**
Intangible assets	**17**
Long-term debt	**(182)**
Other long-term liabilities	**(21)**
	5
Purchase Price:	
Cash (net of $15 million cash acquired)	**5**

No revenue from Tonbridge was recognized in 2011 as the transmission line is not yet in service. A net loss of $1 million was recognized in income for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expenses. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in income in 2011 had the acquisition occurred on January 1, 2011.

DISPOSITIONS

GAIN ON SALE OF INVESTMENTS

December 31,	2011	2010	2009
(millions of Canadian dollars)			
NetThruPut (NTP)	**–**	–	29
Oleoducto Central S.A. (OCENSA)	**–**	–	336
	–	–	365

NTP

On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million and were included in the Corporate operating segment.

OCENSA

On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million. Earnings from the OCENSA investment were included in the Gas Pipelines, Processing and Energy Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

7. Accounts Receivable and Other

December 31,	**2011**	2010
(millions of Canadian dollars)		
Unbilled revenues	**1,535**	1,284
Trade receivables	**699**	740
Taxes receivable	**157**	205
Regulatory assets	**80**	182
Current derivative assets *(Note 23)*	**465**	170
Due from affiliates *(Note 30)*	**69**	63
Prepaid expenses and deposits	**42**	36
Dividends receivable	**32**	16
Other	**113**	72
Allowance for doubtful accounts *(Note 23)*	**(56)**	(62)
	3,136	2,706

8. Inventory

December 31,	**2011**	2010
(millions of Canadian dollars)		
Natural gas	**488**	537
Other commodities	**251**	276
	739	813

9. Property, Plant and Equipment

December 31, 2011	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.8%	**7,482**	**1,811**	**5,671**
Pumping equipment, buildings, tanks and other	3.5%	**5,098**	**1,367**	**3,731**
Land and right-of-way	3.0%	**232**	**38**	**194**
Under construction	–	**1,718**	**–**	**1,718**
		14,530	**3,216**	**11,314**
Gas Distribution				
Gas mains, services and other	4.0%	**6,961**	**1,401**	**5,560**
Land and right-of-way	2.5%	**79**	**30**	**49**
Under construction	–	**137**	**–**	**137**
		7,177	**1,431**	**5,746**
Gas Pipelines, Processing and Energy Services				
Pipeline	3.6%	**2,171**	**814**	**1,357**
Wind turbines, solar panels and other [1]	5.8%	**1,208**	**125**	**1,083**
Land and right-of-way	2.6%	**50**	**14**	**36**
Under construction	–	**567**	**–**	**567**
		3,996	**953**	**3,043**
Sponsored Investments				
Pipeline	4.0%	**1,105**	**398**	**707**
Wind turbines, solar panels and other [1]	3.4%	**1,744**	**225**	**1,519**
Under construction	–	**23**	**–**	**23**
		2,872	**623**	**2,249**
Corporate				
Other	2.9%	**270**	**30**	**240**
Under construction	–	**31**	**–**	**31**
		301	**30**	**271**
		28,876	**6,253**	**22,623**

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Liquids Pipelines				
Pipeline	2.7%	7,295	1,618	5,677
Pumping equipment, buildings, tanks and other	3.6%	4,728	1,221	3,507
Land and right-of-way	1.8%	232	29	203
Under construction	–	728	–	728
		12,983	2,868	10,115
Gas Distribution				
Gas mains, services and other	3.6%	6,605	1,272	5,333
Land and right-of-way	2.6%	68	15	53
Under construction	–	103	–	103
		6,776	1,287	5,489
Gas Pipelines, Processing and Energy Services				
Pipeline	3.4%	2,121	706	1,415
Wind turbines, solar panels and other [1]	3.1%	1,527	142	1,385
Land and right-of-way	2.4%	62	13	49
Under construction	–	622	–	622
		4,332	861	3,471
Sponsored Investments				
Pipeline	4.0%	1,598	484	1,114
Wind turbines, solar panels and other [1]	8.5%	108	29	79
Under construction	–	17	–	17
		1,723	513	1,210
Corporate				
Other	11.3%	67	20	47
		67	20	47
		25,881	5,549	20,332

1 *In October 2011, Enbridge Pipelines Inc. (EPI) sold three renewable energy assets to the Fund. As a result, at December 31, 2011, $1,087 million of property, plant and equipment was reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The December 31, 2010 balance of $1,103 million has not been reclassified for presentation purposes.*

10. Joint Ventures

The impact of the Company's joint venture interests on net assets, earnings, cash flows and financial position is summarized below.

December 31,	Ownership Interest	Net Assets 2011	Net Assets 2010
(millions of Canadian dollars)			
Liquids Pipelines			
Chicap Pipeline	43.8%	**27**	27
Mustang Pipeline	30.0%	**27**	26
Woodland Pipeline	50.0%	**79**	23
Seaway Pipeline *(Note 6)*	50.0%	**1,186**	–
Gas Pipelines, Processing and Energy Services			
Enbridge Offshore Pipelines – various joint ventures	22.0% – 74.3%	**420**	433
Alliance Pipeline US	50.0%	**293**	318
Vector Pipeline	60.0%	**347**	349
Aux Sable [1]	42.7% – 50.0%	**217**	86
Lac Alfred Wind Project (Lac Alfred) [2]	50.0%	**130**	–
Other	33.3% – 70.0%	**21**	27
Sponsored Investments			
Alliance Pipeline Canada	50.0%	**642**	660
Other	33.0% – 50.0%	**58**	56
		3,447	2,005

1 *In July 2011, the Company, through its affiliate Aux Sable, acquired a 42.7% interest in the Palermo Conditioning Plant and the Prairie Rose Pipeline for $76 million.*

2 *In December 2011, the Company acquired a 50% interest in Lac Alfred for $128 million.*

The following table summarizes the impact of proportionately consolidating the joint ventures to the consolidated financial statements of the Company.

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Earnings			
Revenues	**804**	771	781
Commodity costs	**(138)**	(92)	(74)
Operating and administrative	**(200)**	(203)	(226)
Depreciation and amortization	**(163)**	(163)	(171)
Interest expense	**(75)**	(82)	(99)
Other income/(expense)	**(2)**	(1)	10
Proportionate share of earnings	**226**	230	221
Cash flows			
Cash provided by operating activities	**392**	349	342
Cash used in investing activities	**(196)**	(57)	(49)
Cash used in financing activities	**(71)**	(78)	(133)
Proportionate share of increase in cash and cash equivalents	**125**	214	160

December 31,	2011	2010
(millions of Canadian dollars)		
Financial position		
Current assets	**229**	171
Property, plant and equipment, net	**3,019**	2,331
Intangible assets	**210**	166
Goodwill	**959**	321
Deferred amounts and other assets	**267**	270
Current liabilities	**(239)**	(150)
Non-recourse long-term debt	**(951)**	(1,061)
Other long-term liabilities	**(47)**	(43)
Proportionate share of net assets	**3,447**	2,005

During the year ended December 31, 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic Pipeline), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic Pipeline. Prior to August 9, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline) for $28 million (US$27 million), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was classified as a joint venture.

11. Long-Term Investments

December 31,	Ownership Interest	2011	2010
(millions of Canadian dollars)			
Equity investments			
Sponsored Investments			
The Partnership	23.0%	**1,711**	1,473
Enbridge Energy, Limited Partnership – Series AC	66.7%	**453**	463
Corporate			
Noverco Common Shares	38.9%	**–**	14
Other	5.0% – 20.0%	**35**	13
Other investments			
Corporate			
Noverco Preferred Shares		**285**	181
Value Creation Inc.		**29**	29
Fuel Cell Energy Ltd.		**11**	25
Other		**16**	–
		2,540	2,198

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $120 million at December 31, 2011 (2010 – $123 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values at the purchase date and is amortized over the economic life of the assets.

THE PARTNERSHIP

The Partnership includes the Company's investments in EEP and Enbridge Energy Management, L.L.C. (EEM). The Company has a combined 23.0% ownership in EEP, through a 2.0% general partner interest, a 16.0% interest in Class A units, a 2.7% interest in Class B units and a 2.3% interest in EEP as a result of a 16.8% investment in EEM, which owns 13.3% of EEP through its 100% interest in EEP's i-units.

The Company recorded investment income inclusive of incentive earnings, before tax, of $296 million (2010 – $51 million; 2009 – $175 million) for the year ended December 31, 2011.

During the year ended December 31, 2011, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $66 million net of income taxes of $53 million and noncontrolling interests of $22 million, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 25.5% to 23.0%.

During the year ended December 31, 2010, EEP issued Class A units and, because Enbridge did not fully participate in this issuance, a dilution gain of $81 million before tax and noncontrolling interest, was recognized in earnings. As a result, Enbridge's ownership interest in EEP decreased from 27.0% to 25.5%.

Although 83.2% of EEM is widely held, the Company has voting control and therefore consolidates its investment in EEM.

ENBRIDGE ENERGY, LIMITED PARTNERSHIP

The Company has a 66.7% interest in the series AC units of EELP, which constructed the United States segment of the Alberta Clipper project *(Note 30)*. The Company recorded investment income from EELP of $53 million for the year ended December 31, 2011 (2010 – $63 million; 2009 – $12 million).

During 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 – $40 million (US$39 million)) payable to the Company relating to its series AC interest in the Alberta Clipper project.

NOVERCO

During the year ended December 31, 2011, the Company invested $144 million in cash and $255 million in a dividend received from Noverco to increase its common share investment from 32.1% to 38.9%. In addition, the Company received $399 million of preferred shares which are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.40%. There has been no change in the accounting for the Company's common or preferred share investments in Noverco as a result of the restructuring. The Company's interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

The Company adjusted its preferred share investments in Noverco which are entitled to cumulative preferred dividends based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40% to $285 million at December 31, 2011 (2010 – $181 million) due to the restructure of Noverco in 2011.

The Company also reduced its equity investment in Noverco common shares to nil at December 31, 2011 (2010 – $14 million) due to the restructure. Noverco owns an approximate 8.9% (2010 – 9.0%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.5% (2010 – 2.9%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $187 million at December 31, 2011 (2010 – $154 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2011, the Company recorded an equity investment loss of $6 million (2010 – $6 million of earnings; 2009 – $10 million of earnings) related to its interest in Noverco.

12. Deferred Amounts and Other Assets

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory assets	**1,434**	1,419
Long-term portion of derivative assets *(Note 23)*	**549**	462
Affiliate long-term note receivable *(Note 30)*	**336**	334
Pension asset *(Note 27)*	**320**	301
Contractual receivables	**288**	277
Other	**293**	93
	3,220	2,886

At December 31, 2011, deferred amounts of $63 million (2010 – $66 million) were subject to amortization and are presented net of accumulated amortization of $43 million (2010 – $39 million). Amortization expense in 2011 was $6 million (2010 – $9 million; 2009 – $7 million).

13. Intangible Assets

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.4%	**521**	**199**	**322**
Transportation agreements	4.2%	**241**	**79**	**162**
Power purchase agreements and other	10.4%	**122**	**6**	**116**
		884	**284**	**600**

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.4%	457	172	285
Transportation agreements	4.2%	231	66	165
Power purchase agreements and other	5.0%	33	5	28
		721	243	478

Total amortization expense for intangible assets was $61 million for the year ended December 31, 2011 (2010 – $60 million; 2009 – $44 million). Assuming no asset additions or impairments, the Company expects aggregate amortization expense for the years ending December 31, 2012 through 2016 of $62 million, $55 million, $48 million, $43 million and $38 million, respectively.

14. Goodwill

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at December 31, 2009	19	–	45	308	–	372
Foreign exchange and other	(1)	–	(3)	–	–	(4)
Business acquisition	17	–	–	–	–	17
Balance at December 31, 2010	35	–	42	308	–	385
Foreign exchange and other	**–**	**–**	**1**	**–**	**–**	**1**
Acquired *(Note 6)*	**638**	**–**	**–**	**–**	**–**	**638**
Balance at December 31, 2011	**673**	**–**	**43**	**308**	**–**	**1,024**

In 2011, the Company recognized $638 million of goodwill on the acquisition of a 50% interest in Seaway Pipeline. In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty Caverns.

15. Accounts Payable and Other

December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating accrued liabilities	**2,068**	1,677
Trade payables	**153**	232
Construction payables	**224**	253
Taxes payable	**283**	156
Current derivative liabilities *(Note 23)*	**711**	138
Security deposits	**84**	78
Contractor holdbacks	**40**	78
Other	**159**	76
	3,722	2,688

16. Debt

December 31,	Weighted Average Interest Rate	Maturity	2011	2010
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.20%	2024	**200**	200
Medium-term notes	5.05%	2012 – 2040	**2,435**	2,435
Southern Lights project financing [1]	2.52%	2013 – 2014	**1,449**	1,488
Commercial paper and credit facility draws, net			**26**	26
Other [2]			**13**	15
Gas Distribution				
Debentures	9.85%	2024	**85**	235
Medium-term notes	5.51%	2014 – 2050	**2,295**	2,195
Commercial paper and credit facility draws, net			**556**	334
Sponsored Investments				
Medium-term notes	4.72%	2014 – 2020	**415**	290
Credit facility draws, net			**260**	130
Corporate				
U.S. dollar term notes [3]	5.48%	2014 – 2017	**1,119**	1,094
Medium-term notes	4.74%	2013 – 2040	**3,518**	2,918
Commercial paper and credit facility draws, net [4]			**2,785**	2,776
Deferred debt issue costs and other			**(99)**	(95)
Total debt			**15,057**	14,041
Current maturities			**(252)**	(154)
Short-term borrowings	1.07%		**(548)**	(326)
Long-term debt			**14,257**	13,561

1 *2011 – $360 million and US$1,071 million (2010 – $388 million and US$1,106 million).*

2 *Primarily capital lease obligations.*

3 *2011 – US$1,100 million (2010 – US$1,100 million).*

4 *2011 – $987 million and US$1,780 million (2010 – $2,515 million and US$265 million).*

Debenture and term note maturities for the years ending December 31, 2012 through 2016 are $252 million, $451 million, $898 million, $916 million and $701 million, respectively. The Company's debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $557 million, $536 million, $515 million, $475 million and $450 million, respectively.

INTEREST EXPENSE

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Debentures and medium-term notes	**598**	578	494
Non-recourse long-term debt *(Note 17)*	**65**	75	83
Commercial paper and credit facility draws	**71**	63	71
Southern Lights project financing	**38**	37	45
Capitalized	**(61)**	(66)	(96)
	711	687	597

CREDIT FACILITIES

December 31, 2011	Maturity Dates [2]	Total Facilities	Credit Facility Draws [3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**26**	**274**
Gas Distribution	2012 – 2013	**717**	**556**	**161**
Sponsored Investments	2013	**500**	**268**	**232**
Corporate	2012 – 2016	**5,653**	**2,832**	**2,821**
		7,170	**3,682**	**3,488**
Southern Lights project financing [1]	2013 – 2014	**1,576**	**1,466**	**110**
Total credit facilities		**8,746**	**5,148**	**3,598**

1 *Total facilities inclusive of $61 million for debt service reserve letters of credit.*

2 *Total facilities include $30 million in demand facilities with no maturity date.*

3 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

Credit facilities carry a weighted average standby fee of 0.17% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,079 million (2010 – $2,940 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. Non-Recourse Debt

December 31,	Weighted Average Interest Rate	Maturity	2011	2010
(millions of Canadian dollars)				
Gas Pipelines, Processing and Energy Services				
Long-term credit facilities [1]		2015	**5**	1
Senior notes [2]	6.78%	2015 – 2025	**325**	347
Term debt [3]	3.54%	2012 – 2019	**31**	29
Capital lease obligations	10.60%	2020	**31**	32
Sponsored Investments				
Credit facilities		2012 – 2015	**23**	23
Senior notes	6.67%	2015 – 2025	**638**	675
Fair value increment on senior notes acquired			**25**	29
Deferred debt issue costs and other			**(5)**	(5)
Total non-recourse debt			**1,073**	1,131
Current maturities			**(122)**	(70)
Non-recourse long-term debt			**951**	1,061

1 *2011 – US$5 million (2010 – US$1 million).*

2 *2011 – US$319 million (2010 – US$349 million).*

3 *2011 – US$26 million (2010 – US$24 million).*

Maturities on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $122 million, $78 million, $81 million, $86 million and $64 million, respectively. The medium-term notes and senior notes bear interest at fixed rates. Interest obligations on non-recourse borrowings for the years ending December 31, 2012 through 2016 are $67 million, $62 million, $56 million, $51 million and $46 million, respectively.

Certain assets of Alliance Pipeline Canada and Alliance Pipeline US, with a carrying value of $959 million and $693 million, respectively, are pledged as collateral to Alliance Pipeline Canada and to Alliance Pipeline US lenders.

18. Other Long-Term Liabilities

December 31,	2011	2010
(millions of Canadian dollars)		
Future removal and site restoration reserves *(Note 5)*	**836**	773
Regulatory liabilities	**189**	198
Derivative liabilities *(Note 23)*	**433**	133
OPEB liabilities *(Note 27)*	**127**	118
Other	**307**	251
	1,892	1,473

19. Noncontrolling Interests

December 31,	2011	2010
(millions of Canadian dollars)		
Enbridge Energy Management, L.L.C. (EEM)	**475**	394
Enbridge Income Fund (the Fund)	**227**	109
Enbridge Gas Distribution Inc. (EGD) Preferred Shares	**100**	100
Talbot Windfarm, LP (Talbot)	**–**	26
Greenwich Windfarm, LP (Greenwich)	**26**	12
Other	**18**	17
	846	658

Noncontrolling interests in EEM represents the 83.2% of the listed shares of EEM not held by the Company. During the year ended December 31, 2011, EEM completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests.

Noncontrolling interests in the Fund at December 31, 2011 represents 64.6% of interests that are held by third parties. During the year ended December 31, 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly owned subsidiary of Enbridge for proceeds of $1.2 billion. Ordinary trust units were issued by the Fund to partially finance the acquisition, resulting in an increase in interests held by third parties. Contributions from noncontrolling interests for the year ended December 31, 2011 included $168 million attributable to the Fund's common trust unit issuance.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2011, no preferred shares have been redeemed.

Noncontrolling interests in both Talbot and Greenwich represent 10% of partnership units held by a third party. During the year ended December 31, 2011, the Company acquired the remaining 10% interest in Talbot for $28 million, increasing its ownership interest to 100%. Effective October 21, 2011, ownership of Talbot was transferred to the Fund.

20. Share Capital

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2011		2010		2009	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**770**	**3,683**	756	3,379	746	3,194
Common shares issued	**–**	**–**	–	–	–	4
Shares issued on exercise of stock options	**4**	**57**	6	80	2	38
Dividend Reinvestment and Share Purchase Plan (DRIP)	**7**	**229**	8	224	8	143
Balance at end of year	**781**	**3,969**	770	3,683	756	3,379

PREFERENCE SHARES

	2011		2010		2009	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference shares, Series A	**5**	**125**	5	125	5	125
Preference shares, Series B issued [1]	**20**	**490**	–	–	–	–
Preference shares, Series D issued [2]	**18**	**441**	–	–	–	–
Balance at end of year		**1,056**		125		125

1 *Gross proceeds – $500 million; net issuance costs – $10 million.*

2 *Gross proceeds – $450 million; net issuance costs – $9 million.*

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend [1]	Per Share Cash Dividend Declared	Per share Base Redemption Value [2]	Redemption and Conversion Option Date [2,3]	Right to Convert [3,4]
(Canadian dollars unless otherwise stated)						
Preference shares, Series A	5.5%	1.3750	1.3750	25	–	–
Preference shares, Series B	4.0%	1.0000	0.4192	25	June 1, 2017	Series C
Preference shares, Series D	4.0%	1.0000	0.2705	25	March 1, 2018	Series E

1 *Fixed, cumulative, quarterly preferential dividend per share per year.*

2 *The Company may at its option, redeem all or a portion of the outstanding preference shares for the base redemption value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified Series on the Conversion Option Date and every fifth anniversary thereafter.*

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C) or 2.37% (Series E)).*

Subsequent to year end, on January 18, 2012, the Company issued 20 million Series F Preference Shares for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to the same dividends, redemption and conversion terms as the Series B and Series D Preference Shares. Redemption of Series F Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series G can occur on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Series G Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada treasury bill rate plus 2.51%.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 25 million (2010 – 22 million; 2009 – 22 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

December 31,	**2011**	2010	2009
(number of common shares in millions)			
Weighted average shares outstanding	**751**	741	728
Effect of dilutive options	**10**	7	5
Diluted weighted average shares outstanding	**761**	748	733

For the year ended December 31, 2011, 48,000 anti-dilutive stock options (2010 – 92,000; 2009 – 1,113,000) with a weighted average exercise price of $32.02 (2010 – $27.84; 2009 – $20.49) were excluded from the diluted earnings per share calculation.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. Stock Option and Stock Unit Plans

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 43 million have been issued to date. In 2007, a new reserve of 33 million common shares was approved and established and in 2011 an increase of 19 million to the reserved common shares was approved, resulting in a total of 52 million shares being available for the 2007 ISO and PBSO plans, of which 1 million have been issued to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2011 for ISOs is $16 million (2010 – $11 million; 2009 – $17 million).

OUTSTANDING INCENTIVE STOCK OPTIONS

	2011		2010		2009	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**25,460**	**18.34**	24,932	17.01	21,300	15.53
Options granted	**6,041**	**28.78**	4,000	22.70	6,056	19.81
Options exercised	**(3,926)**	**14.23**	(3,436)	14.52	(2,374)	11.01
Options cancelled or expired	**(110)**	**25.87**	(36)	12.45	(50)	20.33
Options at end of year	**27,465**	**21.19**	25,460	18.34	24,932	17.01
Options vested	**14,214**	**17.93**	13,764	16.01	13,100	14.48

The total intrinsic value of ISOs exercised during the year ended December 31, 2011 was $68 million (2010 – $38 million; 2009 – $22 million) and cash received on exercise was $56 million (2010 – $50 million; 2009 – $26 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2011 was $285 million (2010 – $182 million) and $194 million (2010 – $131 million), respectively.

INCENTIVE STOCK OPTION CHARACTERISTICS

December 31, 2011	Options Outstanding			Options Vested		
Exercise Price Range	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
10.00 – 12.49	**1,195**	**1.0**	**10.45**	**1,195**	**1.0**	**10.45**
12.50 – 14.99	**1,440**	**2.1**	**12.86**	**1,440**	**2.1**	**12.86**
15.00 – 17.49	**2,578**	**4.7**	**15.99**	**1,963**	**4.0**	**15.94**
17.50 – 19.99	**7,877**	**6.0**	**19.30**	**5,486**	**5.5**	**19.08**
20.00 – 22.49	**5,202**	**6.4**	**20.55**	**3,390**	**6.2**	**20.37**
22.50 – 24.99	**3,102**	**8.1**	**23.30**	**717**	**8.1**	**23.30**
27.50 – 29.99	**6,023**	**9.1**	**28.90**	**23**	**8.9**	**27.84**
30.00 – 32.49	**48**	**9.7**	**32.02**	**–**	**–**	**–**
	27,465	**6.5**	**21.08**	**14,214**	**4.9**	**17.83**

The total fair value of options vested under the ISO Plan during the year ended December 31, 2011 was $17 million (2010 – $14 million; 2009 – $13 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	**2011**	2010	2009
Fair value per option *(Canadian dollars)* [1]	**4.19**	3.44	3.56
Valuation assumptions			
Expected option term *(years)* [2]	**6**	6	6
Expected volatility [3]	**18.63%**	19.72%	28.08%
Expected dividend yield [4]	**3.40%**	3.64%	3.87%
Risk-free interest rate [5]	**2.85%**	2.70%	2.24%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States options and the Canadian options. The fair value per option was $4.01 (2010 – $3.28; 2009 – $3.37) for Canadian employees and US$5.11 (2010 – US$4.00; 2009 – US$3.43) for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility. Beginning in 2010, implied volatility observable in call option values near the grant date is also considered in determining the expected volatility.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and United States Treasury Bond Yields.*

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $24 million. The cost is expected to be fully recognized by December 31, 2014.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2011 for PBSOs was $2 million (2010 – $2 million; 2009 – $2 million).

OUTSTANDING PERFORMANCE BASED STOCK OPTIONS

	2011		2010		2009	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**4,294**	**18.51**	6,790	16.85	7,476	16.36
Options exercised	**(167)**	**18.29**	(2,078)	13.12	(686)	11.58
Options cancelled	**–**	**–**	(418)	18.29	–	–
Options at end of year	**4,127**	**18.52**	4,294	18.51	6,790	16.85
Options vested	**3,191**	**18.47**	2,524	18.44	1,600	11.58

The total intrinsic value of PBSOs exercised during the year ended December 31, 2011 was $2 million (2010 – $26 million; 2009 – $6 million) and cash received on exercise was $3 million (2010 – $27 million; 2009 – $8 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2011 is $54 million (2010 – $30 million) and $42 million (2010 – $18 million), respectively.

PERFORMANCE BASED STOCK OPTION CHARACTERISTICS

December 31, 2011	Options Outstanding			Options Vested		
Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
18.29	**3,627**	**3.6**	**18.29**	**2,891**	**3.6**	**18.29**
20.21	**500**	**3.6**	**20.21**	**300**	**3.6**	**20.21**
	4,127	**3.6**	**18.52**	**3,191**	**3.6**	**18.47**

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2011 was $2 million (2010 – $2 million; 2009 – $2 million).

As of December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $1 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two, if the Company performs within the highest range of its performance targets. The 2009, 2010 and 2011 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2011 for PSUs was $42 million (2010 – $27 million; 2009 – $20 million). To calculate the 2011 expense, multipliers of two, based upon multiplier estimates at December 31, 2011, were used for each of the 2009, 2010 and 2011 PSU grants.

OUTSTANDING PERFORMANCE STOCK UNITS

December 31,	**2011**	2010	2009
Units at beginning of year	**955,894**	660,832	590,856
Units granted	**317,000**	572,400	339,200
Units matured	**(375,190)**	(319,634)	(303,764)
Dividend reinvestment	**39,453**	42,296	34,540
Units at end of year	**937,157**	955,894	660,832

Of the PSUs outstanding at December 31, 2011, 610,459 units have a performance period ending December 31, 2012 and 326,698 have a performance period ending December 31, 2013. The total intrinsic value of PSUs outstanding at December 31, 2011 is $71 million (2010 – $54 million; 2009 – $31 million). The total amount paid during the year ended December 31, 2011 for PSUs was $17 million (2010 – $14 million; 2009 – $9 million).

RESTRICTED STOCK UNITS

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date. Compensation expense recorded for the year ended December 31, 2011 for RSUs was $31 million (2010 – $29 million; 2009 – $23 million).

OUTSTANDING RESTRICTED STOCK UNITS

December 31,	**2011**	2010	2009
Units at beginning of year	**2,095,970**	1,975,754	1,400,068
Units granted	**938,100**	937,200	1,087,000
Units cancelled	**(92,276)**	(60,908)	(36,858)
Units matured	**(1,132,674)**	(855,504)	(565,312)
Notional dividend reinvestment	**92,865**	99,428	90,856
Units at end of year	**1,901,985**	2,095,970	1,975,754

The total intrinsic value of RSUs outstanding at December 31, 2011 is $72 million (2010 – $59 million; 2009 – $47 million). The total liability paid during the year ended December 31, 2011 for RSUs was $39 million (2010 – $24 million; 2009 – $12 million).

As of December 31, 2011, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $68 million and is expected to be fully recognized by December 31, 2013.

22. Components of Accumulated Other Comprehensive Income/(Loss)

	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Noncontrolling Interests	Cash Flow Hedges	Total
(millions of Canadian dollars)						
Balance at January 1, 2009	278	(275)	(8)	17	21	33
Changes during the year	181	(815)	(38)	72	71	(529)
Tax impact	(30)	–	14	–	(31)	(47)
	151	(815)	(24)	72	40	(576)
Balance at December 31, 2009	429	(1,090)	(32)	89	61	(543)
Changes during the year	61	(274)	(18)	33	(133)	(331)
Tax impact	(10)	–	7	–	(5)	(8)
	51	(274)	(11)	33	(138)	(339)
Balance at December 31, 2010	480	(1,364)	(43)	122	(77)	(882)
Changes during the year	**(21)**	**242** [1]	**(91)**	**13**	**(513)**	**(370)**
Tax impact	**2**	**–**	**30**	**–**	**126**	**158**
	(19)	**242**	**(61)**	**13**	**(387)**	**(212)**
Balance at December 31, 2011	**461**	**(1,122)**	**(104)**	**135**	**(464)**	**(1,094)**

1 *Changes in the Cumulative Translation Adjustment balance during the year included the release of a $155 million loss to earnings following the partial liquidation of an investment in a foreign subsidiary.*

23. Risk Management and Financial Instruments

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

Earnings at Risk (EaR), a variant of Value at Risk, is the principal risk management metric used to quantify market price risk at Enbridge. EaR is an objective, statistically derived risk metric that measures the maximum adverse change in projected 12-month earnings that could result from market price risk over a one-month period within a 97.5% confidence interval. The Company's policy is to operate within a maximum EaR of 5% of earnings. Earnings exposure from market price risk is managed within the overall consolidated EaR limits of the Company. Further, commodity price risk is managed within business unit EaR sub-limits. The Company's Corporate Financial Risk Management Committee (CFRMC) establishes and monitors the EaR limits on a monthly basis. Compliance with EaR limits is reported to the CFRMC and variances, if any, are remediated as necessary.

The Company calculates EaR using Monte Carlo simulation to produce projections of earnings using a randomly generated series of forecasted market prices and Enbridge's current market exposures. Historical statistical distributions of market prices and the correlation among those market prices are used to generate an entire probability distribution of possible deviations from forecast earnings.

There is currently no uniform industry methodology for estimating EaR. The use of this metric has limitations because it is based on historical correlations and volatilities in commodity prices and assumes future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated EaR on 97.5% of occasions, losses on the other 2.5% of occasions could be substantially greater than the estimated EaR.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

FOREIGN EXCHANGE RISK

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues and expenses denominated in United States dollars. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues and expenses denominated in United States dollars.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at December 31, 2011 would have resulted in a $310 million increase (2010 – $81 million) to earnings. The foreign exchange sensitivity analysis is limited to changes in the fair value of financial instruments, external debt and loans to non-consolidated foreign operations within the Company that are not denominated in the Company's functional currency and are not considered a net investment. A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company's United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

INTEREST RATE RISK

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.27%.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long term interest rate variability on select forecast term debt issuances through 2015. A total of $5,200 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%. Further, many of the Company's existing commercial arrangements and certain construction projects provide for the full recovery of financing costs through tolls.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit band of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 – nil) in earnings and a $457 million increase (2010 – $178 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011. A 1% increase across the interest rate yield curve, with all other variables constant, would have caused a $23 million decrease (2010 – $22 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

COMMODITY PRICE RISK

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil and NGLs. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and its indirect ownership of the gathering and process business held by EEP.

The Company uses EaR as a metric to monitor certain commodity price risk exposures, principally those associated with its ownership of Aux Sable, its ownership of EEP and the activities of its energy services subsidiaries. The EaR metric measures the price exposures, net of the impact of financial derivatives used to manage such exposures. The Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from such commodity price risk over a one month period.

	2011	2010
(millions of Canadian dollars)		
Average EaR during the year	**23**	22
High EaR during the year	**27**	29
Low EaR during the year	**18**	16
Closing EaR at year end	**20**	25

EQUITY PRICE RISK

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock based compensation, RSUs *(Note 21)*.

Due to revaluation of the equity derivative contracts at December 31, 2011, the impact of a $4 increase in the Company's share price would have been a $3 million increase in earnings (2010 – $2 million) and a $2 million increase in OCI (2010 – $1 million). The earnings impact of non-qualifying equity derivatives partially offsets earnings impacts due to the revaluation of liabilities associated with the Company's RSUs.

TOTAL DERIVATIVE INSTRUMENTS

The following tables summarize the balance sheet location and fair value of the Company's derivative instruments. The Company had no outstanding fair value hedges as at December 31, 2011 or 2010.

December 31, 2011	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	4	15	315	334
Interest rate contracts	–	–	7	7
Commodity contracts	–	–	114	114
Equity contracts	3	–	7	10
	7	15	443	465
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	15	79	203	297
Interest rate contracts	1	–	22	23
Commodity contracts	1	–	223	224
Equity contracts	3	–	2	5
	20	79	450	549
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	(4)	–	(275)	(279)
Interest rate contracts	(341)	–	(3)	(344)
Commodity contracts	(1)	–	(87)	(88)
	(346)	–	(365)	(711)
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	(35)	(5)	(51)	(91)
Interest rate contracts	(303)	–	(18)	(321)
Commodity contracts	(2)	–	(19)	(21)
	(340)	(5)	(88)	(433)
Total net derivative asset/(liability)				
Foreign exchange contracts	(20)	89	192	261
Interest rate contracts	(643)	–	8	(635)
Commodity contracts	(2)	–	231	229
Equity contracts	6	–	9	15
	(659)	89	440	(130)

December 31, 2010	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments
(millions of Canadian dollars)				
Accounts receivable and other *(Note 7)*				
Foreign exchange contracts	4	15	111	130
Interest rate contracts	6	–	–	6
Commodity contracts	–	–	33	33
Equity contracts	–	–	1	1
	10	15	145	170
Deferred amounts and other *(Note 12)*				
Foreign exchange contracts	18	100	275	393
Interest rate contracts	67	–	–	67
Commodity contracts	–	–	2	2
	85	100	277	462
Accounts payable and other *(Note 15)*				
Foreign exchange contracts	(4)	–	(11)	(15)
Interest rate contracts	(72)	–	–	(72)
Commodity contracts	–	–	(51)	(51)
	(76)	–	(62)	(138)
Other long-term liabilities *(Note 18)*				
Foreign exchange contracts	(47)	–	(3)	(50)
Interest rate contracts	(80)	–	–	(80)
Commodity contracts	–	–	(3)	(3)
	(127)	–	(6)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	(29)	115	372	458
Interest rate contracts	(79)	–	–	(79)
Commodity contracts	–	–	(19)	(19)
Equity contracts	–	–	1	1
	(108)	115	354	361

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

	2011		2010	
December 31,	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards – purchase *(millions of United States dollars)*	2012 – 2020	**1,281**	2011 – 2020	1,185
U.S. dollar forwards – sell *(millions of United States dollars)*	2012 – 2020	**10,866**	2011 – 2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	2012 – 2029	**16,540**	2011 – 2029	10,772
Commodity contracts – energy *(billions of cubic feet equivalent)*	2012 – 2013	**2**	2011 – 2013	41
Commodity contracts – power *(megawatts per hour)*	2012 – 2024	**53**	2011 – 2024	2
Equity contracts *(millions of shares)*	2011 – 2013	**2**	2011 – 2012	1

THE EFFECT OF DERIVATIVE INSTRUMENTS ON THE STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**(22)**	(25)
Interest rate contracts	**(545)**	(172)
Commodity contracts	**(6)**	97
Equity contracts	**6**	(1)
Net investment hedges		
Foreign exchange contracts	**(26)**	19
Total unrealized loss recognized in OCI	**(593)**	(82)
Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)*		
Cash flow hedges		
Foreign exchange contracts [1]	**1**	(7)
Interest rate contracts [2]	**18**	68
Commodity contracts [3]	**5**	(95)
Equity contracts [4]	**(2)**	1
Total gain/(loss) reclassified from AOCI to earnings *(effective portion)*	**22**	(33)
Amount of ineffectiveness reclassified from AOCI to earnings		
Cash flow hedges		
Interest rate contracts [2]	**11**	–
Total ineffectiveness reclassified from AOCI to earnings	**11**	–

1 *(Gain)/loss reported within Other income in the Consolidated Statements of Earnings.*

2 *(Gain)/loss reported within Interest expense in the Consolidated Statements of Earnings.*

3 *(Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

4 *(Gain)/loss reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $33 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all significant forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months at December 31, 2011.

NON-QUALIFYING DERIVATIVES

The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Foreign exchange contracts [1]	**(179)**	33	232
Interest rate contracts [2]	**9**	(2)	2
Commodity contracts [3]	**244**	(5)	(88)
Equity contracts [4]	**4**	–	–
Total unrealized derivative fair value gain	**78**	26	146

1 *Gain/(loss) reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*

2 *Gain/(loss) reported within Interest expense in the Consolidated Statements of Earnings.*

3 *Gain/(loss) reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*

4 *Gain reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

Additional information regarding the Company's derivative instruments is included in Note 24, *Fair Value of Financial Instruments.*

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 31 and 32)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, as well as access to capital markets. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

MATURITIES OF FINANCIAL INSTRUMENTS

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt *(Notes 16 and 17)*.

For the years ending December 31, 2012 through 2016, and thereafter, the Company has estimated the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

	2012	2013	2014	2015	2016	Thereafter
(millions of Canadian dollars)						
Cash inflows	440	213	180	69	74	105
Cash outflows	(401)	(133)	(124)	(77)	(65)	(610)
Net cash flows	39	80	56	(8)	9	(505)

CREDIT RISK

Entering into derivative financial instruments can result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and industry standard netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011 and 2010, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments.

December 31,	2011	2010
(millions of Canadian dollars)		
Canadian financial institutions	**426**	451
Non-Canadian financial institutions	**509**	125
Other	**73**	50
	1,008	626

Credit risk also arises from trade and other long-term receivables and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Credit risk in the Gas Distribution segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 24, *Fair Value of Financial Instruments*.

The change in allowance for doubtful accounts in respect of accounts receivable is detailed below.

Year ended December 31,	2011	2010
(millions of Canadian dollars)		
Balance at beginning of year	**(62)**	(74)
Additional allowance	**(26)**	(23)
Amounts used	**32**	35
Balance at end of year	**(56)**	(62)

24. Fair Value of Financial Instruments

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2011	Held for Trading	Available for Sale [1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	**420**	–	–	–	–	–	–	**420**	**420**
Accounts receivable and other	**443**	–	**2,392**	–	–	**22**	**279**	**3,136**	**2,857**
Long-term investments	–	**56**	–	**285**	–	–	**2,199**	**2,540**	**285**
Deferred amounts and other assets	**450**	–	**4**	–	–	**99**	**2,667**	**3,220**	**553**
Liabilities									
Bank indebtedness	**102**	–	–	–	–	–	–	**102**	**102**
Short-term borrowings	–	–	–	–	**548**	–	–	**548**	**548**
Accounts payable and other	**365**	–	–	–	**2,728**	**346**	**283**	**3,722**	**3,439**
Interest payable	–	–	–	–	**114**	–	–	**114**	**114**
Long-term debt	–	–	–	–	**14,509**	–	–	**14,509**	**16,772**
Non-recourse long-term debt	–	–	–	–	**1,073**	–	–	**1,073**	**1,248**
Other long-term liabilities	**88**	–	–	–	–	**345**	**1,459**	**1,892**	**433**

December 31, 2010	Held for Trading	Available for Sale [1]	Loans and Receivables	Held to Maturity	Other Financial Liabilities	Qualifying Derivatives	Non-Financial Instruments	Total	Fair Value [2]
(millions of Canadian dollars)									
Assets									
Cash and cash equivalents	342	–	–	–	–	–	–	342	342
Accounts receivable and other	145	–	2,113	–	–	25	423	2,706	2,283
Long-term investments	–	54	339	181	–	–	1,624	2,198	520
Deferred amounts and other assets	277	–	334	–	–	185	2,090	2,886	462
Liabilities									
Bank indebtedness	100	–	–	–	–	–	–	100	100
Short-term borrowings	–	–	–	–	326	–	–	326	326
Accounts payable and other	62	–	–	–	2,393	76	157	2,688	2,531
Interest payable	–	–	–	–	117	–	–	117	117
Long-term debt	–	–	–	–	13,715	–	–	13,715	14,770
Non-recourse long-term debt	–	–	–	–	1,131	–	–	1,131	1,298
Other long-term liabilities	6	–	–	–	–	127	1,340	1,473	133

1 *Classified as Other investments carried at cost under U.S. GAAP.*

2 *Fair value does not include non-financial instruments, which includes investments accounted for under the equity method, available for sale equity instruments held at cost that do not trade on an actively quoted market and affiliate long-term notes receivable resulting from related party transactions carried at historical cost.*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of financial assets carried as long-term investments, other than those classified as available for sale, approximates their carrying value due to interest terms which approximate floating market rates. The fair value of the Company's long-term debt and non-recourse long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

LEVEL 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations in the Gas Pipelines, Processing and Energy Services segment.

LEVEL 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts as well as commodity swaps and options for which observable inputs can be obtained. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services and Corporate segments.

LEVEL 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services segment.

When possible the estimated fair value is based on quoted market prices and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and commodity) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2011	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	–	334	–	334
Interest rate contracts	–	7	–	7
Commodity contracts	1	59	54	114
Equity contracts	–	10	–	10
	1	410	54	465
Long-term derivative assets				
Foreign exchange contracts	–	297	–	297
Interest rate contracts	–	23	–	23
Commodity contracts	–	193	31	224
Equity contracts	–	5	–	5
	–	518	31	549
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	–	(279)	–	(279)
Interest rate contracts	–	(344)	–	(344)
Commodity contracts	–	(42)	(46)	(88)
	–	(665)	(46)	(711)
Long-term derivative liabilities				
Foreign exchange contracts	–	(91)	–	(91)
Interest rate contracts	–	(321)	–	(321)
Commodity contracts	–	(16)	(5)	(21)
	–	(428)	(5)	(433)
Total net derivative asset/(liability)				
Foreign exchange contracts	–	261	–	261
Interest rate contracts	–	(635)	–	(635)
Commodity contracts	1	194	34	229
Equity contracts	–	15	–	15
	1	(165)	34	(130)

December 31, 2010	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	–	130	–	130
Interest rate contracts	–	6	–	6
Commodity contracts	–	5	28	33
Other contracts	–	–	1	1
	–	141	29	170
Long-term derivative assets				
Foreign exchange contracts	–	393	–	393
Interest rate contracts	–	67	–	67
Commodity contracts	–	–	2	2
	–	460	2	462
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	–	(15)	–	(15)
Interest rate contracts	–	(72)	–	(72)
Commodity contracts	(9)	(2)	(40)	(51)
	(9)	(89)	(40)	(138)
Long-term derivative liabilities				
Foreign exchange contracts	–	(50)	–	(50)
Interest rate contracts	–	(80)	–	(80)
Commodity contracts	–	(1)	(2)	(3)
	–	(131)	(2)	(133)
Total net derivative asset/(liability)				
Foreign exchange contracts	–	458	–	458
Interest rate contracts	–	(79)	–	(79)
Commodity contracts	(9)	2	(12)	(19)
Other contracts	–	–	1	1
	(9)	381	(11)	361

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of year	**(11)**	(28)
Total gains/(losses), unrealized		
Included in earnings [1]	**46**	19
Included in OCI	**(4)**	3
Settlements	**3**	(5)
Level 3 net derivative asset/(liability) at end of year	**34**	(11)

1 *Gain reported within Transportation and other services revenue, Commodity costs and Operating and administrative expense.*

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as of December 31, 2011 and December 31, 2010.

25. Capital Disclosures

The Company defines capital as shareholders' equity (excluding AOCI and reciprocal shareholdings), long-term debt (excluding non-recourse debt and transaction costs), short-term borrowings and noncontrolling interests less cash and cash equivalents (excluding restricted cash of amounts in trust and proportionately consolidated cash from joint ventures, net of bank indebtedness). Non-recourse debt, including debt proportionately consolidated from joint venture interests, is excluded from the Company's definition of capital as it is not controlled or managed exclusively by the Company.

The Company's capital is calculated as follows.

December 31,	**2011**	2010
(millions of Canadian dollars)		
Short-term borrowings	**548**	326
Long-term debt (includes current portion)	**14,608**	13,810
Noncontrolling interests	**846**	658
Shareholders' equity	**10,122**	8,601
Cash and cash equivalents	**(77)**	(282)
	26,047	23,113

The Company seeks to balance a number of objectives when managing capital, including enabling its businesses to operate at the highest efficiency while maintaining safety and reliability; ensuring liquidity for growth opportunities; and minimizing cost of capital. These objectives are primarily met through maintenance of an investment grade credit rating, disciplined investment criteria and sufficient committed credit facilities. Capital is available generally through the issuance of both short and long-term debt and various forms of equity.

The Company manages its capital by monitoring its debt to debt plus equity ratio (excluding non-recourse debt), with a target range of 60% to 70%, to meet its capital management objectives. The debt to capitalization ratio at December 31, 2011, including short-term borrowings but excluding non-recourse short and long-term debt, was 58.0% compared with 60.4% at the end of 2010.

Under terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company must maintain a ratio of consolidated funded obligations (essentially all debt except non-recourse debt) to total consolidated capitalization of less than 75%. This covenant also applies to the Company's credit facilities that are used to backstop its commercial paper program. Total consolidated capitalization consists of shareholders' equity, long-term debt, noncontrolling interests and future income taxes.

During the year ended December 31, 2011, the Company was in compliance with externally imposed capital requirements.

26. Income Taxes

INCOME TAX RATE RECONCILIATION

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars)			
Earnings attributable to Enbridge Inc. before income taxes	**1,572**	1,221	1,868
Combined statutory income tax rate	**27.3%**	28.9%	30.5%
Income taxes at statutory rate	**429**	353	570
Increase/(decrease) resulting from:			
Future income taxes related to regulated operations	**(35)**	(62)	(68)
Higher/(lower) foreign tax rates	**84**	(22)	(61)
Tax rates and legislated tax changes	**2**	(23)	(58)
Non-taxable items, net	**1**	(2)	11
Intercompany sale of investments [1]	**98**	–	(99)
Other	**(11)**	7	11
Income taxes	**568**	251	306
Effective income tax rate	**36.1%**	20.6%	16.4%

1 *In October 2011, EPI sold three renewable energy assets to the Fund. As the transaction occurred between entities under common control of the Company, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $98 million remain as a charge to earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.*

COMPONENTS OF FUTURE INCOME TAXES

December 31,	2011	2010
(millions of Canadian dollars)		
Net future income tax liabilities/(assets)		
Differences in accounting and tax bases of property, plant and equipment	**1,831**	1,468
Differences in accounting and tax bases of investments	**603**	479
Regulatory assets/(liabilities)	**308**	340
Financial instruments	**(24)**	105
Loss carryforwards	**(126)**	(81)
Other	**63**	56
Net future income tax liability	**2,655**	2,367

Net future income tax liability of $2,655 million (2010 – $2,367 million) is comprised of future income tax liabilities of $2,696 million (2010 – $2,447 million) net of future income tax assets of $41 million (2010 – $80 million).

At December 31, 2011, the Company had recognized the benefit of unused tax loss carryforwards of $401 million (2010 – $248 million) which start to expire in 2020 and beyond.

GEOGRAPHICAL COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**600**	711	954
United States	**839**	379	334
Other	**133**	131	580
	1,572	1,221	1,868
Current income taxes			
Canada	**207**	(29)	49
United States	**(48)**	37	35
Other	**(6)**	5	4
	153	13	88
Future income taxes			
Canada	**31**	134	117
United States	**384**	104	101
	415	238	218
Current and future income taxes	**568**	251	306

27. Post-Employment Benefits

PENSION PLANS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation for the Canadian and United States Plans.

DEFINED BENEFIT PLANS

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2010	December 31, 2011
Gas Distribution	December 31, 2009	December 31, 2012
United States Plan	December 31, 2010	December 31, 2011

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

DEFINED CONTRIBUTION PLANS

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

POST-EMPLOYMENT BENEFITS OTHER THAN PENSIONS

OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,323**	1,119	**195**	170
Service cost	**61**	48	**6**	5
Interest cost	**73**	72	**11**	11
Amendments	**–**	–	**–**	6
Employees' contributions	**–**	–	**1**	1
Actuarial loss [1]	**270**	145	**28**	12
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**8**	–	**7**	–
Effect of foreign exchange rate changes	**5**	(9)	**2**	(3)
Benefit obligation at end of year	**1,686**	1,323	**243**	195
Change in plan assets				
Fair value of plan assets at beginning of year	**1,324**	1,167	**41**	38
Actual return on plan assets [1]	**16**	127	**1**	2
Employer's contributions	**72**	89	**13**	9
Employees' contributions	**–**	–	**1**	1
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**4**	(1)	**4**	–
Effect of foreign exchange rate changes	**3**	(6)	**1**	(2)
Fair value of plan assets at end of year	**1,365**	1,324	**54**	41
Funded status				
Benefit obligation	**(1,686)**	(1,323)	**(243)**	(195)
Fair value of plan assets	**1,365**	1,324	**54**	41
Overfunded/(underfunded) status at end of year	**(321)**	1	**(189)**	(154)
Unamortized prior service cost	**2**	4	**5**	6
Unamortized transitional obligation/(asset)	**(9)**	(11)	**7**	8
Unamortized net loss	**648**	307	**50**	22
Net amount recognized in the Consolidated Statements of Financial Position at end of year	**320**	301	**(127)**	(118)
Presented as follows:				
Deferred amounts and other assets *(Note 12)*	**320**	301	**–**	–
Other long-term liabilities *(Note 18)*	**–**	–	**(127)**	(118)

1 *Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**4.46%**	5.64%	6.46%	**4.44%**	5.55%	6.28%
Average rate of salary increases	**3.50%**	3.50%	3.73%			

NET BENEFIT COSTS RECOGNIZED

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
(millions of Canadian dollars)						
Benefits earned during the year	**61**	48	53	**6**	5	4
Interest cost on projected benefit obligations	**73**	72	71	**11**	11	11
Actual return on plan assets	**(16)**	(127)	(51)	**(1)**	(2)	(6)
Difference between actual and expected return on plan assets	**(76)**	47	(27)	**(2)**	–	3
Amortization of prior service costs	**2**	2	2	**1**	–	–
Amortization of transitional obligation	**(2)**	(2)	(2)	**1**	1	1
Amortization of actuarial loss	**25**	19	21	**1**	1	1
Amount charged to EEP [1]	**(15)**	(15)	(20)	**(6)**	(5)	(5)
Net defined benefit costs on an accrual basis	**52**	44	47	**11**	11	9
Defined contribution benefit costs	**4**	5	4	**–**	–	–
Net benefit cost recognized in the Consolidated Statements of Earnings	**56**	49	51	**11**	11	9

1 EEP does not have employees and uses the services of the Company for managing and operating its businesses. EEP is charged an amount, measured at cost, for pension benefits and OPEB.

For certain gas distribution businesses, regulatory adjustments are recorded in the Consolidated Statement of Earnings and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Differences arise since accounting is based on an accrual basis whereas ratemaking is based on a cash basis or funding approach. Regulatory assets or liabilities recognized in the Consolidated Statements of Financial Position are disclosed in Note 5.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows.

	Pension Benefits			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.64%**	6.47%	6.59%	**5.55%**	6.31%	6.42%
Average rate of return on pension plan assets	**7.30%**	7.30%	7.30%	**6.00%**	6.00%	6.09%
Average rate of salary increases	**3.50%**	3.73%	5.00%			

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows.

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.4%	4.5%	2029
Other Medical and Dental	4.5%	4.5%	2029
United States Plan	7.8%	4.5%	2030

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $36 million in the accumulated post-employment benefit obligations and an increase of $3 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $29 million in the accumulated post-employment benefit obligations and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its defined benefit pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

TARGET MIX FOR PLAN ASSETS

	Liquids Pipelines Pension Plan	Gas Distribution Pension Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

EXPECTED RATE OF RETURN ON PLAN ASSETS

	Pension Benefits		OPEB	
Years ended December 31,	**2011**	2010	**2011**	2010
Canadian Plans	**7.0%**	7.25%		
United States Plan	**7.5%**	7.75%	**6.0%**	6.00%

MAJOR CATEGORIES OF PLAN ASSETS

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

As at December 31, 2011, assets securing pension benefits were invested 56.6% (2010 – 60.2%) in equity securities, 36.5% (2010 – 33.8%) in fixed income securities and 6.9% (2010 – 6.0%) in other. OPEB assets securing OPEB benefits were invested 55.3% (2010 – 51.2%) in equity securities, 40.3% (2010 – 48.8%) in fixed income securities and 4.3% (2010 – nil) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $82 million (2010 – $69 million) have been excluded from the table below.

December 31,	**2011** Level 1 [1]	Level 2 [2]	Level 3 [3]	Total	2010 Level 1 [1]	Level 2 [2]	Level 3 [3]	Total
(millions of Canadian dollars)								
Pension benefits								
Cash and cash equivalents	**14**	**–**	**–**	**14**	10	–	–	10
Fixed income securities								
Canadian government bonds	**–**	**115**	**–**	**115**	–	97	–	97
Corporate bonds and debentures	**–**	**4**	**–**	**4**	4	–	–	4
Canadian corporate bond index fund	**158**	**–**	**–**	**158**	151	–	–	151
Canadian government bond index fund	**157**	**–**	**–**	**157**	149	–	–	149
United States debt index fund	**62**	**–**	**–**	**62**	47	–	–	47
Equity								
Canadian equity securities	**148**	**–**	**–**	**148**	163	–	–	163
Canadian equity funds	**23**	**74**	**–**	**97**	26	80	–	106
United States equity funds	**172**	**89**	**–**	**261**	147	76	–	223
Global equity funds	**192**	**7**	**–**	**199**	221	19	–	240
Private equity investment [4]	**–**	**–**	**68**	**68**	–	–	65	65
OPEB								
Cash and cash equivalents	**3**	**–**	**–**	**3**	–	–	–	–
Fixed income securities								
United States government and government agency bonds	**22**	**–**	**–**	**22**	20	–	–	20
Equity								
United States equity funds	**15**	**14**	**–**	**29**	9	–	–	9
Global equity funds	**–**	**–**	**–**	**–**	–	12	–	12

1 *Level 1 assets include assets with quoted prices in active markets for identical assets.*

2 *Level 2 assets include assets with significant observable inputs.*

3 *Level 3 assets include assets with significant unobservable inputs.*

4 *The fair value of the investment in United States Limited Partnership – Global Infrastructure Fund is established through the use of valuation models.*

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows.

	Private Equity Investment
Balance at beginning of year	65
Total gains, unrealized	8
Purchases, issuances, settlements, net	(5)
Balance at end of year	68

PLAN CONTRIBUTIONS BY THE COMPANY

Year ended December 31,	Pension Benefits **2011**	2010	OPEB **2011**	2010
(millions of Canadian dollars)				
Total contributions	**72**	89	**13**	9
Contributions expected to be paid in 2012	**94**		**11**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2012	2013	2014	2015	2016	2017 – 2021
(millions of Canadian dollars)						
Expected future benefit payments	66	68	72	76	80	466

28. Other Income

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	**(109)**	132	444
Gain on reduction of EEP ownership interest	**141**	81	–
AEDC	**3**	80	135
Interest income on affiliate loans	**38**	37	38
Noverco preferred dividends income	**30**	15	15
Hurricane insurance recoveries	**–**	5	13
OCENSA investment income	**–**	–	6
Other	**9**	24	27
	112	374	678

29. Changes in Operating Assets and Liabilities

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Accounts receivable and other	**(94)**	(480)	99
Inventory	**54**	(42)	99
Deferred amounts and other assets	**(253)**	(98)	(354)
Accounts payable and other	**504**	254	105
Interest payable	**(3)**	13	2
Other long-term liabilities	**43**	60	281
	251	(293)	232

30. Related Party Transactions

All related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

EEP, an equity investee, does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are as follows.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
EEP	**380**	332	342
Vector Pipeline	**6**	7	6
	386	339	348

At December 31, 2011, the Company had accounts receivable of $35 million (2010 – $29 million) from EEP and nil (2010 – nil) from Vector Pipeline.

The Company previously provided EEP with an unsecured revolving credit agreement for general liquidity support. The credit facility provided for a maximum principal amount of US$500 million for a three-year term maturing in December 2010. In March 2010, the unsecured revolving credit agreement was cancelled in accordance with the terms of the agreement and without penalty.

EGD, a subsidiary of the Company, has contracts for gas transportation services with Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**25**	25	24
Alliance Pipeline US	**17**	17	18
Vector Pipeline	**25**	28	29
	67	70	71

Tidal Energy Marketing (US) L.L.C., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts charged/(recovered) are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Purchases	**1**	2	16
Sales	**–**	–	(6)
	1	2	10

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. Amounts charged are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**17**	13	9
Alliance Pipeline US	**11**	9	7
Vector Pipeline	**11**	10	16
	39	32	32

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Purchases	**122**	151	80
Sales	**(4)**	(3)	(7)
	118	148	73

ALBERTA CLIPPER PROJECT

In July 2009, the Company committed to fund 66.7% of the United States segment of the Alberta Clipper Project. The total cost of the United States segment was US$1,200 million. As at December 31, 2011, the Company had met all funding commitments. The Company funded 66.7% of the project's equity requirements through EELP, an equity investee.

The Company also provided a $348 million (US$342 million) (2010 – $346 million (US$347 million)) loan to EEP for debt financing related to the construction. At December 31, 2011, $336 million (2010 – $334 million) is included in Deferred amounts and other assets with the remaining $12 million (2010 – $12 million) included in Accounts receivable and other. The loan, denominated in United States dollars, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. Semi-annual payments of principal and accrued interest are required. Semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period.

During the year ended December 31, 2011, the Board of Directors of EEM declared distributions of $74 million (US$76 million) (2010 – $40 million (US$39 million)) payable to the Company relating to its series AC interests in the Alberta Clipper Project.

SPEARHEAD NORTH PIPELINE

In May 2009, the Company sold a section of the Spearhead Pipeline to its affiliate EEP for proceeds of US$75 million. This related party transaction has been recorded at the exchange amount which was equal to the carrying amount.

SOUTHERN LIGHTS PIPELINE

In February 2009, as part of its Southern Lights Pipeline project, the Company transferred the United States section of a newly constructed light sour pipeline to EEP in exchange for a pipeline referred to as Line 13. This non-monetary transaction has been recorded at the carrying amount.

In connection with the exchange discussed above, EEP entered into an arrangement to lease Line 13 from the Company for monthly payments of US$2 million to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Project. The lease arrangement, which became effective in February 2009, expired in April 2010. For the year ended December 31, 2010, EEP paid $5 million (2009 – $21 million) to the Company to lease Line 13.

LONG-TERM RECEIVABLE FROM AFFILIATE

An affiliate long-term note receivable of $159 million (US$130 million) was repaid by EEP in November 2009. Interest income for the year ended December 31, 2009 related to the note receivable was $11 million.

LAKEHEAD LINE 6B CRUDE OIL RELEASE

In connection with the Lakehead Line 6B Leak, the Company provided personnel support and other services to its affiliate, EEP, to assist in the clean-up and remediation efforts. These services, which were charged at cost, totaled $6 million (2010 – $18 million) for the year ended December 31, 2011.

31. Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation totaling $4,120 million which are expected to be paid within the next five years.

ENBRIDGE GAS DISTRIBUTION INC.

BLOOR STREET INCIDENT

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

ENBRIDGE GAS NEW BRUNSWICK INC.

REGULATORY MATTERS

On December 9, 2011, the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permits the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. Significant details of the rate setting process were left to be established in the new regulations which have yet to be published.

As at December 31, 2011, the carrying value of EGNB's regulatory asset and property, plant and equipment totaled $180 million and $264 million, respectively (2010 – $171 million and $254 million, respectively). Earnings from EGNB approximate $20 million per year. As the details of the regulations have not yet been made available, the effect of such regulations is not determinable as at February 21, 2012. While EGNB continues to engage in discussions with the province about the potential effect of the regulations, EGNB will preserve its legal rights.

ENBRIDGE ENERGY PARTNERS, L.P.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

Enbridge holds an approximate 23.0% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

LINE 6B CRUDE OIL RELEASE

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas—a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The change in estimate was primarily based on a review of costs and commitments incurred, and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the EPA directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

LINE 6A CRUDE OIL RELEASE

A crude oil release from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

INSURANCE RECOVERIES

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

LEGAL AND REGULATORY PROCEEDINGS

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LEGAL AND REGULATORY PROCEEDINGS

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

32. Guarantees

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under these indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The above-noted indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. United States Accounting Principles

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to Enbridge Inc. common shareholders under Canadian GAAP	**991**	963	1,555
Earnings attributable to Enbridge Inc. under Canadian GAAP	**1,004**	970	1,562
Dilution gains, net of tax [4]	**(88)**	(52)	–
Gain on acquisition, net of tax [1]	**–**	20	–
Inventory valuation adjustment, net of tax [2]	**13**	4	(24)
Amortization of underfunded pension adjustment [3]	**(7)**	(7)	(7)
Unrealized foreign exchange loss adjustment [12]	**155**	–	–
Earnings/(loss) attributable to noncontrolling interests			
EEP	**351**	(172)	177
Other	**56**	25	37
Earnings under U.S. GAAP	**1,484**	788	1,745
(Earnings)/loss attributable to noncontrolling interests	**(407)**	147	(214)
Earnings attributable to Enbridge Inc. under U.S. GAAP	**1,077**	935	1,531
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders under U.S. GAAP	**1,064**	928	1,524
Earnings per common share attributable to Enbridge Inc. common shareholders	**1.42**	1.25	2.09
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	**1.40**	1.24	2.08

COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings under U.S. GAAP	**1,484**	788	1,745
Other comprehensive loss including noncontrolling interests under Canadian GAAP	**(225)**	(372)	(648)
Underfunded pension adjustment [3]	**(145)**	(38)	11
Unrealized foreign exchange loss adjustment [12]	**(155)**	–	–
Other comprehensive loss attributable to noncontrolling interests in EEP under U.S. GAAP [4]	**(124)**	(29)	(62)
Other comprehensive loss including noncontrolling interests under U.S. GAAP	**(649)**	(439)	(699)
Comprehensive income	**835**	349	1,046
Comprehensive (income)/loss attributable to noncontrolling interests	**(270)**	224	(80)
Comprehensive income attributable to Enbridge Inc. under U.S. GAAP	**565**	573	966
Preference share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders under U.S. GAAP	**552**	566	959

FINANCIAL POSITION

December 31,	2011 Canada	2011 United States	2010 Canada	2010 United States
(millions of Canadian dollars)				
Assets				
Current assets				
Cash and cash equivalents [4,6]	**420**	**811**	342	456
Accounts receivable and other [4,6,9]	**3,136**	**3,990**	2,706	3,582
Inventory [2,4,6]	**739**	**714**	813	915
	4,295	**5,515**	3,861	4,953
Property, plant and equipment, net [4,6,8,9]	**22,623**	**31,833**	20,332	28,562
Long-term investments [4,6]	**2,540**	**510**	2,198	367
Deferred amounts and other assets [3,4,6,7,9]	**3,220**	**2,615**	2,886	2,212
Intangible assets [4,8]	**600**	**798**	478	676
Goodwill [4,8]	**1,024**	**1,091**	385	445
Future income taxes [1]	**41**	**40**	80	79
	34,343	**42,402**	30,220	37,294
Liabilities and shareholders' equity				
Current liabilities				
Bank indebtedness	**102**	**102**	100	100
Short-term borrowings	**548**	**548**	326	326
Accounts payable and other [4,6,9]	**3,722**	**4,904**	2,688	3,811
Interest payable [4]	**114**	**185**	117	177
Current maturities of long-term debt [4]	**252**	**354**	154	185
Current maturities of non-recourse long-term debt [6]	**122**	**103**	70	68
	4,860	**6,196**	3,455	4,667
Long-term debt [4,7,8]	**14,257**	**19,222**	13,561	18,374
Non-recourse long-term debt [6]	**951**	**606**	1,061	701
Other long-term liabilities [3,4,6,9]	**1,892**	**2,306**	1,473	1,658
Future income taxes [1,2,3,6,8]	**2,696**	**2,574**	2,447	2,370
	24,656	**30,904**	21,997	27,770
Redeemable noncontrolling interests [5]	**–**	**640**	–	364
Shareholders' equity				
Share capital				
Preference shares	**1,056**	**1,056**	125	125
Common shares	**3,969**	**3,969**	3,683	3,683
Contributed surplus	**106**	**–**	59	–
Retained earnings [1,2,3,5,8,9,12]	**4,991**	**4,172**	4,734	3,977
Additional paid-in capital [4]	**–**	**244**	–	131
Accumulated other comprehensive loss [3,12]	**(1,094)**	**(1,536)**	(882)	(1,026)
Reciprocal shareholding	**(187)**	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders' equity	**8,841**	**7,718**	7,565	6,736
Noncontrolling interests [4,5]	**846**	**3,140**	658	2,424
	9,687	**10,858**	8,223	9,160
	34,343	**42,402**	30,220	37,294

1 ***Gain on Acquisition*** *At December 31, 2010 under Canadian GAAP, the original equity interest in a step acquisition continued to be carried at book value subsequent to the acquisition date of the additional interest. Under U.S. GAAP, the original equity interest and noncontrolling interest in a step acquisition were re-measured to fair value on the date control was obtained. Under Canadian GAAP, the original equity interest and noncontrolling interest were not re-measured to fair value. At December 31, 2011, this recognition difference between Canadian GAAP and U.S. GAAP no longer exists.*

On June 16, 2010, the Company acquired the remaining 50% interest in Hardisty Caverns, an oil storage facility, increasing its ownership interest to 100%. The acquisition date fair value of the original equity interest in Hardisty Caverns was $52 million, which was determined based on the valuation of the additional 50% interest. As a result of the re-measurement of Hardisty Caverns, a $20 million gain, net of tax, was recorded in earnings for the year ended December 31, 2010 under U.S. GAAP.

2 **Commodity Inventories Valuation** Under Canadian GAAP commodity inventories are recorded at fair value. U.S. GAAP requires that commodity inventories be recorded at the lower of cost or market. For the year ended December 31, 2011, lower of cost or market adjustments resulted in a $11 million (2010 – $32 million) decrease to inventory, a $4 million increase (2010 – $6 million decrease) to the future income tax liability and a $13 million increase (2010 – $4 million increase; 2009 – $24 million decrease) to earnings.

3 **Pension Accounting** U.S. GAAP requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB plan as an asset or liability and to recognize changes in the funded status in the period in which they occur through OCI while Canadian GAAP does not require the recognition of the defined benefit post retirement plan or OPEB plan funding status. Pension funding status adjustments resulted in a decrease in the net pension asset of $704 million (2010 – $337 million) for the underfunded status of the plans, a decrease in regulatory liabilities of $304 million (2010 – $138 million), a decrease in future tax liability of $114 million (2010 – $58 million) and a decrease in AOCI of $286 million (2010 – $141 million) at December 31, 2011.

Under Canadian GAAP, an unrecognized net transitional asset was recognized as part of the net pension asset on the adoption of CICA Handbook Section 3461, Employee Future Benefits. There is no corresponding asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $2 million (2010 – $3 million) increase to the net pension asset with an offset to retained earnings, and a $1 million decrease to earnings (2010 – $1 million; 2009 – $1 million).

Under Canadian GAAP, a regulatory asset is recorded in relation to recoverable costs associated with OPEB plans. There is no corresponding regulatory asset under U.S. GAAP. At December 31, 2011, this adjustment resulted in a $88 million (2010 – $85 million) decrease to regulatory assets with a corresponding decrease to retained earnings, and a $6 million decrease to earnings (2010 – $6 million; 2009 – $6 million).

Amounts removed from OCI and recognized as components of the net pension and OPEB costs in the year are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Prior service cost	**–**	1	–
Net loss	**10**	7	5
	10	8	5

Amounts included in AOCI that have not yet been recognized as a component of net periodic benefit cost are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Prior service cost	**3**	4	1
Accumulated net loss	**283**	137	102
	286	141	103

Net amounts reflected in OCI for the year are as follows:

	2011	2010	2009
(millions of Canadian dollars)			
Unamortized prior service cost	**(1)**	3	–
Net loss/(gain)	**146**	35	(10)
	145	38	(10)

The Company estimates that approximately $25 million related to pension and OPEB plans at December 31, 2011 will be reclassified into earnings in the next twelve months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	–	1	1
Loss	22	2	24
	22	3	25

4 **Consolidation of a Limited Partnership** Under U.S. GAAP the Company is deemed to have control of EEP and therefore consolidates its 23.0 % interest in the partnership, resulting in an increase to assets of $8,920 million (2010 – $7,972 million), an increase in liabilities of $6,398 million (2010 – $6,098 million) and an increase in noncontrolling interests of $2,519 million (2010 – $1,871 million) at December 31, 2011. During the year ended December 31, 2011, dilution gains of $88 million, net of tax of $53 million (2010 – $52 million, net of tax of $30 million) were reclassified from earnings to equity as a result of the consolidation of EEP.

5 **Redeemable Noncontrolling Interests** Under Canadian GAAP, a subsidiary's redeemable units classified as equity are eliminated on consolidation when held by the parent, or presented by the parent in the Consolidated Statements of Financial Position as noncontrolling interest in equity. Under U.S. GAAP, noncontrolling interest in a redeemable equity security is classified outside of permanent equity. Further, under U.S. GAAP, noncontrolling interest in a redeemable equity security is required to be presented at its redemption value with changes in value recognized in retained earnings. At December 31, 2011, this difference resulted in an increase to noncontrolling interests, with a corresponding decrease to retained earnings, of $411 million (2010 – $255 million).

6 **Accounting for Joint Ventures** Canadian GAAP requires that investments in joint ventures are proportionately consolidated. U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the SEC, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only presentation and classification and not earnings or shareholders' equity.

7 **Transaction Costs** Under Canadian GAAP transaction costs arising from the issuance of debt are recorded in Long-term debt. For U.S. GAAP, these costs are reclassified to Deferred amounts and other assets. As at December 31, 2011, $92 million (2010 – $89 million) of transaction costs were reclassified.

8 **Common Control Transactions** *U.S. GAAP requires common control transactions to be measured at the carrying amount, with any difference between the carrying value and consideration reflected as a charge or credit to equity. At December 31, 2011, a decrease in assets of $408 million (2010 – $414 million), a decrease in liabilities of $54 million (2010 – $61 million), and a decrease in retained earnings of $354 million (2010 – $353 million), related to a historic transaction with the Fund were retroactively reflected in the U.S. GAAP Statement of Financial Position. There was a $1 million decrease to earnings (2010 – $1 million; 2009 – $1 million).*

9 **Accounting for Leases** *The criteria for determining whether an arrangement contains a lease are consistent under both Canadian and U.S. GAAP; however, the U.S. GAAP guidance was effective prior to the Canadian GAAP guidance. As a result, one of the Company's pipeline transportation agreements is considered a lease under U.S. GAAP, resulting in an increase in assets of $122 million (2010 – $129 million), an increase in liabilities of $114 million (2010 – $122 million), an increase in retained earnings of $8 million (2010 – $7 million) and an increase in earnings of $1 million (2010 – $1 million; 2009 – $1 million).*

10 **Unrecognized Tax Benefits**

	2011	2010
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**17**	22
Gross increases for tax positions of current year	**3**	2
Gross increases for tax positions of prior years	**–**	–
Gross decreases for tax positions of prior years	**(1)**	(2)
Reduction for lapse of statute of limitations	**(1)**	(2)
Changes in translation of foreign currency	**–**	–
Decreases relating to settlements with taxing authority	**–**	(3)
Unrecognized tax benefits at end of year	**18**	17

The unrecognized tax benefits at December 31, 2011, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense. Income tax expense for the year ended December 31, 2011 includes a $1 million expense (2010 – $2 million recovery; 2009 – $1 million expense) of interest and penalties. As at December 31, 2011, interest and penalties of $9 million (2010 – $8 million; 2009 – $10 million) have been accrued.

The Company and its subsidiaries are subject to either Canadian federal and provincial income tax, United States federal, state and local income tax, or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2007 and all returns are generally closed through 2006. Generally, all United States federal income tax returns and state and local income tax returns are closed through 2007.

11 **Indefinite Reversal Rule** *The Company has not provided future taxes on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. These earnings relate to ongoing operations and as at December 31, 2011 were approximately $524 million (2010 – $491 million; 2009 – $406 million).*

12 **Unrealized Foreign Exchange Loss** *Under Canadian GAAP, an unrealized foreign exchange loss in AOCI was recognized in earnings during the year ended December 31, 2011 due to a dividend paid by a subsidiary. Under U.S. GAAP, this foreign exchange loss should remain in AOCI until the subsidiary is sold. At December 31, 2011, this difference resulted in an increase to earnings of $155 million with a corresponding decrease in OCI. This difference did not result in an adjustment at December 31, 2010 or December 31, 2009.*

FUTURE ACCOUNTING STANDARDS UNDER U.S. GAAP

The following standards will be effective for the Company beginning on January 1, 2012. Management does not expect the adoption of any of these standards to significantly impact the consolidated financial statements.

FAIR VALUE MEASUREMENT

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on fair value measurement under U.S. GAAP as part of the FASB's joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

STATEMENT OF COMPREHENSIVE INCOME

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of net income and OCI either in one continuous statement, referred to as the Statement of Comprehensive Income, or in two separate but consecutive statements of net income and OCI. The adoption of this pronouncement does not affect the Company's presentation of comprehensive income, and will not have an impact on the Company's financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

GOODWILL IMPAIRMENT

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The adoption of this pronouncement is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

BALANCE SHEET OFFSETTING

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's financial statements. This accounting update is effective for annual and interim reporting periods beginning on or after January 1, 2013.

GLOSSARY

AEDC	allowance for equity funds used during construction
AFUDC	allowance for funds used during construction
Alliance	Alliance System
AOCI	accumulated other comprehensive income/loss
ASU	Accounting Standards Update of the FASB
bcf/d	billion cubic feet per day
bcfe	billions of cubic feet equivalent
bpd	barrels per day
Canadian GAAP	Part V – Pre-changeover Accounting Standards of the CICA
CICA	Canadian Institute of Chartered Accountants
CLT	Canadian Local Toll
CSR	corporate social responsibility
CTS	Competitive Toll Settlement
EaR	earnings at risk
EECI	Enbridge Energy Company, Inc.
EELP	Enbridge Energy, Limited Partnership
EEM	Enbridge Energy Management, L.L.C.
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick Inc.
Enbridge	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
EUB	New Brunswick Energy and Utilities Board
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fund	Enbridge Income Fund
GHG	greenhouse gas emissions
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
IJT	International Joint Tariff
IR	incentive regulation
ISO	incentive stock options
ITS	incentive tolling settlement
JRP	Joint Review Panel
kbpd	thousand barrels per day
mmcf/d	million cubic feet per day
MW	megawatts
NEB	National Energy Board
NGL/NGLs	natural gas liquids
OCI	other comprehensive income/loss
OEB	Ontario Energy Board
Offshore	Enbridge Offshore Pipelines
OPA	Ontario Power Authority
OPEB	post-employment benefits other than pensions
Part V	Part V – Pre-changeover Accounting Standards of the CICA
PBSO	performance based stock options
PSU	performance stock units
ROE	return on equity
RSU	restricted stock units
SEC	United States Securities and Exchange Commission
tcf	trillion cubic feet
the Company	Enbridge Inc.
U.S. GAAP	United States Generally Accepted Accounting Principles
WCSB	Western Canadian Sedimentary Basin

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2011	2010	2009	2008	2007
(millions of Canadian dollars; per share amounts in Canadian dollars)					
Earnings attributable to common shareholders					
Liquids Pipelines	**505**	512	445	328	287
Gas Distribution	**176**	155	186	161	167
Gas Pipelines, Processing and Energy Services	**293**	121	428	767	154
Sponsored Investments	**344**	137	141	111	97
Corporate	**(327)**	38	355	(46)	(5)
	991	963	1,555	1,321	700
Earnings per common share [1]	**1.32**	1.30	2.13	1.84	0.99
Diluted earnings per common share [1]	**1.30**	1.29	2.12	1.82	0.98
Adjusted earnings [2]					
Liquids Pipelines	**536**	512	454	332	286
Gas Distribution	**175**	167	154	141	133
Gas Pipelines, Processing and Energy Services	**163**	123	116	141	173
Sponsored Investments	**253**	209	151	101	86
Corporate	**(17)**	(27)	(20)	(38)	(41)
	1,110	984	855	677	637
Adjusted earnings per common share [1,2]	**1.48**	1.33	1.17	0.94	0.90
Cash flow data					
Cash provided by operating activities	**2,703**	1,851	2,017	1,372	1,362
Cash used in investing activities	**(4,017)**	(2,674)	(3,306)	(2,853)	(2,229)
Cash provided by financing activities	**1,380**	766	1,082	1,840	904
Dividends					
Common share dividends declared	**759**	648	555	489	453
Dividends paid per common share [1]	**0.98**	0.85	0.74	0.66	0.62
Shares outstanding *(millions)*					
Weighted average common shares outstanding [1]	**751**	741	728	720	711
Diluted weighted average common shares outstanding [1]	**761**	748	733	725	717

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

2 *Adjusted earnings represent earnings attributable to common shareholders adjusted for non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do no thave any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see pages 37 and 114.*

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2011	2010	2009	2008	2007
(per share amounts in Canadian dollars)					
Common share trading (TSX) [1]					
High	**38.17**	29.13	24.46	21.64	20.74
Low	**27.05**	23.02	17.60	16.55	16.81
Close	**38.09**	28.14	24.32	19.78	20.01
Volume *(millions)*	**396**	461	457	585	408
Financial ratios					
Return on average shareholders' equity [2]	**12.0%**	12.9%	22.2%	22.2%	13.6%
Return on average capital employed [3]	**5.7%**	5.9%	8.9%	9.9%	7.0%
Debt to debt plus shareholders' equity [4]	**64.6%**	66.7%	66.2%	66.6%	66.5%
Earnings coverage of interest [5]	**3.1x**	2.6x	3.6x	3.8x	2.4x
Dividend payout ratio [6]	**66.2%**	63.9%	63.0%	70.2%	68.7%
Operating data					
Liquids Pipelines – Average deliveries *(thousands of barrels per day)*					
Canadian Mainline [7]	**1,554**	1,537	1,562	1,522	1,459
Regional Oil Sands System [8]	**329**	291	259	202	164
Spearhead Pipeline	**82**	144	121	110	103
Gas Pipelines, Processing and Energy Services – Average throughput volume *(millions of cublic feet per day)*					
Alliance Pipeline US	**1,564**	1,600	1,601	1,609	1,598
Vector Pipeline	**1,525**	1,456	1,334	1,321	1,034
Enbridge Offshore Pipelines	**1,595**	1,962	2,037	1,672	2,060
Gas Distribution – Enbridge Gas Distribution					
Volumes *(billions of cubic feet)*	**426**	409	408	433	440
Number of active customers *(thousands)* [9]	**1,997**	1,963	1,937	1,898	1,861
Heating degree days [10]					
Actual	**3,597**	3,466	3,767	3,802	3,659
Forecast based on normal weather	**3,602**	3,546	3,514	3,543	3,617

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

2 *Earnings applicable to common shareholders divided by average shareholders' equity (weighted monthly during the year).*

3 *Sum of after-tax earnings and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of shareholders' equity, Enbridge Gas Distribution preferred shares, future income taxes, deferred credits and total debt (including short-term borrowings).*

4 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*

5 *Earnings before income taxes and interest expense divided by interest expense (including capitalized interest).*

6 *Dividends per common share divided by adjusted earnings per common share.*

7 *Canadian Mainline includes deliveries ex-Gretna, Manitoba and is exclusive of western Canadian deliveries and volumes originating at United States or eastern Canada locations.*

8 *Volumes are for the Athabasca mainline and the Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.*

9 *Number of active customers is the number of natural gas consuming EGD customers at the end of the period.*

10 *Heating degree days is a measure of coldness which is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto area.*

INVESTOR INFORMATION

COMMON AND PREFERENCE SHARES

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange (NYSE) under the trading symbol "ENB". The Preference Shares, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the following trading symbols:

Series A – ENB.PR.A
Series B – ENB.PR.B
Series D – ENB.PR.D
Series F – ENB.PR.F

REGISTRAR AND TRANSFER AGENT IN CANADA

For information relating to shareholdings, shareholder investment plan, dividends, direct dividend deposit, dividend re-investment accounts and lost certificates please contact:

CIBC Mellon Trust Company [1]
P.O. Box 700
Station B
Montreal, Québec, Canada H3B 3K3
Toll free: 800.387.0825
Internet: *canstockta.com/investorinquiry*
CIBC Mellon Trust Company also has offices in Halifax, Toronto, Calgary and Vancouver.

1 *Canadian Stock Transfer Company Inc. acts as the Administrative Agent for CIBC Mellon Trust Company*

CO-REGISTRAR AND CO-TRANSFER AGENT IN THE UNITED STATES

Computershare
480 Washington Blvd.
Jersey City, New Jersey
U.S.A. 07310

AUDITORS

PricewaterhouseCoopers LLP

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. Effective with dividends payable on March 1, 2008, participants in the Plan will receive a two per cent discount on the purchase of common shares with reinvested dividends. Details may be obtained from the Investor Information section of the Enbridge website at or by contacting CIBC Mellon Trust Company at any of the locations listed above.

NEW YORK STOCK EXCHANGE DISCLOSURE DIFFERENCES

As a foreign private issuer, Enbridge Inc. is required to disclose any significant ways in which its corporate governance practices differ from those followed by United States companies under NYSE listing standards. This disclosure can be obtained from the U.S. Compliance subsection of the Corporate Governance section of the Enbridge website at *enbridge.com*.

FORM 40-F

The Company files annually with the United States Securities and Exchange Commission a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company. In addition a link to it is available on the "Reports and Filings" subsection of the "Financial Reports" section of our website.

CORPORATE SOCIAL RESPONSIBILITY REPORT

Enbridge publishes an annual Corporate Social Responsibility report. The 2010 report is available on the Company's website at *csr.enbridge.com*.

REGISTERED OFFICE

Enbridge Inc.
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Facsimile: 403.231.3920
Internet: *enbridge.com*

Annual Meeting

The Annual Meeting of Shareholders will be held in the Vanity Fair Ballroom, Le Meridien King Edward, Toronto, Ontario at 1:30 p.m. ET on Wednesday, May 9, 2012. A live audio webcast of the meeting will be available at enbridge.com and will be archived on the site for approximately one year. Webcast details will be available on the Company's website closer to the meeting date.

Le présent document est disponible en français.

Common and Preference Shares

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Series A – ENB.PR.A

Series B – ENB.PR.B

Series D – ENB.PR.D

Series F – ENB.PR.F

2012 ENBRIDGE INC. COMMON SHARE DIVIDENDS

	1st Q	2nd Q	3rd Q	4th Q
Dividend	$0.2825	$–	$–	$–
Payment date	Mar. 1	Jun. 1	Sep. 1	Dec. 1
Record date [1]	Feb. 15	May 15	Aug. 15	Nov. 15
SPP deadline [2]	Feb. 23	May 25	Aug. 27	Nov. 26
DRIP enrollment [3]	Feb. 8	May 8	Aug. 8	Nov. 8

1 *Dividend record dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year unless the 15th falls on a Saturday or Sunday.*

2 *The Share Purchase Plan cut-off date is five business days prior to the dividend payment date.*

3 *The Dividend Reinvestment Program enrollment cut-off date is five business days prior to the dividend record date.*

Enbridge is committed to reducing its impact on the environment in every way, including the production of this publication. This report was printed entirely on FSC® Certified paper. The cover and feature pages were printed on Mohawk Via, which is manufactured entirely with wind energy and contains 100% post-consumer recycled fibre. The Management's Discussion and Analysis and Financial Statements were printed on Roland Envrio100 Print, which also contains 100% post-consumer recycled fibre and is manufactured using biogas energy.

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ENBRIDGE Where energy meets people™

Enbridge Inc., a Canadian company, is a North American leader in delivering energy and one of the Global 100 Most Sustainable Corporations in the World. As a transporter of energy, Enbridge operates, in Canada and the U.S., the world's longest crude oil and liquids transportation system. The Company also has a significant and growing involvement in natural gas gathering, transmission and midstream businesses, and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company, and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in close to 1,000 megawatts of renewable and alternative energy generating capacity and is expanding its interests in wind and solar energy, geothermal and hybrid fuel cells. Enbridge employs approximately 6,900 people, primarily in Canada and the U.S. and is ranked as one of Canada's Greenest Employers and one of the Top 100 Companies to Work for in Canada. Enbridge's common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit enbridge.com.

enbridge.com

Join the discussion.

Website: enbridge.com

Online Annual Report: ar.enbridge.com/ar2011

Online Corporate Social Responsibility Report:
csr.enbridge.com

eBridge Newsletter: enbridge.com/mediacentre

Enbridge Facebook: facebook.com/enbridge

Enbridge Twitter: @enbridge_news

Northern Gateway Website and Blog:
northerngateway.ca

Northern Gateway Facebook:
facebook.com/enbridgenortherngateway

Northern Gateway Twitter: @northerngateway

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ENBRIDGE
Where energy meets people

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