ENBRIDGE INC. FINANCIAL REPORT 2012

“Our investors have come to expect superior returns, and that’s what we’re delivering.

ENBRIDGE INC. FINANCIAL REPORT 2012

Forward-Looking Information: This Financial 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 8 of this Financial 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.

2012 FINANCIAL REPORT

MANAGEMENT'S DISCUSSION AND ANALYSIS

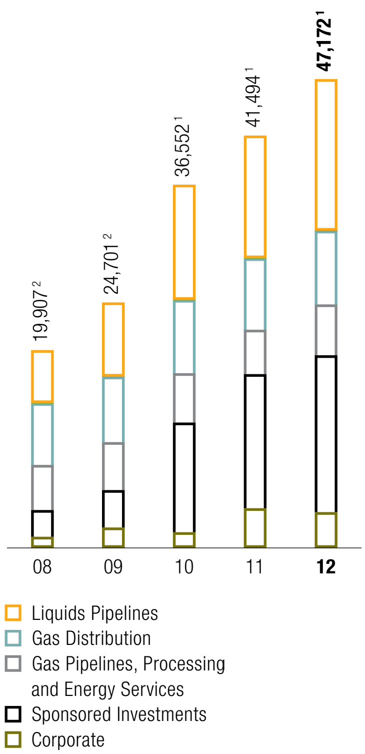
CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 14, 2013 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, 2012, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Where applicable, comparative figures presented within this MD&A have been restated to correspond to the Company's consolidated financial statements prepared in accordance with U.S. GAAP for the years ended December 31, 2011 and 2010. 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.

TOTAL ASSETS
(millions of Canadian dollars)



1 *Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

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 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 1,300 megawatts (MW) of renewable and alternative energy generating capacity and is expanding its interests in wind, solar and geothermal. Enbridge has approximately 10,000 employees and contractors, 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, Seaway Pipeline, Spearhead Pipeline and Feeder Pipelines and Other.

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 and gathering facilities and the Company's energy services businesses, along with renewable energy projects.

Investments in natural gas pipelines include the Company's interests in the United States portion of the Alliance System (Alliance Pipeline US), the Vector Pipeline (Vector) 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 located at the terminus of the Alliance System (Alliance). The energy services businesses undertake physical commodity marketing activity and manage the Company's volume commitments on the Alliance, Vector and other pipeline systems.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 21.8% 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 67.7% 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 NGL. The primary operations of the Fund include renewable power generation projects, crude oil and liquids pipeline and storage businesses in Western Canada and a 50% interest in the Canadian portion of the Alliance System (Alliance Pipeline Canada).

CORPORATE

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

Performance Overview

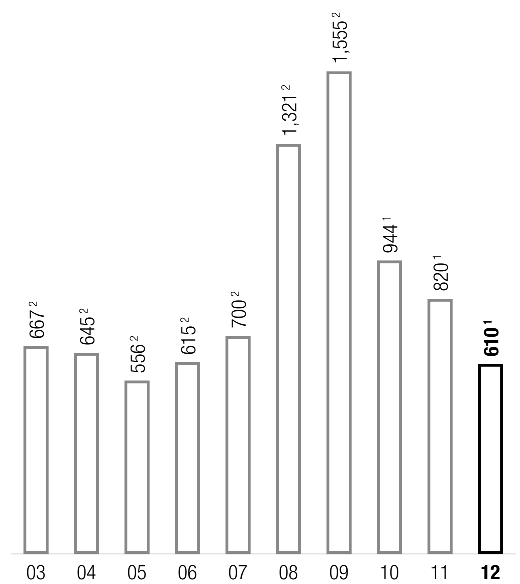
	Three Months Ended December 31,		Year Ended December 31,		
	2012	2011	**2012**	2011	2010
(millions of Canadian dollars, except per share amounts)					
Earnings attributable to common shareholders					
Liquids Pipelines	**136**	203	**726**	505	531
Gas Distribution	**127**	(226)	**207**	(88)	150
Gas Pipelines, Processing and Energy Services	**(52)**	156	**(478)**	305	125
Sponsored Investments	**71**	89	**282**	269	98
Corporate	**(136)**	(63)	**(127)**	(171)	40
	146	159	**610**	820	944
Earnings per common share [1]	**0.19**	0.21	**0.79**	1.09	1.27
Diluted earnings per common share [1]	**0.18**	0.21	**0.78**	1.08	1.26
Adjusted earnings [2]					
Liquids Pipelines	**183**	126	**684**	536	511
Gas Distribution	**63**	48	**176**	173	162
Gas Pipelines, Processing and Energy Services	**37**	41	**154**	163	123
Sponsored Investments	**67**	74	**263**	244	206
Corporate	**(23)**	(16)	**(28)**	(16)	(25)
	327	273	**1,249**	1,100	977
Adjusted earnings per common share [1,2]	**0.42**	0.36	**1.62**	1.46	1.32
Cash flow data					
Cash provided by operating activities	**502**	823	**2,874**	3,371	1,877
Cash used in investing activities	**(2,182)**	(2,676)	**(6,204)**	(5,079)	(3,902)
Cash provided by financing activities	**1,725**	1,435	**4,395**	2,030	1,957
Dividends					
Common share dividends declared	**227**	190	**895**	759	648
Dividends paid per common share [1]	**0.2825**	0.2450	**1.13**	0.98	0.85
Revenues					
Commodity sales	**5,111**	5,195	**19,101**	20,611	15,863
Gas distribution sales	**585**	568	**1,910**	1,906	1,814
Transportation and other services	**1,477**	1,546	**4,295**	4,536	3,843
	7,173	7,309	**25,306**	27,053	21,520
Total assets	**47,172**	41,949	**47,172**	41,949	36,423
Total long-term liabilities	**25,345**	24,074	**25,345**	24,074	22,171

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 page 9.*

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $610 million ($0.79 per common share) for the year ended December 31, 2012 compared with $820 million ($1.09 per common share) for the year ended December 31, 2011 and $944 million ($1.27 per common share) for the year ended December 31, 2010. The Company has delivered significant earnings growth from operations over the course of the last three years, as discussed below in *Performance Overview – Adjusted Earnings*; however, the positive impact of this growth was reduced by a number of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value and foreign exchange gains or losses. The Company has a comprehensive long-term economic hedging program to mitigate exposures to interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings but the Company believes over the long-term it supports reliable cash flows and dividend growth. Earnings for 2012 and 2011 were also negatively impacted by the transfer of assets between entities under common control of Enbridge. Intercompany gains realized as a result of these asset transfers for both years have been eliminated for accounting purposes; however, income taxes of $56 million and $98 million for the years ended December 31, 2012 and 2011, respectively, incurred on the related capital gains remain as charges to consolidated earnings.

EARNINGS APPLICABLE TO COMMON SHAREHOLDERS
(millions of Canadian dollars)



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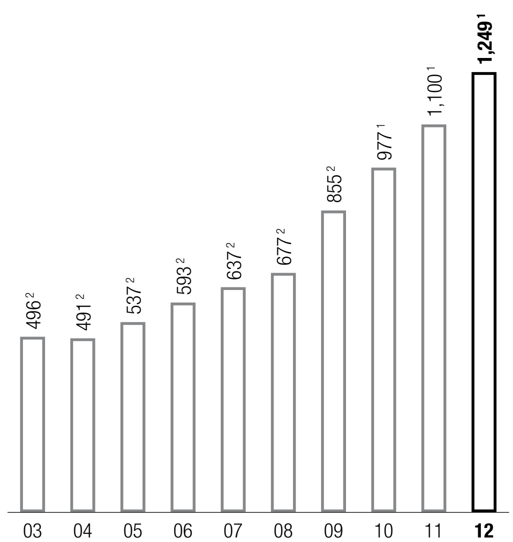
Other significant items impacting the comparability of earnings year-over-year were costs and related insurance recoveries associated with the Lines 6A, 6B and Line 14 crude oil releases. Earnings for the years ended December 31, 2012, 2011 and 2010 included the Company's after-tax share of EEP's costs, before insurance recoveries and excluding fines and penalties, of $9 million, $33 million and $103 million, respectively, related to these incidents. Insurance recoveries recorded for the years ended December 31, 2012 and 2011 were $24 million and $50 million after-tax attributable to Enbridge, respectively, related to the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases.*

Fourth quarter earnings drivers were largely consistent with year-to-date trends and continued to include changes in unrealized fair value derivative and foreign exchange gains and losses. Aside from operating factors discussed in *Performance Overview – Adjusted Earnings*, factors unique to the fourth quarter of 2012 included a $105 million asset impairment to Stingray and Garden Banks assets within Enbridge Offshore Pipelines (Offshore), $56 million of income taxes on the intercompany gain on sale to the Fund not eliminated for accounting purposes and a $63 million gain on recognition of a regulatory asset related to other postretirement benefits (OPEB) within EGD.

Earnings for the comparable fourth quarter of 2011 reflected the discontinuance of rate-regulated accounting at Enbridge Gas New Brunswick Inc. (EGNB), which resulted in a write-off of a deferred regulatory asset and certain capitalized operating costs, totaling $262 million, net of tax. See *Gas Distribution – Other Gas Distribution and Storage – Enbridge Gas New Brunswick Inc. – Regulatory Matters.*

ADJUSTED EARNINGS
(millions of Canadian dollars)



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ADJUSTED EARNINGS

A key tenet of the Company's investor value proposition is "visible growth", supported by an ongoing focus on safe and reliable operations and a disciplined approach to investment and project execution. The Company has consistently delivered on this proposition, growing adjusted earnings from $1.32 per common share in 2010 to $1.46 per common share in 2011 and $1.62 per common share in 2012.

The upward trend in adjusted earnings over these years was predominantly attributable to strong operating performance from the Company's Liquids Pipelines assets as well as contributions from new assets placed into service. Incremental oil sands production in Alberta and strong production growth out of the Bakken in North Dakota has increased volumes transported on the Canadian Mainline system and the Lakehead System owned by EEP. The increase in volumes most notably impacted adjusted earnings from mid-2011 onward when the Competitive Toll Settlement (CTS) on the Canadian Mainline took effect. Under the CTS, Canadian Mainline earnings are exposed to volume and cost variability. In 2012, the Company also began realizing earnings from its 50% interest in the Seaway Crude Pipeline System (Seaway Pipeline). The Seaway Pipeline, which commenced southbound service from the United States midwest to the Gulf Coast in May 2012, has experienced strong volumes since inception as shippers have sought to transport their product to locations where realized prices are more favourable. Similarly, adjusted earnings growth on the Spearhead Pipeline increased in 2012 as it also benefited from producers' desire to move crude onward to Gulf Coast markets in order to capture attractive price differentials. In addition to the Seaway Pipeline, other new assets commencing operations and contributing to adjusted earnings growth included the Cedar Point Wind Energy Project (Cedar Point) in late 2011 and the Silver State North Solar Project (Silver State) in 2012.

The Company has also seen a marked increase in operating costs over this time frame. Under the umbrella of its Operational Risk Management Plan (ORM Plan) launched in 2011, the Company has bolstered spending in the areas of system integrity, environmental and safety programs to ensure the safe and reliable operations of all of its assets.

Other factors which contributed to changes in adjusted earnings year-over-year included market factors impacting the Company's Energy Services and natural gas businesses, as well as increased preference share dividends due to the Company's increased activity in the capital markets to prefund future growth projects. Energy Services experienced strong adjusted earnings growth from 2010 to 2011 but saw this growth temper somewhat in 2012 as changing market conditions gave rise to fewer margin opportunities in crude oil and NGL marketing. Within Sponsored Investments, EEP's natural gas business reflected a similar trend with growth in adjusted earnings in 2011 over 2010 owing to higher natural gas volumes and contributions from acquired assets, followed by a decline in 2012 due to persistent weakness in natural gas commodity prices. Aux Sable contributed to growth over both the 2011 and 2012 time periods as new assets were placed into service and realized fractionation margins remained high.

With respect to the fourth quarter of 2012, many of these same annual trends continued. The primary drivers of adjusted earnings growth period-over-period included strong volumes on the Company's liquids pipelines assets both in Canada and the United States, including contributions from new assets such as the Seaway Pipeline, customer expansion at EGD and growth in the Company's renewable energy portfolio. Contributions from the Gas Pipelines, Processing and Energy Services segment were relatively flat as higher adjusted earnings from Aux Sable were offset by fewer margin opportunities in liquids marketing and increased costs within Offshore.

CASH FLOWS

Cash provided by operating activities was $2,874 million for the year ended December 31, 2012, mainly driven by strong operating performance from the Company's core assets, particularly from Liquids Pipelines and the cash flow generation from growth projects placed into service in recent years. Offsetting this cash inflow were changes in operating assets and liabilities which fluctuate in the normal course due to various factors impacting the timing of cash receipts and payments.

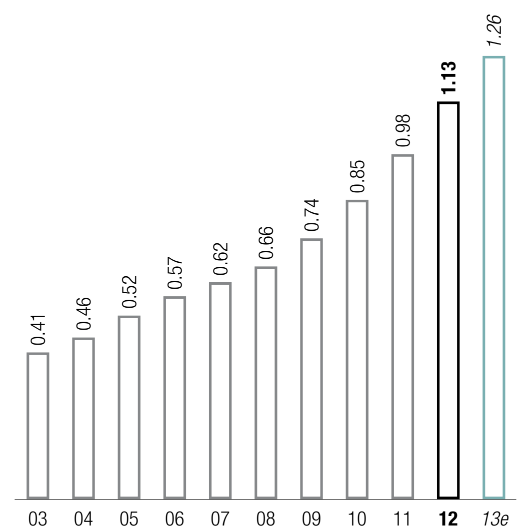
In 2012, the Company was active in the capital markets with the issuance of $2,634 million in preference shares, common shares of approximately $384 million and $2,199 million in medium-term notes and also significantly bolstered its liquidity through the securement of additional credit facilities. The proceeds of the capital market transactions, together with cash from operations, were more than sufficient to finance the Company's $6.2 billion net investment in expansion initiatives during 2012 and provides financing flexibility for the Company's growth opportunities in 2013.

DIVIDENDS

The Company has paid common share dividends since its inception in 1953. In December 2012, the Company announced a 12% increase in its quarterly dividend to $0.315 per common share, or $1.26 annualized effective March 1, 2013. Assuming this currently announced quarterly dividend is annualized for 2013, the Company has generated compound annual average growth of 11.7% since 2003. The Company continues to target a dividend payout of approximately 60% to 70% of adjusted earnings over the longer term. In 2012, the dividend payout was 70% (2011 – 67%; 2010 – 64%) of adjusted earnings per share.

DIVIDENDS PER COMMON SHARE

(millions of Canadian dollars)



REVENUES

The Company generates revenue from three primary sources: commodity sales, gas distribution sales and transportation and other services. Commodity sales of $19,101 million for the year ended December 31, 2012 (2011 – $20,611 million; 2010 – $15,863 million) were earned through the Company's energy services operations. Revenues from these operations depends on activity levels, which vary from year to year depending on market conditions and commodity prices. Commodity prices 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.

Gas distribution sales are primarily earned by EGD and are recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are driven by volumes delivered, which vary with weather and customer base, as well as regulator-approved rates. The cost of natural gas is charged to customers through rates but does not ultimately impact earnings due to the pass through nature of these costs.

Transportation and other services revenues are earned from the Company's crude oil and natural gas pipeline transportation businesses and also includes power production revenue from the Company's portfolio of renewable power generation assets. For the Company's transportation assets operating under market-based arrangements, revenues are driven by volumes transported and tolls. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, is reflective of the Company's cost to provide the service plus a regulator-approved rate of return.

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/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

Although Enbridge believes 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, NGL and green energy; prices of crude oil, natural gas, NGL and green energy; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer and regulatory 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, NGL and green energy, 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/(loss) or adjusted earnings/(loss) 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 date and expected capital expenditures include: the availability and price of labour and 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 unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Management believes 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 U.S. 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, Strategy and Values

VISION

Enbridge's vision is to be the leading energy delivery company in North America. The Company transports, distributes and generates energy and its primary purpose is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible.

Among its peers, Enbridge strives to be the leader, which means not only leadership in value creation for shareholders but also leadership with respect to safety, operational reliability, environmental stewardship, customer service, employee satisfaction and community investment. Value for shareholders is evident in the Company's proven investment value proposition which combines visible growth, a reliable business model and a growing income stream.

STRATEGY

The Company's initiatives center around six areas of strategic emphasis. These strategies are reviewed at least annually with direction from its Board of Directors.

1. Commitment to Operational Safety and Reliability, and Environmental Protection;
2. Focus on Project Execution;
3. Attracting, Retaining and Developing Highly Capable People;
4. Preserving Financial Strength and Flexibility;
5. Strengthening Core Businesses; and
6. Developing New Platforms for Growth and Diversification.

COMMITMENT TO OPERATIONAL SAFETY AND RELIABILITY, AND ENVIRONMENTAL PROTECTION

Operations safety and system integrity continues to be Enbridge's number one priority and sets the foundation for the strategic plan. An important element of this priority is the ORM Plan which broadly aims to position Enbridge as the industry leader for system integrity, environmental and safety programs, and charts the course for best-in-class practices. Through the ORM Plan, the Company has enhanced its integrity management, leak detection and control systems. The ORM Plan has also bolstered incident response capabilities, employee and public safety, and improved communication with landowners and first responders. Further, in an ongoing commitment to foster a positive pervasive safety culture, Life Saving Rules were rolled out in early 2012 to all employees which support the goal of ensuring every employee returns home safely at the end of the day and that the Company's customers and communities in which it operates are kept safe.

FOCUS ON PROJECT EXECUTION

Timely and cost-effective execution of the existing slate of $27 billion in commercially secured projects continues to be a key priority for the Company. Enbridge believes project execution is a core competency and the Company continues to build upon its rigorous project management processes, primarily through the Major Projects group. The key strategy for Major Projects of delivering projects safely, on time and on budget is supported by repeatable and competitive proposal development; long-term supply chain agreements; quality design, materials and construction; extensive public consultation; robust cost, schedule and risk controls; developed project management expertise; and efficient project transition to operating units.

ATTRACTING, RETAINING AND DEVELOPING HIGHLY CAPABLE PEOPLE

Investing in the attraction, retention and development of employees and future leaders is fundamental to executing Enbridge's aggressive growth strategy and creating sustainability for future success. People-related focus areas include broadening recruiting efforts beyond traditional industry and geographical reaches, ensuring succession capability through accelerated leadership development programs and building change management capabilities throughout the enterprise to ensure projects and initiatives achieve the intended benefits. Furthermore, Enbridge strives to maintain industry competitive compensation and retention programs that provide both short-term and long-term incentives.

PRESERVING FINANCIAL STRENGTH AND FLEXIBILITY

The maintenance of adequate financial strength and flexibility is crucial to Enbridge's growth strategy. Enbridge's financial strategies are designed to ensure the Company has sufficient financial flexibility to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to maintain or improve its credit ratings, diversify its funding sources and maintain substantial standby bank credit capacity and 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.

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.

STRENGTHENING CORE BUSINESSES

The Company has an established history of delivering on its value proposition through its Liquids Pipelines and gas transportation businesses which serve the transportation needs of key North American crude oil and natural gas markets. Shifting supply and demand fundamentals and North American price dislocations are driving significant infrastructure investment opportunities that Enbridge is well suited to capture in these core business segments.

Within the Liquids Pipelines segment, strategies are focused on expanding access to new markets in North America for growing production from western Canada and the Bakken, expanding the capacity of the mainline pipeline system and strengthening the Company's position in the Alberta oil sands and Bakken regions to ensure growing production volumes ultimately flow on Enbridge's downstream systems.

Through Enbridge's new market access initiatives, shippers will be provided greater connectivity to markets in Ontario, Quebec, the Gulf Coast and upper-midwest, with the objective of being able to secure the best pricing for their products. Significant market access programs announced in 2012 included the Gulf Coast Access, Eastern Access and Light Oil Market Access programs. To facilitate these downstream growth projects and continued growth in base volumes, a number of supporting mainline expansions are being undertaken. The Company's efforts to expand market access and provide better netbacks for producers include further initiatives to access the Canadian and United States east coast and eastern Gulf Coast markets, as well as development of the proposed Northern Gateway Project (Northern Gateway), 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 developing close to $3.5 billion of commercially secured regional oil sands transportation facilities that are expected to be placed into service between 2012 and 2015, including the twinning and expansion of its Athabasca Pipeline and the expansion of its Waupisoo Pipeline. The Company also has $3.2 billion of secured system expansion projects in Saskatchewan and North Dakota, where Enbridge believes it 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 competitive advantages of its existing assets and expanding its footprint in these emerging areas. Alliance is well positioned to service developing regions in northeast British Columbia and the Bakken play, and is evaluating opportunities to expand its service offerings in those areas as well as strategies to attract liquids rich gas onto the system. Development of 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's first operations within this space are expected to commence with the completion of its Peace River Arch (PRA) Gas Development in 2013. Within the United States gas business, 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.

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. The Company is currently focusing its development efforts towards securing investment opportunities in renewable and gas-fired power generation, power transmission and select international assets. The Company also invests in early stage energy technologies that complement the Company's core businesses.

Enbridge has advanced its renewable power strategy considerably over the last several years and has interests in a renewable energy portfolio with a generation capacity of more than 1,300 MW. Future investment may include earlier stage development opportunities, including expansion of existing sites. 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 and the long-term natural gas price outlook. Power transmission is also an attractive growth opportunity and a complement to the Company's electricity generation platform. There is substantial need for new transmission infrastructure in North America, with risk and return profiles that fit Enbridge's investment value proposition. The Company is targeting completion of construction of the initial phase of its first transmission project, the Montana-Alberta Tie-Line (MATL), by the middle of 2013.

CORPORATE VALUES

Enbridge adheres to a strong set of core values that govern how it conducts its business and pursues strategic priorities. In light of the significant growth in employees in recent years and projected future growth, the Company recently refreshed and re-emphasized these values, articulated as: "Enbridge employees demonstrate integrity, safety and respect in support of our communities, the environment and each other". Employees are required to uphold these values in their interactions with each other, with customers, suppliers, landowners, community members and all others with whom the Company deals, and to ensure the Company's business decisions are consistent with these values.

MAINTAINING THE COMPANY'S SOCIAL LICENSE

Earning and maintaining "social license"—the approval and acceptance of the communities in which the Company is proposing projects—is critical to Enbridge's ability to execute on its growth plans. To earn the public's trust, and to protect and reinforce the Company's reputation with its stakeholders, Enbridge is committed to integrating Corporate Social Responsibility (CSR) into every aspect of its business. The Company 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 the Company operates, supporting universal human rights and employing a variety of policies, programs and practices to manage corporate governance and ensure fair, full and timely disclosure. The Company provides its stakeholders with open, transparent disclosure of its CSR performance and prepares its annual CSR Report using the Global Reporting Initiative sustainability reporting guidelines, which serve as a generally accepted framework for reporting on an organization's economic, environmental and social performance. The 2012 CSR Report can be found at *csr.enbridge.com*. ***None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.***

One of Enbridge's CSR environmental objectives is its Neutral Footprint plan, which includes initiatives to counteract the environmental impact of all Enbridge's pipeline expansion projects within five years of their occurrence. Neutral Footprint initiatives include:

- planting a tree for every tree the Company removes to build new facilities;
- conserving an acre of land for every acre of wilderness the Company permanently impacts; and
- generating a kilowatt of renewable energy for every kilowatt the Company's expansions consume.

Progress updates on the Company's Neutral Footprint initiatives can be found at *enbridge.com/neutralfootprint* and in the annual CSR Report. ***None of the information contained on, or connected to, the Enbridge website is incorporated or otherwise part of this MD&A.***

To complement community investments in its Canadian and United States operating areas, Enbridge created the energy4everyone foundation (the Foundation) in 2009. The Foundation aims to leverage the expertise and resources of the Canadian energy industry to affect significant positive change through the delivery and deployment of affordable, reliable and sustainable energy services and technologies in communities in need around the world. To date, the Foundation has completed projects in Costa Rica, Ghana, Nicaragua, Peru and Tanzania.

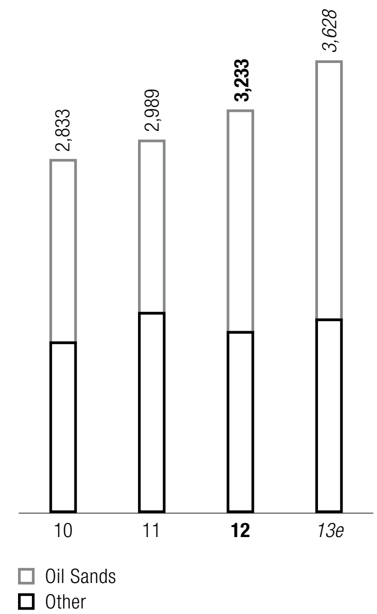
Industry Fundamentals

SUPPLY AND DEMAND FOR LIQUIDS

Enbridge has an established and successful history of being the largest transporter of crude oil to the United States, the world's largest market. While United States demand for Canadian crude oil production will support the use of Enbridge infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting and Enbridge has a crucial role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-use markets.

Overall, global energy consumption is expected to continue to grow; however, growth in crude oil demand is expected to be increasingly driven by emerging markets, such as China, India and the Middle East. In Organisation for Economic Co-operation and Development countries, including Canada, the United States and western Europe, conservation, stagnant population growth and a shift to alternative energy will reduce crude oil demand over the long term. Accordingly, there is a strategic opportunity for North American producers to meet growing global demand outside North America. Access to new markets is expected to improve netbacks for domestic producers as land-locked North American crude has, of late, traded at significant discounts to world oil prices.

CANADIAN CRUDE OIL PRODUCTION
(thousands of barrels per day)



Sources: National Energy Board
Canadian Association of Petroleum Producers.

In terms of supply, the Western Canada Sedimentary Basin (WCSB) continues to be viewed as one of the world's largest and most secure supply sources of crude oil, and production from this region is expected to increase over the long term through continued investment in the Alberta oil sands. Investment in the WCSB has recovered significantly since the period of economic downturn in 2009 and 2010. Several new projects and expansions of existing oil sands production facilities have been added or accelerated due to supportive oil prices and the emergence of increased foreign investment.

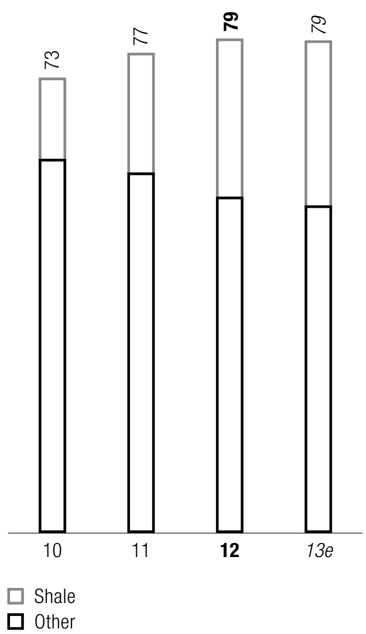
One of the most fundamental shifts in crude oil supply in recent years is the emergence of shale oil plays. Shale oil plays, such as the Bakken in North Dakota, will be significant contributors to the overall forecasted increase in North American crude production. Increased production from these plays has been facilitated by new drilling and completion methods, which include hydraulic fracturing and horizontal drilling techniques.

The substantial growth in North American supply without a corresponding increase in domestic demand has introduced a number of challenges for the industry. In recent years, inventory levels have increased and several transportation bottlenecks have arisen within North America. A notable bottleneck exists in Cushing, Oklahoma, a major pipeline and storage hub, which has experienced heightened receipt of product without commensurate takeaway capacity. The oversupply to this land-locked market has resulted in a divergence between West Texas Intermediate (WTI) and world pricing, resulting in lower netbacks for North American producers than could otherwise be achieved if selling into global markets. In 2012, this price differential ranged from US$10 to as high as US$23 per barrel.

For WCSB producers, the oversupply on the continental United States continues to have an adverse effect on heavy crude oil prices from western Canada. With the United States over supplied and with insufficient access to alternative markets, including Asia, heavy crude oil prices for western Canada are expected to remain significantly discounted against WTI.

Enbridge's role in helping to address evolving supply and demand fundamentals, and improving netbacks for producers, is to provide expanded pipeline capacity and sustainable connectivity to alternative markets. In 2012, Enbridge announced a record number of commercially secured projects within Liquids Pipelines to create additional market access solutions and regional oil sands infrastructure. Most notably, the Company's announced market access initiatives included a $5.8 billion upsized Gulf Coast Access Program, a $2.7 billion Eastern Access Program and a $6.2 billion Light Oil Market Access Program. The Company is developing additional initiatives to access Canadian and United States east coast and eastern Gulf Coast markets. Despite these initiatives, and those of competitors, North American oil prices, including heavy oil prices from western Canada, will likely continue to lag behind world prices, heightening the need for pipeline access to growing Asian markets. Details of the Company's Northern Gateway, a proposed pipeline system from Alberta to the coast of British Columbia, and associated marine terminal, along with the Company's other projects under development, can be found in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development*.

NORTH AMERICAN NATURAL GAS PRODUCTION
(billions of cubic feet per day)



Sources: Energy Information Administration (United States), National Energy Board (Canada), Enbridge research.

SUPPLY AND DEMAND FOR NATURAL GAS

Strong growth in North American natural gas production over the past few years has created an oversupplied market and a weak price environment. Although production growth is slowing, North America will continue to be over supplied until significant incremental gas demand arises.

North American gas demand has been outpaced by robust supply growth as a prolonged and fragile economic recovery has translated into weak industrial gas demand growth, despite relatively low gas prices. Further, consecutive warm winters have curbed heating demand. In contrast, low gas prices have supported gas-fired power generation as displacement of less competitive coal-fired generation reached unprecedented levels over the past year. Low gas prices are expected to persist, which should enable continued displacement of coal-fired generation. Any future retirement of older, less efficient coal generators could also potentially increase the share of overall power production portfolio held by gas-fired generation. Within Canada, natural gas demand growth is expected to be driven primarily by oil sands development.

Strong production growth from shale plays, supported by technological advancements in drilling techniques, has propelled United States domestic gas production to historic highs and has resulted in an enormous resource base. However, as the North American market has become oversupplied, gas prices have weakened and producers have in turn sharply reduced drilling activity except in regions where the gas is rich in NGL. Dry gas production has been supplanted by production from increased rich-gas drilling and associated gas volumes from oil drilling. However, the overall rate of gas production growth has slowed from prior years. In addition, the development of shale plays in close proximity to major gas markets, such as the Marcellus and Utica shale plays in the northeast United States, have been shifting North American gas flows, creating opportunities for new regional infrastructure but also challenges for existing infrastructure serving more traditional supply areas.

North American gas prices in 2012 fell to 10-year lows as rising gas production outpaced modest demand growth. While gas prices have recovered somewhat, the expectation is that gas prices will remain relatively low until there is more pervasive demand recovery.

Similar to crude oil, significant differentials exist between North American and world gas prices. Globally, liquefied natural gas (LNG) is being supplied to meet increasing energy demand as gas supplies in certain regions are abundant and gas is cleaner burning than other forms of hydrocarbons. The price for LNG in the world market is more closely linked to crude prices, providing an opportunity to capture more favourable netbacks on LNG exports from North America. Based on these fundamentals, there is an increasing probability that one or more projects to export LNG off the west Coast of Canada will proceed.

The NGL which can be extracted from liquids-rich gas streams include ethane, propane, butane, pentanes plus and natural gasoline, which are used in a variety of industrial, commercial and other applications. Prices for NGL are generally closely correlated with crude oil prices. In the current environment, where the differential between crude oil and natural gas prices is expected to remain historically wide, producers are being incented to shift drilling activity to rich gas regions in order to take advantage of strong NGL fractionation margins. This, in turn, is expected to drive a need for additional midstream processing facilities and transportation solutions to move growing supplies of NGL to market.

In response to these evolving natural gas and NGL fundamentals, Enbridge believes it is well positioned to provide value added solutions to producers. Alliance is uniquely configured to transport liquids-rich gas and is currently evaluating service offerings to best meet the needs of producers. The focus on liquids-rich gas development also creates opportunities for Aux Sable, a 50%-owned extraction and fractionation facility near Chicago, Illinois at the terminus of Alliance. Enbridge is also responding to the need for regional infrastructure with additional United States gathering and processing investments and is growing its Canadian midstream business. In addition, Enbridge is a partner in the Texas Express Pipeline (TEP) that will increase NGL pipeline capacity into Mont Belvieu, Texas, with an expected in-service date of mid-2013.

SUPPLY AND DEMAND FOR GREEN ENERGY

While traditional forms of energy are expected to continue to represent the major source of North American energy supply for the foreseeable future, a shift to a lower carbon-intensive economy has gained momentum. Over the last several years, many large power and infrastructure players, including Enbridge, have increased investment in renewable assets. Enbridge now has interests in more than 1,300 MW of renewable generation capacity.

Over the longer term, North American economic growth is anticipated to drive growing electricity consumption. In turn, growing electricity demand is expected to drive new generation capacity growth. The general consensus of energy analysts appears to be that the new generation capacity mix over the next 20 years will shift to lower carbon options such as natural gas or renewable sources of power generation. Although coal and nuclear facilities will continue to provide core electricity generation needs in North America, various emission regulations are anticipated which are expected to force the retirement of aging coal-fired units and restrict the permitting of new coal-fired electrical generation facilities (absent carbon capture and storage technologies). Most North American jurisdictions have also established or are in the process of establishing renewable portfolio standards which mandate the inclusion of a certain proportion of renewable energy generation in their future electricity generation mix. As a result, according to the United States Energy Information Administration, North America is expected to require sizable new generation capacity from alternative sources in order to meet growing electricity demand. Natural gas and renewable energy sources, including biomass, hydro, solar and wind, are likely to play an increasingly important role in the supply of longer-term electricity needs.

The United States National Renewable Energy Laboratory reports that North America has significant wind and solar resources, with wind alone having the potential to provide capacity for over 10,000 gigawatts of power generation. Solar resources in southwestern states such as Arizona, California, Colorado and Nevada are considered by many to be the best in the world for large-scale solar plants. According to Environment Canada, Canada also has an abundance of wind and solar resources, particularly with strong wind resources in the northeastern regions. Expanding renewable energy infrastructure in North America is not without challenges as these high quality wind and solar resources are often found in regions which are not in close proximity to high demand markets, requiring the need for new transmission capacity.

To date, the profitability of renewable energy projects has in part been supported by certain tax and government incentives. In the near-term, uncertainty over the continuing availability of tax or other government incentives, and the ability to secure long-term power purchase agreements (PPA) through government or investor-owned power authorities will hinder the pace of future new renewable capacity development. However, over time renewable generation is expected to be competitive with other modes of generation as wind turbine and solar panel costs continue to decline.

Enbridge owns nine wind farms and four solar farms, including the recently announced investment in the Massif du Sud Wind Project (Massif du Sud) in Quebec, and will continue to seek new opportunities to grow its portfolio of renewable power generation capacity. As noted, incremental renewable power generation requires increased transmission infrastructure. Enbridge expects to commence operating its first significant power transmission line, running between Montana and Alberta, in 2013, and will continue to seek opportunities to invest in new transmission facilities which meet the Company's investment criteria.

Growth Projects – Commercially Secured Projects

In 2012, Enbridge secured a record number of new infrastructure growth projects. In aggregate, the Company added approximately $14 billion of projects across several business units, bringing the total inventory of commercially secured projects to approximately $27 billion. All of these projects are expected to come into service by 2016, and enable the Company to generate industry leading adjusted earnings per share growth over this period.

The bulk of new projects secured were within Liquids Pipelines and Sponsored Investments, highlighted by three major new market access initiatives. The $5.8 billion Gulf Coast Access Program, which includes the Seaway Pipeline, the Flanagan South Pipeline Project and elements of the Canadian Mainline and Lakehead System Mainline expansions, is expected to provide capacity for as much as 850,000 barrels per day (bpd) of crude oil to reach the large refinery markets in the Gulf Coast. The $2.7 billion Eastern Access Program is expected to allow for greater access for crude oil into Chicago, further east into Toledo and ultimately into Ontario and Quebec. The Eastern Access Program includes the Company's Toledo pipeline expansion, Line 9 reversal, the existing Spearhead North pipeline expansion, Line 6B replacement and Line 5 expansion. Finally, the $6.2 billion Light Oil Market Access Program brings together a group of projects to support the increasing supply of light oil from Canada and the Bakken and also supplement the Eastern Access Program through the upsize of the Line 9B and Line 6B capacity expansion. The Light Oil Market Access Program also includes the Southern Access Extension, Canadian Mainline System Terminal Flexibility and Connectivity and twinning of the Spearhead North pipeline and Line 61 expansion included within the Lakehead System Mainline Expansion. These market access initiatives include several mainline system expansion projects which are designed to ensure that there is sufficient capacity to feed these new extensions.

The table below summarizes the current status of the Company's commercially secured projects, organized by business segment.

	Estimated Capital Cost [1]	Expenditures to Date [2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Edmonton Terminal Expansion	$0.2 billion	$0.2 billion	2012	Complete
2. Wood Buffalo Pipeline	$0.4 billion	$0.3 billion	2012	Complete
3. Woodland Pipeline	$0.3 billion	$0.3 billion	2012	Complete
4. Waupisoo Pipeline Capacity Expansion	$0.3 billion	$0.3 billion	2012 – 2013 (in phases)	Complete
5. Seaway Crude Pipeline System				
Acquisition/Reversal/Expansion	US$1.3 billion	US$1.2 billion	2012 – 2013	Complete
Twinning/Extension	US$1.1 billion	US$0.1 billion	2014	Pre-construction
6. Suncor Bitumen Blend	$0.2 billion	$0.1 billion	2013	Under construction
7. Norealis Pipeline	$0.5 billion	$0.2 billion	2013	Under construction
8. Eddystone Rail Project	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
9. Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.2 billion	2013 – 2014 (in phases)	Under construction
10. Eastern Access [3]				
Toledo Expansion	US$0.2 billion	US$0.1 billion	2013	Under construction
Line 9 Reversal	$0.4 billion	No significant expenditures to date	2013 – 2014	Pre-construction
11. Flanagan South Pipeline Project	US$2.8 billion	US$0.2 billion	2014	Pre-construction
12. Canadian Mainline Expansion	$0.6 billion	No significant expenditures to date	2014 – 2015 (in phases)	Pre-construction
13. Athabasca Pipeline Twinning	$1.2 billion	No significant expenditures to date	2015	Pre-construction
14. Edmonton to Hardisty Expansion	$1.8 billion	No significant expenditures to date	2015	Pre-construction
15. Southern Access Extension	US$0.8 billion	No significant expenditures to date	2015	Pre-construction
16. Canadian Mainline System Terminal Flexibility and Connectivity	$0.6 billion	No significant expenditures to date	2013 – 2016 (in phases)	Pre-construction
GAS DISTRIBUTION				
17. Greater Toronto Area Project	$0.6 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
18. Silver State North Solar Project [4]	US$0.2 billion	US$0.2 billion	2012	Complete
19. Massif du Sud Wind Project	$0.2 billion	$0.1 billion	2012 – 2013	Complete
20. Lac Alfred Wind Project	$0.3 billion	$0.2 billion	2013 (in phases)	Under construction
21. Cabin Gas Plant	$0.8 billion	$0.7 billion	To be determined	Deferred
22. Peace River Arch Gas Development	$0.3 billion	$0.1 billion	2012 – 2014 (in phases)	Under construction
23. Tioga Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2013	Under construction
24. Venice Condensate Stabilization Facility	US$0.2 billion	US$0.1 billion	2013	Under construction
25. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.1 billion	2014	Pre-construction
26. Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2014	Pre-construction
27. Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Pre-construction

	Estimated Capital Cost [1]	Expenditures to Date [2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
SPONSORED INVESTMENTS				
28. EEP – Bakken Expansion Program	US$0.3 billion	US$0.2 billion	2013	Substantially complete
29. The Fund – Bakken Expansion Program	$0.2 billion	$0.1 billion	2013	Substantially complete
30. EEP – Berthold Rail Project	US$0.1 billion	US$0.1 billion	2013	Under construction
31. EEP – Ajax Cryogenic Processing Plant	US$0.2 billion	US$0.2 billion	2013	Under construction
32. EEP – Cushing Terminal Storage Expansion Project	US$0.2 billion	US$0.1 billion	2012 – 2013 (in phases)	Under construction
33. EEP – South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+ (in phases)	Under construction
34. EEP – Bakken Access Program	US$0.1 billion	US$0.1 billion	2013	Under construction
35. EEP – Texas Express Pipeline	US$0.4 billion	US$0.2 billion	2013	Under construction
36. EEP – Line 6B 75-Mile Replacement Program	US$0.3 billion	US$0.2 billion	2013	Under construction
37. EEP – Eastern Access	US$2.6 billion	US$0.3 billion	2013 – 2016 (in phases)	Pre-construction
38. EEP – Lakehead System Mainline Expansion	US$2.4 billion	No significant expenditures to date	2014 – 2016 (in phases)	Pre-construction
39. EEP – Sandpiper Project	US$2.5 billion	No significant expenditures to date	2016	Pre-construction
CORPORATE				
40. Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2013 – 2014 (in stages)	Under construction

1 *These amounts are estimates 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 reflect total cumulative expenditures incurred from inception of project up to December 31, 2012.*
3 *See* Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Eastern Access *for project discussion.*
4 *Expenditures to date reflect total expenditures before receipt of US$55 million payment from the United States Treasury. See* Growth Projects – Commercially Secured Projects – Gas Pipelines, Processing and Energy Services – Silver State North Solar Project.

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

LIQUIDS PIPELINES

EDMONTON TERMINAL EXPANSION

The Edmonton Terminal Expansion Project involved expanding the tankage of the mainline terminal at Edmonton, Alberta. The expansion was required to accommodate growing oil sands production receipts both from Enbridge's Waupisoo Pipeline and other non-Enbridge pipelines. Construction was completed and the project was placed into service in December 2012, adding four tanks, three booster pumps and related infrastructure, and expanding the tankage of the mainline terminal by one million barrels. The project was completed under budget with a final cost of approximately $0.2 billion.

Liquids Pipelines

1 Edmonton Terminal Expansion
2 Wood Buffalo Pipeline
3 Woodland Pipeline
4 Waupisoo Pipeline Capacity Expansion
5 Seaway Crude Pipeline System (including acquisition, reversal, expansion, twinning and extension)
6 Suncor Bitumen Blend
7 Norealis Pipeline
8 Eddystone Rail Project
9 Athabasca Pipeline Capacity Expansion
10 Eastern Access (Toledo expansion and Line 9 reversal)
11 Flanagan South Pipeline Project
12 Canadian Mainline Expansion
13 Athabasca Pipeline Twinning
14 Edmonton to Hardisty Expansion
15 Southern Access Extension
16 Canadian Mainline System Terminal Flexibility and Connectivity

WOOD BUFFALO PIPELINE

Under an agreement with Suncor Energy Inc. (Suncor), Enbridge constructed 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 delivers crude oil from several oil sands projects to the Edmonton, Alberta mainline hub. The new Wood Buffalo Pipeline was placed into service in October 2012 and it parallels the existing Athabasca Pipeline. Additional expenditures will be incurred in 2013 and the estimated capital cost remains at approximately $0.4 billion, with expenditures to date of approximately $0.3 billion.

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 is being 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 total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, of which Enbridge's share is approximately $0.3 billion. Enbridge's share of total project expenditures to date is approximately $0.3 billion. Although the completed pipeline was available for service in November 2012, Enbridge expects the pipeline will be placed into service in the first quarter of 2013, commensurate with the start-up of the Kearl oil sands mine.

WAUPISOO PIPELINE CAPACITY EXPANSION

The Waupisoo Pipeline Capacity Expansion provided 65,000 bpd of additional capacity in the fourth quarter of 2012. Two stations that will provide a further 190,000 bpd of additional capacity have been completed and are anticipated to be placed into service in the third quarter of 2013 when they are expected to be required to accommodate additional throughput. The total cost of the project was approximately $0.3 billion.

SEAWAY CRUDE PIPELINE SYSTEM

ACQUISITION OF INTEREST

In 2011, Enbridge acquired a 50% interest in the Seaway Pipeline at a cost of approximately US$1.2 billion. Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma. For further details about Seaway Pipeline refer to *Liquids Pipelines – Seaway Pipeline*.

REVERSAL AND EXPANSION

The flow direction of the Seaway Pipeline has been reversed, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. The initial reversal of the pipeline and preliminary service commenced in the second quarter of 2012, providing initial capacity of 150,000 bpd. Further pump station additions and modifications were completed in January 2013, increasing capacity available to shippers to up to approximately 400,000 bpd, depending on crude slate. Actual throughput experienced to date in 2013 has been curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek tankage to the ECHO crude oil terminal in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013.

TWINNING AND EXTENSION

In March 2012, based on additional capacity commitments from shippers, plans were announced to proceed with an expansion of the Seaway Pipeline through construction of a second line that is expected to more than double its capacity to 850,000 bpd in mid-2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway system. Included in the project scope is a 105-kilometre (65-mile), 36-inch new-build lateral from the Seaway Jones Creek facility southwest of Houston, Texas into Enterprise Product Partners L.P.'s (Enterprise) ECHO crude oil terminal (ECHO Terminal) southeast of Houston.

In addition, a 137-kilometre (85-mile) pipeline will be constructed from the ECHO Terminal to the Port Arthur/ Beaumont, Texas refining center to provide shippers access to the region's heavy oil refining capabilities. This extension will offer capacity of 560,000 bpd and, subject to regulatory approvals, is expected to be available in the first quarter of 2014.

Including the acquisition of the 50% interest in the Seaway Pipeline, Enbridge's total expected cost for the Seaway Pipeline is approximately US$2.4 billion. The acquisition, reversal and expansion are expected to cost US$1.3 billion, with the twinning, extension and lateral to the ECHO Terminal components of the project expected to cost approximately US$1.1 billion. Total expenditures incurred to date were approximately US$1.3 billion.

SUNCOR BITUMEN BLEND

In September 2012, Enbridge entered into an agreement with Suncor for a Bitumen Blend project, which includes the construction of a new 350,000 barrel tank, new blend and diluent lines and pumping capacity to connect with Suncor's lines just outside Enbridge's Athabasca Tank Farm. These new facilities will enable Suncor to transport blended bitumen volumes from its Firebag production into the Wood Buffalo pipeline. The estimated cost for the project is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion. The Bitumen Blend project is expected to be in-service in the second quarter of 2013.

SOUTH CHEECHAM RAIL AND TRUCK TERMINAL

The Company has partnered with Keyera Corp. to construct the South Cheecham Rail and Truck Terminal (the Terminal), located approximately 75 kilometres (47 miles) southeast of Fort McMurray, Alberta. The Terminal, to be developed in phases, will be a multi-purpose hydrocarbon rail and truck terminal, designed to support bitumen producers within the Athabasca oil sands area and facilitate product in and out. In addition to the facilities for handling diluent and diluted bitumen at the Terminal, the initial phase is planned to include a diluted bitumen pipeline connection to Enbridge's existing Cheecham Terminal. Construction is underway and completion of the first phase is expected to take place in the second quarter of 2013 for a total cost of approximately $90 million. Enbridge's share of the project costs will be based upon its 50% joint venture interest.

NOREALIS PIPELINE

In order to provide pipeline and terminaling services to the proposed Husky Energy Inc. operated Sunrise Oil Sands Project, the Company is undertaking construction of a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline from the Norealis Terminal to the Cheecham Terminal, and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5 billion, with expenditures to date of approximately $0.2 billion. The project is expected to be available for service by the end of 2013.

EDDYSTONE RAIL PROJECT

In November 2012, the Company announced that it had entered into a joint venture agreement with Canopy Prospecting Inc. to develop a unit-train unloading facility and related local pipeline infrastructure near Philadelphia, Pennsylvania to deliver Bakken and other light sweet crude oil to Philadelphia area refineries. The Eddystone Rail Project will include leasing portions of a power generation facility and reconfiguring existing track to accommodate 120-car unit-trains, installing crude oil offloading equipment, refurbishing an existing 200,000 barrel tank and upgrading an existing barge loading facility. Subject to regulatory and other approvals, the project is expected to be placed into service by the end of 2013 to receive and deliver an initial capacity of 80,000 bpd, expandable to 160,000 bpd. The total estimated cost of the project is approximately US$68 million and Enbridge's share of the project costs will be based upon its 75% joint venture interest.

ATHABASCA PIPELINE CAPACITY EXPANSION

The Company is undertaking an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oilsands Project operated by Cenovus Energy Inc. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the mix of crude oil types. The estimated cost of the entire expansion is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion. The initial expansion to 430,000 bpd of capacity is expected to be placed into service by the end of the first quarter of 2013. 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 950-kilometre (590-mile) Flanagan South Pipeline will have an initial capacity of approximately 585,000 bpd to transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline will be installed adjacent to the Company's Spearhead Pipeline for the majority of the route. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$0.2 billion.

CANADIAN MAINLINE EXPANSION

In May 2012, Enbridge announced an estimated $0.2 billion expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The current scope of the project involves the addition of pumping horsepower sufficient to raise the capacity of the Alberta Clipper line by 120,000 bpd to a capacity of 570,000 bpd and is expected to be in service by mid-2014. The expansion remains subject to National Energy Board (NEB) approval.

In January 2013, Enbridge announced a further expansion of the Canadian Mainline system between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba, at an estimated cost of $0.4 billion, bringing the total expected cost for the expansion to approximately $0.6 billion. Subject to NEB approval, the current scope of the additional expansion involves the addition of pumping horsepower sufficient to raise the capacity of the Alberta Clipper line by another 230,000 bpd to its full capacity of 800,000 bpd. This component of the expansion is expected to be in service in 2015.

ATHABASCA PIPELINE TWINNING

This project involves the twinning of the southern section of the Company's Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to provide additional capacity to serve expected oil sands growth in the Kirby Lake producing region. The expansion project, with an estimated cost of approximately $1.2 billion, will include 345 kilometres (210 miles) of 36-inch pipeline adjacent to the existing Athabasca Pipeline right-of-way. The initial annual capacity of the pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. The line is expected to enter service in 2015.

EDMONTON TO HARDISTY EXPANSION

In November 2012, the Company announced plans to proceed with an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project, with an estimated cost of approximately $1.8 billion, will include 181 kilometres (112 miles) of new 36-inch diameter pipeline, expected to generally follow the same route as Enbridge's existing Line 4 pipeline, and new terminal facilities at Edmonton which include five new 500,000 barrel tanks and connections into existing infrastructure at Hardisty Terminal. The initial capacity of the new line is expected to be approximately 570,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory approvals, the project is expected to be placed into service in 2015.

SOUTHERN ACCESS EXTENSION

In December 2012, Enbridge announced that it will undertake the Southern Access Extension project, which will consist of the construction of a new 265-kilometre (165-mile), 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois as well as additional tankage and two new pump stations. Subject to regulatory approval, the project is expected to be placed into service in 2015 at an approximate cost of US$0.8 billion. The initial capacity of the new line is expected to be approximately 300,000 bpd. The Company also announced a binding open season to solicit commitments from shippers for capacity on the proposed pipeline. The open season closed in January 2013 and the Company is evaluating the results. Prior to launching the open season, Enbridge had already received sufficient capacity commitments from an anchor shipper to support the 24-inch pipeline as proposed.

CANADIAN MAINLINE SYSTEM TERMINAL FLEXIBILITY AND CONNECTIVITY

In December 2012, as part of the Light Oil Market Access Program initiative, the Company announced that it will undertake the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The cost of the project is expected to be approximately $0.6 billion, with varying completion dates between 2013 and 2016 related to existing terminal facility modifications, comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections.

GAS DISTRIBUTION

GREATER TORONTO AREA PROJECT

In September 2012, EGD announced plans to expand its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $0.6 billion, the proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. In December 2012, the Company filed an application with the Ontario Energy Board (OEB), and, subject to OEB approval, construction is targeted to start in 2014, with completion expected by the end of 2015.

Gas Distribution

17 Greater Toronto Area Project

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

SILVER STATE NORTH SOLAR PROJECT

In March 2012, Enbridge secured a 100% interest in the development of the 50-MW Silver State, located 65 kilometres (40 miles) south of Las Vegas, Nevada. The project, which began commercial operation in May 2012, was constructed under a fixed-price engineering, procurement and construction agreement with First Solar. First Solar is providing operations and maintenance services under a long-term contract. Energy output is being delivered to NV Energy, Inc. under a 25-year PPA. The Company's total investment in the project was approximately US$0.2 billion. In October 2012, the Company received a US$55 million 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.

MASSIF DU SUD WIND PROJECT

In December 2012, Enbridge secured a 50% interest in the 150-MW Massif du Sud development, located 100 kilometres (60 miles) east of Quebec City, Quebec. Project construction was completed in December 2012 and commercial operation commenced in January 2013. Massif du Sud delivers energy to Hydro-Quebec under a 20-year PPA. The Company's total investment in the project is approximately $0.2 billion with expenditures to date of approximately $0.1 billion. Additional expenditures are expected to be incurred into 2013.

LAC ALFRED WIND PROJECT

Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred), located 400 kilometres (250 miles) northeast of Quebec City in Quebec's Bas-Saint-Laurent region. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and is being undertaken in two phases. Phase 1, providing 150-MW, was completed and commenced commercial operations in January 2013, with Phase 2, for the remaining 150-MW, expected to be completed in the third quarter of 2013. Lac Alfred is delivering energy to Hydro-Quebec under a 20-year PPA. The Company's total investment in the project is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.2 billion.

CABIN GAS PLANT

In 2011, the Company secured a 71% interest in the development of the Cabin Gas Plant (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 was expected to be approximately $1.1 billion. In October 2012, the Company and its partners announced plans to defer both the commissioning of phase 1 and the construction of phase 2. In December 2012, Enbridge began earning fees for its investment made to date in both phases 1 and 2. Under the deferral, the Company's total investment in phases 1 and 2 is now expected to be approximately $0.8 billion, with expenditures to date of approximately $0.7 billion. Additional expenditures related to the deferral will continue to be incurred in 2013.

PEACE RIVER ARCH GAS DEVELOPMENT

In November 2012, the Company completed the acquisition from Encana Corporation (Encana) of certain sour gas gathering and compression facilities. These facilities, which are either currently in service or under construction, are located in the PRA region of northwest Alberta. The project will be completed in phases with new gathering lines expected to be in service in late 2013 and new NGL handling facilities expected to be completed in first quarter of 2014. Enbridge's investment in the PRA Gas Development is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.1 billion. Enbridge is also working exclusively with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region. Financial terms of the PRA Gas Development are expected to be substantially consistent with previously established terms of the Cabin development.

Current Assets
Growth Opportunities

Gas Pipelines, Processing and Energy Services

18 Silver State North Solar Project
19 Massif du Sud Wind Project
20 Lac Alfred Wind Project
21 Cabin Gas Plant
22 Peace River Arch Gas Development
23 Tioga Lateral Pipeline
24 Venice Condensate Stabilization Facility
25 Walker Ridge Gas Gathering System
26 Big Foot Oil Pipeline
27 Heidelberg Lateral Pipeline

TIOGA LATERAL PIPELINE

Alliance Pipeline US is constructing 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. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of Alliance. The pipeline will have an initial design capacity of approximately 106 million cubic feet per day (mmcf/d), which can be expanded based on shipper demand. Through its 50% ownership interest in Alliance Pipeline US, Enbridge's expected cost related to the project is approximately US$0.1 billion. In October 2012, Alliance Pipeline US executed a contract with Hess Corporation (Hess) as an anchor shipper. Aux Sable Liquids Products and Hess have reached a concurrent agreement for the provision of NGL services. Regulatory approval from the Federal Energy Regulatory Commission (FERC) was received in September 2012 and construction commenced early October 2012, with an expected third quarter 2013 in-service date.

VENICE CONDENSATE STABILIZATION FACILITY

The Company is carrying out an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within its Offshore business. Expenditures to date are approximately US$0.1 billion. The expanded condensate processing capacity is required to accommodate additional natural gas production from the 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 system 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 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-deep water 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, with expenditures to date of approximately US$0.1 billion.

BIG FOOT OIL PIPELINE

The Company executed definitive agreements in 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-deep water 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, which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion. This project is expected to be in service in 2014.

HEIDELBERG LATERAL PIPELINE

In November 2012, Enbridge announced it will build, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation (Anadarko), to an existing third-party system. The Heidelberg Lateral Pipeline (Heidelberg), a 20-inch, 55-kilometre (34-mile) pipeline, will originate in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans, Louisiana, and in an estimated 1,600 metres (5,300 feet) of water. Subject to regulatory and other approvals, as well as sanctioning of the development by Anadarko and its project co-owners, Heidelberg is expected to be operational by 2016 at an approximate cost of US$0.1 billion.

SPONSORED INVESTMENTS

BAKKEN EXPANSION PROGRAM

A joint project to further expand crude oil pipeline capacity to accommodate growing crude oil production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. Upon completion, which is expected in the first quarter of 2013, and subject to NEB approval, the Bakken Expansion Program will provide capacity of 145,000 bpd. The United States component is being undertaken by EEP and the Canadian component is being undertaken by the Fund. The estimated capital cost for the Canadian portion remains at approximately $0.2 billion, with expenditures incurred to the end of December 2012 of approximately $0.1 billion. The estimated capital cost for the United States portion of the project is now approximately US$0.3 billion, with expenditures incurred to the end of December 2012 of approximately US$0.2 billion.

ENBRIDGE ENERGY PARTNERS, L.P.

BERTHOLD RAIL PROJECT

The Berthold Rail project will 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 infrastructure. The first phase of terminal facilities was completed in September 2012, providing additional capacity of 10,000 bpd to the Berthold Terminal. The loading facility and crude oil tankage are expected to be placed into service in the first quarter of 2013. The estimated cost of the project is approximately US$0.1 billion, with project expenditures to date of approximately US$0.1 billion.

AJAX CRYOGENIC PROCESSING PLANT

EEP is constructing an additional natural gas processing plant and other facilities on its Anadarko System. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service mid-2013. When operational, the Ajax Plant, in conjunction with the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d. The estimated cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.2 billion.

CUSHING TERMINAL STORAGE EXPANSION PROJECT

EEP has completed construction and placed into service 13 new crude oil storage tanks at its Cushing Terminal with an approximate shell capacity of 4.4 million barrels. With five tanks completed in 2011, the remaining eight tanks were placed into service throughout 2012. In July 2012, engineering design commenced on an additional three new tanks and associated infrastructure totaling 936,000 barrels of incremental shell capacity at EEP's Cushing Terminal, at an estimated cost of US$39 million. The expected in-service date for the three tanks is now the fourth quarter of 2013. The total estimated cost to construct the 16 storage tanks and infrastructure, as required, is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion.

SOUTH HAYNESVILLE SHALE EXPANSION

EEP has expanded its East Texas natural gas pipeline 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, completed in the second quarter of 2012 at an approximate cost of US$0.1 billion, increased capacity of EEP's East Texas system by 900 mmcf/d.

Current Assets
Growth Opportunities

Sponsored Investments

28 EEP – Bakken Expansion Program
29 The Fund – Bakken Expansion Program
30 EEP – Berthold Rail Project
31 EEP – Ajax Cryogenic Processing Plant
32 EEP – Cushing Terminal Storage Expansion Project
33 EEP – South Haynesville Shale Expansion
34 EEP – Bakken Access Program
35 EEP – Texas Express Pipeline
36 EEP – Line 6B 75-Mile Replacement Program
37 EEP – Eastern Access
38 EEP – Lakehead System Mainline Expansion
39 EEP – Sandpiper Project

EEP plans to invest an additional US$0.2 billion, with expenditures to date of approximately US$0.1 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. Due to lower levels of producer activity in response to weak natural gas prices, EEP has deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

BAKKEN ACCESS PROGRAM

The Bakken Access Program represents an upstream expansion that will further complement EEP's Bakken expansion. This expansion program will enhance crude oil gathering capabilities on the North Dakota System by 100,000 bpd. The program involves increasing pipeline capacity, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota at an approximate cost of US$0.1 billion, with expenditures to date of approximately US$0.1 billion. The Bakken Access Program is expected to be in service by mid-2013.

TEXAS EXPRESS PIPELINE

The TEP is a joint venture with Enterprise, Anadarko and DCP Midstream LLC to design and construct a new NGL pipeline and two new NGL gathering systems which EEP will build and operate. EEP will invest approximately US$0.4 billion in the TEP, which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. Expenditures to date are approximately US$0.2 billion. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. Approximately 250,000 bpd of capacity has been subscribed on the pipeline.

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 the third quarter of 2013.

LINE 6B 75-MILE REPLACEMENT PROGRAM

This program includes the replacement of 120 kilometres (75 miles) of non-contiguous sections of Line 6B of EEP's Lakehead System. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments are expected to be placed in service during 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 for the Lakehead System. The total capital for this replacement program is estimated to be US$0.3 billion, with expenditures to date of approximately US$0.2 billion.

EASTERN ACCESS

The Eastern Access initiative includes several crude oil pipeline projects announced by Enbridge and EEP in 2011 and 2012 to provide increased access to refineries in the United States upper mid-west and eastern Canada. The current scope of Enbridge projects includes a reversal of its Line 9 and expansion of the Toledo Pipeline. The current scope of EEP projects includes an expansion of its Line 5 as well as United States mainline system expansions involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. The individual projects are further described below.

Enbridge plans to reverse a portion of its Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a revised estimated cost of approximately $48 million. With NEB approval received in July 2012, the Line 9A reversal is expected to be in service in late 2013.

Enbridge also plans to undertake a full reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec. The Line 9B reversal is expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required an additional 80,000 bpd of delivery capacity within Ontario and Quebec. The Line 9B capacity expansion is expected to be completed at an estimated cost of approximately $0.1 billion. Subject to NEB regulatory approval, the Line 9B reversal and Line 9B capacity expansion are expected to be available for service in 2014 at a total estimated cost of approximately $0.4 billion.

Enbridge is also undertaking an 80,000 bpd expansion of its Toledo Pipeline (Line 17), which connects with the EEP mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan. The Toledo Pipeline expansion is expected to be available for service by the second quarter of 2013 at a cost of approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion.

Both the Toledo Pipeline and Line 9 assets are included in the Company's Liquids Pipelines segment.

EEP is expanding its 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. The Line 5 expansion is targeted to be in service during the first quarter of 2013.

EEP is also undertaking the expansion of its Line 62 between Flanagan and Griffith, Indiana by adding horsepower to increase capacity from 130,000 bpd to 235,000 bpd and adding a 330,000 barrel tank at Griffith. The Line 62 capacity expansion project is expected to be placed into service by the end of 2013. EEP also plans to replace additional sections of Line 6B in Indiana and Michigan to increase capacity from 240,000 bpd to 500,000 bpd, with a target in-service date of early 2014. The replacement of these sections of Line 6B is in addition to the Line 6B Replacement Program announced in 2011 and discussed previously. The expected cost of the United States mainline expansions is US$2.2 billion, and includes the US$0.1 billion cost of the previously discussed Line 5 expansion.

In December 2012, Enbridge and EEP announced a further upsizing of EEP's Line 6B component of the Eastern Access Expansion initiative. The Line 6B capacity expansion from Griffith to Stockbridge, Michigan will increase capacity from 500,000 bpd to 570,000 bpd and will involve the addition of new pumps, existing station modifications and breakout tankage at the Griffith and Stockbridge terminals. Subject to regulatory and other approvals, the project is expected to be placed into service in 2016 at an estimated capital cost of approximately US$0.4 billion.

The total estimated cost of the United States mainline expansions, including the Line 6B capacity expansion project, is approximately US$2.6 billion, with expenditures to date of approximately US$0.3 billion. The Eastern Access projects will be funded 60% by Enbridge and 40% with EEP having the option to reduce its funding and associated economic interest in the project by up to 15% before June 30, 2013. Furthermore, within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to 15%.

LAKEHEAD SYSTEM MAINLINE EXPANSION

In 2012, Enbridge and EEP announced several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota, to Flanagan, Illinois. Included in the expansion are Alberta Clipper (Line 67) and Southern Access (Line 61).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase, announced in May 2012, includes a planned increase in capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. In January 2013, EEP announced a further expansion of the Lakehead System mainline between the border and Superior, to increase capacity from 570,000 bpd to 800,000 bpd, at an estimated capital cost of approximately US$0.2 billion. Subject to finalization of scope and regulatory and shipper approvals, including an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd, the target in-service dates for the proposed projects are mid-2014 for the initial phase and 2015 for the second phase. Both phases of the Alberta Clipper expansion would require only the addition of pumping horsepower and no pipeline construction.

The current scope of the Southern Access expansion between Superior and Flanagan, Illinois also consists of two phases. The initial phase, announced in May 2012, includes a planned increase in capacity from 400,000 bpd to 560,000 bpd at an estimated capital cost of approximately US$0.2 billion. In December 2012, EEP announced a further expansion of the Southern Access line between Superior and Flanagan, to increase capacity from 560,000 bpd to 1,200,000 bpd at an estimated capital cost of approximately US$1.3 billion. Both phases of the expansion would require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction. Subject to finalization of scope and regulatory approvals, the target in-service date for the first phase of the expansion is expected to be in mid-2014. For the second phase of the expansion, which is also subject to finalization of design and regulatory approvals, the pump station expansion is expected to be available for service in 2015, with additional tankage requirements expected to be completed in 2016.

As part the Light Oil Market Access Program, Enbridge and EEP announced the capacity expansion of the Lakehead System between Flanagan, Illinois and Griffith, Indiana. This section of the Lakehead System will be expanded by constructing a 122-kilometre (76-mile), 36-inch diameter twin of the existing Spearhead North Pipeline (Line 62). The project is expected to be completed at an estimated cost of approximately US$0.5 billion. The new line will have an initial capacity of 570,000 bpd and is expected to be placed into service in 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.4 billion and will operate on a cost-of-service basis. The projects will be funded 60% by Enbridge and 40% by EEP under similar joint funding arrangement terms to those described under *Growth Projects – Commercially Secured Projects – Sponsored Investments – Eastern Access*. Furthermore, within one year of the final in service date, EEP will also have the option to increase its economic interest held at that time by up to 15%.

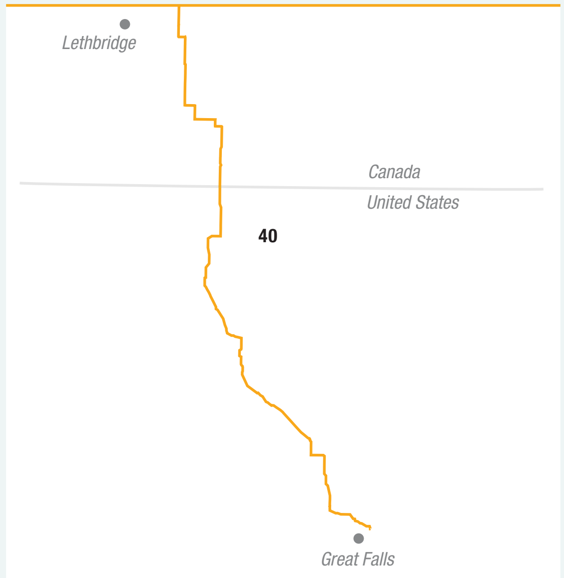
SANDPIPER PROJECT

In December 2012, Enbridge and EEP announced the Light Oil Market Access Program which consists of several individual projects. As part of this initiative, EEP plans to undertake the Sandpiper Project which will expand and extend EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd, with a target in-service date in 2016. The expansion will involve construction of an approximate 965-kilometre (600-mile) 24-inch diameter line from Beaver Lodge, North Dakota, to the Superior, Wisconsin, mainline system terminal. The new line will twin the 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 225,000 bpd of capacity on the twin line between Beaver Lodge and Clearbrook, and 375,000 bpd of capacity between Clearbrook and Superior. The Sandpiper Project will be fully funded by EEP at an estimated capital cost of approximately US$2.5 billion. Subject to finalization of scope and regulatory approval, the capital cost will be rolled into the existing North Dakota System rate base, with the associated cost of service to be recovered in tolls.

CORPORATE

MONTANA-ALBERTA TIE-LINE

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 buoyant power demand in Alberta. The total expected cost for both the first 300-MW phase of MATL and the expansion for an additional 300-MW has been increased to approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion. The permits required for construction had been previously obtained and in December 2012 the Alberta Utility Commission in Canada approved the Company's updated design modifications. The system's north-bound capacity, which is fully contracted, is now targeted to be in service in the second quarter of 2013, with the expansion targeted to be completed by the end of 2014.



Corporate
40 Montana-Alberta Tie-Line

NEAL HOT SPRINGS GEOTHERMAL PROJECT

The Company has partnered with U.S. Geothermal Inc. (U.S. Geothermal) to develop the 35-MW (22-MW, net) Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. The project declared commercial operation in November 2012, with the facility delivering electricity to the Idaho Power grid under a 25-year PPA. Enbridge invested approximately US$33 million for a 41% interest in the project.

Growth Projects – Other Projects Under Development

The following projects are also currently under development by the Company, but have not yet met Enbridge's criteria to be classified as commercially secured.

LIQUIDS PIPELINES

WOODLAND PIPELINE EXTENSION

In September 2012, Enbridge received approval from the Alberta Energy Resources Conservation Board (ERCB) to construct the Woodland Pipeline Extension Project. The project will extend the Woodland Pipeline south from Enbridge's Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 385-kilometre (228-mile), 36-inch diameter pipeline, requiring an investment of approximately $1.0 billion to $1.4 billion for an initial capacity of 400,000 bpd, expandable to 800,000 bpd. The estimated investment remains subject to finalization of scope and a definitive cost estimate. All major environmental approvals have been received and, subject to final commercial approval, Enbridge anticipates a 2015 in-service date. Project expenditures to date are approximately $0.1 billion, with pre-development costs backstopped by shippers pending final commercial approval.

TRUNKLINE JOINT VENTURE

In February 2013, Enbridge entered into an agreement with Energy Transfer Partners L.P. (Energy Transfer) on the terms for joint development of a project to provide access to the eastern Gulf Coast refinery market from the Patoka, Illinois hub. Subject to FERC approval, the project will involve the conversion from natural gas service of certain segments of pipeline that are currently in operation as part of the natural gas system of Trunkline Gas Company, LLC, a wholly owned subsidiary of Energy Transfer and Energy Transfer Equity, L.P. The converted pipeline is expected to have a capacity of up to 420,000 to 660,000 bpd, depending on crude slate and the level of subscriptions received in an open season, and is expected to be in service by early 2015. Enbridge and Energy Transfer would each own a 50% interest in the venture. Enbridge's participation in the venture is subject to a minimum level of commitments being obtained in the open season and on completion of due diligence on the conversion cost. Depending on the level of commitments and finalization of scope and capital cost estimates, Enbridge expects to invest approximately US$1.2 billion to US$1.7 billion.

NORTHERN GATEWAY PROJECT

Northern Gateway involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine 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 in May 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. Following sessions with the public, including Aboriginal groups, and the provision of additional information by Northern Gateway, the JRP issued a Hearing Order in May 2011 outlining the procedures to be followed.

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 the fall of 2011, Northern Gateway responded to written questions by intervenors and government participants.

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the Panel would hear all oral evidence from registered intervenors first, followed by oral statements from registered participants. Community hearings for oral evidence and statements took place between January and August 2012 in various communities. A written record of what was said each day in the community hearings is available on the Panel's website. Intervenors responded to questions by Northern Gateway on July 6, 2012. Northern Gateway filed reply evidence to the evidence of the intervenors on July 20, 2012. The reply evidence contained details of further enhancements in pipeline design and operations. These extra measures, estimated to cost an additional $400 million to $500 million, together with additional marine infrastructure, result in a total estimated project cost of approximately $6.6 billion. The enhancements include: increasing pipeline wall thickness of the oil pipeline; additional pipeline wall thickness for water crossings such as major tributaries to the Fraser, Skeena and Kitimat Rivers; increasing the number of remotely-operated isolation valves by 50% within British Columbia to protect high-value fish habitat; increasing frequency of in-line inspection surveys across the entire Northern Gateway pipeline system by a minimum of 50% over and above current standards; installing dual leak detection systems; and staffing pump stations in remote locations on a 24 hour/7 day basis for on-site monitoring, heightened security and rapid response to abnormal conditions.

The final hearings commenced on September 4, 2012 where Northern Gateway, intervenors, government participants and the JRP questioned those who have presented oral or written evidence.

The final hearings and the remaining oral statements from interested parties who do not reside along the pipeline corridor or shipping routes are expected to be completed by May 2013. Based on this projected schedule, the JRP expects to issue its reports and findings on the proposed project by December 2013.

Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. 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 in 2018 at the earliest.

On February 23, 2012, Transport Canada published its TERMPOL Review Process Report of the Northern Gateway's proposed marine operations. Transport Canada has filed the results of the study with the federal JRP tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: "While there will always be residual risk in any project, after reviewing the proponent's studies and taking into account the proponent's commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway." The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. The Gitxaala First Nations (Gitxaala) filed a Notice of Judicial Review with the Federal Court of Canada challenging the TERMPOL process on the grounds that there had not been adequate consultation with the Gitxaala with respect to the potential impacts on its Rights and Title resulting from the routine operation of the tankers servicing the Northern Gateway terminal in Kitimat. Following the hearing, the Federal Court of Canada issued a decision rejecting the Gitxaala challenge.

Expenditures to date, which relate primarily to the regulatory process, are approximately $0.3 billion, of which approximately half is being funded by potential shippers on Northern Gateway. Given the many uncertainties surrounding the Northern Gateway, 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 website in addition to information available on *www.enbridge.com*. The full regulatory application submitted to the NEB and the 2010 Enbridge Northern Gateway Community Social Responsibility Report are available on *www.northerngateway.ca*. ***None of the information contained on, or connected to, the JRP website, the Northern Gateway website or Enbridge's website is incorporated in or otherwise part of this MD&A.***

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

NEXUS GAS TRANSMISSION PROJECT

In September 2012, Enbridge, DTE Energy Company (DTE) and Spectra Energy Corp (Spectra) announced the execution of a Memorandum of Understanding to jointly develop the NEXUS Gas Transmission System (NEXUS), a project that will move growing supplies of Ohio Utica shale gas to markets in the United States midwest, including Ohio and Michigan and Ontario, Canada. The proposed NEXUS project will originate in northeastern Ohio, include approximately 400 kilometres (250 miles) of large diameter pipe, and be capable of transporting one bcf/d of natural gas. The line will follow existing utility corridors to an interconnect in Michigan and utilize the existing Vector pipeline to reach the Ontario market. Upon completion, Spectra would become a 20% owner in Vector, a joint venture between DTE and Enbridge. The next steps include analyzing open season service requests from the October 2012 open season and working with potential customers to formalize these requests into binding contract commitments. The targeted in-service date is late 2016.

Liquids Pipelines

EARNINGS

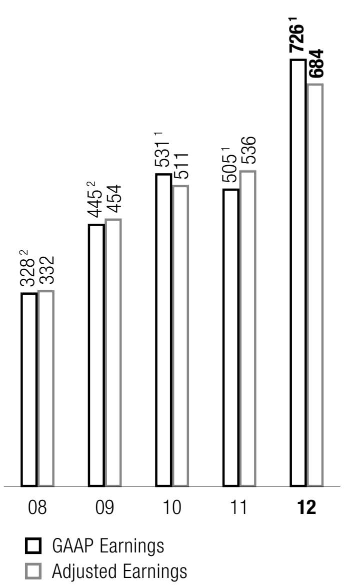
	2012	2011	2010
(millions of Canadian dollars)			
Canadian Mainline	**432**	336	326
Regional Oil Sands System	**110**	111	73
Southern Lights Pipeline	**71**	75	82
Seaway Pipeline	**24**	(3)	–
Spearhead Pipeline	**37**	17	29
Feeder Pipelines and Other	**10**	–	1
Adjusted earnings	**684**	536	511
Canadian Mainline – Line 9 tolling adjustment	**6**	10	–
Canadian Mainline – changes in unrealized derivative fair value gains/(loss)	**42**	(48)	–
Canadian Mainline – shipper dispute settlement	**–**	14	–
Regional Oil Sands System – prior period adjustment	**(6)**	–	–
Regional Oil Sands System – asset impairment write-off	**–**	(8)	–
Regional Oil Sands System – gain on acquisition	**–**	–	20
Spearhead Pipeline – changes in unrealized derivative fair value gains	**–**	1	–
Earnings attributable to common shareholders	**726**	505	531

Liquids Pipelines adjusted earnings were $684 million in 2012 compared with adjusted earnings of $536 million in 2011 and $511 million in 2010. The Company continued to realize earnings growth on the Canadian Mainline in 2011 and 2012, primarily due to strong volume throughput and favourable operating performance under the CTS which took effective July 1, 2011. Other factors which contributed to the adjusted earnings increase included earnings from Seaway Pipeline since the initial reversal in May 2012, increased volumes on Spearhead Pipeline, as well as increased earnings from a number of the Company's feeder pipelines.

Liquids Pipelines earnings were impacted by the following adjusting items:

- Canadian Mainline earnings for 2012 and 2011 included Line 9 tolling adjustments related to services provided in prior periods.
- Canadian Mainline earnings for 2012 and 2011 reflected changes in unrealized fair value gains and 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.
- Canadian Mainline earnings for 2011 included $14 million from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- Regional Oil Sands System earnings for 2012 included a revenue recognition adjustment related to prior periods.
- Regional Oil Sands System earnings for 2011 included the write-off of development expenditures on certain project assets.
- Regional Oil Sands System earnings for 2010 included a gain on step-acquisition of crude oil storage assets.
- Spearhead Pipeline earnings for 2011 included changes in unrealized fair value gains on derivative financial instruments used to manage exposures to allowance oil commodity prices.

LIQUIDS PIPELINES EARNINGS
(millions of Canadian dollars)

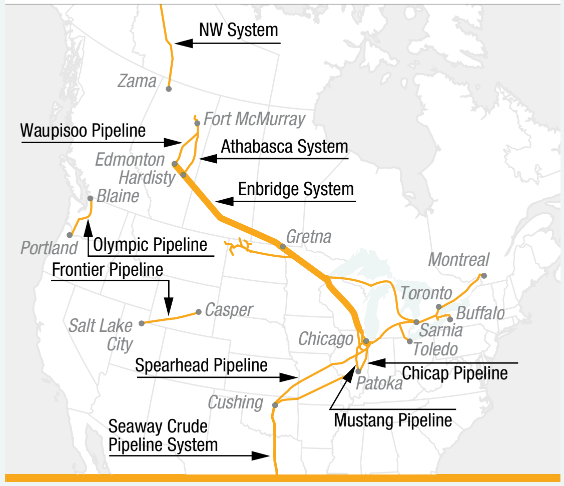


1 *Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

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, which cross the Canada/United States border near Gretna, Manitoba and Neche, North Dakota, 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.

LIQUIDS PIPELINES



COMPETITIVE TOLL SETTLEMENT

Canadian Mainline tolls are governed by the 10-year settlement reached between Enbridge and shippers on its mainline system and approved by the NEB in 2011. The CTS, which took effect on July 1, 2011, covers local tolls 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, was 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 1, 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 limited circumstances the shippers or Enbridge may elect to renegotiate the toll. 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. Under the terms of the IJT agreement between Enbridge and EEP, the Company's share of the IJT toll relating to pipeline transportation of a batch from any western Canada receipt point to the United States border is equal to the IJT toll applicable to that batch's United States delivery point less the Lakehead System's local toll to that delivery point. This amount is referred to as the Canadian Mainline IJT Residual Toll.

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. Earnings under the CTS are subject to variability in volume throughput, as well as capital and operating costs, and the United States dollar exchange rate. 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 crude oil and power prices.

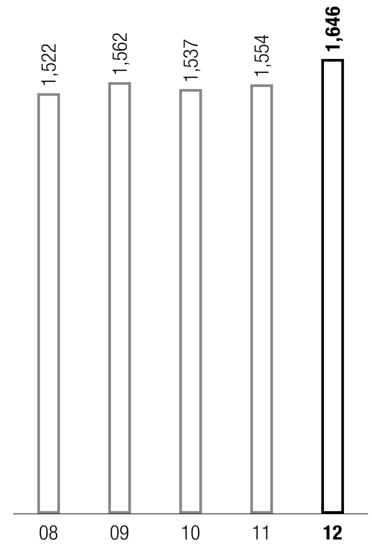
INCENTIVE TOLLING

Prior to the CTS taking effect on July 1, 2011, 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 $432 million for the year ended December 31, 2012 compared with $336 million for the year ended December 31, 2011 and $326 million for the year ended December 31, 2010. The comparability of Canadian Mainline earnings year-over-year is affected by the change in tolling methodology. As noted previously, from July 1, 2011 onward, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS, whereas operations 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. Under the CTS, earnings are subject to variability in volume throughput and operating costs compared with prior tolling arrangements which were based on a cost-of-service methodology.

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



Canadian Mainline revenues for the year ended December 31, 2012 reflected increased volumes and a higher Canadian Mainline IJT Residual Benchmark Toll which, under the IJT, is impacted by changes in the Lakehead System Local Toll. Volume throughput in 2012 was impacted by market conditions as incremental oil sands crude production in Alberta and strong production growth out of the Bakken in North Dakota bolstered supply to midwest markets and placed increased downward pressure on crude oil prices in that market. This discounted crude oil, coupled with strong refining margins, increased demand in the midwest for Canadian and Bakken crude oil supply and drove increased long haul barrels on Canadian Mainline and EEP's Lakehead System. However, during the fourth quarter of 2012, Canadian Mainline was not able to capture the full throughput benefit of the increased supply available to it due to capacity limitations which arose from pressure restrictions being applied to certain lines pending completion of inspection and repair programs. The Company expects that capacity limitations will continue to constrain throughput during the first quarter of 2013 and, to a diminishing extent, for the remainder of 2013. An increase in operating and administrative costs, primarily due to higher employee related costs and higher leak remediation costs, also impacted 2012 adjusted earnings.

Supplemental information on Canadian Mainline adjusted earnings for the year ended December 31, 2012 and for the six month period from July 1, the effective date of the CTS, to December 31, 2011 is as follows:

	Year ended December 31,	Six months ended December 31,	
	2012	**2012**	2011
(millions of Canadian dollars)			
Revenues	**1,367**	**711**	618
Expenses			
Operating and administrative	**382**	**192**	194
Power	**112**	**57**	54
Depreciation and amortization	**219**	**110**	104
	713	**359**	352
	654	**352**	266
Other income/(expense)	**(4)**	**(1)**	5
Interest expense	**(131)**	**(66)**	(66)
	519	**285**	205
Income taxes	**(87)**	**(48)**	(31)
Adjusted earnings	**432**	**237**	174
Effective United States to Canadian dollar exchange rate [1]	**0.971**	**0.974**	0.972

December 31,	**2012**	2011
IJT Benchmark Toll [2] *(United States dollars per barrel)*	**$ 3.94**	$ 3.85
Lakehead System Local Toll [3] *(United States dollars per barrel)*	**$ 1.85**	$ 2.01
Canadian Mainline IJT Residual Benchmark Toll [4] *(United States dollars per barrel)*	**$ 2.09**	$ 1.84

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

2 *The IJT 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. Effective July 1, 2012, the IJT benchmark toll increased from US$3.85 to US$3.94.*

3 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2012, this toll decreased from US$2.01 to US$1.76 and, effective July 1, 2012, this toll increased from US$1.76 to US$1.85.*

4 *The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. Effective April 1, 2012, this toll increased from US$1.84 to US$2.09, with no change effective July 1, 2012. For any shipment, this toll is the difference between the IJT toll for that shipment and the Lakehead System Local Toll for that shipment.*

THROUGHPUT VOLUME [1]

2012					2011				
Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Total
1,687	**1,659**	**1,617**	**1,622**	**1,646**	1,602	1,457	1,565	1,594	1,554

1 *Throughput volume, presented in thousand barrels per day, represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries from western Canada.*

Canadian Mainline revenues include the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Lines 8 and 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 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 and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. The Company currently utilizes 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 expense 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, the addition of new facilities and more extensive integrity and maintenance programs.

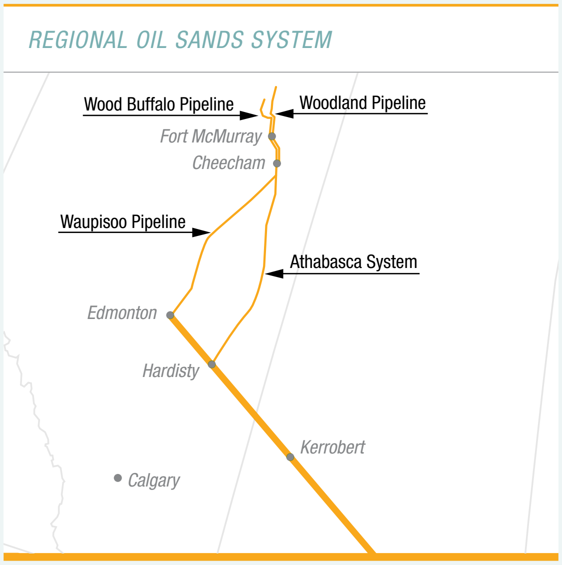
Power, the most significant variable operating cost, is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements; however, the primary determinants of this cost are the power prices in various jurisdictions and throughput volume. The relationship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

Depreciation and amortization expense will adjust over time as a result of additions to property, plant and equipment due to new facilities, including integrity capital expenditures.

Canadian Mainline income taxes reflect current income taxes only. Under the CTS, the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to deferred 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, revenues 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. A regulatory asset of approximately $470 million related to deferred income taxes recorded at the date of discontinuance continued to be recognized as the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment. 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.



REGIONAL OIL SANDS SYSTEM

Regional Oil Sands System consists of two long haul pipelines, the Athabasca Pipeline and the Waupisoo Pipeline, as well as the recently completed lateral pipeline and the receipt Wood Buffalo Pipeline. Regional Oil Sands System also includes a variety of other facilities such as the MacKay River, Christina Lake, Surmont and Long Lake facilities, as well as the Woodland Pipeline. It also includes 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, which 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. Revenues are recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered service in 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 had an initial design capacity, dependent on crude slate, of up to 350,000 bpd. The pipeline capacity was expanded to 415,000 bpd in the fourth quarter of 2012 and can ultimately be expanded to 600,000 bpd. Enbridge has a long-term (25-year) take-or-pay commitment with multiple shippers on the Waupisoo Pipeline who collectively have contracted for approximately three-quarters of the capacity.

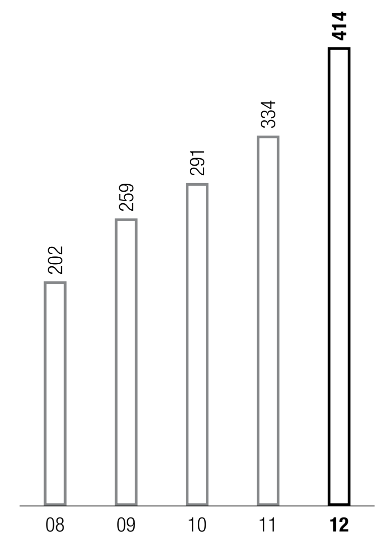
Prior to December 10, 2012 Regional Oil Sands System included the Hardisty Storage Caverns which included four salt caverns totaling 3.1 million barrels of storage capacity. The capacity at the facility is fully subscribed under long-term contracts that generate revenues from storage and terminaling fees. Along with the Hardisty Contract Terminals, the Hardisty Storage Caverns were transferred to the Fund in December 2012. See *Sponsored Investments – Enbridge Income Fund – Crude Oil Storage and Renewable Energy Transfers* for details of the transfer.

RESULTS OF OPERATIONS

Adjusted earnings for the year ended December 31, 2012 were $110 million compared with $111 million for the year ended December 31, 2011. Higher shipped volumes and increased tolls on certain laterals, and higher earnings from an annual escalation in storage and terminaling fees were more than offset by higher operating and administrative expense, and higher depreciation expense. Adjusted earnings for 2012 also included contributions from new regional infrastructure, the Woodland and Wood Buffalo pipelines, placed into service in the fourth quarter, although offset by earnings no longer being generated on assets sold to the Fund in December.

Adjusted earnings increased from $73 million for the year ended December 31, 2010 to $111 million for the year ended December 31, 2011. This increase in adjusted earnings reflected higher shipped volumes and increased tolls, as well as the continued positive impact of terminal infrastructure additions. Adjusted earnings for 2011 also included the impact of lower depreciation expense due to extended estimated useful lives of certain assets reflecting increased probable reservoir supply and commercial viability.

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



ELK POINT PUMP STATION FACILITY OIL RELEASE

On June 19, 2012, Enbridge reported an oil release at its Elk Point pumping station on Line 19 (Athabasca Pipeline), approximately 70 kilometres (44 miles) south of Bonnyville, Alberta and approximately 24 kilometres (15 miles) from the town of Elk Point, Alberta. On June 24, 2012, the Company restarted the Elk Point pumping station after completing necessary repairs. The contaminated soil and free product has been removed from the site for processing and disposal. On-going environmental testing and monitoring of the site is being conducted. Estimated volume of the release is approximately 1,400 barrels which were largely contained within the station.

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 return on equity (ROE) of 10%. Uncommitted volumes, up to a specified amount, generate 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 uncommitted rates on Southern Lights Pipeline for 2010, 2011 and 2012 were challenged by certain shippers. 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 and stating that tolls in place were just and reasonable, and more recently approved the 2010, 2011 and 2012 interim tolls as final. A FERC hearing was held in January 2012. Briefs were filed on February 27, 2012 and March 28, 2012 and an initial decision was issued on June 5, 2012. The initial decision found that the uncommitted rates were just and reasonable. The parties have filed briefs in response to this decision and the case is awaiting a final decision from the FERC.

RESULTS OF OPERATIONS

Southern Lights earnings decreased to $71 million for the year ended December 31, 2012 compared with $75 million for the year ended December 31, 2011 due to higher income tax expense which exceeded the deemed tax recovery in rates. For the year ended December 31, 2010, earnings of $82 million included leasing income from a pipeline until it was transferred to the mainline system effective May 1, 2010.

SEAWAY PIPELINE

In 2011, Enbridge acquired a 50% interest in the 1,078-kilometre (670-mile) Seaway Pipeline including the 805-kilometre (500-mile), 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. The Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast.

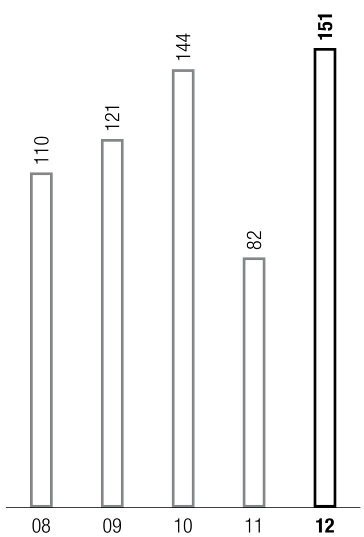
The reversal of the Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast, was completed in May 2012, providing initial capacity of 150,000 bpd. In January 2013, further pump station additions and modifications were completed, increasing capacity available to shippers to up to 400,000 bpd, depending on crude slate. Actual throughput experienced to date in 2013 has been curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek tankage to the ECHO crude oil terminal in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013. Tolls are based on the contract terms agreed upon with shippers during the open seasons.

Seaway Pipeline filed for market-based rates in December 2011. As the FERC had not issued a ruling on this application, Seaway Pipeline filed for initial rates in order to have rates in effect by the in-service date. The uncommitted rate on the Seaway Pipeline has been challenged by several shippers. A FERC hearing has been scheduled for March 2013.

RESULTS OF OPERATIONS

Seaway Pipeline earnings for the year ended December 31, 2012 of $24 million reflected preliminary service at an approximate capacity of 150,000 bpd which commenced in May 2012. Subsequent to year end, in January 2013, with further pump station additions and modifications, the reversal was completed, increasing to its intended capacity of 400,000 bpd. The $3 million loss recognized for the year ended December 31, 2011 was related to early stage business development costs that were not eligible for capitalization.

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



SPEARHEAD PIPELINE

Spearhead Pipeline delivers crude oil from the Flanagan, Illinois delivery point of the Lakehead System to Cushing, Oklahoma. The pipeline was originally placed into service in March 2006 and the Spearhead Pipeline Expansion was completed in May 2009, increasing capacity from 125,000 bpd to 193,300 bpd.

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

RESULTS OF OPERATIONS

Spearhead Pipeline adjusted earnings were $37 million for the year ended December 31, 2012 compared with $17 million for the year ended December 31, 2011. Spearhead Pipeline adjusted earnings increased as a result of higher volumes and tolls, partially offset by higher operating and administrative costs, including power and repairs and maintenance. Volumes significantly increased over 2011 due to higher commodity price differentials which increased demand at Cushing, Oklahoma in anticipation of additional capacity on the Seaway Pipeline for further transportation to the Gulf Coast.

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 market pricing dynamics at the time which weakened demand at Cushing, partially offset by the recognition of make-up rights which expired in the period.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the Company's 85% interest in Olympic Pipe Line Company (Olympic), 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 to Zama, Alberta; interests in a number of liquids pipelines in the United States; and business development costs related to Liquids Pipelines activities.

Prior to December 10, 2012, Feeder Pipelines and Other also included the Hardisty Contract Terminals, which is comprised of 19 tanks with a working capacity of approximately 7.5 million barrels of storage capacity. Along with the Hardisty Storage Caverns, the Hardisty Contract Terminals were transferred to the Fund in December 2012. See *Sponsored Investments – Enbridge Income Fund – Crude Oil Storage and Renewable Energy Transfers* for details of the transfer.

RESULTS OF OPERATIONS

In 2012, Feeder Pipelines and Other earnings were $10 million compared with nil for the year ended December 31, 2011 and earnings of $1 million in 2010. The increase in earnings was primarily a result of a higher contribution from Olympic due to a tariff increase, higher volumes on Toledo Pipeline and increased terminaling fees. In 2011, earnings from Toledo Pipeline were negatively impacted by integrity work on Lines 6A and 6B of EEP's Lakehead System. The decrease in earnings from 2010 to 2011 reflected higher business development costs.

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 – General Business Risks.*

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 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 and are expected to be sustained at levels that will incent continued development of oil sands and conventional exploration and drilling, increasing production, and creating increased demand for new pipeline infrastructure to access markets both in North America and abroad.

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 earnings. 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. This risk is partially mitigated by the CTS agreement, which allows Enbridge to negotiate an amendment to the agreement in the event certain minimum threshold volumes are not met.

MARKET PRICE RISK

The CTS agreement for the Canadian Mainline exposes the Company to risks related to movements in foreign exchange rates, interest rates and commodity prices, particularly power prices. Foreign exchange risk arises as the Company's IJT under the CTS is 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 changes in the mark-to-market value of these contracts.

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 existing and proposed pipelines that provide, or are proposed to provide, access to market areas currently served by the Company's liquids pipelines. One such competing project serves markets at Wood River, Illinois and Cushing, Oklahoma. This pipeline has a capacity of 590,000 bpd, and could connect to a proposed 700,000 bpd pipeline serving Gulf Coast refineries, which is expected to be in-service in late 2013. Commercial support has also been announced for the construction of additional ex-Alberta capacity of 830,000 bpd to Steele City, Nebraska, with an expected in-service date of 2015, to further supply WCSB crude to the Gulf Coast. Additionally, due to deep discounting of WCSB commodities compared with WTI pricing and the relatively long lead-times required to build new pipeline capacity, transportation of crude oil by rail is gaining favour with shippers seeking flexibility in accessing current markets. While pricing differentials remain high, shipper support for pipeline expansion out of the WCSB could be tempered. However, the Company believes that its liquids pipelines continue to provide attractive options to producers in the WCSB due to its competitive tolls and multiple delivery and storage points. Enbridge's current complement of growth projects to expand market access are also expected to provide shippers long-term competitive solutions for oil transport. The Company's existing right-of-way for the Canadian Mainline also provides a competitive advantage as it can be difficult and costly to obtain rights of way for new pipelines traversing new areas.

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, could be adversely affected by pressure restrictions that reduce volumes transported. Temporary pressure restrictions have been established on some sections of certain pipelines pending completion of specific inspection and repair programs, and had the effect of limiting throughput during the fourth quarter of 2012.

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

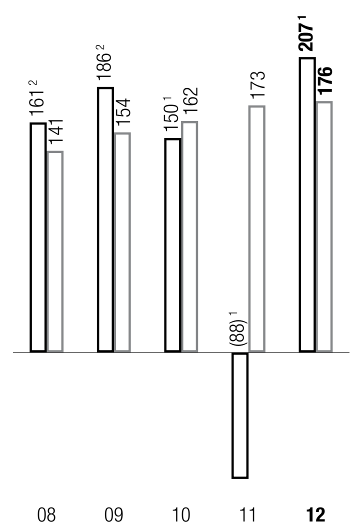
	2012	2011	2010
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc. (EGD)	**149**	135	132
Other Gas Distribution and Storage	**27**	38	30
Adjusted earnings	**176**	173	162
EGD – (warmer)/colder than normal weather	**(23)**	1	(12)
EGD – tax rate changes	**(9)**	–	–
EGD – recognition of regulatory asset	**63**	–	–
Other Gas Distribution and Storage – regulatory deferral write-off	**–**	(262)	–
Earnings/(loss) attributable to common shareholders	**207**	(88)	150

Adjusted earnings from Gas Distribution were $176 million for the year ended December 31, 2012 compared with $173 million for 2011 and $162 million for the year ended December 31, 2010. The increase in Gas Distribution's adjusted earnings over these years primarily resulted from customer growth and favourable performance by EGD under its Incentive Regulation (IR) arrangement. In 2012, adjusted earnings were negatively impacted by changes in rate setting methodology applicable to gas distribution operations in New Brunswick.

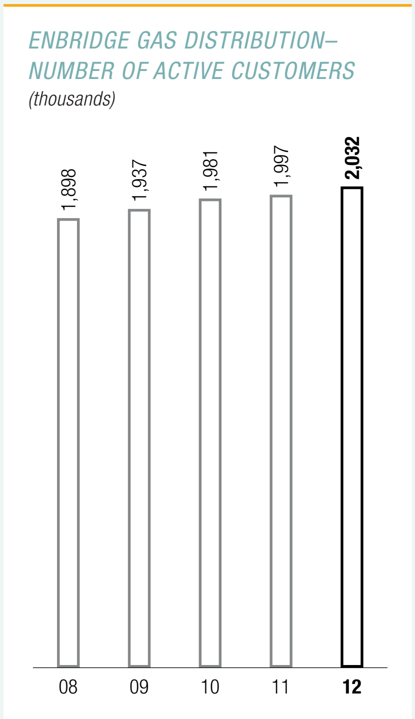
Gas Distribution earnings were impacted by the following adjusting items:

- EGD earnings were adjusted to reflect the impact of weather.
- Earnings from EGD for 2012 reflected the impact of unfavourable tax rate changes on deferred income tax liabilities.
- EGD earnings for 2012 included the recognition of a regulatory asset related to recovery of OPEB costs pursuant to an OEB rate order. See *Gas Distribution – Enbridge Gas Distribution Inc. – 2013 Rate Application*.
- Other Gas Distribution and Storage earnings for 2011 reflected the discontinuation of rate-regulated accounting for EGNB and the related write-off of a deferred regulatory asset and certain capitalized operating costs, net of tax. See *Gas Distribution – Other Gas Distribution and Storage – Enbridge Gas New Brunswick Inc. – Regulatory Matters.*

GAS DISTRIBUTION EARNINGS
(millions of Canadian dollars)



1 *Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*



ENBRIDGE GAS DISTRIBUTION INC.

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

INCENTIVE REGULATION

In 2007, the Company filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis with the OEB for the 2008 to 2012 period. The OEB approved the settlement agreement with customer representatives and the Company moved to an IR methodology, which remained in effect through 2012. The objectives of the settlement agreement were as follows:

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

Under the settlement agreement, the Company was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis. The earnings sharing mechanism resulted in the return of revenue to customers of $10 million for the year ended December 31, 2012 (2011 – $13 million; 2010 – $19 million).

2013 RATE APPLICATION

In January 2012, the Company filed an application with the OEB to set rates for 2013 on a cost of service basis and on October 3, 2012 the Company filed with the OEB a settlement agreement reached with its interveners relating to the Company's 2013 rate application. The settlement agreement was approved by the OEB on November 2, 2012, which resolved all elements of the rate application except a requested change in deemed equity supporting the rate base which was heard by the OEB in November 2012. In its final decision issued on February 7, 2013, the OEB denied the Company's requested increase in the deemed equity level.

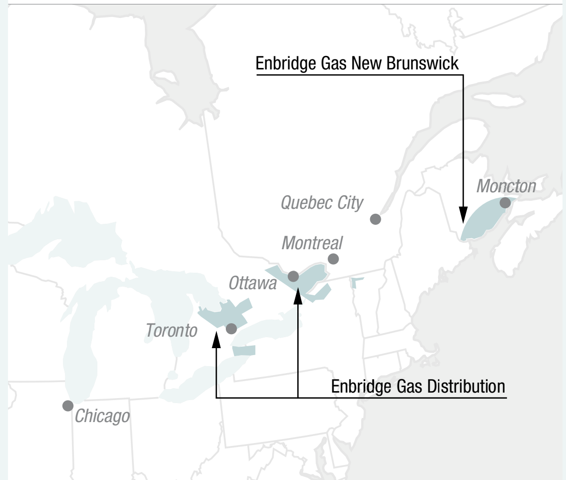
The settlement agreement approved in November 2012 also established the right to recover an existing OPEB liability of approximately $89 million ($63 million after-tax). The amount will be collected in rates over a 20-year time period commencing in 2013. The rate order further provided for future OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

RESULTS OF OPERATIONS

Adjusted earnings for the year ended December 31, 2012 were $149 million compared with $135 million for the year ended December 31, 2011. The increase in EGD's adjusted earnings was primarily due to customer growth, favourable rate variances and higher pipeline capacity optimization. This growth was partially offset by an increase in system integrity and safety-related costs and higher employee costs, as well as higher depreciation due to a higher in-service asset base.

Adjusted earnings for the year ended December 31, 2011 were $135 million compared with $132 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 increjased due to a higher overall asset base.

GAS DISTRIBUTION



OTHER GAS DISTRIBUTION AND STORAGE

Other Gas Distribution includes natural gas distribution utility operations in Quebec and New Brunswick, the most significant being EGNB (100% owned and operated by the Company), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB has approximately 11,000 customers and is regulated by the New Brunswick Energy and Utilities Board (EUB).

ENBRIDGE GAS NEW BRUNSWICK INC. – REGULATORY MATTERS

On December 9, 2011 the Government of New Brunswick tabled and then subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permitted 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. However, significant details of the rate setting process were left to be established in the new regulations and, as such, the effect of such legislation was not determinable at that time.

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amended rate setting methodology and specific conditions outlined therein, EGNB no longer met the criteria for the continuation of rate-regulated accounting. As a result, the Company eliminated from its Consolidated Statements of Financial Position a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million. As the final rates and tariffs regulation published on April 16, 2012 provided further evidence of a condition that existed on December 31, 2011, the charge totaling $262 million, after tax, was reflected as a subsequent event in the Company's Consolidated Financial Statements for the year ended December 31, 2011 presented in accordance with U.S. GAAP and filed in May 2012. The charge reflected Management's best estimate based on facts available at the time and may be subject to further revision based on future actions or interpretations of the regulator, the Government of New Brunswick or other factors, including legal proceedings which Enbridge has commenced.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen's Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen's Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. In a decision released on August 23, 2012, the Court dismissed EGNB's Application. EGNB has filed a Notice of Appeal with the New Brunswick Court of Appeal and a hearing of the appeal is expected to be held during the first quarter of 2013. On September 20, 2012, the EUB issued a decision regarding EGNB's rates that were to take effect as of October 1, 2012. The EUB's decision applies the rate-setting methodology set out in the rates and tariffs regulation. EGNB has filed an application for judicial review of the EUB's rate order with the New Brunswick Court of Appeal, which is expected to hear the application during the first half of 2013, sometime after the hearing of the appeal of the August 2012 New Brunswick Court of Queen's Bench decision discussed above. There is no assurance these actions will be successful or will result in any recovery.

RESULTS OF OPERATIONS

Other Gas Distribution and Storage adjusted earnings were $27 million for the year ended December 31, 2012 compared with $38 million for the year ended December 31, 2011. This adjusted earnings decrease was primarily due to the change in rate setting methodology applicable to EGNB enacted in 2012. Effective January 1, 2012, the discontinuance of rate-regulated accounting at EGNB resulted in earnings subject to increased variability, including quarterly seasonality, as there was no further accumulation of the regulatory deferral account. Earnings for 2012 were impacted by lower volume due to a decrease in demand for natural gas, which was the result of a warmer than normal winter.

Adjusted earnings for the year ended December 31, 2011 were $38 million compared with $30 million for the year ended December 31, 2010, primarily due to an increased contribution from Enbridge's Ontario unregulated gas storage business.

BUSINESS RISKS

The risks identified below are specific to Gas Distribution business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks.*

REGULATION

The utility operations of Gas Distribution are regulated by the OEB and EUB among others. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environment in which Gas Distribution operates. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or that would have been recorded on the Consolidated Statements of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

In 2012, EGD operated under the IR Framework which permitted it to recover, with OEB approval, certain costs that were beyond management control, but that were necessary for the maintenance of its services. The IR Framework also included a mechanism to reassess the IR plan and return to cost of service if there were significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the settlement agreement mitigated the Company's risk to factors beyond management's control. Commencing in 2013, EGD's rates will be established on a cost of service basis, under which EGD will be entitled to recover costs of providing its service and to earn a specified ROE. Rate relief may be sought for significant amounts that were not forecasted; however, to the extent the OEB denies recovery of such costs, the Company's earnings may be impacted.

In 2012, the Government of New Brunswick enacted a final rates and tariffs regulation amending the rate setting methodology applicable to EGNB, resulting in a write-off of certain regulatory balances totaling $262 million, net of tax, reflected as a subsequent event in the Consolidated Statements of Earnings for the year ended December 31, 2011. The Company commenced actions against the Province of New Brunswick; however, there is no assurance these actions will be successful or will result in any recovery.

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 may request interim rate relief to recover or refund the natural gas cost differential. While the cost of natural gas does not impact EGD's earnings, it does affect the amount of EGD's investment in gas in storage. EGNB is also subject to natural gas cost risk as increases in natural gas prices that cannot be charged to customers could negatively impact earnings.

VOLUME RISK

Since customers are billed on a volumetric basis, EGD's ability to collect its total revenue requirement (the cost of providing service) depends on achieving the forecast distribution volume established in the rate-making process. 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.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. 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 may further contribute to a decline in annual average consumption.

Sales and transportation of gas for customers in the residential and small commercial sectors account for approximately 80% 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 from all market sectors are important as continued expansion adds to the total consumption of natural gas.

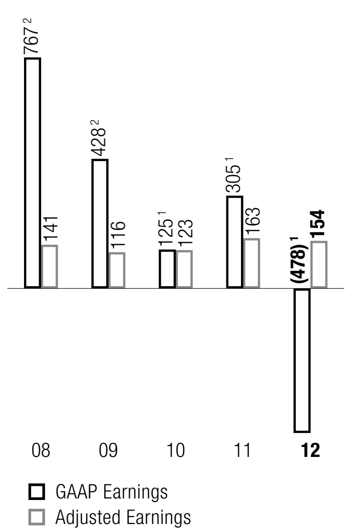
Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. EGNB is also subject to volume risk as the impact of weather conditions on demand for natural gas could result in earnings fluctuations.

Gas Pipelines, Processing and Energy Services

EARNINGS

	2012	2011	2010
(millions of Canadian dollars)			
Aux Sable	**68**	55	37
Energy Services	**40**	56	21
Alliance Pipeline US	**24**	26	25
Vector Pipeline	**16**	18	15
Enbridge Offshore Pipelines (Offshore)	**(3)**	(7)	23
Other	**9**	15	2
Adjusted earnings	**154**	163	123
Aux Sable – changes in unrealized derivative fair value gains/(loss)	**10**	(7)	7
Energy Services – changes in unrealized derivative fair value gains/(loss)	**(537)**	125	(8)
Energy Services – credit recovery	**–**	–	1
Offshore – asset impairment loss	**(105)**	–	–
Offshore – property insurance recoveries from hurricanes	**–**	–	2
Other – changes in unrealized derivative fair value gains	**–**	24	–
Earnings/(loss) attributable to common shareholders	**(478)**	305	125

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



1 *Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $154 million for the year ended December 31, 2012 compared with $163 million for the year ended December 31, 2011 and $123 million for the year ended December 31, 2010. Notable trends over these years included favourable performance from Aux Sable, due to higher realized fractionation margins and new assets placed into service, and continued weakness in the Company's Offshore operations. The variability in earnings year-over-year attributable to Energy Services is due to changing market conditions which give rise to greater or fewer margin opportunities.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following adjusting items:

- Aux Sable earnings for each period reflected changes in the fair value of unrealized derivative financial instruments related to the Company's forward gas processing risk management position.
- Energy Services earnings for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions. A gain or loss on such a financial derivative corresponds to a similar but opposite loss or gain on the value of the underlying physical transaction which is expected to be realized in the future when the physical transaction settles. Unlike the change in the value of the financial derivative, the loss or gain on the value of the underlying physical transaction is not recorded for financial statement purposes until the periods in which it is realized.

- Energy Services earnings for 2010 included partial recoveries from the sale of its receivable from Lehman Brothers.
- Offshore earnings for 2012 were impacted by an asset impairment loss related to certain of its assets, predominantly located within the Stingray and Garden Banks corridors. See *Gas Pipelines, Processing and Energy Services – Enbridge Offshore Pipelines – Asset Impairment* for further details.
- Offshore earnings for 2010 included insurance proceeds related to the replacement of damaged infrastructure as a result of a 2008 hurricane.
- Other earnings for 2011 reflected changes in the fair value of unrealized derivative financial instruments.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGL extraction and fractionation business, which owns and operates a plant near Chicago, Illinois at the terminus of Alliance. The plant extracts NGL 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 a single counterparty under a long-term contract. Aux Sable receives 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, Aux Sable is compensated for all operating, maintenance and capital costs associated with its facilities subject to certain limits on capital costs. The counterparty 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 Alliance held by an Aux Sable affiliate. The contract 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 Alliance 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.

Aux Sable has contracted capacity of the Septimus Pipeline and the Septimus Gas Plant to a producer under a 10-year take-or-pay contract which provides for a return on and of invested capital. Actual operating costs are recovered from the producer. Additional revenues are earned by Aux Sable based on a sharing of NGL margin available.

In 2012, 80% of the capacity in the Palermo Gas Plant and the Prairie Rose Pipeline was contracted to producers under take-or-pay contracts. Several producers' contract commitments decline over the next few years while certain producer contract commitments continue through 2020 under 10-year take or pay contracts or with life-of-lease reserve dedication.

RESULTS OF OPERATIONS

Aux Sable adjusted earnings were $68 million for the year ended December 31, 2012 compared with $55 million for the year ended December 31, 2011 and $37 million for the year ended December 31, 2010. Adjusted earnings increased primarily due to higher realized fractionation margins and earnings contributions from the Prairie Rose Pipeline and the Palermo Conditioning Plant acquired in July 2011.

BUSINESS RISKS

The risks identified below are specific to Aux Sable. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risk*s.

COMMODITY PRICE RISK

Aux Sable's margin earned through the upside sharing mechanism is subject to commodity price risk arising from movements in natural gas and NGL prices and differentials. These risks may be mitigated through the Company's risk management activities.

VOLUME RISK

A decrease in gas volumes or a decrease in the NGL content of the gas stream delivered by Alliance to the Aux Sable plant can directly and adversely affect the margin earned through the upside sharing mechanism. Alliance is well positioned to deliver incremental liquids-rich gas production from new developments in the Montney and Bakken regions, thereby mitigating volume risk. In addition, Aux Sable attracts liquids-rich gas to Alliance through inducement and rich gas premium contracts with producers.

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, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company focused on capturing value from quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Any commodity price exposure created from this physical business is closely monitored and must comply with the Company's formal risk management policies.

Tidal Energy also provides natural gas marketing services, including marketing natural gas to optimize commitments on certain natural gas pipelines. To the extent transportation costs exceed the basis (location) differential, earnings will be negatively affected. Tidal Energy also provides natural gas supply, transportation, balancing and storage for third parties, leveraging its natural gas marketing expertise and access to transportation capacity.

RESULTS OF OPERATIONS

Energy Services adjusted earnings decreased from $56 million for the year ended December 31, 2011 to $40 million for the year ended December 31, 2012. The decline was primarily due to changing market conditions which gave rise to fewer margin opportunities in crude oil and NGL marketing.

Energy Services adjusted earnings were $56 million for the year ended December 31, 2011 compared with $21 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. 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, quality, time and location differentials, and may not be indicative of results to be achieved in future periods.

BUSINESS RISKS

The risks identified below are specific to Energy Services. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risk*s.

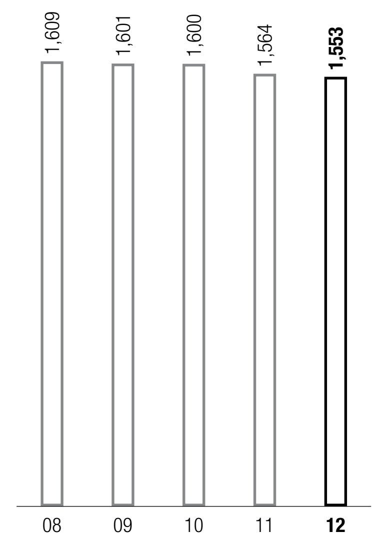
COMMODITY PRICE RISK

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Volatility in commodity prices and changing marketing conditions could limit margin opportunities. Furthermore, commodity prices could have negative earnings impacts if the cost of the commodity is greater than resell prices achieved by the Company. Energy Services activities are conducted in compliance with and under the oversight of the Company's formal risk management policies.

ALLIANCE PIPELINE US

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



Alliance connects with Aux Sable (of which Enbridge owns 42.7%), a 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.

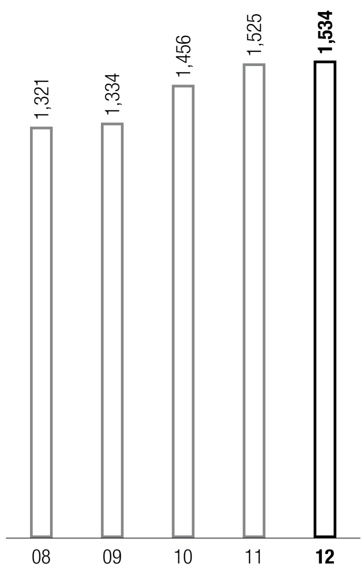
TRANSPORTATION CONTRACTS

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 10.9%.

RESULTS OF OPERATIONS

Alliance Pipeline US earnings of $24 million for the year ended December 31, 2012 were comparable with earnings of $26 million and $25 million for the years ended December 31, 2011 and 2010, respectively, reflecting its stable, cost-of-service commercial construct.

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



VECTOR PIPELINE

Vector, 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 November 2015. Approximately 55% of the long haul capacity is committed through firm negotiated rate transportation contracts with shippers and approved by the FERC, while the remaining committed capacity is sold at market rates. In December 2012, shippers under negotiated rate transportation contracts which represent 27% of the systems long haul capacity elected to extend their commitments beyond December 1, 2015 for one additional year and preserve the option to continue their commitments on an annual basis. The remaining 28% of negotiated rate transportation contract shippers elected not to extend their commitments beyond its original contract term of November 2015. Vector is entitled to additional compensation from shippers that elected not to extend their contracts beyond 2015.

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 2012, the FERC approved maximum tariff rates included an underlying weighted average after-tax ROE component of 11.2%. 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 2012, maximum tariff tolls include a ROE component of 10.5% after-tax.

RESULTS OF OPERATIONS

Vector earnings were $16 million for the year ended December 31, 2012 comparable with $18 million for the year ended December 31, 2011 and $15 million for the year ended December 31, 2010.

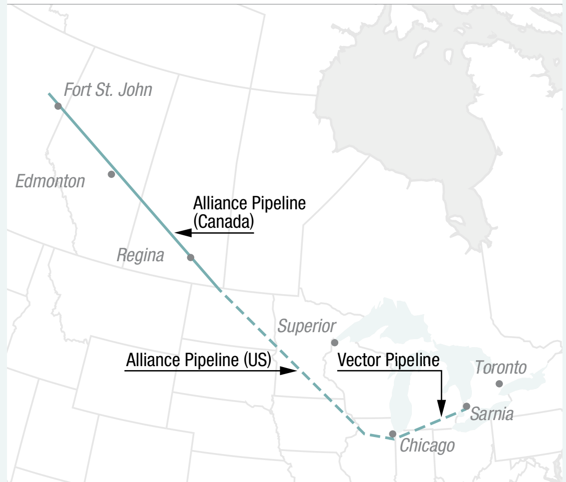
BUSINESS RISKS

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 – General Business Risks*.

SUPPLY AND DEMAND

Currently, natural gas pipeline capacity out of the WCSB exceeds supply, due to the low price of natural gas and increased production from new shale gas discoveries. Alliance Pipeline US and Vector have been unaffected by this excess supply environment to date mainly because of long-term capacity contracts extending primarily to 2015. However, excess capacity out of the WCSB and depressed natural gas prices have led to a reduction or deferral of investment in upstream gas development, and 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.

NATURAL GAS PIPELINES



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 convert or upgrade existing pipelines or to build new pipelines to serve 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 currently 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 and the effectiveness of these contracts 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 plays 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 Statements 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 groups to ensure it is informed of emerging issues in a timely manner.

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 7.3 bcf/d. Offshore currently moves approximately 40% of offshore deepwater gas production through its systems in the Gulf of Mexico.

TRANSPORTATION CONTRACTS

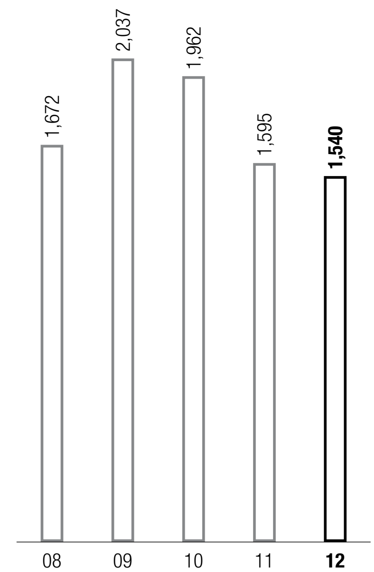
The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects 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, Venice and Heidelberg 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 may 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. Adjustment is allowed for many of the Heidelberg project variables affecting its cost, with Enbridge bearing the residual capital cost risk after these adjustments have been applied.

ASSET IMPAIRMENT

In December 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas in the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

ENBRIDGE OFFSHORE PIPELINES— AVERAGE THROUGHPUT VOLUMES
(millions of cubic feet per day)



RESULTS OF OPERATIONS

For the year ended December 31, 2012, Offshore incurred an adjusted loss of $3 million compared with a loss of $7 million for the year ended December 31, 2011. Offshore realized a second year of consecutive losses due to weak volumes from delayed drilling programs and more scheduled production outages by producers in the Gulf of Mexico. The decrease in loss year-over-year resulted from a higher transportation rate for volumes shipped on the Stingray Pipeline System, a reduction in interest expense and a $2 million favourable impact related to the reversal of a shipper reserve pertaining to a rate case from 2011.

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 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.

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 – General Business Risk*s.

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. Offshore's insurance policy includes specific coverage related to named windstorms (such as hurricanes), for all systems, but does not cover business interruption. The occurrence of hurricanes in the Gulf Coast increases the cost and availability of insurance coverage and Enbridge may not be able, or may choose not, to insure against this risk in the future. Enbridge facilities are engineered to withstand hurricane forces and constant monitoring of weather allows for timely evacuation of personnel and shutdown of facilities; however, damages to assets may still occur.

COMPETITION

There is competition for new and existing business in the Gulf of Mexico, with an increasing number of competitors willing to construct and operate production host platforms for future deepwater prospects. 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 planned Big Foot Oil and Heidelberg pipelines. Given rates of decline, offshore pipelines typically have available capacity, resulting in significant competition for new developments in the Gulf of Mexico. Competing developments may impact the recoverability of the Company's long-lived offshore assets.

SUPPLY AND DEMAND

Low natural gas prices, in part due to the prevalence of onshore 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. To date, crude oil prices have supported stable offshore investment; however, a future decline in crude oil prices could change the potential for future investment opportunities. Further, a sustained decline in either natural gas or crude oil commodity prices could impact the recoverability of long-lived offshore assets.

In the fourth quarter of 2012, Offshore recognized an impairment charge of $105 million, net of tax, primarily related to shallow water natural gas assets, due to changing competitive conditions and sustained weakness in natural gas prices.

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 has been 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.

OTHER

Other includes operating results from the Company's investments in renewable energy projects and business development expenditures.

WIND AND SOLAR RESOURCES TRANSFER

In May 2012, the Company acquired from Renewable Energy Systems Canada Inc. the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP, for $27 million, increasing its ownership to 100%. On December 10, 2012, Greenwich, the Amherstburg Solar Project (Amherstburg) and the Tilbury Solar Project (Tilbury) were transferred to the Fund. See *Sponsored Investments – Enbridge Income Fund – Crude Oil Storage and Renewable Energy Transfers* for details of the transfer.

In October 2011, ownership of the Ontario Wind, Sarnia Solar and Talbot Wind energy projects was transferred to the Fund with earnings contributions from these assets, net of noncontrolling interests, reflected within the Sponsored Investments segment effective October 21, 2011.

RESULTS OF OPERATIONS

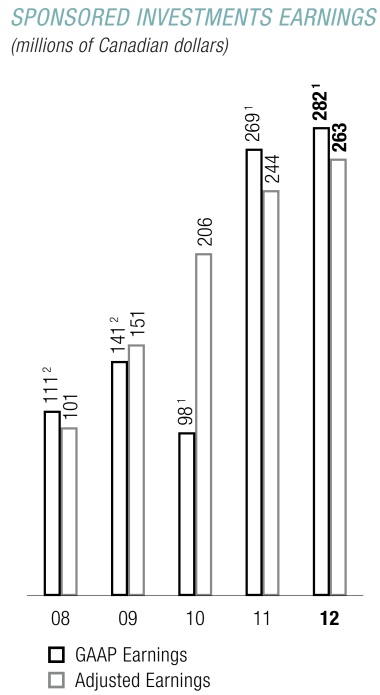
Other adjusted earnings for the year ended December 31, 2012 were $9 million compared with $15 million for the year ended December 31, 2011. The decrease in adjusted earnings was primarily due to the sale of Ontario Wind, Sarnia Solar and Talbot Wind energy projects to the Fund in October 2011, followed by the sale of Greenwich, Amherstburg and Tilbury to the Fund in December 2012. Higher business development costs also contributed to the decrease in adjusted earnings. Partially offsetting this increase were the contributions from Cedar Point and Greenwich, which were commissioned in late 2011, and Silver State which was commissioned in early 2012.

Other adjusted earnings increased from $2 million for the year ended December 31, 2010 to $15 million for the year ended December 31, 2011. This 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 for 2011 reflected several newly constructed green energy projects, including Cedar Point, Greenwich and Amherstburg.

Sponsored Investments

EARNINGS

	2012	2011	2010
(millions of Canadian dollars)			
Enbridge Energy Partners, L.P. (EEP)	**141**	151	122
Enbridge Energy, Limited Partnership (EELP) – Alberta Clipper US	**38**	42	42
Enbridge Income Fund (the Fund)	**84**	51	42
Adjusted earnings	**263**	244	206
EEP – leak insurance recoveries	**24**	50	–
EEP – leak remediation costs and lost revenue	**(9)**	(33)	(106)
EEP – changes in unrealized derivative fair value gains/(loss)	**(2)**	3	(1)
EEP – NGL trucking and marketing investigation costs	**(1)**	(3)	–
EEP – prior period adjustment	**7**	–	–
EEP – shipper dispute settlement	**–**	8	–
EEP – lawsuit settlement	**–**	1	–
EEP – impact of unusual weather conditions	**–**	(1)	–
EEP – Lakehead System billing correction	**–**	–	1
EEP – asset impairment loss	**–**	–	(2)
Earnings attributable to common shareholders	**282**	269	98



1 Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.

2 Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.

Adjusted earnings from Sponsored Investments were $263 million for the year ended December 31, 2012 compared with $244 million for the year ended December 31, 2011. The increase in adjusted earnings resulted primarily from increased contributions from the Fund following the transfer of certain renewable energy and crude oil storage assets from Enbridge and its wholly-owned subsidiaries in late 2012 and late 2011.

Adjusted earnings from Sponsored Investments were $244 million for the year ended December 31, 2011 compared with $206 million in 2010. The increase in adjusted earnings resulted primarily from increased contributions from EEP as a result of positive operating factors, including growth projects, and contributions from renewable energy assets transferred to the Fund.

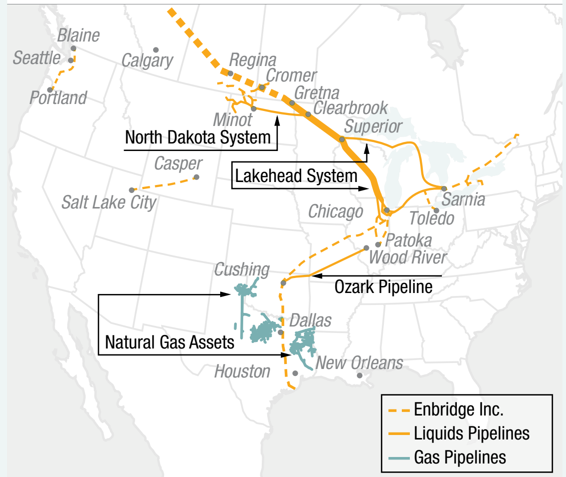
Sponsored Investments earnings were impacted by the following adjusting items:

- Earnings from EEP for 2012 and 2011 included insurance recoveries associated with the Line 6B crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases – Line 6B Crude Oil Release.*
- Earnings from EEP for each period included a charge related to estimated costs, before insurance recoveries, associated with the Lines 6A, 6B and Line 14 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 *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Line 14 Crude Oil Release* and *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases.*
- Earnings from EEP included changes in the unrealized fair value on derivative financial instruments in each period.
- EEP earnings for 2012 and 2011 reflected charges for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.
- EEP earnings for 2012 reflected a non-recurring out-of-period adjustment.
- 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 of 2011.
- EEP earnings for 2011 included an unfavourable effect related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations of its natural gas systems.
- EEP earnings for 2010 included Lakehead System billing corrections.
- EEP earnings for 2010 included charges related to asset impairment losses.

ENBRIDGE ENERGY PARTNERS, L.P.

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.

ENBRIDGE ENERGY PARTNERS, L.P.



In September 2010, EEP acquired the entities that comprise the Elk City Natural Gas Gathering and Processing System (Elk City System) 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, 2012, Enbridge's ownership interest in EEP was 21.8% (2011 – 23.0%; 2010 – 25.5%). The Company's average ownership interest in EEP during 2012 was 23.0% (2011 – 24.4%; 2010 – 26.7%).

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 July 2012, EEP increased its quarterly distribution to $0.5435 per unit from $0.5325. Of the $141 million Enbridge recognized as adjusted earnings from EEP during 2012, $59 million (2011 – $46 million; 2010 – $33 million) were GP incentive earnings, while the remainder was Enbridge's limited partner share of EEP's earnings.

RESULTS OF OPERATIONS

Adjusted earnings from EEP were $141 million for the year ended December 31, 2012 compared with $151 million for the year ended December 31, 2011. Adjusted earnings from EEP for 2012 included higher GP incentive income and strong results from the liquids business primarily due to higher average delivery volumes and increased tolls on all major liquids systems, as well as contributions from storage terminal and other facilities that were placed into service during 2012. Earnings from the natural gas business decreased as a result of lower natural gas and NGL prices. Earnings were also negatively impacted by an increase in operating and administrative costs, specifically pipeline integrity costs, personnel costs and higher property taxes.

EEP adjusted earnings increased from $122 million for the year ended December 31, 2010 to $151 million for the year ended December 31, 2011. 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 GP 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.

LAKEHEAD SYSTEM LINE 14 CRUDE OIL RELEASE

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. The CAOs required EEP to take certain corrective actions, some of which have already been completed and some are still ongoing, as part of an overall plan for its Lakehead System. A notable part of the CAOs was to hire an independent third party pipeline expert to review and assess EEP's overall integrity program. An independent third party expert was contracted during the third quarter of 2012 and its work is currently ongoing.

Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. The pressure restrictions will remain in place until such time EEP can demonstrate that the root cause of the incident has been remediated.

EEP has revised the disclosed estimate for repair and remediation related costs associated with this crude oil release as at December 31, 2012 to approximately US$10 million ($1 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenue, and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge's comprehensive insurance policy, although it does not expect any recoveries to be significant.

LAKEHEAD SYSTEM LINES 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 released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the release, a unified command structure was established under the jurisdiction of the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other federal, state and local agencies.

During the second quarter of 2012, local authorities allowed the Kalamazoo River and Morrow Lake, which were affected by the Line 6B crude oil release, to be re-opened for recreational use. EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations, including reassessment, remediation and restoration of the area, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the PHMSA related to the July 26, 2010 Line 6B crude oil release, which resulted in payment of a US$3.7 million civil penalty in the third quarter of 2012. EEP included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012 the National Transportation Safety Board presented the results of its investigation into the Line 6B crude oil release and subsequently publicly posted its final report on July 26, 2012.

As at December 31, 2012, EEP revised the total incident cost accrual to US$820 million ($137 million after-tax attributable to Enbridge), primarily due to an estimate of extended oversight by regulators and additional legal costs associated with various lawsuits, which is an increase of US$55 million ($8 million after-tax attributable to Enbridge) from its estimate at December 31, 2011. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above. On October 3, 2012, EEP received a letter from the EPA regarding a Proposed Order for potential incremental containment and active recovery of submerged oil. EEP is in discussions with the EPA regarding the agency's intent with respect to certain elements of the Proposed Order and the appropriate scope of these activities. The nature and scope of any additional remediation activities that regulators may require is currently uncertain. Studies and additional technical evaluation by EEP, the EPA and other regulatory agencies may need to be completed before a final determination of any additional remediation activities can be determined. EEP has accrued the estimated costs it deemed likely to be incurred. However, when a final determination of the appropriate nature and scope of any additional remediation is made, it could result in significant cost being accrued.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 2012. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

LINE 6A CRUDE OIL RELEASE

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that 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. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by 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 near Romeoville, Illinois in September 2010 for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed.

In connection with this crude oil release, the cost estimate as at December 31, 2012 remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. 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. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and one of Enbridge's subsidiaries. The insurance 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 remediation spending through December 31, 2012, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

For the years ended December 31, 2012 and 2011, EEP recognized US$170 million ($24 million after-tax attributable to Enbridge) and US$335 million ($50 million after-tax attributable to Enbridge), respectively, of insurance recoveries as reductions to Environmental costs in the Consolidated Statements of Earnings. As at December 31, 2012, EEP had recorded total insurance recoveries of US$505 million ($74 million after-tax attributable to Enbridge) for the Line 6B crude oil release and expects to recover the balance of the aggregate liability insurance coverage of US$145 million from its insurers in future periods. EEP will record receivables for additional amounts received through insurance recoveries during the period it deems recovery to be probable.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability.

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 30 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. Based on the current status of these cases, EEP does not expect the outcome of these actions to be material. As noted above, on July 2, 2012, PHMSA announced a NOPV related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. 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 the Illinois 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. Alberta Clipper is a 1,670-kilometre (1,000 mile) crude oil pipeline that provides service between Hardisty, Alberta and Superior, Wisconsin with capacity of 450,000 bpd.

RESULTS OF OPERATIONS

Earnings from EELP – Alberta Clipper US were $38 million for the year ended December 31, 2012 compared with $42 million for both the years ended December 31, 2011 and 2010. These earnings, which 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, decreased due to a reduction in rates which took effect April 1, 2012.

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 – General Business Risk*s.

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 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.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGL and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas and, with current low natural gas prices, infrastructure plans have been increasingly deferred or cancelled. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Supply for the marketing operations 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. To the extent commodity price differentials exist between markets serviced by the Company's assets and other market hubs, producers may be incented to seek alternate transportation options, such as rail, thereby decreasing volumes available to ship on the Company's systems.

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 *Liquids Pipelines – Business Risks*. EEP's Mid-Continent and North Dakota systems also face competition from existing competing pipelines, proposed future pipelines and alternative gathering facilities, 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 NGL 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.

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 FERC 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.

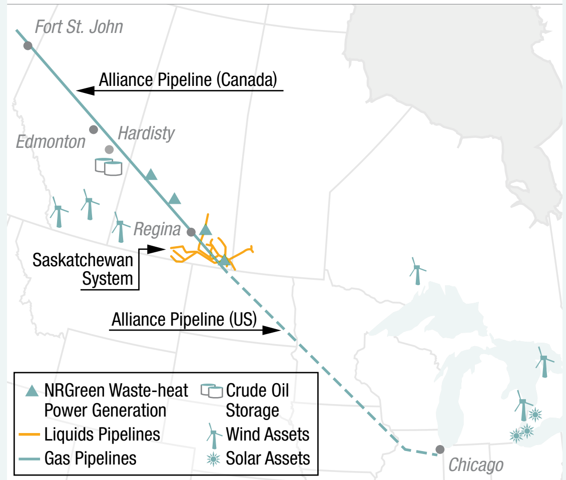
MARKET PRICE RISK

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 NGL. Certain of these financial contracts do not qualify for cash flow hedge accounting and; therefore, EEP's earnings are exposed to associated changes in the mark-to-market value of these contracts.

ENBRIDGE INCOME FUND

The Fund is involved in the generation and transportation of energy through its crude oil and liquids pipeline and storage business in Western Canada (Liquids Transportation and Storage), interests in more than 500 MW of renewable power generation capacity and its 50% interest in Alliance Pipeline Canada. Liquids Transportation and Storage 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 Saskatchewan System). 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. In December 2012, the Fund completed the acquisition of crude oil storage facilities along with additional wind and solar energy assets from Enbridge and its wholly-owned subsidiaries, as discussed below.

ENBRIDGE INCOME FUND



CRUDE OIL STORAGE AND RENEWABLE ENERGY TRANSFERS

In December 2012, ENF and the Fund finalized the acquisition of Hardisty Storage Caverns, Hardisty Contract Terminals, Greenwich, and Amherstburg and Tilbury projects from Enbridge and its wholly-owned subsidiaries for an aggregate purchase price of approximately $1.2 billion, financed in part by the issuance of additional ordinary trust units of the Fund to ENF and additional Enbridge Commercial Trust (ECT) preferred units to Enbridge. ENF in turn issued additional common shares to the public and to Enbridge. Enbridge also provided bridge debt financing (Bridge Financing) to the Fund for the balance of the purchase price, which was repaid in December 2012. Enbridge's overall economic interest in the Fund was reduced from 69.2% to 67.7% upon completion of the transaction.

In October 2011, the Fund also 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 ECT 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 72.3% to 69.2% upon completion of the transaction and associated financing.

The asset transfers described above occurred between entities under common control of Enbridge, and the intercompany gains realized by the selling entities in each of the years ended December 31, 2012 and 2011 have been eliminated from the Consolidated Financial Statements of Enbridge. Income taxes of $56 million and $98 million for the years ended December 31, 2012 and 2011, respectively, incurred on the related capital gains remain as charges 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 entities; however, accounting recognition of such benefit is not permitted until such time as the entities are sold outside of the consolidated group.

Through these transactions, which essentially resulted in a partial monetization of these assets by Enbridge through sale to noncontrolling interests (being ENF's public shareholders), Enbridge realized a source of funds of $213 million and $210 million, as presented within Financing Activities on the Consolidated Statements of Cash Flows for the years ended December 31, 2012 and 2011, respectively. In December 2012, the Fund issued $500 million in medium-term notes. The funds from this issuance, together with its cash on hand and draws on the Fund's committed credit facility, were used to repay the $582 million Bridge Financing to Enbridge.

SASKATCHEWAN SYSTEM SHIPPER COMPLAINT

On December 17, 2010, the Saskatchewan System filed amended tariffs for the Westspur pipeline 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 that the information provided 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. As directed by the NEB, negotiation among the parties has been ongoing and as of February 14, 2013, the Fund continues to review the structure of its 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 paid by the Fund that exceed a base distribution amount. In 2012, the Company received intercompany incentive fees of $12 million (2011 – $10 million; 2010 – $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.

CORPORATE RESTRUCTURING

In 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 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.

RESULTS OF OPERATIONS

Earnings from the Fund totaled $84 million for the year ended December 31, 2012 compared with $51 million for the year ended December 31, 2011. The increased earnings from the Fund reflected a full year of earnings from the assets acquired from a wholly-owned subsidiary of Enbridge in October 2011. Earnings also reflected the December 2012 transfer of Hardisty Storage Caverns, Hardisty Contract Terminals, Greenwich, Amherstburg and Tilbury projects. Partially offsetting the earnings contributions were increased interest costs, higher business development expense and non-cash deferred income taxes.

Earnings from the Fund increased from $42 million for the year ended December 31, 2010 to $51 million in 2011. The increased earnings reflected increased contributions from the Saskatchewan System following substantial completion of its Phase II expansion project in December 2010, as well as contribution from the wind and solar resources acquired by the Fund in October 2011. These positive impacts were partially offset by higher operating and administrative costs as a result of the 2011 asset acquisition and an increase in interest expense and taxes.

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 businesses, as indicated. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risk*s.

SASKATCHEWAN SYSTEM

COMPETITION

The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably rail. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers, thereby reducing shipments on the Saskatchewan System or resulting in pressure to reduce tolls. The Saskatchewan System's right-of-way and expansion efforts provide a competitive advantage and the Company believes its tolls are competitive relative to alternative pipeline transportation options; however, the Fund is currently engaged in discussions with shippers regarding the reasonableness of its tolls.

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 and could adversely impact the timing and amount of recovery or settlement of regulatory balances.

WIND AND SOLAR

REGULATION

The Fund's wind and solar assets which operate in Ontario are classified as intermittent generators under the Independent Electricity System Operator (IESO) market rules. IESO market rules allow delivery of electrical energy to the transmission and distribution grid as it is produced regardless of prevailing power price. Recent amendments to these market rules allow the IESO to curtail intermittent generators during periods of surplus base load generation when the prevailing power price falls below a threshold. As the wind and solar assets currently operate under long-term PPAs the Fund is in discussions with the Ontario Power Authority to determine its rights and obligations under its PPA for economic compensation during future periods of economic curtailment.

AVAILABILITY OF TRANSMISSION

The ability to deliver electricity is affected by the availability of the various transmission and distributions systems in the areas in which it operates. The failure of existing transmission or distribution facilities or lack of adequate transmission or distribution capacity could have a material adverse effect on the ability to deliver electricity and receive payment under the PPA.

WEATHER

Earnings from wind and solar projects are highly dependent on weather and atmospheric conditions. While the expected energy yields for the wind and solar projects are predicted using long-term historical data, wind and solar resources will be subject to natural variation from year to year and from season to season. Any prolonged reduction in wind or solar resources at any of the wind or solar facilities could lead to decreased earnings for the Fund.

Corporate

EARNINGS

	2012	2011	2010
(millions of Canadian dollars)			
Noverco	**27**	24	21
Other Corporate	**(55)**	(40)	(46)
Adjusted loss	**(28)**	(16)	(25)
Noverco – equity earnings adjustment	**(12)**	–	–
Noverco – changes in unrealized derivative fair value loss	**(10)**	–	–
Other Corporate – changes in unrealized derivative fair value gains/(loss)	**(22)**	(87)	25
Other Corporate – foreign tax recovery	**29**	–	–
Other Corporate – unrealized foreign exchange gains/(loss) on translation of intercompany balances, net	**(17)**	24	40
Other Corporate – impact of tax rate changes	**(11)**	6	–
Other Corporate – tax on intercompany gain on sale	**(56)**	(98)	–
Earnings/(loss) attributable to common shareholders	**(127)**	(171)	40

Total adjusted loss from Corporate was $28 million for the year ended December 31, 2012 compared with adjusted losses of $16 million for the year ended December 31, 2011 and $25 million for the year ended December 31, 2010.

Corporate earnings/(loss) were impacted by the following adjusting items:

- Earnings from Noverco for 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Earnings from Noverco for 2012 included changes in the unrealized fair value loss of derivative financial instruments.
- Loss for each year included changes in the unrealized fair value gains and losses on derivative financial instruments related to forward foreign exchange risk management positions.
- Loss for 2012 were impacted by taxes related to a historical foreign investment.
- Loss for each year included net unrealized foreign exchange gains and losses on the translation of foreign-denominated intercompany balances.
- Loss for 2012 and 2011 reflected tax rate changes.
- Loss for 2012 and 2011 were impacted by tax on an intercompany gain of sale. See *Sponsored Investments – Enbridge Income Fund – Crude Oil Storage and Renewable Energy Transfers* for details of the transactions.

NOVERCO

At December 31, 2012, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2011 – 38.9%; 2010 – 32.1%) of its common shares and an 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. In early 2012, Noverco advised Enbridge that the substantial increase in the value of these shares over the last decade had resulted in a significant shift in the balance of Noverco's asset mix. The Board of Directors of Noverco authorized its manager to sell a portion of its Enbridge common share holding and rebalance Noverco's asset mix. On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge's share of the proceeds of approximately $317 million was received as a dividend from Noverco on May 18, 2012 and was used to pay a portion of the Company's quarterly dividend on June 1, 2012. This portion of the quarterly dividend did not qualify for the enhanced dividend tax credit in Canada and, accordingly, was not designated as an "eligible dividend". For United States tax purposes, the dividend was a "qualified dividend".

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 margin of 4.3% to 4.4%. Virtually all of Noverco's residual earnings are from Gaz Metro's regulated assets. Rates for these natural gas and electricity distribution networks are established primarily using a cost-of-service method. Consequently, Gaz Metro's profitability is dependent on its ability to invest in the development of its rate base and on the rates of return on deemed equity authorized by the regulatory agencies. Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk.

RESULTS OF OPERATIONS

Noverco adjusted earnings were $27 million for the year ended December 31, 2012 compared with $24 million for the year ended December 31, 2011 and $21 million for the year ended December 31, 2010. Noverco adjusted earnings for each year reflected contributions from the Company's increased preferred share investment and Noverco's underlying gas distribution investments.

OTHER CORPORATE

Corporate also consists of the new business development activities, general corporate investments and financing costs not allocated to the business segments. Other corporate costs include dividends on preference shares as such dividends are a deduction in determining earnings attributable to common shareholders.

PREFERENCE SHARE ISSUANCES

Since July 2011, the Company has issued 146 million preference shares for gross proceeds of approximately $3,660 million with the following characteristics. See *Liquidity and Capital Resources – Outstanding Share Data*.

	Gross Proceeds	Initial Yield	Dividend [1]	Per Share Base Redemption Value [2]	Redemption and Conversion Option Date [2,3]	Right to Convert Into [3,4]
(Canadian dollars, unless otherwise stated)						
Series B [5]	$500 million	4.0%	$1.00	$25	June 1, 2017	Series C
Series D [5]	$450 million	4.0%	$1.00	$25	March 1, 2018	Series E
Series F [5]	$500 million	4.0%	$1.00	$25	June 1, 2018	Series G
Series H [5]	$350 million	4.0%	$1.00	$25	September 1, 2018	Series I
Series J [5]	US$200 million	4.0%	US$1.00	US$25	June 1, 2017	Series K
Series L [5]	US$400 million	4.0%	US$1.00	US$25	September 1, 2017	Series M
Series N [5]	$450 million	4.0%	$1.00	$25	December 1, 2018	Series O
Series P [5]	$400 million	4.0%	$1.00	$25	March 1, 2019	Series Q
Series R [5]	$400 million	4.0%	$1.00	$25	June 1, 2019	Series S

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend per year, as declared by the Board of Directors of the Company.*
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 + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q) or 2.5% (Series S)); or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.1% (Series K) or 3.2% (Series M)).*
5 *See* Liquidity and Capital Resources – Outstanding Share Data *for dividends declared on December 6, 2012.*

RESULTS OF OPERATIONS

Other Corporate adjusted loss was $55 million for the year ended December 31, 2012 compared with $40 million for the year ended December 31, 2011. Although net Corporate segment financing costs decreased in 2012 compared with 2011, this decrease was more than offset by increased preference share dividends and higher personnel costs.

Adjusted loss from Corporate was $40 million for the year ended December 31, 2011 compared with $46 million for the year ended December 31, 2010. The decreased adjusted loss reflected lower interest expense, partially offset by an increase in preference share dividends following the issuance of 38 million preference shares during the year, as well as higher tax expense.

Liquidity and Capital Resources

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the unprecedented level of growth projects secured or under development. With continued volatility in global capital markets, the Company's access to timely funding may be subject to risks from factors outside its control, including but not limited to, United States economic uncertainty and slow economic recovery. To mitigate such risks, the Company actively manages financing plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. The Company targets to maintain sufficient liquidity to bridge fund through any periods of protracted capital markets disruption, up to one year.

In the near term, the Company generally 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. The Company also maintains a longer horizon funding plan which considers growth capital needs and identifies potential sources of debt and equity funding alternatives, with the objective of maintaining access to low cost capital.

Several of the Company's growth projects that will be undertaken jointly with EEP will be funded 60% by Enbridge and 40% by EEP, with EEP having the option to reduce its funding and associated economic interest in the projects by up to 15% before June 30, 2013. Furthermore, within one year of the final in-service date of either the Eastern Access or Lakehead System Mainline Expansion projects, EEP will have the option to increase its economic interest held at those times in each project by up to 15%.

In accordance with its funding plan, the Company has been active in the capital markets with the following issuances during 2012:

- Corporate – $2,710 million in preference shares; $400 million in common equity; $750 million of medium-term notes;
- Enbridge Pipelines Inc. (EPI) – $100 million Century Bond; $150 million of medium-term notes;
- ENF/the Fund – $213 million in ENF common equity; $1,199 million of medium-term notes in the Fund; and
- EEP – US$447 million in Class A common units.

In addition to these debt and equity issuances, the Company received a $317 million one-time dividend from its investment in Noverco which resulted from Noverco's disposal of Enbridge shares via a secondary offering, as well as the monetization of crude oil storage and renewable energy assets through sale to the Fund.

To ensure ongoing liquidity and mitigate the risk of capital market disruption, Enbridge also has a significant amount of committed bank credit facilities which were further bolstered in 2012. The Company's net available liquidity of $10,799 million at December 31, 2012 was inclusive of approximately $1,297 million of unrestricted cash and cash equivalents, net of bank indebtedness. In addition to ensuring adequate liquidity, the Company actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2012 and 2011.

		2011	2012		
	Maturity Dates [1]	Total Facilities	Total Facilities	Draws [2]	Available
(millions of Canadian dollars)					
Liquids Pipelines	2014	300	**300**	**25**	**275**
Gas Distribution	2014	717	**712**	**590**	**122**
Sponsored Investments	2014 – 2017	2,534	**3,162**	**1,645**	**1,517**
Corporate	2014 – 2017	5,653	**9,108**	**1,520**	**7,588**
		9,204	**13,282**	**3,780**	**9,502**
Southern Lights project financing [3]	2014	1,576	**1,484**	**1,429**	**55**
Total credit facilities		10,780	**14,766**	**5,209**	**9,557**

1 *Total facilities include $35 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 $60 million for debt service reserve letters of credit.*

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, 2012, the Company was in compliance with all debt covenants.

With increased borrowing, the Company actively manages certain financial ratios measuring the Company's ability to service its debt from operating cash flows. The Company's internal cash flow growth maintains the financial ratios at a strong level. The Company's access to liquidity from diversified funding sources and its ability to service its debt has allowed it to maintain a stable risk profile, which has led to sustained investment-grade ratings from the major credit rating agencies. The Company also continues to manage its debt-to-capitalization ratio to maintain a strong balance sheet. The Company's debt-to-capitalization ratio, including bank indebtedness and short-term borrowings, was 61.4% at December 31, 2012 compared with 65.6% at December 31, 2011.

The Company invests a portion of its surplus cash in short-term investment grade instruments with creditworthy counterparties. Short-term investments were $950 million as at December 31, 2012 compared with $73 million as at December 31, 2011. This $877 million increase was due to the timing of cash generated from debt and equity market transactions and will be used to fund the Company's growth projects in 2013.

There are no material restrictions on the Company's cash with the exception of restricted cash of $7 million related to Southern Lights project financing and cash in trust of $12 million for specific shipper commitments.

Excluding current maturities of long-term debt, the Company had a positive working capital position of $183 million at December 31, 2012 compared to negative working capital of $164 million for the year ended December 31, 2011. Working capital includes the current portion of unrealized fair value derivative gains and losses related to the Company's risk management activities. The net liability position for current derivatives was $692 million and $394 million for the years ended December 31, 2012 and 2011, respectively. 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. Further, working capital will fluctuate from time to time due to natural gas inventory and borrowing levels at EGD, which in turn are impacted by weather and commodity prices, as well as general activity levels within the Company's Energy Services businesses, among others. Changes in commodity prices also impact accounts receivable and other, inventory and accounts payable and other within Energy Services and EGD.

December 31,	2012	2011
(millions of Canadian dollars)		
Cash and cash equivalents [1]	**1,795**	740
Accounts receivable and other [2]	**4,026**	4,084
Inventory	**779**	823
Bank indebtedness	**(479)**	(102)
Short-term borrowings	**(583)**	(548)
Accounts payable and other [3]	**(5,052)**	(4,801)
Interest payable	**(196)**	(185)
Environmental liabilities	**(107)**	(175)
Working capital	**183**	(164)

1 *Includes short-term investments and restricted cash of amounts in trust.*
2 *Includes Accounts receivable from affiliates.*
3 *Includes Accounts payable to affiliates.*

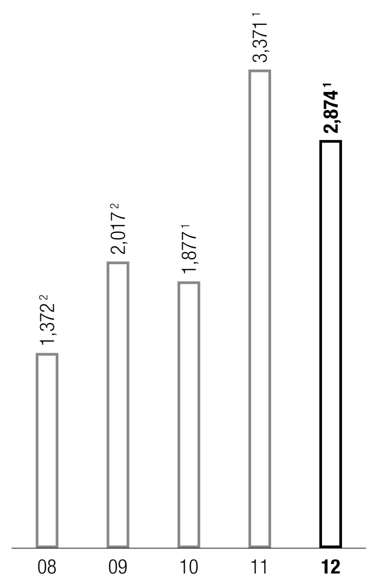
The net available liquidity, together with cash from operations and the proceeds of capital market transactions, is expected to be sufficient to finance all currently secured capital projects and provide flexibility for new investment opportunities in the short-term, in the event of unforeseen economic disturbances.

OPERATING ACTIVITIES

Cash provided by operating activities for the year ended December 31, 2012 was $2,874 million compared with $3,371 million for the year ended December 31, 2011 and $1,877 for the year ended December 31, 2010. The most significant factor which impacted the decline in cash provided by operating activities was a $1,063 million unfavourable variance in the changes in operating assets and liabilities. Working capital fluctuated due to variations in commodity prices and sales volumes within Energy Services, the timing of tax payments, the payment of power deposits to support the Company's growth projects, as well as general variations in activity levels within the Company's businesses. In addition, cash from operating activities during the fourth quarter of 2012 included an outflow of US$202 million related to a voluntary pre-payment of certain derivative liabilities. The payment was transacted to optimize cash management opportunities and did not alter the risk management properties of the derivative position.

The cash outflows within operating activities were partially offset by the favourable operating performance of the Canadian Mainline under CTS, strong volumes across all of the Company's liquids pipelines assets and general cash growth from development projects placed in service in recent years. Additionally, the Company received a $317 million one-time dividend from its investment in Noverco. During 2012, Noverco had realized a substantial gain on the disposition of a portion of its investment in Enbridge shares and subsequently distributed the proceeds from this transaction to its shareholders, by way of dividend.

CASH PROVIDED BY OPERATING ACTIVITIES
(millions of Canadian dollars)



1 *Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*

INVESTING ACTIVITIES

Cash used in investing activities was $6,204 million for the year ended December 31, 2012 compared with $5,079 million and $3,902 million for the corresponding periods of 2011 and 2010, respectively. Cash used in investing activities has increased on a year-over-year basis primarily due to capital expenditure activity, predominantly directed to the construction of the Company's expansion initiatives, all of which are described in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development*. A summary of additions to property, plant and equipment for the years ended December 31, 2012, 2011 and 2010 is as follows:

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Liquids Pipelines	**2,091**	955	684
Gas Distribution	**438**	483	387
Gas Pipelines, Processing and Energy Services	**837**	850	1,114
Sponsored Investments	**1,993**	1,187	868
Corporate	**109**	33	–
Total capital expenditures	**5,468**	3,508	3,053

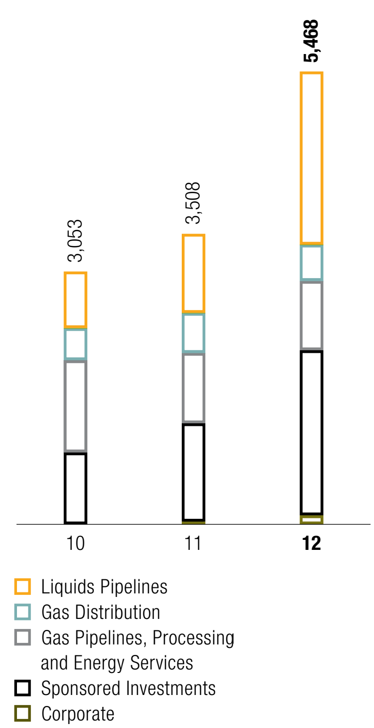
Other notable investing activities in 2012 included the acquisition of Silver State and PRA Gas Development, as well as the remaining 10% interest in Greenwich, for $340 million. The Company also provided additional funding of $531 million to various investments and joint ventures, namely TEP and Seaway Pipeline. In comparison, for the year ended December 31, 2011, the Company acquired its original 50% interest in Seaway Pipeline for $1,192 million, increased its Noverco preferred shares investment by $144 million and provided additional funding of $179 million to various equity investments. In 2010, the cash used in investing activities included the acquisition of Elk City System for $705 million.

FINANCING ACTIVITIES

Cash generated from financing activities was $4,395 million for the year ended December 31, 2012 compared with $2,030 million and $1,957 million for the corresponding periods of 2011 and 2010, respectively. The increase in cash provided by financing activities was primarily due to the issuance of redeemable preference shares of $2,634 million in 2012, compared with $926 million in 2011 and nil in 2010, as well as a common equity issuance of $384 million. This cash inflow was partially offset by payments of common and preference share dividends of $690 million in 2012 (2011 – $537 million; 2010 – $433 million).

In 2012, the Company was also successful in issuing debenture and term notes for net proceeds of $2,199 million (2011 – $1,604 million; 2010 – $3,220 million), as well as making draws on short-term borrowings and bank indebtedness of $412 million (2011 – $224 million; 2010 – $165 million repayment). This was partially offset by repayments of term notes, commercial paper and credit facility draws of $803 million in 2012 (2011 – $864 million; 2010 – $843 million). 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)



Cash generated from financing activities for the years ended December 31, 2012 and 2011 also included contributions, net of distributions, from third-party investors in the Fund of $164 million and $175 million, respectively. In both 2012 and 2011, the Fund acquired certain crude oil storage and renewable energy assets from Enbridge, which it financed in part through the issuance of equity to its public noncontrolling interest holders. In 2012, the Company also received contributions, net of distributions, from third-party investors, primarily from EEP, of $27 million (2011 – $518 million; 2010 – $121 million).

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, 2012, dividends declared were $895 million (2011 – $759 million), of which $597 million (2011 – $530 million) were paid in cash and reflected in financing activities. The remaining $297 million (2011 – $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, 2012 and 2011, 33.2% and 30.2%, respectively, of total dividends declared were reinvested.

OUTSTANDING SHARE DATA [1]

	Number
Preference Shares, Series A [2]	5,000,000
Preference Shares, Series B [2,3]	20,000,000
Preference Shares, Series D [2,4]	18,000,000
Preference Shares, Series F [2,5]	20,000,000
Preference Shares, Series H [2,6]	14,000,000
Preference Shares, Series J [2,7]	8,000,000
Preference Shares, Series L [2,8]	16,000,000
Preference Shares, Series N [2,9]	18,000,000
Preference Shares, Series P [2,10]	16,000,000
Preference Shares, Series R [2,11]	16,000,000
Common Shares – issued and outstanding (voting equity shares)	806,456,150
Stock Options – issued and outstanding (14,611,123 vested)	31,907,543

1 *Outstanding share data information is provided as at February 8, 2013.*
2 *All preference shares are non-voting equity shares. Preference Shares, Series A may be redeemed any time at the Company's option. For all other series of Preference Shares, 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 *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.*
4 *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.*
5 *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.*
6 *On September 1, 2018, and on September 1 every five years thereafter, the holders of Preference Shares, Series H will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series H into an equal number of Cumulative Redeemable Preference Shares, Series I.*
7 *On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series J will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series J into an equal number of Cumulative Redeemable Preference Shares, Series K.*
8 *On September 1, 2017, and on September 1 every five years thereafter, the holders of Preference Shares, Series L will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series L into an equal number of Cumulative Redeemable Preference Shares, Series M.*
9 *On December 1, 2018, and on December 1 every five years thereafter, the holders of Preference Shares, Series N will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series N into an equal number of Cumulative Redeemable Preference Shares, Series O.*
10 *On March 1, 2019, and on March 1 every five years thereafter, the holders of Preference Shares, Series P will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series P into an equal number of Cumulative Redeemable Preference Shares, Series Q.*
11 *On June 1, 2019 and on June 1 every five years thereafter, the holders of Preference Shares, Series R will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series R into an equal number of Cumulative Redeemable Preference Shares, Series S.*

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.

On December 6, 2012, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2013 to shareholders of record on February 15, 2013.

Common Shares	$0.31500
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R [1]	$0.23560

1 *This first dividend declared for the Preference Shares, Series R includes accrued dividends from December 5, 2012, the date the shares were issued. The regular quarterly dividend of $0.25 per share will take effect on June 1, 2013. See* Corporate – Other Corporate – Preference Share Issuances.

Commitments and Contingencies

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,639 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]	21,428	1,234	2,195	2,320	15,679
Capital and operating leases	329	40	80	72	137
Long-term contracts [2,3]	5,691	3,322	925	421	1,023
Pension obligations [4]	140	140	–	–	–
Total contractual obligations	27,588	4,736	3,200	2,813	16,839

1 *Excludes interest. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements.*
2 *Approximately $2,507 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 $161 million are within proportionately consolidated joint venture entities and contracts totaling $88 million are within equity investments which the Company is guaranteeing.*
4 *Assumes only required payments will be made into the pension plans in 2013. Contributions are made in accordance with independent actuarial valuations as at December 31, 2012. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

UNITED STATES 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 30 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. Based on the current status of these cases, EEP does not expect the outcome of these actions to be material. On July 2, 2012, PHMSA announced a NOPV related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. 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 the Illinois state court. The parties are currently operating under an agreed interim order. As at December 31, 2012, the Company was not aware of any claims related to the Line 14 crude oil release. See *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Lines 6A and 6B Crude Oil Releases* and *Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Line 14 Crude Oil Release*.

ENBRIDGE GAS NEW BRUNSWICK INC.

REGULATORY MATTERS

In 2011, the Government of New Brunswick passed legislation related to the regulatory process for setting rates for gas distribution within the province. A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick in April 2012. Based on the amended rate setting methodology and specific conditions outlined therein, EGNB no longer met the criteria for the continuation of rate-regulated accounting. As a result, the Company eliminated from its 2011 Consolidated Statements of Financial Position a deferred regulatory asset and certain capitalized operating costs totaling $262 million, net of tax. In April 2012, the Company, Enbridge EEDI and EGNB commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen's Bench, claiming damages as a result of the continuing breaches by the province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen's Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. In a decision released on August 23, 2012, the Court dismissed EGNB's application. EGNB has filed a Notice of Appeal with the New Brunswick Court of Appeal and a hearing of the appeal is expected to be held during the first half of 2013. There is no assurance these actions will be successful or will result in any recovery. See *Gas Distribution – Other Gas Distribution and Storage – Enbridge Gas New Brunswick Inc. – Regulatory Matters.*

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]

2012	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**6,627**	**5,718**	**5,788**	**7,173**	**25,306**
Earnings attributable to common shareholders	**264**	**11**	**189**	**146**	**610**
Earnings per common share	**0.35**	**0.01**	**0.24**	**0.19**	**0.79**
Diluted earnings per common share	**0.34**	**0.01**	**0.24**	**0.18**	**0.78**
Dividends per common share	**0.2825**	**0.2825**	**0.2825**	**0.2825**	**1.13**
EGD – warmer/(colder) than normal weather	**24**	**–**	**–**	**(1)**	**23**
Changes in unrealized derivative fair value and intercompany foreign exchange loss	**110**	**252**	**93**	**81**	**536**

2011	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	6,529	6,938	6,277	7,309	27,053
Earnings attributable to common shareholders	364	302	(5)	159	820
Earnings per common share [2]	0.49	0.40	(0.01)	0.21	1.09
Diluted earnings per common share [2]	0.48	0.40	(0.01)	0.21	1.08
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)
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	(18)	(18)	242	(241)	(35)

1 *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. 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. Gas Distribution's earnings for the fourth quarter of 2011 included an extraordinary charge totaling $262 million, after-tax, as a result of the discontinuance of rate-regulated accounting at EGNB and the related write-off of a deferred regulatory asset and certain capitalized operating 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, changes in unrealized fair value gains and losses on these instruments will impact earnings.

In the fourth quarter of 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. Also included in the fourth quarter of 2012 was a $63 million gain on recognition of a regulatory asset related to OPEB within EGD.

Fourth quarter earnings for 2012 and 2011 were also impacted by the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million and $98 million, respectively, incurred on the related capital gains.

Reflected in earnings is the Company's share of leak remediation costs and lost revenue associated with the Lines 6A, 6B and Line 14 crude oil releases. For the second, third and fourth quarter of 2012, these amounts were $2 million, $7 million and nil (2011 – $6 million, $21 million and $6 million), respectively. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $24 million in the third quarter of 2012 and $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters of 2011, 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 – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development*.

Related Party Transactions

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

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, were $4 million for the year ended December 31, 2012 (2011 – $6 million; 2010 – $7 million).

Certain wholly-owned subsidiaries within the Gas Distribution and Gas Pipelines, Processing and Energy Services segments have transportation commitments with several joint venture affiliates that are accounted for using the equity method. Total amounts charged for transportation services were $127 million, $106 million and $102 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Amounts receivable from affiliates include a series of loans to Vector totaling $178 million (2011 – $190 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates from 5% to 8%.

Risk Management and Financial Instruments

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). Formal risk management policies, processes and systems have been designed to mitigate these risks.

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 denominated in United States dollars and certain expenses denominated in Euros. The Company has implemented a policy whereby 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 and 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 denominated in United States dollars.

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 program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2016 with an average swap rate of 2.2%.

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 2016. Future fixed rate term debt issuances of $10,547 million have been hedged at an average swap rate of 3.5%.

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.

COMMODITY PRICE RISK

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interests in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. 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.

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 Stock Units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

THE EFFECT OF DERIVATIVE INSTRUMENTS ON THE STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

The following table presents the effect of derivative instruments on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(12)**	(22)	(25)
Interest rate contracts	**(46)**	(724)	(217)
Commodity contracts	**52**	72	128
Other contracts	**(3)**	6	(1)
Net investment hedges			
Foreign exchange contracts	**1**	(26)	19
	(8)	(694)	(96)
Amount of (gains)/loss reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*			
Cash flow hedges			
Foreign exchange contracts [1]	**1**	1	(7)
Interest rate contracts [2]	**(1)**	(10)	61
Commodity contracts [3]	**(3)**	(55)	(116)
Other contracts [4]	**2**	(2)	1
	(1)	(66)	(61)
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Cash flow hedges			
Interest rate contracts [2]	**23**	11	–
Commodity contracts [3]	**(3)**	5	(3)
	20	16	(3)
Amount of gains/(loss) from non-qualifying derivatives included in earnings			
Foreign exchange contracts [1]	**120**	(179)	33
Interest rate contracts [2]	**(2)**	9	(3)
Commodity contracts [3]	**(765)**	280	(12)
Other contracts [4]	**(2)**	4	–
	(649)	114	18

1 *Reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, 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 and long-term debt which includes debentures and medium-term notes. 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 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 as at December 31, 2012. 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.

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily 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 netting arrangements.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association agreements, or other similar derivative agreements, with the majority of its 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.

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. Within Gas Distribution, credit risk is mitigated by the large and diversified customer base and the 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 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.

FAIR VALUE MEASUREMENTS

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

GENERAL BUSINESS RISKS

STRATEGIC AND COMMERCIAL RISKS

PUBLIC OPINION

The Company's reputation is one of its most valuable assets. Public opinion or 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, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by media attention directed to development projects such as Northern Gateway. Potential impacts of a negative public opinion 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 the Neutral Footprint Initiative).

PROJECT EXECUTION

As the Company increases its slate of growth projects, it continues to focus on completing projects safely, on-time and on-budget. However, the Company faces the challenge of scaling the business to manage an unprecedented number of commercially secured growth projects. 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 or missed in-service dates on future projects may impact future earnings and may hinder the Company's ability to secure future projects. Construction delays due to regulatory delays, contractor or supplier non-performance and weather conditions may impact project development.

The Company strives to be an industry leader in project execution through its Major Projects group. Major Projects is centralized and has a 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. Enhanced recruiting, and outsourcing where necessary, has been introduced to ensure sufficient resources to address the increasing volume of growth projects.

PLANNING AND INVESTMENT ANALYSIS

The Company evaluates the value proposition for expansion projects, new acquisitions or divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility in the economy, change in cost estimates, project scoping and risk assessment could result in a loss in profits for the Company. Large scale acquisitions may involve significant pricing and integration risk.

The planning and investment analysis process involves all levels of management and Board of Directors' review to ensure alignment across the Company. 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.

HUMAN RESOURCES

As growth in WCSB production maintains its momentum it has presented both opportunities and challenges for the Company. In response to the demands of the announced list of growth projects, the Company expects to add approximately 2,500 permanent additions to its workforce over the next five years. However, the robust economic situation in Alberta has led to a substantially tighter employment market in the province. As the Company continues through a period of growth, attracting and retaining adequate personnel who adhere to Enbridge's values will be critical to fulfilling the Company's growth plan.

ECONOMIC REGULATION

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 economic and regulation risk.

OPERATIONAL RISKS

ENVIRONMENTAL INCIDENT

An environmental incident could have lasting reputational impacts to Enbridge and could impact its ability to work with various stakeholders. In addition to the cost of remediation activities (to the extent not covered by insurance) environmental incidents may lead to an increased cost of operation and insuring the Company's assets, thereby negatively impacting earnings. The Company mitigates risk of environmental incident through its ORM Plan, which broadly aims to position Enbridge as the industry leader for system integrity, environmental and safety programs. Through the ORM Plan, the Company has expanded its maintenance, excavation and repair programs which 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 recently completed a new state-of-the-art control centre. The new control centre was designed with enhanced security measures. The Company also revised and enhanced all of its control room procedures pertaining to decision making, pipeline start-ups and shutdowns, leak detection system alarms, communication protocols and suspected column separations. The Company contributes to research and development initiatives for technological advances to further enhance safety and integrity of pipelines.

The Company maintains comprehensive insurance coverage for its subsidiaries and affiliates which renews annually. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents. The total insurance coverage will be allocated on an equitable basis in the unlikely event multiple insurable incidents exceeding the Company's coverage limits are experienced by Enbridge subsidiaries or affiliates within the same insurance period.

PUBLIC, WORKER AND CONTRACTOR SAFETY

Several of the Company's pipeline systems run adjacent to populated areas and a major incident could result in injury to members of the public. A public safety incident could result in reputational damage to the Company, material repair costs or increased costs of operating and insuring the Company's assets.

The safety of the Company's current and future personnel is a Company priority. As part of the ORM Plan, the Company initiated Enbridge's Life Saving Rules. The Life Saving Rules are designed to highlight key processes and rules to ensure public, worker and contractor safety. The Company also introduced new Safety Culture training sessions for all employees.

Also, within EGD, the Company completed construction of the Enbridge Operations and Technology Centre in 2012. The new training facility provides employees real-life simulations of major incidents and teaches the appropriate actions to resolve them in a safe and controlled environment. Additionally, in 2012, EGD's on-going pipeline integrity program completed the replacement of all remaining cast iron and bare steel pipe in its gas distribution system.

SERVICE INTERRUPTION INCIDENT

A service interruption due to a major power disruption or curtailment on commodity supply could have a significant impact on the Company's ability to operate its assets. Specifically, for Gas Distribution, any prolonged interruptions would ultimately impact gas distribution customers. The Company mitigates service interruption risk through its diversified sources of supply, storage withdrawal flexibility, backup power systems, critical parts inventory and redundancies for critical equipment.

SYSTEMS SECURITY INCIDENT

The Company's infrastructure, applications and data are becoming more integrated, creating increased risk a failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activities targeting industrial control systems. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems.

The Company has broadened the scope and frequency of vulnerability assessments aimed at identification of potentially exposed information systems. The Company also executed a company-wide security education and awareness program in the past year. 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.

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 and Native American 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.***

Critical Accounting Estimates

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2012 of $33,318 million (2011 – $29,074 million), or 70.6% 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.

ASSET IMPAIRMENT

The Company evaluates the recoverability of its property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate it may not recover the carrying amount of the assets. The Company continually monitors its businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the property, plant and equipment and the recognition of an impairment loss in the Consolidated Statements of Earnings.

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 ERCB 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 U.S. 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. As at December 31, 2012, the Company's significant regulatory assets totaled $1,246 million (2011 – $972 million) and significant regulatory liabilities totaled $882 million (2011 – $836 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.

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and 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 by referring to high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans, 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 actual return on plan assets exceeded the expected return on plan assets by $24 million for the year ended December 31, 2012 (2011 – $76 million shortfall) as disclosed in Note 24 to the 2012 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, 2012 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pensions Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	141	19	21	2
Decrease in expected return on assets	–	6	–	–
Decrease in rate of salary increase	(30)	(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 28 of the 2012 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 collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Since then, the NEB has issued 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 the NEB, the Company filed its estimated abandonment costs for its regulated pipeline systems within EPI 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). In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies with a decision expected in the first quarter of 2013. The NEB also requires regulated pipeline companies file a proposed process and mechanism to set aside the funds for future abandonment costs by February 28, 2013 for Group 1 companies and by May 31, 2013 for Group 2 companies. These costs would be recovered from shippers through tolls in accordance with NEB’s determination that abandonment costs are a legitimate cost of providing services and are recoverable upon NEB approval from users of the system. The NEB requires Group 1 and Group 2 companies to file proposals for collection of the funds in tolls by May 31, 2013.

All applications for both Enbridge and EPI will require NEB approval and will result in increased transportation tolls and regulated liabilities. The specific toll impacts are uncertain at this time as the Company anticipates the NEB filings in mid-2013 will go to hearing prior to NEB approval.

Currently, for certain of the Company’s assets, there is insufficient data or information to reasonably determine the timing 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

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities and Exchange Commission (SEC) registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

To facilitate users’ understanding of the transition to U.S. GAAP, the Company restated its 2011 consolidated financial statements, which were originally prepared in accordance with Part V – Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook, to U.S. GAAP, including full comparative information and related note disclosure. The 2011 U.S. GAAP financial statements were filed with securities regulators in Canada and the United States on May 2, 2012 and are available on SEDAR at *www.sedar.com* and on the Company’s website at *www.enbridge.com*. ***None of the information contained on, or connected to, Enbridge’s website is incorporated or otherwise part of this MD&A.***

FAIR VALUE MEASUREMENT

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company's earnings or cash flows for the current or prior periods presented.

STATEMENT OF COMPREHENSIVE INCOME

Effective January 1, 2012, the Company adopted ASU 2011-05, which updated existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

GOODWILL IMPAIRMENT

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. Under this option, an entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

FUTURE ACCOUNTING POLICY CHANGES

BALANCE SHEET OFFSETTING

ASU 2011-11 was issued in December 2011 and 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 consolidated financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

ACCUMULATED OTHER COMPREHENSIVE INCOME

ASU 2013-02 was issued in February 2013 and provides enhanced disclosures on amounts reclassified out of AOCI. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2012.

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 at December 31, 2012, 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 U.S. 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 at December 31, 2012, 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, 2012.

During the year ended December 31, 2012, 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 at December 31, 2012 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

Non-GAAP Reconciliations

	2012	2011	2010
(millions of Canadian dollars)			
Earnings attributable to common shareholders	**610**	820	944
Adjusting items:			
Liquids Pipelines			
Canadian Mainline – Line 9 tolling adjustment	**(6)**	(10)	–
Canadian Mainline – changes in unrealized derivative fair value (gains)/loss	**(42)**	48	–
Canadian Mainline – shipper dispute settlement	**–**	(14)	–
Regional Oil Sands System – prior period adjustment	**6**	–	–
Regional Oil Sands System – asset impairment write-off	**–**	8	–
Regional Oil Sands System – gain on acquisition	**–**	–	(20)
Spearhead Pipeline – changes in unrealized derivative fair value gains	**–**	(1)	–
Gas Distribution			
EGD – warmer/(colder) than normal weather	**23**	(1)	12
EGD – tax rate changes	**9**	–	–
EGD – recognition of regulatory asset	**(63)**	–	–
Other Gas Distribution and Storage – regulatory deferral write-off	**–**	262	–
Gas Pipelines, Processing and Energy Services			
Aux Sable – changes in unrealized derivative fair value (gains)/loss	**(10)**	7	(7)
Energy Services – changes in unrealized derivative fair value (gains)/loss	**537**	(125)	8
Energy Services – credit recovery	**–**	–	(1)
Offshore – asset impairment loss	**105**	–	–
Offshore – property insurance recovery from hurricanes	**–**	–	(2)
Other – changes in unrealized derivative fair value gains	**–**	(24)	–
Sponsored Investments			
EEP – leak insurance recoveries	**(24)**	(50)	–
EEP – leak remediation costs and lost revenue	**9**	33	106
EEP – changes in unrealized derivative fair value (gains)/loss	**2**	(3)	1
EEP – NGL trucking and marketing investigation costs	**1**	3	–
EEP – prior period adjustment	**(7)**	–	–
EEP – shipper dispute settlement	**–**	(8)	–
EEP – lawsuit settlement	**–**	(1)	–
EEP – impact of unusual weather conditions	**–**	1	–
EEP – Lakehead System billing correction	**–**	–	(1)
EEP – asset impairment loss	**–**	–	2
Corporate			
Noverco – equity earnings adjustment	**12**	–	–
Noverco – changes in unrealized derivative fair value loss	**10**	–	–
Other Corporate – changes in unrealized derivative fair value (gains)/loss	**22**	87	(25)
Other Corporate – foreign tax recovery	**(29)**	–	–
Other Corporate – unrealized foreign exchange (gains)/loss on translation of intercompany balances, net	**17**	(24)	(40)
Other Corporate – impact of tax rate changes	**11**	(6)	–
Other Corporate – tax on intercompany gain on sale	**56**	98	–
Adjusted earnings	**1,249**	1,100	977

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 accounting principles generally accepted in the United States of America 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 at December 31, 2012, 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, 2012.

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).

AL MONACO
President & Chief Executive Officer

J. RICHARD BIRD
Executive Vice President &
Chief Financial Officer

February 14, 2013

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Enbridge Inc.

We have completed an integrated audit of Enbridge Inc.'s 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2012 and audits of its 2011 and 2010 consolidated financial statements. 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, 2012 and December 31, 2011 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2012, 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 accounting principles generally accepted in the United States of America 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 the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also 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, 2012 and December 31, 2011 and results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2012, based on 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, 2012, based on criteria established in Internal Control – Integrated Framework issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada

February 14, 2013

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**19,101**	20,611	15,863
Gas distribution sales	**1,910**	1,906	1,814
Transportation and other services	**4,295**	4,536	3,843
	25,306	27,053	21,520
Expenses			
Commodity costs	**18,566**	19,864	15,276
Gas distribution costs	**1,220**	1,281	1,249
Operating and administrative	**2,890**	2,281	2,032
Depreciation and amortization	**1,206**	1,112	1,017
Environmental costs, net of recoveries *(Note 28)*	**(88)**	(116)	619
	23,794	24,422	20,193
	1,512	2,631	1,327
Income from equity investments *(Note 11)*	**160**	210	228
Other income *(Note 25)*	**240**	117	318
Interest expense *(Note 16)*	**(841)**	(928)	(865)
	1,071	2,030	1,008
Income taxes *(Note 23)*	**(128)**	(526)	(227)
Earnings before extraordinary loss	**943**	1,504	781
Extraordinary loss, net of tax *(Note 5)*	**–**	(262)	–
Earnings	**943**	1,242	781
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(228)**	(409)	170
Earnings attributable to Enbridge Inc.	**715**	833	951
Preference share dividends	**(105)**	(13)	(7)
Earnings attributable to Enbridge Inc. common shareholders	**610**	820	944
Earnings attributable to Enbridge Inc. common shareholders			
Earnings before extraordinary loss	**610**	1,082	944
Extraordinary loss, net of tax *(Note 5)*	**–**	(262)	–
	610	820	944
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 19)*			
Earnings before extraordinary loss	**0.79**	1.44	1.27
Extraordinary loss, net of tax	**–**	(0.35)	–
	0.79	1.09	1.27
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 19)*			
Earnings before extraordinary loss	**0.78**	1.42	1.26
Extraordinary loss, net of tax	**–**	(0.34)	–
	0.78	1.08	1.26

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings	**943**	1,242	781
Other comprehensive income/(loss), net of tax			
Change in unrealized loss on cash flow hedges	**(176)**	(582)	(156)
Change in unrealized gain/(loss) on net investment hedges	**13**	(19)	51
Other comprehensive income/(loss) from equity investees	**2**	(17)	4
Reclassification to earnings of realized cash flow hedges	**7**	14	(15)
Reclassification to earnings of unrealized cash flow hedges *(Note 22)*	**20**	12	(3)
Reclassification to earnings of pension plans and other postretirement benefits amortization amounts	**18**	21	16
Actuarial loss on pension plans and other postretirement benefits	**(56)**	(165)	(54)
Change in foreign currency translation adjustment	**(159)**	151	(376)
Other comprehensive loss	**(331)**	(585)	(533)
Comprehensive income	**612**	657	248
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(164)**	(329)	331
Comprehensive income attributable to Enbridge Inc.	**448**	328	579
Preference share dividends	**(105)**	(13)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders	**343**	315	572

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 19)*			
Balance at beginning of year	**1,056**	125	125
Preference shares issued	**2,651**	931	–
Balance at end of year	**3,707**	1,056	125
Common shares *(Note 19)*			
Balance at beginning of year	**3,969**	3,683	3,379
Common shares issued	**388**	–	–
Dividend reinvestment and share purchase plan	**297**	229	224
Shares issued on exercise of stock options	**78**	57	80
Balance at end of year	**4,732**	3,969	3,683
Additional paid-in capital			
Balance at beginning of year	**242**	131	90
Stock-based compensation	**26**	18	13
Options exercised	**(17)**	(7)	(8)
Issuance of treasury stock *(Note 11)*	**236**	–	–
Dilution gains and other	**35**	100	36
Balance at end of year	**522**	242	131
Retained earnings			
Balance at beginning of year	**3,926**	3,993	3,828
Earnings attributable to Enbridge Inc.	**715**	833	951
Preference share dividends	**(105)**	(13)	(7)
Common share dividends declared	**(895)**	(759)	(648)
Dividends paid to reciprocal shareholder	**20**	25	19
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 18)*	**(197)**	(153)	(150)
Balance at end of year	**3,464**	3,926	3,993
Accumulated other comprehensive loss *(Note 21)*			
Balance at beginning of year	**(1,532)**	(1,027)	(654)
Other comprehensive loss attributable to Enbridge Inc. common shareholders	**(267)**	(505)	(373)
Balance at end of year	**(1,799)**	(1,532)	(1,027)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(187)**	(154)	(154)
Issuance of treasury stock	**61**	–	–
Acquisition of equity investment	**–**	(33)	–
Balance at end of year	**(126)**	(187)	(154)
Total Enbridge Inc. shareholders' equity	**10,500**	7,474	6,751
Noncontrolling interests *(Note 18)*			
Balance at beginning of year	**3,141**	2,424	2,740
Earnings/(loss) attributable to noncontrolling interests	**241**	416	(182)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized loss on cash flow hedges	**(39)**	(84)	(12)
Change in foreign currency translation adjustment	**(60)**	66	(121)
Reclassification to earnings/(loss) of realized cash flow hedges	**23**	(63)	(13)
Reclassification to earnings/(loss) of unrealized cash flow hedges	**13**	4	(2)
	(63)	(77)	(148)
Comprehensive income/(loss) attributable to noncontrolling interests	**178**	339	(330)
Distributions *(Note 18)*	**(421)**	(355)	(318)
Contributions *(Note 18)*	**382**	735	358
Dilution gains	**6**	22	15
Acquisitions *(Note 6)*	**(25)**	(27)	(41)
Other	**(3)**	3	–
Balance at end of year	**3,258**	3,141	2,424
Total equity	**13,758**	10,615	9,175
Dividends paid per common share	**1.13**	0.98	0.85

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Operating activities			
Earnings	**943**	1,242	781
Depreciation and amortization	**1,206**	1,112	1,017
Deferred income taxes (recovery)/expense *(Note 23)*	**(40)**	368	203
Changes in unrealized (gains)/loss on derivative instruments, net	**665**	(73)	–
Cash distributions in excess of equity earnings	**474**	125	102
Regulatory asset write-off *(Note 5)*	**–**	262	–
Gain on acquisition *(Note 6)*	**–**	–	(22)
Asset impairment *(Note 9)*	**166**	11	11
Allowance for equity funds used during construction	**(1)**	(3)	(96)
Other	**110**	14	9
Changes in regulatory assets and liabilities	**37**	28	29
Changes in environmental liabilities, net of recoveries *(Note 28)*	**(26)**	(118)	267
Changes in operating assets and liabilities *(Note 26)*	**(660)**	403	(424)
	2,874	3,371	1,877
Investing activities			
Additions to property, plant and equipment	**(5,468)**	(3,508)	(3,053)
Long-term investments	**(531)**	(1,515)	(35)
Additions to intangible assets	**(163)**	(154)	(56)
Acquisitions, net of cash acquired *(Note 6)*	**(340)**	(33)	(850)
Affiliate loans, net	**8**	7	14
Proceeds on sale of investments and net assets	**18**	–	23
Government grant	**–**	145	–
Changes in restricted cash	**(2)**	(2)	(5)
Changes in construction payable	**274**	(19)	60
	(6,204)	(5,079)	(3,902)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**412**	224	(165)
Net change in commercial paper and credit facility draws	**(294)**	(630)	(212)
Net change in Southern Lights project financing	**(13)**	(62)	14
Debenture and term note issues	**2,199**	1,604	3,220
Debenture and term note repayments	**(349)**	(234)	(631)
Repayment of acquired debt	**(160)**	–	–
Contributions from noncontrolling interests	**448**	873	439
Distributions to noncontrolling interests	**(421)**	(355)	(318)
Contributions from redeemable noncontrolling interests	**213**	210	–
Distributions to redeemable noncontrolling interests	**(49)**	(35)	(23)
Preference shares issued	**2,634**	926	–
Common shares issued	**465**	46	66
Preference share dividends	**(93)**	(7)	(7)
Common share dividends	**(597)**	(530)	(426)
	4,395	2,030	1,957
Effect of translation of foreign denominated cash and cash equivalents	**(12)**	25	(12)
Increase/(decrease) in cash and cash equivalents	**1,053**	347	(80)
Cash and cash equivalents at beginning of year	**723**	376	456
Cash and cash equivalents at end of year	**1,776**	723	376
Supplementary cash flow information			
Income taxes (received)/paid	**267**	(28)	115
Interest paid	**988**	955	871

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	2012	2011
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,776**	723
Restricted cash	**19**	17
Accounts receivable and other *(Note 7)*	**4,014**	4,029
Accounts receivable from affiliates	**12**	55
Inventory *(Note 8)*	**779**	823
	6,600	5,647
Property, plant and equipment, net *(Note 9)*	**33,318**	29,074
Long-term investments *(Note 11)*	**3,386**	3,081
Deferred amounts and other assets *(Note 12)*	**2,622**	2,500
Intangible assets, net *(Note 13)*	**817**	711
Goodwill *(Note 14)*	**419**	440
Deferred income taxes *(Note 23)*	**10**	41
	47,172	41,494
Liabilities and equity		
Current liabilities		
Bank indebtedness	**479**	102
Short-term borrowings *(Note 16)*	**583**	548
Accounts payable and other *(Note 15)*	**5,052**	4,753
Accounts payable to affiliates	**–**	48
Interest payable	**196**	185
Environmental liabilities *(Note 28)*	**107**	175
Current maturities of long-term debt *(Note 16)*	**652**	354
	7,069	6,165
Long-term debt *(Note 16)*	**20,203**	19,251
Other long-term liabilities *(Note 17)*	**2,541**	2,208
Deferred income taxes *(Note 23)*	**2,601**	2,615
	32,414	30,239
Commitments and contingencies *(Note 28)*		
Redeemable noncontrolling interests *(Note 18)*	**1,000**	640
Equity		
Share capital *(Note 19)*		
Preference shares	**3,707**	1,056
Common shares *(805 and 781 outstanding at December 31, 2012 and 2011, respectively)*	**4,732**	3,969
Additional paid-in capital	**522**	242
Retained earnings	**3,464**	3,926
Accumulated other comprehensive loss *(Note 21)*	**(1,799)**	(1,532)
Reciprocal shareholding *(Note 11)*	**(126)**	(187)
Total Enbridge Inc. shareholders' equity	**10,500**	7,474
Noncontrolling interests *(Note 18)*	**3,258**	3,141
	13,758	10,615
	47,172	41,494

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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 business 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, Seaway Pipeline, Spearhead Pipeline, Feeder Pipelines and Other.

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 and gathering facilities and the Company's energy services businesses, along with renewable energy projects.

Investments in natural gas pipelines include the Company's interests in the United States portion of the Alliance System (Alliance Pipeline US), the Vector Pipeline (Vector) 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 located at the terminus of the Alliance System. The energy services businesses undertake physical commodity marketing activity and manage the Company's volume commitments on the Alliance System, the Vector Pipeline and other pipeline systems.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 21.8% (2011 – 23.0%) ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% (2011 – 66.7%) investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership and an overall 67.7% (2011 – 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 NGL. The primary operations of the Fund include renewable power generation projects, crude oil and liquids pipeline and storage businesses in Western Canada and a 50% interest in the Canadian portion of the Alliance System (Alliance Pipeline Canada).

CORPORATE

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

2. Summary of Significant Accounting Policies

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities and Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. 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 the 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 20)*; fair value of financial instruments *(Note 22)*; provisions for income taxes *(Note 23)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 24)*; commitments and contingencies *(Note 28)*; fair value of asset retirement obligations (ARO); and estimates of losses related to environmental remediation obligations *(Note 28)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and a variable interest entity (VIE) for which the Company is the primary beneficiary. The consolidated financial statements also include the accounts of any limited partnerships where the Company represents the general partner and, based on all facts and circumstances, controls such limited partnerships.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which the Company exercises significant influence are accounted for using the equity method.

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 U.S. 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, the amount of revenue can be reliably measured and collectability is reasonably assured. 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 rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. From July 1, 2011 onward, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective on that date, the Company prospectively discontinued the application of rate-regulated accounting for those assets 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. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area.

For natural gas and marketing businesses, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

NON-QUALIFYING DERIVATIVES

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income and Interest expense.

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 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 Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. 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 at that date is deferred in OCI and 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 derivative instruments for which hedge accounting has been discontinued 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 at December 31, 2012 or 2011.

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 resulting from a disposal of the foreign operation.

CLASSIFICATION OF DERIVATIVES

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

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

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 Deferred amounts and other assets. 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. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, the Company capitalizes interest costs associated with its investment during such period.

OTHER INVESTMENTS

Generally, the Company classifies equity investments in entities over which it does not exercise significant influence and that do not trade on an actively quoted market as other investments carried at cost. Financial assets in this category are initially recorded at fair value with no subsequent re-measurement. Any investments which do trade on an active market are measured at fair value through OCI. Dividends received from these financial assets are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS

Noncontrolling interests represent the outstanding ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of equity in entities not owned by the Company is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position and, in the case of redeemable noncontrolling interests, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

The Fund's noncontrolling interest holders have the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests are recognized at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares. On a quarterly basis, changes in estimated redemption values are reflected as a charge or credit to retained earnings.

INCOME TAXES

The liability method of accounting for income taxes is followed. Deferred 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. Deferred 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 deferred income tax liability is recognized along with a corresponding regulatory asset. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND 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, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. 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.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar presentation currency are included in the cumulative translation adjustment component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH

Cash and cash equivalents that are restricted, in accordance with specific customer agreements, as to withdrawal or usage are presented as Restricted cash on the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES

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

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 comprised of natural gas in storage held in EGD and crude oil and natural gas held primarily by energy services businesses. Natural gas in storage in EGD 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 commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

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.

For non rate-regulated assets depreciation is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; contractual receivables under the terms of long-term delivery contracts; derivative financial instruments; and deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation or power purchase agreements, natural gas supply opportunities and certain software costs. Natural gas supply opportunities are growth opportunities, identified upon acquisition, present in gas producing zones where certain of EEP's gas systems are located. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets 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, 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. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, 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

ARO 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. ARO 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 ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT 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 including discount rates. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of the 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, changes in headcount 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 OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

Certain regulated utility operations of the Company expect to recover pension expense in future rates and therefore record a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012 an offsetting regulatory asset related to OPEB obligations was not recorded given recovery in rates was not probable. Commencing in 2012, pursuant to a specific rate order allowing for recovery in rates of OPEB costs determined on an accrual basis, an offsetting OPEB regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings on an accrual basis.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted 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 Additional paid-in capital. Balances in Additional paid-in capital 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 of the PBSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period with a corresponding credit to Additional paid-in capital. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Additional paid-in capital 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.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

The Company expenses or capitalizes, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. The Company expenses costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. The Company records liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. The Company's estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, 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. The Company evaluates recoveries from insurance coverage separately from the liability and, when recovery is probable, the Company records and reports an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. Changes in Accounting Policies

FAIR VALUE MEASUREMENT

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company's earnings or cash flows for the current or prior periods presented.

STATEMENT OF COMPREHENSIVE INCOME

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

GOODWILL IMPAIRMENT

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. Under this option, an entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

FUTURE ACCOUNTING POLICY CHANGES

BALANCE SHEET OFFSETTING

ASU 2011-11 was issued in December 2011 and 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 consolidated financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

ACCUMULATED OTHER COMPREHENSIVE INCOME

ASU 2013-02 was issued in February 2013 and provides enhanced disclosures on amounts reclassified out of AOCI. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2012.

4. Segmented Information

Year ended December 31, 2012	Liquids Pipelines [1]	Gas Distribution	Gas Pipelines, Processing and Energy Services [1]	Sponsored Investments [1]	Corporate [2]	Consolidated
(millions of Canadian dollars)						
Revenues	**2,452**	**2,438**	**13,745**	**6,671**	**–**	**25,306**
Commodity and gas distribution costs	**–**	**(1,220)**	**(14,283)**	**(4,283)**	**–**	**(19,786)**
Operating and administrative	**(943)**	**(528)**	**(289)**	**(1,076)**	**(54)**	**(2,890)**
Depreciation and amortization	**(363)**	**(336)**	**(62)**	**(431)**	**(14)**	**(1,206)**
Environmental costs, net of recoveries	**–**	**–**	**–**	**88**	**–**	**88**
	1,146	**354**	**(889)**	**969**	**(68)**	**1,512**
Income/(loss) from equity investments	**46**	**–**	**108**	**53**	**(47)**	**160**
Other income/(expense)	**(7)**	**83**	**30**	**49**	**85**	**240**
Interest income/(expense)	**(250)**	**(164)**	**(51)**	**(397)**	**21**	**(841)**
Income taxes recovery/(expense)	**(205)**	**(66)**	**325**	**(169)**	**(13)**	**(128)**
Earnings/(loss)	**730**	**207**	**(477)**	**505**	**(22)**	**943**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(4)**	**–**	**(1)**	**(223)**	**–**	**(228)**
Preference share dividends	**–**	**–**	**–**	**–**	**(105)**	**(105)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**726**	**207**	**(478)**	**282**	**(127)**	**610**
Additions to property, plant and equipment [3]	**2,092**	**438**	**837**	**1,993**	**109**	**5,469**
Total assets	**15,252**	**7,416**	**5,119**	**15,780**	**3,605**	**47,172**

Year ended December 31, 2011	Liquids Pipelines [1]	Gas Distribution	Gas Pipelines, Processing and Energy Services [1]	Sponsored Investments [1]	Corporate [2]	Consolidated
(millions of Canadian dollars)						
Revenues	1,942	2,516	13,599	8,996	–	27,053
Commodity and gas distribution costs	–	(1,282)	(13,051)	(6,812)	–	(21,145)
Operating and administrative	(752)	(508)	(138)	(847)	(36)	(2,281)
Depreciation and amortization	(322)	(320)	(75)	(383)	(12)	(1,112)
Environmental costs, net of recoveries	–	–	–	116	–	116
	868	406	335	1,070	(48)	2,631
Income/(loss) from equity investments	5	–	153	57	(5)	210
Other income/(expense)	31	(12)	40	68	(10)	117
Interest expense	(256)	(166)	(56)	(350)	(100)	(928)
Income taxes recovery/(expense)	(140)	(54)	(166)	(171)	5	(526)
Earnings/(loss) before extraordinary loss	508	174	306	674	(158)	1,504
Extraordinary loss, net of tax	–	(262)	–	–	–	(262)
Earnings/(loss)	508	(88)	306	674	(158)	1,242
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(3)	–	(1)	(405)	–	(409)
Preference share dividends	–	–	–	–	(13)	(13)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	505	(88)	305	269	(171)	820
Additions to property, plant and equipment [3]	958	483	850	1,187	33	3,511
Total assets	12,348	7,189	4,468	13,492	3,997	41,494

Year ended December 31, 2010	Liquids Pipelines [1]	Gas Distribution	Gas Pipelines, Processing and Energy Services [1]	Sponsored Investments [1]	Corporate [2]	Consolidated
(millions of Canadian dollars)						
Revenues	1,627	2,484	9,604	7,805	–	21,520
Commodity and gas distribution costs	–	(1,249)	(9,386)	(5,890)	–	(16,525)
Operating and administrative	(579)	(508)	(105)	(807)	(33)	(2,032)
Depreciation and amortization	(303)	(310)	(55)	(339)	(10)	(1,017)
Environmental costs	–	–	–	(619)	–	(619)
	745	417	58	150	(43)	1,327
Income from equity investments	9	–	151	59	9	228
Other income/(expense)	139	(17)	28	36	132	318
Interest expense	(224)	(179)	(51)	(280)	(131)	(865)
Income taxes recovery/(expense)	(136)	(66)	(61)	(44)	80	(227)
Earnings/(loss)	533	155	125	(79)	47	781
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	(5)	–	177	–	170
Preference share dividends	–	–	–	–	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	531	150	125	98	40	944
Additions to property, plant and equipment [3]	764	387	1,114	884	–	3,149

1 *In December 2012 and October 2011, certain crude oil storage and renewable energy assets were transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $33 million (2011 – $71 million; 2010 – $42 million) have not been reclassified among segments for presentation purposes.*
2 *Included within the Corporate segment was Interest income of $336 million (2011 – $239 million; 2010 – $188 million) charged to other operating segments.*
3 *Includes allowance for equity funds used during construction.*

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

REVENUES [1]

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Canada	**12,171**	12,097	9,385
United States	**13,135**	14,956	12,135
	25,306	27,053	21,520

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

PROPERTY, PLANT AND EQUIPMENT

December 31,	**2012**	2011
(millions of Canadian dollars)		
Canada	**19,293**	16,690
United States	**14,025**	12,384
	33,318	29,074

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. 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 and is subject to regulation by the NEB. Canadian Mainline tolls (excluding Lines 8 and 9) are currently governed by the CTS and do not attract rate-regulated accounting with the exception of flow-through income taxes covered by a specific rate order.

Prior to July 1, 2011, the effective date of the CTS, the Incentive Tolling Settlement (ITS) defined the methodology for calculation of tolls on the core component of Canadian Mainline and was recorded in accordance with rate-regulated accounting guidance. 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.

Upon transition to the CTS on July 1, 2011 and the discontinuance of rate-regulated accounting at that time, a regulatory asset of approximately $470 million continued to be recognized as a NEB rate order governing flow-through income tax treatment permits future recovery.

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, which expire in 2025, 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 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. For the years ended December 31, 2012, 2011 and 2010, EGD's annual rates were set based on a revenue per customer cap incentive regulation methodology which adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. EGD's after-tax rate of return on common equity embedded in rates was 8.4% for the years ended December 31, 2012, 2011 and 2010 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

In November 2012, EGD received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million ($63 million after-tax). The amount will be collected in rates over a 20-year period commencing in 2013. The gain is presented within Other income on the Consolidated Statements of Earnings. The rate order further provides for future OPEB costs, determined on an accrual basis, to be recovered in rates.

ENBRIDGE GAS NEW BRUNSWICK

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB. As at December 31, 2011, EGNB discontinued rate-regulated accounting due to amendments in the rate setting methodology enacted by the Government of New Brunswick, and consequently wrote-off a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million. The write-off of $262 million, net of tax, was presented as an extraordinary loss on the Consolidated Statements of Earnings for the year ended December 31, 2011.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	2012	2011
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes [1]	**605**	527
Deferred transportation revenues [2]	**155**	84
Gas Distribution		
Deferred income taxes [3]	**201**	170
Future removal and site restoration reserves [4]	**(882)**	(836)
Pension plans and OPEB [5]	**212**	108
Sponsored Investments		
Deferred income taxes [3]	**73**	83

1 *The asset represents the regulatory offset to deferred income tax liabilities that are expected to be recovered under flow-through income tax treatment. The recovery period depends on future temporary differences.*

2 *Deferred transportation revenues are related to the cumulative difference between U.S. GAAP depreciation expense for Southern Lights and the negotiated depreciation rates included in the regulated transportation tolls. The Company expects to recover this difference after 2020 when depreciation rates in the transportation agreements are expected to exceed U.S. GAAP depreciation rates.*

3 *The asset represents the regulatory offset to deferred income tax liabilities to the extent that deferred 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.*

4 *The future removal and site restoration reserves balance results from amounts collected from customers by certain 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 as future removal and site restoration costs are incurred.*

5 *The pension plans and OPEB balances represent the regulatory offset to pension plan and OPEB obligations to the extent the amounts are expected to be collected from customers in future rates. An OPEB balance of $89 million is expected to be collected on a straight-line basis over a 20-year period commencing in 2013, whereas the settlement period for the pension regulatory asset is not determinable.*

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, certain 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, 2012, cumulative costs relating to this consulting contract of $144 million (2011 – $133 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

ACQUISITIONS

SILVER STATE NORTH SOLAR PROJECT

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada for cash consideration of $195 million (US$190 million). Silver State expands the Company's renewable energy business. Revenues and earnings of $10 million and $1 million, respectively, were recognized in the year ended December 31, 2012. No revenues or earnings were recognized in any prior period as the solar project commenced operations in the second quarter of 2012. Silver State is included within the Gas Pipelines, Processing and Energy Services segment.

March 22,	2012
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Accounts receivable and other [1]	**54**
Property, plant and equipment	**141**
	195
Purchase price:	
Cash	**195**

1 *The Company acquired the right to apply for a $54 million (US$55 million) United States Treasury grant under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property. The grant, which was applied for subsequent to commercial operations, was received in October 2012.*

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. Tonbridge is included within the Corporate segment.

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 revenues from Tonbridge were recognized in 2011 as the transmission line was not in service. A net loss of $1 million was recognized in earnings for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expense. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in earnings in 2011 had the acquisition occurred on January 1, 2011.

ELK CITY NATURAL GAS GATHERING AND PROCESSING SYSTEM

On September 16, 2010, EEP acquired a 100% ownership interest in entities that comprise the Elk City Natural Gas Gathering and Processing System (Elk City System) for $705 million (US$686 million). The results of operations of Elk City System have been included within the Sponsored Investments segment from the date of acquisition.

September 16,	2010
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	4
Property, plant and equipment	503
Intangible assets [1]	194
Other assets	5
Other long-term liabilities	(1)
	705
Purchase price:	
Cash	705

1 *Intangible assets acquired are natural gas supply opportunities, which are being amortized on a straight line basis over the weighted average estimated useful life of the underlying reserves at the time of acquisition, which approximate 25 to 30 years.*

OTHER ACQUISITIONS

In November 2012, Enbridge acquired certain sour gas gathering and compression facilities for a purchase price of $118 million. These facilities, which are currently in service or under construction, are located in the Peace River Arch region of northwest Alberta and are presented within the Gas Pipelines, Processing and Energy Services segment. As at December 31, 2012, the allocation of consideration paid to the assets was not complete as the Company had not yet concluded its valuation.

In May 2012, Enbridge acquired the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP, for cash consideration of $27 million, increasing its ownership interest to 100%. The Company's interest in Greenwich was consolidated and presented within the Gas Pipelines, Processing and Energy Services segment until such time as it was transferred to the Fund in December 2012 *(Note 18)*.

In October 2011, the Company acquired the remaining 10% interest in Talbot Windfarm, LP (Talbot) for $28 million, increasing its ownership interest to 100%. The Company's interest in Talbot was consolidated and presented within the Gas Pipelines, Processing and Energy Services segment until such time as it was transferred to the Fund in October 2011.

In August 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controlled the entity, it consolidated its interest in Olympic. Prior to August 2010, the entity was accounted for as a joint venture using the equity method.

In June 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%. The original equity interest and noncontrolling interests were re-measured to fair value on the date control was obtained and a $22 million gain was recorded in Other income *(Note 25)* for the year ended December 31, 2010.

During the year ended December 31, 2010, the Company acquired the remaining 27.5% of EGNB limited partnership units held by third parties for $52 million, increasing its partnership interest to 100%.

Other acquisitions during 2010 totaled $29 million (US$27 million) and are included within the Sponsored Investments segment.

Unaudited proforma consolidated revenues and earnings that give effect to all of the Company's other acquisitions as if they had occurred as of January 1 in the year of acquisition are not presented as the information would not be materially different from the information presented in the accompanying Consolidated Statements of Earnings.

7. Accounts Receivable and Other

December 31,	**2012**	2011
(millions of Canadian dollars)		
Unbilled revenues	**2,289**	2,210
Trade receivables	**677**	802
Taxes receivable	**123**	157
Regulatory assets	**–**	42
Short-term portion of derivative assets *(Note 22)*	**383**	486
Prepaid expenses and deposits	**132**	54
Current deferred income taxes *(Note 23)*	**167**	135
Dividends receivable	**26**	30
Other	**266**	171
Allowance for doubtful accounts	**(49)**	(58)
	4,014	4,029

8. Inventory

December 31,	**2012**	2011
(millions of Canadian dollars)		
Natural gas	**448**	566
Other commodities	**331**	257
	779	823

Commodity costs on the Consolidated Statements of Earnings included non-cash charges of $10 million (2011 – $9 million; 2010 – $9 million) for the year ended December 31, 2012 to reduce the cost basis of inventory to market value.

9. Property, Plant and Equipment

December 31,	Weighted Average Depreciation Rate	2012	2011
(millions of Canadian dollars)			
Liquids Pipelines			
Pipeline	2.6%	**8,249**	7,538
Pumping equipment, buildings, tanks and other [1]	3.1%	**5,094**	5,017
Land and right-of-way	2.4%	**225**	232
Under construction	–	**1,675**	1,111
		15,243	13,898
Accumulated depreciation		**(3,432)**	(3,170)
		11,811	10,728
Gas Distribution			
Gas mains, services and other	4.3%	**7,583**	6,846
Land and right-of-way	2.5%	**79**	79
Under construction	–	**102**	137
		7,764	7,062
Accumulated depreciation		**(1,912)**	(1,419)
		5,852	5,643
Gas Pipelines, Processing and Energy Services			
Pipeline	4.6%	**544**	568
Wind turbines, solar panels and other [1]	4.9%	**519**	781
Land and right-of-way	4.9%	**6**	7
Under construction	–	**1,477**	512
		2,546	1,868
Accumulated depreciation		**(350)**	(213)
		2,196	1,655
Sponsored Investments			
Pipeline	3.0%	**6,890**	6,600
Pumping equipment, buildings, tanks and other [1]	3.3%	**4,787**	3,792
Wind turbines, solar panels and other [1]	4.0%	**1,544**	1,074
Land and right-of-way	2.4%	**642**	611
Under construction	–	**2,002**	913
		15,865	12,990
Accumulated depreciation		**(2,770)**	(2,213)
		13,095	10,777
Corporate			
Other	9.4%	**105**	71
Under construction	–	**296**	230
		401	301
Accumulated depreciation		**(37)**	(30)
		364	271
		33,318	29,074

1 *In December 2012, wholly-owned subsidiaries of Enbridge sold two crude oil storage and three renewable energy assets to the Fund. As a result, at December 31, 2012, $599 million and $338 million of Property, plant and equipment were reclassified from Liquids Pipelines and Gas Pipelines, Processing and Energy Services, respectively, to Sponsored Investments. The December 31, 2011 balances of $600 million and $354 million, in Liquids Pipelines and Gas Pipelines, Processing and Energy Services, respectively, have not been reclassified for presentation purposes.*

Depreciation expense for the year ended December 31, 2012 was $1,174 million (2011 – $1,089 million; 2010 – $987 million).

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

In December 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Enbridge Offshore Pipelines (Offshore) assets, predominantly located within the Stingray and Garden Banks corridors in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas of the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

The impairment charge was based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows, and is presented within Operating and administrative expense on the Consolidated Statements of Earnings. The charge is inclusive of $50 million related to abandonment costs now reasonably determined given the expected timing and scope of certain asset retirements.

10. Variable Interest Entity

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. The Company is the primary beneficiary of the Fund through its combined 67.7% (2011 – 69.2%; 2010 – 72%) economic interest, held indirectly through a common investment in ENF, a direct common trust unit investment in the Fund and a preferred unit investment in a wholly-owned subsidiary of the Fund. Enbridge also serves in the capacity of Manager of ENF, the Fund and its subsidiaries.

The summarized impact of the Company's interest in the Fund on earnings, cash flows and financial position is presented below. Earnings include the results of operations of certain assets acquired by the Fund from wholly-owned subsidiaries of Enbridge from the dates of acquisition of October 2011 and December 2012 *(Note 18)*. Earnings, cash flows and financial position information exclude the effect of intercompany transactions.

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Revenues	**288**	146	89
Operating and administrative expense	**(83)**	(66)	(52)
Depreciation and amortization	**(87)**	(47)	(19)
Income from equity investments	**52**	60	60
Interest expense and other	**(68)**	(32)	(13)
Income taxes	**(35)**	(21)	(17)
Earnings	**67**	40	48
(Earnings)/loss attributable to noncontrolling interest	**13**	7	(11)
Earnings attributable to Enbridge	**80**	47	37
Cash flows			
Cash provided by operating activities	**198**	140	29
Cash used in investing activities	**(158)**	(98)	(107)
Cash provided by financing activities	**1,495**	381	85
Increase in cash and cash equivalents	**1,535**	423	7

December 31,	2012	2011
(millions of Canadian dollars)		
Current assets	**224**	109
Property, plant and equipment, net	**2,390**	1,349
Long-term investments	**314**	343
Deferred amounts and other assets	**179**	125
Current liabilities	**(250)**	(90)
Long-term debt	**(1,864)**	(675)
Other long-term liabilities	**(22)**	(36)
Deferred income taxes	**(438)**	(403)
Net assets before noncontrolling interests	**533**	722

11. Long-Term Investments

December 31,	Ownership Interest	2012	2011
(millions of Canadian dollars)			
Equity Investments			
Joint Ventures			
Liquids Pipelines			
Chicap Pipeline	43.8%	**27**	27
Mustang Pipeline	30.0%	**21**	27
Seaway Pipeline	50.0%	**1,385**	1,186
Gas Pipelines, Processing and Energy Services			
Offshore – various joint ventures	22.0% – 74.3%	**391**	420
Vector	60.0%	**142**	160
Alliance Pipeline US	50.0%	**282**	293
Aux Sable [1]	42.7% – 50.0%	**266**	217
Other	33.3% – 70.0%	**10**	21
Sponsored Investments			
Alliance Pipeline Canada	50.0%	**277**	296
Texas Express Pipeline	35.0%	**183**	11
Other	50.0%	**35**	47
Other Equity Investments			
Corporate			
Noverco Common Shares	38.9%	**–**	–
Other	8.9% – 41.0%	**55**	34
Other Long-Term Investments			
Corporate			
Noverco Preferred Shares		**246**	285
Other		**66**	57
		3,386	3,081

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.*

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date which is comprised of $636 million (2011 – $651 million) in Goodwill and $493 million (2011 – $450 million) in amortizable assets.

JOINT VENTURES

Summarized combined financial information of the Company's interest in unconsolidated equity investments of joint ventures is as follows:

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Revenues	**921**	804	771
Commodity costs	**(236)**	(138)	(92)
Operating and administrative expense	**(244)**	(200)	(203)
Depreciation and amortization	**(159)**	(158)	(158)
Other expense	**4**	(3)	(1)
Interest expense	**(81)**	(87)	(96)
Earnings before income taxes	**205**	218	221

December 31,	2012	2011
(millions of Canadian dollars)		
Current assets	**299**	231
Property, plant and equipment, net	**3,192**	2,864
Deferred amounts and other assets	**204**	273
Intangible assets	**74**	87
Goodwill	**639**	651
Current liabilities	**(333)**	(230)
Long-term debt	**(895)**	(926)
Other long-term liabilities	**(161)**	(245)
Net assets	**3,019**	2,705

ALLIANCE PIPELINE

Certain assets of Alliance Pipeline Canada are pledged as collateral to Alliance Pipeline Canada lenders and to the lenders of Alliance Pipeline US. As well, certain assets of Alliance Pipeline US are pledged as collateral to Alliance Pipeline US lenders and to the lenders of Alliance Pipeline Canada.

OTHER EQUITY INVESTMENTS

NOVERCO

At December 31, 2012, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2011 – 38.9%; 2010 – 32.1%) of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a range of 4.3% to 4.4%.

At December 31, 2011, Noverco owned an approximate 8.9% reciprocal shareholding in the Common Shares of the Company. During the year ended December 31, 2012, Noverco sold 22.5 million Enbridge Common Shares through a secondary offering, thereby reducing the Company's reciprocal shareholding to 6.0%. Both the Company's equity investment in Noverco and Equity increased by $297 million, net of tax, as a result of this transaction. The Company's share of the proceeds of approximately $317 million was received as a dividend from Noverco in May 2012.

As a result of Noverco's 6.0% (2011 – 8.9%; 2010 – 9.0%) reciprocal shareholding in Enbridge shares, the Company has an indirect pro-rata interest of 2.1% (2011 – 3.5%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $126 million at December 31, 2012 (2011 – $187 million; 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.

12. Deferred Amounts and Other Assets

December 31,	2012	2011
(millions of Canadian dollars)		
Regulatory assets	**1,284**	1,000
Long-term portion of derivative assets *(Note 22)*	**408**	562
Affiliate long-term note receivable *(Note 27)*	**182**	194
Contractual receivables	**303**	288
Deferred financing costs	**127**	132
Other	**318**	324
	2,622	2,500

At December 31, 2012, deferred amounts of $265 million (2011 – $255 million) were subject to amortization and are presented net of accumulated amortization of $123 million (2011 – $106 million). Amortization expense for the year ended December 31, 2012 was $25 million (2011 – $20 million; 2010 – $20 million).

13. Intangible Assets

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	11.9%	**622**	**180**	**442**
Natural gas supply opportunities	3.8%	**291**	**50**	**241**
Power purchase agreements	4.7%	**85**	**4**	**81**
Transportation agreements	2.9%	**50**	**13**	**37**
Other	5.6%	**20**	**4**	**16**
		1,068	**251**	**817**

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.7%	471	155	316
Natural gas supply opportunities	3.6%	296	39	257
Power purchase agreements	4.6%	78	2	76
Transportation agreements	2.9%	53	10	43
Other	6.0%	27	8	19
		925	214	711

Total amortization expense for intangible assets was $64 million (2011 – $58 million; 2010 – $52 million) for the year ended December 31, 2012. The Company expects aggregate amortization expense for the years ending December 31, 2013 through 2017 of $67 million, $61 million, $55 million, $49 million and $44 million, respectively.

14. Goodwill

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2011	47	–	29	355	–	431
Foreign exchange and other	1	–	1	7	–	9
Balance at December 31, 2011	**48**	**–**	**30**	**362**	**–**	**440**
Transfer of assets to the Fund	**(29)**	**–**	**–**	**29**	**–**	**–**
Foreign exchange and other	**3**	**–**	**(17)**	**(7)**	**–**	**(21)**
Balance at December 31, 2012	**22**	**–**	**13**	**384**	**–**	**419**

The Company did not recognize any goodwill impairments for the years ended December 31, 2012 and 2011.

15. Accounts Payable and Other

December 31,	2012	2011
(millions of Canadian dollars)		
Operating accrued liabilities	**2,729**	2,751
Trade payables	**123**	176
Construction payables	**568**	327
Current derivative liabilities *(Note 22)*	**1,075**	880
Contractor holdbacks	**86**	46
Taxes payable	**206**	339
Security deposits	**69**	81
Current deferred income taxes *(Note 23)*	**–**	7
Other	**196**	146
	5,052	4,753

16. Debt

December 31,	Weighted Average Interest Rate	Maturity	2012	2011
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.2%	2024	**200**	200
Medium-term notes	4.9%	2015 – 2112	**2,435**	2,435
Southern Lights project financing [1]	2.7%	2014	**1,413**	1,449
Commercial paper and credit facility draws			**25**	26
Other [2]			**12**	13
Gas Distribution				
Debentures	9.9%	2024	**85**	85
Medium-term notes	5.5%	2014 – 2050	**2,295**	2,295
Commercial paper and credit facility draws			**590**	556
Sponsored Investments				
Junior subordinated notes [3]	8.1%	2067	**398**	406
Medium-term notes	3.8%	2013 – 2023	**1,615**	415
Senior notes [4]	6.2%	2013 – 2040	**4,129**	4,322
Commercial paper and credit facility draws [5]			**1,405**	540
Corporate				
United States dollar term notes [6]	5.5%	2014 – 2017	**1,094**	1,119
Medium-term notes	4.5%	2013 – 2042	**4,268**	3,518
Commercial paper and credit facility draws [7]			**1,488**	2,785
Other [8]			**(14)**	(11)
Total debt			**21,438**	20,153
Current maturities			**(652)**	(354)
Short-term borrowings [9]			**(583)**	(548)
Long-term debt			**20,203**	19,251

1 *2012 – $357 million and US$1,061 million (2011 – $360 million and US$1,071 million).*
2 *Primarily capital lease obligations.*
3 *2012 – US$400 million (2011 – US$400 million).*
4 *2012 – US$4,150 million (2011 – US$4,250 million).*
5 *2012 – $250 million and US$1,160 million (2011 – $260 million and US$275 million).*
6 *2012 – US$1,100 million (2011 – US$1,100 million).*
7 *2012 – $1,140 million and US$350 million (2011 – $1,655 million and US$1,111 million).*
8 *Primarily debt discount.*
9 *Weighted average interest rate – 1.1% (2011 – 1.1%).*

For the years ending December 31, 2013 through 2017, debenture and term note maturities are $649 million, $1,287 million, $908 million, $998 million, $1,321 million, respectively, and $11,356 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2013 through 2017 are $997 million, $976 million, $926 million, $901 million and $826 million, respectively. At December 31, 2012 and 2011, all debt is unsecured except for the Southern Lights project financing which is collateralized by the Southern Lights project assets.

INTEREST EXPENSE

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Debentures and term notes	**986**	891	835
Commercial paper and credit facility draws	**33**	74	66
Southern Lights project financing	**38**	38	37
Capitalized	**(216)**	(75)	(73)
	841	928	865

CREDIT FACILITIES

December 31, 2012	Maturity Dates [1]	Total Facilities	Draws [2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2014	**300**	**25**	**275**
Gas Distribution	2014	**712**	**590**	**122**
Sponsored Investments	2014 – 2017	**3,162**	**1,645**	**1,517**
Corporate	2014 – 2017	**9,108**	**1,520**	**7,588**
		13,282	**3,780**	**9,502**
Southern Lights project financing [3]	2014	**1,484**	**1,429**	**55**
Total credit facilities		**14,766**	**5,209**	**9,557**

1 *Total facilities include $35 million in demand facilities with no maturity date.*
2 *Includes credit facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *Total facilities inclusive of $60 million for debt service reserve letters of credit.*

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2014 to 2017.

Commercial paper and credit facility draws, net of short-term borrowings, of $2,925 million (2011 – $3,359 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. Other Long-Term Liabilities

December 31,	2012	2011
(millions of Canadian dollars)		
Future removal and site restoration liabilities *(Note 5)*	**882**	836
Derivative liabilities *(Note 22)*	**763**	557
Pension and OPEB liabilities *(Note 24)*	**573**	515
Other	**323**	300
	2,541	2,208

18. Noncontrolling Interests

December 31,	2012	2011
(millions of Canadian dollars)		
EEP	**2,636**	2,528
Enbridge Energy Management, L.L.C. (EEM)	**498**	464
EGD preferred shares	**100**	100
Greenwich *(Note 6)*	**–**	26
Other	**24**	23
	3,258	3,141

Noncontrolling interests in EEP represent the 78.2% interest in EEP not owned by the Company. During the year ended December 31, 2012, EEP completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests from 77.0% to 78.2%. The listed share issuance during the year ended December 31, 2012 resulted in contributions of $382 million (2011 – $695 million; 2010 – $330 million) from noncontrolling interest holders. During the year ended December 31, 2012, EEP also distributed $419 million (2011 – $353 million; 2010 – $311 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions in an amount equal to its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors.

Noncontrolling interests in EEM represent the 83.2% of the listed shares of EEM not held by the Company. A listed share issuance during the year ended December 31, 2011 resulted in contributions of $26 million from noncontrolling interest holders.

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 preferred shares have no fixed maturity date and have floating adjustable cash dividends that are payable at 80% of the prime rate. 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, 2012, no preferred shares have been redeemed.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Balance at beginning of year	**640**	362	236
Earnings/(loss)	**(13)**	(7)	12
Other comprehensive loss			
Change in unrealized loss on cash flow hedges, net of tax	**(1)**	(3)	(13)
Comprehensive loss	**(14)**	(10)	(1)
Distributions to unitholders	**(49)**	(33)	(23)
Contributions from unitholders	**226**	168	–
Redemption value adjustment	**197**	153	150
Balance at end of year	**1,000**	640	362

Redeemable noncontrolling interests in the Fund at December 31, 2012 represented 67.7% (2011 – 64.6%; 2010 – 58.2%) of interests in the Fund's trust units that are held by third parties.

In December 2012, the Fund acquired Greenwich, Amherstburg and Tilbury solar energy projects, Hardisty Caverns and Hardisty Contract Terminals from Enbridge and wholly-owned subsidiaries of Enbridge for proceeds of $1.2 billion. In October 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for $1.2 billion. In both cases, ordinary trust units were issued by the Fund to partially finance these acquisitions, resulting in an increase in interests held by third parties in 2012 and 2011 and contributions from noncontrolling unitholders of $226 million and $168 million, respectively.

Distributions to noncontrolling unitholders are made on a monthly basis in line with the Fund's objective of distributing a high proportion of its cash available for distribution, as approved by its Board of Trustees.

19. 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

	2012		2011		2010	
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	**781**	**3,969**	770	3,683	756	3,379
Common Shares issued [1]	**10**	**388**	–	–	–	–
Shares issued on exercise of stock options	**6**	**78**	4	57	6	80
Dividend Reinvestment and Share Purchase Plan (DRIP)	**8**	**297**	7	229	8	224
Balance at end of year	**805**	**4,732**	781	3,969	770	3,683

1 *Gross proceeds – $400 million; net issuance costs – $12 million.*

PREFERENCE SHARES

	2012		2011		2010	
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	**20**	**500**	20	500	–	–
Preference Shares, Series D	**18**	**450**	18	450	–	–
Preference Shares, Series F	**20**	**500**	–	–	–	–
Preference Shares, Series H	**14**	**350**	–	–	–	–
Preference Shares, Series J	**8**	**199**	–	–	–	–
Preference Shares, Series L	**16**	**411**	–	–	–	–
Preference Shares, Series N	**18**	**450**	–	–	–	–
Preference Shares, Series P	**16**	**400**	–	–	–	–
Preference Shares, Series R	**16**	**400**	–	–	–	–
Issuance costs		**(78)**		(19)		–
Balance at end of year		**3,707**		1,056		125

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend [1]	Per Share Base Redemption Value [2]	Redemption and Conversion Option Date [2,3]	Right to Convert Into [3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.5%	$1.375	$25	–	–
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R [5]	4.0%	$1.000	$25	June 1, 2019	Series S

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend per year, as declared by the Board of Directors of the Company.*

2 *Preference Shares, Series A may be redeemed any time at the Company's option. For all other series of Preference Shares, 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 + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q) or 2.5% (Series S)); or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.1% (Series K) or 3.2% (Series M)).*

5 *A cash dividend of $0.2356 per share will be paid on March 1, 2013 to Series R shareholders. The regular quarterly dividend of $0.25 per share will begin in the second quarter of 2013.*

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable 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 20 million (2011 – 25 million; 2010 – 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,	**2012**	2011	2010
(number of common shares in millions)			
Weighted average shares outstanding	**772**	751	741
Effect of dilutive options	**13**	10	7
Diluted weighted average shares outstanding	**785**	761	748

For the year ended December 31, 2012, 5,733,000 anti-dilutive stock options (2011 – 48,000; 2010 – 92,000) with a weighted average exercise price of $38.32 (2011 – $32.02; 2010 – $27.84) 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.

20. 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 46 million have been issued to date. In 2007, a new reserve of 33 million 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 common shares being available for the 2007 ISO and PBSO plans, of which four 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.

December 31, 2012	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**27,465**	**21.19**		
Options granted	**5,802**	**38.32**		
Options exercised [1]	**(5,796)**	**16.99**		
Options cancelled or expired	**(103)**	**27.78**		
Options outstanding at end of year	**27,368**	**25.69**	**6.7**	**375**
Options vested at end of year [2]	**13,703**	**20.33**	**5.2**	**261**

1 *The total intrinsic value of ISOs exercised during the year ended December 31, 2012 was $130 million (2011 – $68 million; 2010 – $38 million) and cash received on exercise was $69 million (2011 – $56 million; 2010 – $50 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2012 was $19 million (2011 – $17 million; 2010 – $14 million).*

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	2012	2011	2010
Fair value per option *(Canadian dollars)* [1]	**4.81**	4.19	3.44
Valuation assumptions			
Expected option term *(years)* [2]	**5**	6	6
Expected volatility [3]	**19.7%**	18.6%	19.7%
Expected dividend yield [4]	**3.0%**	3.4%	3.6%
Risk-free interest rate [5]	**1.3%**	2.9%	2.7%

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 and the Canadian options. The fair values per option were $4.65 (2011 – $4.01; 2010 – $3.28) for Canadian employees and US$5.58 (2011 – US$5.11; 2010 – US$4.00) 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 and consideration of the implied volatility observable in call option values near the grant date.*
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 the United States Treasury Bond Yields.*

Compensation expense recorded for the year ended December 31, 2012 for ISOs was $23 million (2011 – $16 million; 2010 – $11 million). At December 31, 2012, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $30 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

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, February 19, 2008 and August 15, 2012 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 were fulfilled evenly over a five-year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Time vesting requirements for the 2012 grant will be fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on the Company's share price and must be met by February 15, 2019 or the options expire. If targets are met by February 15, 2019, the options are exercisable until August 15, 2020.

December 31, 2012	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**4,127**	**18.52**		
Options granted	**3,543**	**39.34**		
Options exercised [1]	**(966)**	**18.29**		
Options outstanding at end of year	**6,704**	**29.56**	**5.3**	**66**
Options vested at end of year [2]	**3,061**	**18.54**	**2.6**	**64**

1 *The total intrinsic value of PBSOs exercised during the year ended December 31, 2012 was $20 million (2011 – $2 million; 2010 – $26 million) and cash received on exercise was $12 million (2011 – $3 million; 2010 – $27 million).*
2 *The total fair value of options vested under the PBSO Plan during the year ended December 31, 2012 was $1 million (2011 – $2 million; 2010 – $2 million).*

Assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2012
Fair value per option *(Canadian dollars)*	**4.25**
Valuation assumptions	
Expected option term *(years)* [1]	**8**
Expected volatility [2]	**16.1%**
Expected dividend yield [3]	**2.8%**
Risk-free interest rate [4]	**1.6%**

1 *The expected option term is based on historical exercise practice.*
2 *Expected volatility is determined with reference to historic daily share price volatility.*
3 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
4 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.*

Compensation expense recorded for the year ended December 31, 2012 for PBSOs was $2 million (2011 – $2 million; 2010 – $2 million). At December 31, 2012, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $14 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for executives 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 2010, 2011 and 2012 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 unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2012 expense, multipliers of two, based upon multiplier estimates at December 31, 2012, were used for each of the 2010, 2011 and 2012 PSU grants.

December 31, 2012	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**937**		
Units granted	**307**		
Units matured [1]	**(627)**		
Dividend reinvestment	**35**		
Units outstanding at end of year	**652**	**1.5**	**56**

1 *The total amount paid during the year ended December 31, 2012 for PSUs was $25 million (2011 – $17 million; 2010 – $14 million).*

Compensation expense recorded for the year ended December 31, 2012 for PSUs was $49 million (2011 – $42 million; 2010 – $27 million). As at December 31, 2012, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $25 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a 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.

December 31, 2012	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**1,902**		
Units granted	**891**		
Units cancelled	**(114)**		
Units matured [1]	**(939)**		
Dividend reinvestment	**79**		
Units outstanding at end of year	**1,819**	**1.5**	**78**

1 *The total amount paid during the year ended December 31, 2012 for RSUs was $37 million (2011 – $39 million; 2010 – $24 million).*

Compensation expense recorded for the year ended December 31, 2012 for RSUs was $32 million (2011 – $31 million; 2010 – $29 million). As at December 31, 2012, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $37 million and is expected to be fully recognized over a weighted average period of approximately two years.

21. Components of Accumulated Other Comprehensive Loss

Changes in AOCI attributable to Enbridge common shareholders for the years ended December 31, 2012, 2011 and 2010, are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Actuarial Gain/(Loss) Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2010	69	429	(1,033)	(15)	(104)	(654)
Changes during the year	(136)	61	(255)	3	(52)	(379)
Tax impact	1	(10)	–	1	14	6
	(135)	51	(255)	4	(38)	(373)
Balance at December 31, 2010	(66)	480	(1,288)	(11)	(142)	(1,027)
Changes during the year	(563)	(21)	85	(20)	(200)	(719)
Tax impact	153	2	–	3	56	214
	(410)	(19)	85	(17)	(144)	(505)
Balance at December 31, 2011	**(476)**	**461**	**(1,203)**	**(28)**	**(286)**	**(1,532)**
Changes during the year	**(190)**	**16**	**(99)**	**7**	**(52)**	**(318)**
Tax impact	**45**	**(3)**	**–**	**(5)**	**14**	**51**
	(145)	**13**	**(99)**	**2**	**(38)**	**(267)**
Balance at December 31, 2012	**(621)**	**474**	**(1,302)**	**(26)**	**(324)**	**(1,799)**

22. Derivative Financial Instruments and Hedging Activities

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.

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 denominated in United States dollars and certain expenses denominated in Euros. 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 denominated in United States dollars.

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 program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2016 with an average swap rate of 2.2%.

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 2016. A total of $10,547 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.5%.

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.

COMMODITY PRICE RISK

The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interests in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. 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.

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 20)*. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the balance sheet location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at December 31, 2012 or 2011.

December 31, 2012	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments [1]
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	**4**	**16**	**210**	**230**	**–**	**230**
Interest rate contracts	**7**	**–**	**11**	**18**	**(2)**	**16**
Commodity contracts	**18**	**–**	**127**	**145**	**(17)**	**128**
Other contracts	**3**	**–**	**6**	**9**	**–**	**9**
	32	**16**	**354**	**402**	**(19)**	**383**
Deferred amounts and other assets *(Note 12)*						
Foreign exchange contracts	**11**	**79**	**225**	**315**	**–**	**315**
Interest rate contracts	**21**	**–**	**12**	**33**	**(3)**	**30**
Commodity contracts	**5**	**–**	**60**	**65**	**(5)**	**60**
Other contracts	**2**	**–**	**1**	**3**	**–**	**3**
	39	**79**	**298**	**416**	**(8)**	**408**
Accounts payable and other *(Note 15)*						
Foreign exchange contracts	**(5)**	**–**	**(100)**	**(105)**	**–**	**(105)**
Interest rate contracts	**(673)**	**–**	**(2)**	**(675)**	**2**	**(673)**
Commodity contracts	**(10)**	**–**	**(304)**	**(314)**	**17**	**(297)**
	(688)	**–**	**(406)**	**(1,094)**	**19**	**(1,075)**
Other long-term liabilities *(Note 17)*						
Foreign exchange contracts	**(41)**	**(5)**	**(23)**	**(69)**	**–**	**(69)**
Interest rate contracts	**(293)**	**–**	**(15)**	**(308)**	**3**	**(305)**
Commodity contracts	**(6)**	**–**	**(388)**	**(394)**	**5**	**(389)**
	(340)	**(5)**	**(426)**	**(771)**	**8**	**(763)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(31)**	**90**	**312**	**371**	**–**	**371**
Interest rate contracts	**(938)**	**–**	**6**	**(932)**	**–**	**(932)**
Commodity contracts	**7**	**–**	**(505)**	**(498)**	**–**	**(498)**
Other contracts	**5**	**–**	**7**	**12**	**–**	**12**
	(957)	**90**	**(180)**	**(1,047)**	**–**	**(1,047)**

December 31, 2011	Derivative Instruments used as Cash Flow Hedges	Derivative Instruments used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments [1]
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	4	15	315	334	–	334
Interest rate contracts	–	–	12	12	(4)	8
Commodity contracts	7	–	146	153	(19)	134
Other contracts	3	–	7	10	–	10
	14	15	480	509	(23)	486
Deferred amounts and other assets *(Note 12)*						
Foreign exchange contracts	15	79	203	297	–	297
Interest rate contracts	1	–	24	25	(3)	22
Commodity contracts	12	–	241	253	(15)	238
Other contracts	3	–	2	5	–	5
	31	79	470	580	(18)	562
Accounts payable and other *(Note 15)*						
Foreign exchange contracts	(4)	–	(275)	(279)	–	(279)
Interest rate contracts	(477)	–	(8)	(485)	4	(481)
Commodity contracts	(32)	–	(107)	(139)	19	(120)
	(513)	–	(390)	(903)	23	(880)
Other long-term liabilities *(Note 17)*						
Foreign exchange contracts	(35)	(5)	(51)	(91)	–	(91)
Interest rate contracts	(415)	–	(20)	(435)	3	(432)
Commodity contracts	(29)	–	(20)	(49)	15	(34)
	(479)	(5)	(91)	(575)	18	(557)
Total net derivative asset/(liability)						
Foreign exchange contracts	(20)	89	192	261	–	261
Interest rate contracts	(891)	–	8	(883)	–	(883)
Commodity contracts	(42)	–	260	218	–	218
Other contracts	6	–	9	15	–	15
	(947)	89	469	(389)	–	(389)

1 *As presented in the Consolidated Statements of Financial Position.*

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

December 31, 2012	2013	2014	2015	2016	2017	Thereafter
Foreign exchange contracts – United States dollar forwards – purchase *(millions of United States dollars)*	**558**	**468**	**25**	**25**	**413**	**6**
Foreign exchange contracts – United States dollar forwards – sell *(millions of United States dollars)*	**2,088**	**2,402**	**2,751**	**2,323**	**2,557**	**158**
Foreign exchange contracts – Euro dollar forwards – purchase *(millions of Euros)*	**6**	**–**	**–**	**–**	**–**	**–**
Interest rate contracts – short-term borrowings *(millions of Canadian dollars)*	**3,644**	**3,591**	**3,455**	**3,157**	**2,841**	**171**
Interest rate contracts – long-term debt *(millions of Canadian dollars)*	**4,590**	**3,055**	**1,760**	**1,142**	**–**	**–**
Equity contracts *(millions of Canadian dollars)*	**39**	**36**	**–**	**–**	**–**	**–**
Commodity contracts – natural gas *(billions of cubic feet)*	**55**	**19**	**10**	**10**	**11**	**3**
Commodity contracts – crude oil *(millions of barrels)*	**37**	**38**	**29**	**23**	**18**	**9**
Commodity contracts – NGL *(millions of barrels)*	**1**	**2**	**–**	**–**	**–**	**–**
Commodity contracts – power *(megawatt hours (MWH))*	**51**	**67**	**48**	**63**	**83**	**66**

December 31, 2011	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts – United States dollar forwards – purchase *(millions of United States dollars)*	58	287	468	25	25	418
Foreign exchange contracts – United States dollar forwards – sell *(millions of United States dollars)*	2,017	1,865	2,182	2,583	2,039	180
Interest rate contracts – short-term borrowings *(millions of Canadian dollars)*	3,227	3,237	2,787	2,641	2,428	215
Interest rate contracts – long-term debt *(millions of Canadian dollars)*	2,650	2,000	1,650	750	–	–
Equity contracts (*millions of Canadian dollars)*	36	26	–	–	–	–
Commodity contracts – natural gas *(billions of cubic feet)*	20	59	1	1	1	–
Commodity contracts – crude oil *(millions of barrels)*	11	26	17	8	7	10
Commodity contracts – NGL *(millions of barrels)*	4	1	–	–	–	–
Commodity contracts – power *(MWH)*	40	28	40	48	63	58

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, before the effect of income taxes.

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(12)**	(22)	(25)
Interest rate contracts	**(46)**	(724)	(217)
Commodity contracts	**52**	72	128
Other contracts	**(3)**	6	(1)
Net investment hedges			
Foreign exchange contracts	**1**	(26)	19
	(8)	(694)	(96)
Amount of (gains)/loss reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts [1]	**1**	1	(7)
Interest rate contracts [2]	**(1)**	(10)	61
Commodity contracts [3]	**(3)**	(55)	(116)
Other contracts [4]	**2**	(2)	1
	(1)	(66)	(61)
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts [2]	**23**	11	–
Commodity contracts [3]	**(3)**	5	(3)
	20	16	(3)

1 *Reported within Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $101 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 forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 60 months at December 31, 2012.

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,	**2012**	2011	2010
(millions of Canadian dollars)			
Foreign exchange contracts [1]	**120**	(179)	33
Interest rate contracts [2]	**(2)**	9	(3)
Commodity contracts [3]	**(765)**	280	(12)
Other contracts [4]	**(2)**	4	–
Total unrealized derivative fair value gains/(loss)	**(649)**	114	18

1 *Reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 28 and 29)*, 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 and long-term debt which includes debentures and medium-term notes. 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 as at December 31, 2012. 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.

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily 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 netting arrangements.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association (ISDA) agreements, or other similar derivative agreements, with the majority of its 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, 2012 and 2011, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2012**	2011
(millions of Canadian dollars)		
Canadian financial institutions	**306**	431
United States financial institutions	**129**	287
European financial institutions	**244**	257
Other [1]	**128**	112
	807	1,087

1 *Other is comprised of commodity clearing house and natural gas and crude physical counterparties.*

As at December 31, 2012, the Company had provided letters of credit totaling $273 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at December 31, 2012 or 2011.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

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 is mitigated by the large and diversified customer base and the 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 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.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. 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.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative instruments 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. The Company does not have any other financial instruments categorized as Level 1.

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.

The Company has also categorized the fair value of its held to maturity preferred share investment and long-term debt as Level 2. The fair value of the Company's held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

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 primarily include long-dated derivative power contracts and NGL and natural gas contracts. The Company does not have any other financial instruments categorized in Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	–	230	–	230	–	230
Interest rate contracts	–	18	–	18	(2)	16
Commodity contracts	3	24	118	145	(17)	128
Other contracts	–	9	–	9	–	9
	3	281	118	402	(19)	383
Long-term derivative assets						
Foreign exchange contracts	–	315	–	315	–	315
Interest rate contracts	–	33	–	33	(3)	30
Commodity contracts	–	56	9	65	(5)	60
Other contracts	–	3	–	3	–	3
	–	407	9	416	(8)	408
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	–	(105)	–	(105)	–	(105)
Interest rate contracts	–	(675)	–	(675)	2	(673)
Commodity contracts	(9)	(229)	(76)	(314)	17	(297)
	(9)	(1,009)	(76)	(1,094)	19	(1,075)
Long-term derivative liabilities						
Foreign exchange contracts	–	(69)	–	(69)	–	(69)
Interest rate contracts	–	(308)	–	(308)	3	(305)
Commodity contracts	–	(319)	(75)	(394)	5	(389)
	–	(696)	(75)	(771)	8	(763)
Total net financial asset/(liability)						
Foreign exchange contracts	–	371	–	371	–	371
Interest rate contracts	–	(932)	–	(932)	–	(932)
Commodity contracts	(6)	(468)	(24)	(498)	–	(498)
Other contracts	–	12	–	12	–	12
	(6)	(1,017)	(24)	(1,047)	–	(1,047)

December 31, 2011	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	–	334	–	334	–	334
Interest rate contracts	–	12	–	12	(4)	8
Commodity contracts	1	66	86	153	(19)	134
Other contracts	–	10	–	10	–	10
	1	422	86	509	(23)	486
Long-term derivative assets						
Foreign exchange contracts	–	297	–	297	–	297
Interest rate contracts	–	25	–	25	(3)	22
Commodity contracts	–	208	45	253	(15)	238
Other contracts	–	5	–	5	–	5
	–	535	45	580	(18)	562
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	–	(279)	–	(279)	–	(279)
Interest rate contracts	–	(485)	–	(485)	4	(481)
Commodity contracts	–	(59)	(80)	(139)	19	(120)
	–	(823)	(80)	(903)	23	(880)
Long-term derivative liabilities						
Foreign exchange contracts	–	(91)	–	(91)	–	(91)
Interest rate contracts	–	(435)	–	(435)	3	(432)
Commodity contracts	–	(30)	(19)	(49)	15	(34)
	–	(556)	(19)	(575)	18	(557)
Total net financial asset/(liability)						
Foreign exchange contracts	–	261	–	261	–	261
Interest rate contracts	–	(883)	–	(883)	–	(883)
Commodity contracts	1	185	32	218	–	218
Other contracts	–	15	–	15	–	15
	1	(422)	32	(389)	–	(389)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2012	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(Fair value in millions of Canadian dollars)						
Commodity contracts – financial [1]						
Natural gas	8	Forward gas price	3.21	4.31	3.54	$/mmbtu[3]
Crude	(3)	Forward crude price	58.42	108.14	100.40	$/barrel
Power	(60)	Forward power price	50.25	68.25	55.98	$/MWH
Commodity contracts – physical [1]						
Natural gas	(12)	Forward gas price	2.88	5.10	3.67	$/mmbtu[3]
Crude	37	Forward crude price	51.13	116.56	92.49	$/barrel
NGL	1	Forward NGL price	0.00	2.54	1.42	$/gallon
Power	(1)	Forward power price	30.09	36.35	32.74	$/MWH
Commodity options [2]						
Natural gas	1	Option volatility	29.0%	36.0%	34.0%	
NGL	5	Option volatility	33.0%	104.0%	57.0%	
	(24)					

1 *Financial and physical forward commodity contracts are valued using a market approach valuation technique.*
2 *Commodity options contracts are valued using an option model valuation technique.*
3 *One million British thermal units (mmbtu).*

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of the Company's Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices and, for option contracts, price volatility. Changes in forward commodity prices would result in significantly different fair values for the Company's Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally speaking, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

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,	2012	2011
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of year	**32**	(24)
Total unrealized gains/(loss)		
Included in earnings [1]	**(69)**	31
Included in OCI	**13**	(41)
Purchases	**–**	8
Settlements	**–**	58
Level 3 net derivative asset/(liability) at end of year	**(24)**	32

1 *Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at December 31, 2012 or 2011.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totaled $66 million at December 31, 2012 (2011 – $57 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $246 million at December 31, 2012 (2011 – $285 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. At December 31, 2012, the fair value of this preferred share investment approximates its face value of $580 million (2011 – $580 million).

At December 31, 2012, the Company's long-term debt had a carrying value of $20,855 million (2011 – $19,605 million) and a fair value of $24,809 million (2011 – $22,620 million).

23. Income Taxes

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings before income taxes and extraordinary loss	**1,071**	2,030	1,008
Combined statutory income tax rate	**25.8%**	27.2%	28.8%
Income taxes at statutory rate	**276**	552	290
Increase/(decrease) resulting from:			
Deferred income taxes related to regulated operations	**(67)**	(35)	(62)
Higher/(lower) foreign tax rates	**(56)**	65	(38)
Tax rates and legislated tax changes	**9**	1	(15)
Non-taxable items, net	**(6)**	(16)	(8)
Intercompany sale of investments [1]	**56**	98	–
Noncontrolling interests in Limited Partnerships	**(79)**	(130)	55
Other	**(5)**	(9)	5
Income taxes before extraordinary loss	**128**	526	227
Effective income tax rate	**12.0%**	25.9%	22.5%

1 *In December 2012 and October 2011, Enbridge and certain wholly-owned subsidiaries of Enbridge sold certain assets to the Fund. As these transactions occurred between entities under common control of the Company, the intercompany gains realized as a result of these transfers have been eliminated, although current income tax expense of $56 million and $98 million remain as a charge to earnings in 2012 and 2011, respectively. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying entities; however, accounting recognition of such benefit is not permitted until such time as the entities are sold outside of the consolidated group.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings before income taxes and extraordinary loss			
Canada	**1,041**	694	759
United States	**(177)**	1,203	118
Other	**207**	133	131
	1,071	2,030	1,008
Current income taxes			
Canada	**130**	194	(24)
United States	**35**	(30)	43
Other	**3**	(6)	5
	168	158	24
Deferred income taxes			
Canada	**160**	30	136
United States	**(200)**	338	67
	(40)	368	203
Total income taxes before extraordinary loss	**128**	526	227

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2012**	2011
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,325)**	(1,499)
Investments	**(1,479)**	(973)
Regulatory liabilities	**(221)**	(197)
Other	**(144)**	(117)
Total deferred income tax liabilities	**(3,169)**	(2,786)
Deferred income tax assets		
Financial instruments	**380**	37
Pension and OPEB plans	**180**	145
Loss carryforwards	**161**	174
Other	**51**	29
Total deferred income tax assets	**772**	385
Less valuation allowance	**(27)**	(45)
Total deferred income tax assets, net	**745**	340
Net deferred income tax liabilities	**(2,424)**	(2,446)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 7)*	**167**	135
Deferred income taxes	**10**	41
Total deferred income tax assets	**177**	176
Liabilities		
Accounts payable and other *(Note 15)*	**–**	(7)
Deferred income taxes	**(2,601)**	(2,615)
Total deferred income tax liabilities	**(2,601)**	(2,622)
Net deferred income tax liabilities	**(2,424)**	(2,446)

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred income tax assets to an amount that will more likely than not be realized.

At December 31, 2012, the Company recognized the benefit of unused tax loss carryforwards of $183 million (2011 – $214 million) in Canada which start to expire in 2022 and beyond.

At December 31, 2012, the Company recognized the benefit of unused tax loss carryforwards of $222 million (2011 – $187 million) in the United States which start to expire in 2022 and beyond.

The Company has not provided for deferred income taxes on $548 million (2011 – $524 million) of foreign subsidiaries' undistributed earnings as at December 31, 2012 as such earnings are intended to be indefinitely reinvested in the operations and potential acquisitions. Upon distribution of these earnings in the form of dividends or otherwise, the Company would be subject to income taxes. It is not practicable to determine the income tax liability that might be incurred if these earnings were to be distributed.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of Income taxes. Income tax expense for the year ended December 31, 2012 included $1 million (2011 – $1 million; 2010 – $2 million recovery) of interest and penalties. As at December 31, 2012, interest and penalties of $10 million (2011 – $9 million) have been accrued.

The Company and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The Company is under examination by certain tax authorities for the 2007 to 2011 tax years. The material jurisdictions in which the Company is subject to potential examinations include the United States (Federal and Texas) and Canada (Federal, Alberta and Ontario).

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2012**	2011
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**18**	17
Gross increases for tax positions of current year	**38**	3
Gross decreases for tax positions of prior years	**3**	(1)
Reduction for lapse of statute of limitations	**(5)**	(1)
Unrecognized tax benefits at end of year	**54**	18

The unrecognized tax benefits at December 31, 2012, if recognized, would affect the Company's effective income tax rate. The gross increases for current year positions included $16 million in respect of filing positions based on substantively enacted tax law and $22 million in respect of a request for refund of Texas Gross Margin Tax. Although U.S. GAAP only permits recognition of tax positions based on enacted law it is widely accepted by the Canadian tax authorities to file and remit taxes based on substantively enacted tax law. It is anticipated that the law will be enacted in 2013.

24. Retirement and Postretirement 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, 2012 was used to determine the plan assets and 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, 2011	December 31, 2012
Gas Distribution	December 31, 2009	December 31, 2012
United States Plan	December 31, 2011	December 31, 2012

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.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health and dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS

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		OPEB	
December 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,686**	1,323	**243**	195
Service cost	**84**	61	**8**	6
Interest cost	**74**	73	**10**	11
Employees' contributions	**–**	–	**1**	1
Actuarial loss	**106**	270	**14**	28
Benefits paid	**(64)**	(54)	**(8)**	(7)
Effect of foreign exchange rate changes	**(5)**	5	**(2)**	2
Other	**(2)**	8	**(5)**	7
Benefit obligation at end of year	**1,879**	1,686	**261**	243
Change in plan assets				
Fair value of plan assets at beginning of year	**1,355**	1,314	**54**	41
Actual return on plan assets	**117**	16	**5**	1
Employer's contributions	**97**	72	**13**	13
Employees' contributions	**–**	–	**1**	1
Benefits paid	**(64)**	(54)	**(8)**	(7)
Effect of foreign exchange rate changes	**(3)**	3	**(1)**	1
Other	**(2)**	4	**(2)**	4
Fair value of plan assets at end of year	**1,500**	1,355	**62**	54
Underfunded status at end of year	**(379)**	(331)	**(199)**	(189)
Presented as follows:				
Accounts payable and other	**–**	–	**(5)**	(5)
Other long-term liabilities *(Note 17)*	**(379)**	(331)	**(194)**	(184)
	(379)	(331)	**(199)**	(189)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Discount rate	**4.2%**	4.5%	5.6%	**4.0%**	4.4%	5.6%
Average rate of salary increases	**3.7%**	3.5%	3.5%			

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
(millions of Canadian dollars)						
Benefits earned during the year	**84**	61	48	**8**	6	5
Interest cost on projected benefit obligations	**74**	73	72	**10**	11	11
Expected return on plan assets	**(93)**	(92)	(80)	**(3)**	(3)	(2)
Amortization of prior service costs	**2**	2	2	**–**	1	–
Amortization of actuarial loss	**51**	25	19	**2**	1	1
Net defined benefit costs on an accrual basis	**118**	69	61	**17**	16	15
Defined contribution benefit costs	**4**	4	5	**–**	–	–
Net benefit cost recognized in the Consolidated Statements of Earnings	**122**	73	66	**17**	16	15
Net amount recognized in OCI						
Net actuarial loss [1]	**42**	172	35	**10**	29	11
Net prior service cost/(credit) [2]	**–**	–	–	**–**	(1)	6
Total amount recognized in OCI	**42**	172	35	**10**	28	17
Total amount recognized in Comprehensive income	**164**	245	101	**27**	44	32

1 *Unamortized actuarial losses included in AOCI, before tax, were $388 million (2011 – $346 million) relating to the pension plans and $60 million (2011 – $51 million) relating to OPEB at December 31, 2012.*

2 *Unamortized prior service costs included in AOCI, before tax, were $4 million (2011 – $5 million) relating to OPEB at December 31, 2012.*

The Company estimates that approximately $24 million related to pension plans and $2 million related to OPEB at December 31, 2012 will be reclassified from AOCI into earnings in the next 12 months.

Regulatory adjustments are recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 5)*.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Discount rate	**4.5%**	5.6%	6.5%	**4.4%**	5.6%	6.3%
Average rate of return on pension plan assets	**7.1%**	7.3%	7.3%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.7%			

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	8.6%	4.5%	2029
Other Medical	4.5%	4.5%	–
United States Plan	7.6%	4.5%	2030

A 1% increase in the assumed medical care trend rate would result in an increase of $36 million in the benefit obligation and an increase of $3 million in benefit and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $29 million in the benefit obligation and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its 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.

EXPECTED RATE OF RETURN ON PLAN ASSETS

	Pension		OPEB	
Year ended December 31,	**2012**	2011	**2012**	2011
Canadian Plans	**6.9%**	7.0%		
United States Plan	**7.3%**	7.5%	**6.0%**	6.0%

TARGET MIX FOR PLAN ASSETS

	Liquids Pipelines Plan	Gas Distribution 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%

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, 2012, the pension assets were invested 59.1% (2011 – 56.7%) in equity securities, 32.4% (2011 – 36.6%) in fixed income securities and 8.5% (2011 – 6.7%) in other. The OPEB assets were invested 58.1% (2011 – 55.3%) in equity securities, 35.5% (2011 – 40.3%) in fixed income securities and 6.4% (2011 – 4.4%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $59 million (2011 – $77 million) have been excluded from the table below.

December 31,	2012 Level 1 [1]	2012 Level 2 [2]	2012 Level 3 [3]	2012 Total	2011 Level 1 [1]	2011 Level 2 [2]	2011 Level 3 [3]	2011 Total
(millions of Canadian dollars)								
Pension								
Cash and cash equivalents	**44**	**–**	**–**	**44**	14	–	–	14
Fixed income securities								
Canadian government bonds	**87**	**–**	**–**	**87**	115	–	–	115
Corporate bonds and debentures	**–**	**4**	**–**	**4**	–	4	–	4
Canadian corporate bond index fund	**196**	**–**	**–**	**196**	158	–	–	158
Canadian government bond index fund	**152**	**–**	**–**	**152**	157	–	–	157
United States debt index fund	**45**	**2**	**–**	**47**	62	–	–	62
Equity								
Canadian equity securities	**190**	**–**	**–**	**190**	148	–	–	148
United States equity securities	**24**	**–**	**–**	**24**	–	–	–	–
Global equity securities	**9**	**–**	**–**	**9**	–	–	–	–
Canadian equity funds	**64**	**39**	**–**	**103**	21	74	–	95
United States equity funds	**60**	**26**	**–**	**86**	170	89	–	259
Global equity funds	**255**	**159**	**–**	**414**	191	7	–	198
Private equity investment [4]	**–**	**–**	**61**	**61**	–	–	68	68
Real estate [5]	**–**	**–**	**24**	**24**	–	–	–	–
OPEB								
Cash and cash equivalents	**4**	**–**	**–**	**4**	3	–	–	3
Fixed income securities								
United States government and government agency bonds	**22**	**–**	**–**	**22**	22	–	–	22
Equity								
United States equity funds	**17**	**19**	**–**	**36**	15	14	–	29

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.*
5 *The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd 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:

	2012	2011
(millions of Canadian dollars)		
Balance at beginning of year	**68**	65
Unrealized and realized gains	**11**	8
Purchases and settlements, net	**6**	(5)
Balance at end of year	**85**	68

PLAN CONTRIBUTIONS BY THE COMPANY

Year ended December 31,	Pension **2012**	Pension 2011	OPEB **2012**	OPEB 2011
(millions of Canadian dollars)				
Total contributions	**97**	72	**13**	13
Contributions expected to be paid in 2013	**140**		**13**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2013	2014	2015	2016	2017	2018 – 2022
(millions of Canadian dollars)						
Expected future benefit payments	73	78	83	88	93	558

25. Other Income

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Net foreign currency gains	**71**	48	132
Allowance for equity funds used during construction	**1**	3	96
Interest income on affiliate loans	**20**	17	20
Interest income	**7**	3	17
Noverco preferred shares dividend income	**42**	30	15
OPEB recovery *(Note 5)*	**89**	–	–
Gain on acquisition *(Note 6)*	**–**	–	22
Other	**10**	16	16
	240	117	318

26. Changes in Operating Assets and Liabilities

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Accounts receivable and other	**(122)**	121	(878)
Accounts receivable from affiliates	**43**	(17)	8
Inventory	**42**	93	(124)
Deferred amounts and other assets	**(380)**	(320)	(16)
Accounts payable and other	**(319)**	421	642
Accounts payable to affiliates	**(48)**	41	(22)
Interest payable	**15**	7	31
Other long-term liabilities	**109**	57	(65)
	(660)	403	(424)

27. Related Party Transactions

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

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 were $6 million for the year ended December 31, 2012 (2011 – $6 million; 2010 – $7 million).

Certain wholly-owned subsidiaries within the Gas Distribution and Gas Pipelines, Processing and Energy Services segments have transportation commitments with several joint venture affiliates that are accounted for using the equity method. Total amounts charged for transportation services were $127 million, $106 million and $102 million for the years ended December 31, 2012, 2011 and 2010, respectively.

LONG-TERM NOTE RECEIVABLE FROM AFFILIATE

Amounts receivable from affiliates include a series of loans to Vector totaling $178 million (2011 – $190 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates from 5% to 8%.

28. Commitments and Contingencies

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,668 million which are expected to be paid within the next five years and $1,023 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $329 million in aggregate. Estimated annual lease payments for the years ending December 31, 2013 through 2017 are $40 million, $41 million, $39 million, $38 million and $34 million, respectively, and $137 million thereafter. Total rental expense for operating leases, included in Operating and administrative expense, were $31 million, $28 million and $23 million for the years ended December 31, 2012, 2011 and 2010, respectively.

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 21.8% combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

ENVIRONMENTAL LIABILITIES

As at December 31, 2012, the Company had $107 million (2011 – $175 million) included in current liabilities and $18 million (2011 – $32 million) included in Other long-term liabilities, which have been accrued for costs incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of EEP's liquids and natural gas assets and penalties that have been or are expected to be assessed.

LAKEHEAD SYSTEM LINE 14 CRUDE OIL RELEASE

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. The CAOs required EEP to take certain corrective actions, some of which have already been completed and some are still ongoing, as part of an overall plan for its Lakehead System. A notable part of the CAOs was to hire an independent third party pipeline expert to review and assess EEP's overall integrity program. An independent third party expert was contracted during the third quarter of 2012 and its work is currently ongoing.

Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. The pressure restrictions will remain in place until such time EEP can demonstrate that the root cause of the incident has been remediated.

EEP has revised the disclosed estimate for repair and remediation related costs associated with this crude oil release as at December 31, 2012 to approximately US$10 million ($1 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenue, and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge's comprehensive insurance policy, although it does not expect any recoveries to be significant.

LAKEHEAD SYSTEM LINES 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 released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the release, a unified command structure was established under the jurisdiction of the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other federal, state and local agencies.

During the second quarter of 2012, local authorities allowed the Kalamazoo River and Morrow Lake, which were affected by the Line 6B crude oil release, to be re-opened for recreational use. EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations, including reassessment, remediation and restoration of the area, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the PHMSA related to the July 26, 2010 Line 6B crude oil release, which resulted in payment of a US$3.7 million civil penalty in the third quarter of 2012. EEP included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012 the National Transportation Safety Board presented the results of its investigation into the Line 6B crude oil release and subsequently publicly posted its final report on July 26, 2012.

As at December 31, 2012, EEP revised the total incident cost accrual to US$820 million ($137 million after-tax attributable to Enbridge), primarily due to an estimate of extended oversight by regulators and additional legal costs associated with various lawsuits, which is an increase of US$55 million ($8 million after-tax attributable to Enbridge) from its estimate at December 31, 2011. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above. On October 3, 2012, EEP received a letter from the EPA regarding a Proposed Order for potential incremental containment and active recovery of submerged oil. EEP is in discussions with the EPA regarding the agency's intent with respect to certain elements of the Proposed Order and the appropriate scope of these activities. The nature and scope of any additional remediation activities that regulators may require is currently uncertain. Studies and additional technical evaluation by EEP, the EPA and other regulatory agencies may need to be completed before a final determination of any additional remediation activities can be determined. EEP has accrued the estimated costs it deemed likely to be incurred. However, when a final determination of the appropriate nature and scope of any additional remediation is made, it could result in significant cost being accrued.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 2012. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

LINE 6A CRUDE OIL RELEASE

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that 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. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by 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 near Romeoville, Illinois in September 2010 for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed.

In connection with this crude oil release, the cost estimate as at December 31, 2012 remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. 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. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and one of Enbridge's subsidiaries. The insurance 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 remediation spending through December 31, 2012, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

For the years ended December 31, 2012 and 2011, EEP recognized US$170 million ($24 million after-tax attributable to Enbridge) and US$335 million ($50 million after-tax attributable to Enbridge), respectively, of insurance recoveries as reductions to Environmental costs in the Consolidated Statements of Earnings. As at December 31, 2012, EEP had recorded total insurance recoveries of US$505 million ($74 million after-tax attributable to Enbridge) for the Line 6B crude oil release and expects to recover the balance of the aggregate liability insurance coverage of US$145 from its insurers in future periods. EEP will record receivables for additional amounts received through insurance recoveries during the period it deems recovery to be probable.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability.

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 30 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. Based on the current status of these cases, EEP does not expect the outcome of these actions to be material. As noted above, on July 2, 2012, PHMSA announced a NOPV related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. 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 the Illinois 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.

29. 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. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations; warranties or covenants; loss or damages to property; environmental liabilities; changes in laws; valuation differences; litigation; and contingent liabilities. 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 Company may also indemnify for breaches of representations; warranties or covenants; changes in laws; intellectual property rights infringement; and litigations.

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. 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.

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2012 [1]	2011 [1]	2010 [1]	2009 [2]	2008 [2]
(millions of Canadian dollars; per share amounts in Canadian dollars)					
Earnings attributable to common shareholders					
Liquids Pipelines	**726**	505	531	445	328
Gas Distribution	**207**	(88)	150	186	161
Gas Pipelines, Processing and Energy Services	**(478)**	305	125	428	767
Sponsored Investments	**282**	269	98	141	111
Corporate	**(127)**	(171)	40	355	(46)
	610	820	944	1,555	1,321
Earnings per common share [3]	**0.79**	1.09	1.27	2.13	1.84
Diluted earnings per common share [3]	**0.78**	1.08	1.26	2.12	1.82
Adjusted earnings					
Liquids Pipelines	**684**	536	511	454	332
Gas Distribution	**176**	173	162	154	141
Gas Pipelines, Processing and Energy Services	**154**	163	123	116	141
Sponsored Investments	**263**	244	206	151	101
Corporate	**(28)**	(16)	(25)	(20)	(38)
	1,249	1,100	977	855	677
Adjusted earnings per common share [3,4]	**1.62**	1.46	1.32	1.17	0.94
Cash flow data					
Cash provided by operating activities	**2,874**	3,371	1,877	2,017	1,372
Cash used in investing activities	**(6,204)**	(5,079)	(3,902)	(3,306)	(2,853)
Cash provided by financing activities	**4,395**	2,030	1,957	1,082	1,840
Dividends					
Common share dividends declared	**895**	759	648	555	489
Dividends paid per common share [3]	**1.13**	0.98	0.85	0.74	0.66
Shares outstanding *(millions)*					
Weighted average common shares outstanding [3]	**772**	751	741	728	720
Diluted weighted average common shares outstanding [3]	**785**	761	748	733	725

1 *Financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*
3 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*
4 *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 not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 9.*

FIVE-YEAR CONSOLIDATED HIGHLIGHTS

	2012 [1]	2011 [1]	2010 [1]	2009 [2]	2008 [2]
(per share amounts in Canadian dollars)					
Common share trading (TSX) [3]					
High	**43.05**	38.17	29.13	24.46	21.64
Low	**35.39**	27.05	23.02	17.60	16.55
Close	**43.02**	38.09	28.14	24.32	19.78
Volume *(millions)*	**365**	396	461	457	585
Financial ratios					
Return on average equity [4]	**6.3%**	11.3%	14.1%	22.2%	22.2%
Return on average capital employed [5]	**3.5%**	4.5%	5.0%	8.9%	9.9%
Debt to debt plus equity [6]	**67.1%**	72.9%	73.7%	66.2%	66.6%
Dividend payout ratio [7]	**69.8%**	67.1%	64.4%	63.0%	70.2%
Operating data					
Liquids Pipelines – Average deliveries *(thousands of barrels per day)*					
Canadian Mainline [8]	**1,646**	1,554	1,537	1,562	1,522
Regional Oil Sands System [9]	**414**	334	291	259	202
Spearhead Pipeline	**151**	82	144	121	110
Gas Distribution – Enbridge Gas Distribution (EGD)					
Volumes *(billions of cubic feet)*	**395**	426	409	408	433
Number of active customers *(thousands)* [10]	**2,032**	1,997	1,963	1,937	1,898
Heating degree days [11]					
Actual	**3,194**	3,597	3,466	3,767	3,802
Forecast based on normal weather	**3,532**	3,602	3,546	3,514	3,543
Gas Pipelines, Processing and Energy Services – Average throughput volume *(millions of cublic feet per day)*					
Alliance Pipeline US	**1,553**	1,564	1,600	1,601	1,609
Vector Pipeline	**1,534**	1,525	1,456	1,334	1,321
Enbridge Offshore Pipelines	**1,540**	1,595	1,962	2,037	1,672

1 *Financial ratios have been calculated using information from financial statements prepared in accordance with U.S. GAAP.*
2 *Financial ratios have been calculated using information from financial statements prepared in accordance with Canadian GAAP.*
3 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*
4 *Earnings applicable to common shareholders divided by average equity.*
5 *Sum of after-tax earnings and after-tax interest expense, divided by weighted average capital employed. Capital employed is equal to the sum of equity, Enbridge Gas Distribution preferred shares, deferred income taxes, deferred credits and total debt (including short-term borrowings).*
6 *Total debt (including short-term borrowings) divided by the sum of total debt and equity.*
7 *Dividends per common share divided by adjusted earnings per common share.*
8 *Canadian Mainline includes deliveries ex-Gretna, Manitoba, which is made up of United States and eastern Canada deliveries originating from western Canada.*
9 *Volumes are for the Athabasca mainline and the Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.*
10 *Number of active customers is the number of natural gas consuming EGD customers at the end of the period.*
11 *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.*

GLOSSARY

AFUDC	allowance for funds used during construction
Alliance	Alliance System
Amherstburg	Amherstburg Solar Project
AOCI	accumulated other comprehensive income/(loss)
ASU	Accounting Standards Update
bcf/d	billion cubic feet per day
bpd	barrels per day
CLT	Canadian Local Toll
CSR	corporate social responsibility
CTS	Competitive Toll Settlement
EECI	Enbridge Energy Company, Inc.
EEDI	Enbridge Energy Distribution 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.
EPI	Enbridge Pipelines Inc.
EUB	New Brunswick Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
Greenwich	Greenwich Wind Energy Project
IJT	International Joint Tariff
IR	incentive regulation
ISO	incentive stock options
ITS	incentive tolling settlement
JRP	Joint Review Panel
MD&A	Management's Discussion and Analysis
mmcf/d	million cubic feet per day
MW	megawatts
MWH	megawatt hours
NEB	National Energy Board
NGL	natural gas liquids
Northern Gateway	proposed Northern Gateway Project
OCI	other comprehensive income/(loss)
OEB	Ontario Energy Board
Offshore	Enbridge Offshore Pipelines
OPEB	other postretirement benefits
ORM Plan	Operational Risk Management Plan
PBSO	performance based stock options
PPA	power purchase agreement
PRA	Peace River Arch
PSU	performance stock units
ROE	return on equity
RSU	restricted stock units
Seaway Pipeline	Seaway Crude Pipeline System
SEC	Securities and Exchange Commission
Silver State	Silver State North Solar Project
TEP	Texas Express Pipeline
the Company	Enbridge Inc.
the Fund	Enbridge Income Fund
Tilbury	Tilbury Solar Project
U.S. GAAP	accounting principles generally accepted in the United States of America
Vector	Vector Pipeline
WCSB	Western Canadian Sedimentary Basin
WRGGS	Walker Ridge Gas Gathering System

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 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 J – ENB.PR.U
Series B – ENB.PR.B	Series L – ENB.PF.U
Series D – ENB.PR.D	Series N – ENB.PR.N
Series F – ENB.PR.F	Series P – ENB.PR.P
Series H – ENB.PR.H	Series R – ENB.PR.T

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
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Toll free: 800.387.0825
Internet: *www.canstockta.com/investorinquiry*

CIBC Mellon Trust Company also has offices in Halifax, Montreal, Calgary and Vancouver.

1 *Canadian Stock Transfer Company Inc. acts as the Administrative Agent for CIBC Mellon Trust Company*

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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 report is available on the Company's website at *csr.enbridge.com*.

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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 1,300 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 10,000 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