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This Management's Discussion and Analysis (MD&A) dated February 13, 2012 should be read in conjunction with the accompanying audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2011 which are prepared in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2011. "TransCanada" or "the Company" includes TransCanada Corporation and its subsidiaries, unless otherwise indicated. Amounts are stated in Canadian dollars unless otherwise indicated. Abbreviations and acronyms not defined in this MD&A are defined in the Glossary of Terms in the Company's 2011 Annual Report.

TRANSCANADA OVERVIEW

With more than 60 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

Today, TransCanada is:

- One of the largest natural gas transmission companies in North America with a network of wholly- and partially-owned natural gas pipelines extending more than 68,500 kilometres (km) (42,500 miles), tapping into virtually all major gas supply basins;
- One of the continent's largest providers of natural gas storage and related services with approximately 380 billion cubic feet (Bcf) of storage capacity;
- The largest private sector power company in Canada and owns or has interests in over 10,800 megawatts (MW) of power generation in Canada and the United States (U.S.); and
- A significant player in the oil transmission business with the start up of the Keystone oil pipeline system and the large expansion opportunity to the U.S. Gulf Coast (Keystone XL).

In pursuing its vision to be the leading energy infrastructure company in North America, TransCanada continually strives to execute a large portfolio of attractive growth projects. Each of these new projects are large scale, long life assets supported by strong business fundamentals and long-term contracts that provide attractive and sustainable returns to shareholders over a long-term time horizon.

With assets of approximately $49 billion and a substantial growth portfolio, TransCanada believes it is well positioned to build on its track record of strong and sustainable earnings, cash flow and dividends. Since the spring of 2010, TransCanada has brought $10 billion of growth projects in service and is positioned to complete another $12 billion of new projects by the end of 2014.

TransCanada's 2011 Key Developments
The Company advanced its significant entry into the oil pipelines transmission business:

- Achieved full commercial operations in February 2011 on the sections of the Keystone crude oil pipeline system, extending from Hardisty, Alberta to Wood River and Patoka in Illinois (Wood River/Patoka) and from Steele City, Nebraska, to Cushing, Oklahoma (Cushing Extension) and recorded earnings before interest, taxes, depreciation and amortization (EBITDA) of $0.6 billion in Keystone's first eleven months of operations;
- Received a favourable Final Environmental Impact Statement (FEIS) in August from the U.S. Department of State (DOS) for Keystone XL;
- Secured commercial support for an extension and expansion of Keystone XL to provide crude oil transportation service from Hardisty, Alberta to Houston, Texas; and
- Received notice that the DOS had denied the Presidential Permit for Keystone XL, based on the DOS's position that it did not have sufficient time to receive and review additional information necessary to assess alternative routes that

would avoid the Sandhills region of Nebraska. TransCanada will submit a revised Presidential Permit application to the DOS.

The Company completed construction, placed in service and advanced the following initiatives in Natural Gas Pipelines, which included connecting new shale and unconventional natural gas supply:

- Continued to advance pipeline development projects on the Alberta System to transport new natural gas supply from the Horn River and Montney shale basins in northeastern British Columbia (B.C.) as well as the Deep Basin in Alberta:
  - Received approval from the National Energy Board (NEB) for the construction of natural gas pipeline projects on the Alberta System with capital costs totalling approximately $910 million including the $275 million Horn River pipeline; and
  - Filed additional pipeline development projects with the NEB costing approximately $810 million that included new agreements to further extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of $230 million.
- Placed in service:
  - The US$630 million Bison pipeline in January 2011, which delivers natural gas from the Powder River Basin in Wyoming to an interconnection with the Northern Border Pipeline; and
  - The US$360 million Guadalajara pipeline in June 2011, which transports natural gas from Manzanillo to Guadalajara in Mexico.
- Filed a comprehensive application, with the NEB in September 2011, to change the business structure and the terms and conditions of service for the Canadian Mainline to address tolls for 2012 and 2013;
- Closed the sale of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$605 million, which included US$81 million or 25 per cent of GTN LLC debt outstanding; and
- Filed a supplemental application with the NEB to construct $130 million of new pipeline infrastructure on the Canadian Mainline to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets.

The Company completed, placed in service and advanced the following power generation assets in Energy:

- Placed in service the US$500 million Coolidge generation station in May 2011, capable of producing 575 MW;
- Completed construction and placed in service the Montagne-Sèche and phase one of the Gros-Morne wind farms in November 2011, capable of producing 159 MW of renewable energy;
- Executed an agreement in December 2011 for the purchase of nine Ontario solar projects, with a combined capacity of 86 MW, for approximately $470 million that are expected to come into service between late 2012 and mid-2013; and
- Continued to progress the $4.8 billion refurbishment and restart of two reactors at the Bruce Power nuclear facility in Ontario. TransCanada's expected net capital cost of the project is $2.4 billion. Fuelling of both Unit 1 and Unit 2 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012.

The following are other key developments in Energy in 2012.

- Both units at Sundance A were not operational throughout 2011 and have been subject to force majeure and economic destruction claims by the asset owner. TransCanada has recorded revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the power purchase arrangement (PPA). An arbitration hearing is scheduled for April 2012 to hear both claims.

- Since July 2011, spot prices for capacity sales applicable to Ravenswood have been negatively impacted by the manner in which New York Independent System Operator (NYISO) has applied pricing rules for a new power plant in the New York City Zone J market. TransCanada has filed formal complaints with the Federal Energy Regulatory Commission (FERC) that are pending.
- TransCanada reached a formal agreement to use an arbitration process to settle the Oakville contract dispute resulting from the termination of a 20-year Clean Energy Supply contract with the Ontario Power Authority (OPA).

TransCanada's Businesses Are Organized Into Three Segments – Natural Gas Pipelines, Oil Pipelines and Energy

The Natural Gas Pipelines and Oil Pipelines businesses consist of large-scale natural gas and crude oil pipelines, respectively, primarily situated in Canada and the U.S. TransCanada is also the general partner of TC PipeLines, LP, a master limited partnership that owns interests in U.S. natural gas pipelines.

Natural Gas Pipelines
TransCanada's natural gas pipeline systems consist of a network of more than 57,000 km (35,500 miles) of wholly owned natural gas pipelines, and more than 11,500 km (7,000 miles) of partially owned natural gas pipelines. The network connects major natural gas supply basins and markets, transporting approximately 20 per cent of the natural gas consumed in North America or 14 Bcf of natural gas per day, which is delivered to local distribution companies, power generation facilities and other businesses in markets across North America. The Company's U.S. Natural Gas Pipelines include regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf.

TransCanada is also pursuing additional natural gas pipeline projects to diversify both the supply and market sides of this business and add incremental value to existing assets. Key areas of focus include greenfield development opportunities that connect TransCanada's natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies and that play a critical role in satisfying increased natural gas demand in North America especially for power generation. TransCanada continues to advance opportunities to optimize its existing natural gas pipelines systems to respond to the changing flow patterns of natural gas supply in North America.

Oil Pipelines
The Company's Keystone crude oil pipeline system currently operates on the Wood River/Patoka and the Cushing Extension sections and has a nominal design capacity of 591,000 barrels per day (bbl/d). With increasing production of crude oil in Alberta and new crude oil discoveries in the U.S., including the Bakken shale play in Montana and North Dakota, combined with growing demand for secure, reliable sources of energy, TransCanada has identified additional opportunities to develop new oil pipeline capacity.

The Company plans to expand and extend the existing system through Keystone XL which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

Energy
TransCanada's Energy segment primarily consists of a portfolio of essential power generation assets in select regions of Canada and the U.S., and unregulated natural gas storage assets in Alberta.

TransCanada owns, controls or is developing more than 10,800 MW of power generation, comprising a diverse portfolio that includes power sourced from natural gas, nuclear, coal, hydro, wind and solar assets. TransCanada's power business is primarily located in Canada in Alberta, Ontario and Québec, in the northeastern U.S. mainly in the New England states and New York, and in Arizona. The assets are largely underpinned by long-term tolling contracts or represent low-cost baseload generation and essential capacity.

From offices in Western Canada, Ontario and the northeastern U.S., TransCanada complements these assets by conducting wholesale and retail electricity marketing and trading throughout North America.

In addition to power generation assets in the Energy business, TransCanada owns or controls approximately 130 Bcf of unregulated natural gas storage capacity in Alberta, or approximately one-third of all storage capacity in the province. Combined with the regulated natural gas storage in Michigan included in the Natural Gas Pipelines segment, TransCanada provides natural gas storage and related services for approximately 380 Bcf of capacity.

TRANSCANADA'S STRATEGY

TransCanada's vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where it has or can develop a significant competitive advantage. TransCanada's key strategies continue to evolve with the Company's growth and development and its changing business environment. TransCanada's corporate strategy integrates four fundamental value-creating activities:

- **Maximize the full-life value of TransCanada's infrastructure assets and commercial positions**
- **Commercially develop and physically execute new asset investment programs**
- **Cultivate a focused portfolio of high-quality development options**
- **Maximize TransCanada's competitive strengths**

Maximize the full-life value of TransCanada's infrastructure assets and commercial positions
TransCanada relies on a low-risk business model to maximize the full-life value of existing assets and commercial positions. The Company's pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flows and earnings. In Energy, highly efficient, large-scale power generation facilities supply power markets through long-term power purchase and sale agreements and low-volatility, shorter-term commercial arrangements. TransCanada's growing investments in natural gas, nuclear, wind, hydro-power, and solar generating facilities demonstrate the Company's commitment to clean, sustainable energy. Long-life infrastructure assets and long-term commercial arrangements are expected to continue as cornerstones of TransCanada's business model.

Commercially develop and physically execute new asset investment programs
TransCanada's expertise, scale and financial capacity enable access to attractive commercial, financing and input cost arrangements that influence the quality of projects, notably the current $12 billion capital program. These projects are expected to provide further contributions to the Company's earnings over the next three years as they are put in service. Success in this capital program requires effective performance in engineering and in project set-up and delivery. It also requires expert regulatory, legal and financing support, as well as outstanding operational set-up. TransCanada's model for managing construction risks and maximizing capital productivity helps ensure disciplined attention to quality, cost and schedule that produces superior service for its customers and quality returns to shareholders. Many of these functional capabilities also create the basis for successful acquisition and integration of new energy and pipeline facilities, an important dimension of the growth strategy.

Cultivate a focused portfolio of high-quality development options
The Company's core regions within North America are the focus of pipelines and energy growth initiatives. TransCanada will continue to pursue opportunities to connect long-life shale and conventional natural gas resources in Western and Northern Canada, as well as Alaska, the U.S. Rockies, the U.S. Midcontinent and the U.S. Gulf Coast supply regions. TransCanada will also continue to pursue opportunities to connect growing crude oil volumes from the Alberta oil sands and U.S. sources, including the Bakken formation in Montana and North Dakota, to preferred North American markets. The Company will continue to assess energy infrastructure acquisition opportunities that complement its existing pipeline network and provide access to new supply and market regions. In Energy, the Company will continue to focus on low-cost, long-life baseload power generating and natural gas storage assets supported by firm, long-term contracts with reputable and creditworthy counterparties. Selected opportunities will be advanced to full development and construction when market conditions are appropriate and project risks are manageable.

Maximize TransCanada's competitive strengths

TransCanada continues to build competitive strength in areas that directly drive long-term shareholder value. At the core of the Company's competitive advantage are powerful capabilities in strategy development, implementation, and continuous improvement. The Company relies on its scale, presence, operating capabilities, leadership and teams to compete effectively and deliver outstanding value to customers. A disciplined approach to capital investment combined with access to sizeable amounts of competitive-cost capital allows the Company to create significant shareholder value from its large capital projects. TransCanada recognizes that constructive relationships with key customers and stakeholders are critically important in the long-term energy infrastructure business. TransCanada values its reputation for consistent financial performance and long-term financial stability. The Company clearly communicates its financial performance to equity and debt investors, providing insight into both value upside and business risks. We work to sustain the trust and support of our long-term investors and to attract new investors who see long-term value in our disciplined approach to the energy infrastructure business. The Company continues to identify and build on all aspects of competitive strength.

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE-YEAR CONSOLIDATED FINANCIAL DATA

(millions of dollars except per share amounts)	**2011**	2010	2009
Income Statement			
Revenues	**9,139**	8,064	8,181
Comparable EBITDA[1]	**4,806**	3,941	4,107
Net Income Attributable to Common Shares	**1,527**	1,227	1,374
Comparable Earnings[1]	**1,565**	1,361	1,325
Per Share Data			
Net Income per Common Share			
Basic	**$2.18**	$1.78	$2.11
Diluted	**$2.17**	$1.77	$2.11
Comparable Earnings per Common Share[1]	**$2.23**	$1.97	$2.03
Dividends Declared			
Per Common Share	**$1.68**	$1.60	$1.52
Per Series 1 Preferred Share[2]	**$1.15**	$1.15	$0.29
Per Series 3 Preferred Share[2]	**$1.00**	$0.80	–
Per Series 5 Preferred Share[2]	**$1.10**	$0.65	–
Cash Flows			
Funds Generated from Operations[1]	**3,663**	3,331	3,080
Decrease/(Increase) in Operating Working Capital	**310**	(249)	(90)
Net Cash Provided by Operations	**3,973**	3,082	2,990
Capital Expenditures	**3,274**	5,036	5,417
Acquisitions, Net of Cash Acquired	**–**	–	902
Balance Sheet			
Total Assets	**48,995**	46,794	43,841
Total Long-Term Liabilities	**24,326**	23,220	21,959

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable Earnings, Comparable Earnings per Common Share and Funds Generated from Operations.

(2) The Company issued Series 1, 3 and 5 preferred shares in September 2009, March 2010 and June 2010, respectively, rounded to nearest cent.

HIGHLIGHTS

Earnings

- Net Income Attributable to Common Shares was $1.5 billion or $2.18 per share in 2011 compared to $1.2 billion or $1.78 per share, respectively, in 2010.
- TransCanada's Comparable Earnings in 2011 were $1.6 billion or $2.23 per share, a 13 per cent increase on a per share basis compared to the $1.4 billion or $1.97 per share reported in 2010.

Cash Flow

- Funds Generated from Operations were $3.7 billion in 2011, an increase of $0.4 billion or 10 per cent from $3.3 billion in 2010.
- TransCanada invested $3.3 billion in its Natural Gas Pipelines, Oil Pipelines and Energy capital projects in 2011, including the following:
  - capital expenditures of $0.9 billion for Natural Gas Pipelines projects, including expansion of the Alberta System and completion of Bison and Guadalajara;
  - capital expenditures of $1.2 billion for Keystone; and
  - capital expenditures of $1.1 billion for Energy projects, including the refurbishment and restart of Bruce A Units 1 and 2, completion of Coolidge and construction of Cartier Wind, including completion of Montagne-Sèche and phase one of the Gros-Morne project.
- In 2011, TransCanada issued approximately $1.6 billion of long-term debt and $200 million of common shares, primarily comprising the following:
  - in December 2011, TC PipeLines, LP made a draw of US$300 million on its senior revolving credit facility;
  - in November 2011, the issuance of $750 million of medium-term notes;
  - in June 2011, TC PipeLines, LP issued US$350 million of senior notes; and
  - in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of approximately 5 million common shares from treasury in lieu of making cash dividend payments totalling $202 million.

Balance Sheet

- Total assets increased by $2.2 billion to $49.0 billion in 2011 from 2010, primarily due to investments in capital projects, described above.
- TransCanada's Equity Attributable to Controlling Interests increased by $0.6 billion to $17.3 billion in 2011 from 2010.

Dividends

- On February 13, 2012, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares by five per cent to $0.44 per share from $0.42 per share for the quarter ending March 31, 2012. This was the twelfth consecutive year in which the common share dividend was increased. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2012, and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2012.

Refer to the Results of Operations and Liquidity and Capital Resources sections in this MD&A for further discussion of these highlights.

Reconciliation of Non-GAAP Measures

Year ended December 31, 2011 *(millions of dollars)*	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**2,967**	**587**	**1,338**	**(86)**	**4,806**
Depreciation and amortization	**(986)**	**(130)**	**(398)**	**(14)**	**(1,528)**
Comparable EBIT	**1,981**	**457**	**940**	**(100)**	**3,278**
Other Income Statement Items					
Comparable interest expense					**(939)**
Interest expense of joint ventures					**(55)**
Comparable interest income and other					**60**
Comparable income taxes					**(595)**
Net income attributable to non-controlling interests					**(129)**
Preferred share dividends					**(55)**
Comparable Earnings					**1,565**
Specific items (net of tax):					
Risk management activities(1)					**(38)**
Net Income Attributable to Common Shares					**1,527**

Year ended December 31, 2011 *(millions of dollars except per share amounts)*	**2011**
Comparable Interest Expense	**(939)**
Specific item:	
Risk management activities(1)	**2**
Interest Expense	**(937)**
Comparable Interest Income and Other	**60**
Specific item:	
Risk management activities(1)	**(5)**
Interest Income and Other	**55**
Comparable Income Taxes	**(595)**
Specific item:	
Risk management activities(1)	**22**
Income Taxes Expense	**(573)**
Comparable Earnings per Common Share	**$2.23**
Specific item (net of tax):	
Risk management activities(1)	**(0.05)**
Net Income per Common Share	**$2.18**

Reconciliation of Non-GAAP Measures

Year ended December 31, 2010 *(millions of dollars)*	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,915	–	1,125	(99)	3,941
Depreciation and amortization	(977)	–	(377)	–	(1,354)
Comparable EBIT	1,938	–	748	(99)	2,587
Other Income Statement Items					
Comparable interest expense					(701)
Interest expense of joint ventures					(59)
Comparable interest income and other					94
Comparable income taxes					(400)
Net income attributable to non-controlling interests					(115)
Preferred share dividends					(45)
Comparable Earnings					1,361
Specific items (net of tax):					
Valuation provision for MGP					(127)
Risk management activities[1]					(7)
Net Income Attributable to Common Shares					1,227

Year ended December 31, 2010 *(millions of dollars except per share amounts)*	**2010**
Comparable Income Taxes	(400)
Specific items:	
Valuation provision for MGP	19
Risk management activities[1]	1
Income Taxes Expense	(380)
Comparable Earnings per Common Share	$1.97
Specific items:	
Valuation provision for MGP	(0.18)
Risk management activities[1]	(0.01)
Net Income per Common Share	$1.78

Reconciliation of Non-GAAP Measures

Year ended December 31, 2009 *(millions of dollars)*	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	3,093	–	1,131	(117)	4,107
Depreciation and amortization	(1,030)	–	(347)	–	(1,377)
Comparable EBIT	2,063	–	784	(117)	2,730
Other Income Statement Items					
Comparable interest expense					(954)
Interest expense of joint ventures					(64)
Comparable interest income and other					121
Comparable income taxes					(406)
Net income attributable to non-controlling interests					(96)
Preferred share dividends					(6)
Comparable Earnings					1,325
Specific items (net of tax):					
Dilution gain from reduced interest in TC PipeLines, LP					18
Risk management activities[1]					1
Income tax adjustments					30
Net Income Attributable to Common Shares					1,374

Year ended December 31, 2009 *(millions of dollars except per share amounts)*	**2009**
Comparable Income Taxes	(406)
Specific items:	
Dilution gain from reduced interest in TC PipeLines, LP	(11)
Income tax adjustments	30
Income Taxes Expense	(387)
Comparable Earnings per Common Share	$2.03
Specific items:	
Dilution gain from reduced interest in TC PipeLines, LP	0.03
Risk management activities[1]	–
Income tax adjustments	0.05
Net Income per Common Share	$2.11

[1] For the year ended *(millions of dollars)*	**2011**	2010	2009
Risk Management Activities Gains/(Losses):			
U.S. Power derivatives	**(48)**	2	–
Canadian Power derivatives	**(3)**	–	–
Natural Gas Storage proprietary inventory and derivatives	**(6)**	(10)	1
Interest rate derivatives	**2**	–	–
Foreign exchange derivatives	**(5)**	–	–
Income taxes attributable to risk management activities	**22**	1	–
Risk Management Activities	**(38)**	(7)	1

RESULTS OF OPERATIONS

TransCanada had Net Income Attributable to Common Shares of $1,527 million or $2.18 per share in 2011 compared to $1,227 million or $1.78 per share and $1,374 million or $2.11 per share in 2010 and 2009, respectively.

Comparable Earnings in 2011, 2010 and 2009 were $1,565 million or $2.23 per share, $1,361 million or $1.97 per share and $1,325 million or $2.03 per share, respectively. Comparable Earnings in 2011 excluded $38 million of net unrealized after-tax losses ($60 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings in 2010 excluded a $127 million after-tax ($146 million pre-tax) valuation provision for advances to the Aboriginal Pipeline Group (APG) for the Mackenzie Gas Project (MGP) and $7 million of net unrealized after-tax losses ($8 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings in 2009 excluded $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates, an $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced interest in TC PipeLines, LP following a public offering of TC PipeLines, LP common units in fourth quarter 2009 and a $1 million net unrealized after-tax gain ($1 million pre-tax) resulting from changes in the fair value of certain risk management activities.

Comparable Earnings increased $204 million or $0.26 per share in 2011 compared to 2010 and included the following:

- increased Comparable Earnings Before Interest and Taxes (EBIT) from Natural Gas Pipelines primarily due to incremental earnings from Bison and Guadalajara which were placed in service in January 2011 and June 2011, respectively, lower general, administrative and support costs as well as lower business development spending, partially offset by lower revenues from certain U.S. Pipelines and the negative impact of a weaker U.S. dollar;
- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;
- increased Comparable EBIT from Energy primarily due to higher realized power prices for Western Power and incremental earnings from Halton Hills and Coolidge, partially offset by lower contributions from Bruce B, Natural Gas Storage and U.S. Power;
- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service, and higher interest expense as a result of U.S. dollar-denominated debt issuances in June and September 2010, partially offset by gains on derivatives used to manage the Company's exposure to rising interest rates in 2011 compared to losses incurred in 2010 and the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense;
- decreased Comparable Interest Income and Other primarily due to lower realized gains in 2011 compared to 2010 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income;
- increased Comparable Income Taxes primarily due to higher pre-tax earnings in 2011 and higher positive income tax adjustments in 2010 compared to 2011;
- increased Non-Controlling Interests due to the sale of a 25 per cent interest in GTN LLC and Bison LLC to TC PipeLines, LP in May 2011 and the reduction in the Company's ownership interest in TC PipeLines, LP; and
- increased Preferred Share Dividends recorded on preferred shares issued in 2010.

Comparable Earnings increased $36 million and decreased $0.06 per share in 2010 compared to 2009. The increase in Comparable Earnings was primarily due to increased capitalized interest relating to Keystone and other capital projects. This increase was partially offset by decreased EBIT from Natural Gas Pipelines and Energy as discussed later. The decrease in Comparable Earnings on a per share basis reflected the issuance of 58.4 million common shares in second quarter 2009 and common shares issued in 2010 and 2009 under the Company's DRP.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. operations is significantly offset by other U.S. dollar-denominated items as set out in the following table. The resultant pre-tax net exposure is managed using derivatives, further reducing the Company's exposure to changes in Canadian-U.S. foreign exchange rates. The average exchange rate to convert a U.S. dollar to a Canadian dollar for the year ended December 31, 2011 was 0.99 (2010 –1.03; 2009 – 1.14).

Summary of Significant U.S. Dollar-Denominated Amounts

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
U.S. Natural Gas Pipelines Comparable EBIT[1]	**786**	710	682
U.S. Oil Pipelines Comparable EBIT[1]	**301**	–	–
U.S. Power Comparable EBIT[1]	**164**	187	78
Interest on U.S. dollar-denominated long-term debt	**(734)**	(680)	(645)
Capitalized interest on U.S. capital expenditures	**116**	290	123
U.S. non-controlling interests and other	**(192)**	(164)	(132)
	441	343	106

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBIT.

FORWARD-LOOKING INFORMATION

This MD&A contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. Forward-looking statements in this document may include, but are not limited to, statements regarding:

- anticipated business prospects;
- financial performance of TransCanada and its subsidiaries and affiliates;
- expectations or projections about strategies and goals for growth and expansion;
- expected cash flows;
- expected costs;
- expected costs for projects under construction;
- expected schedules for planned projects (including anticipated construction and completion dates);
- expected regulatory processes and outcomes;
- expected outcomes with respect to legal proceedings, including arbitration;
- expected capital expenditures;
- expected operating and financial results; and
- expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements.

Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about:

- inflation rates, commodity prices and capacity prices;
- timing of debt issuances and hedging;
- regulatory decisions and outcomes;

- arbitration decisions and outcomes;
- foreign exchange rates;
- interest rates;
- tax rates;
- planned and unplanned outages and utilization of the Company's pipeline and energy assets;
- asset reliability and integrity;
- access to capital markets;
- anticipated construction costs, schedules and completion dates; and
- acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to:

- the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits;
- the operating performance of the Company's pipeline and energy assets;
- the availability and price of energy commodities;
- amount of capacity payments and revenues from the Company's energy business;
- regulatory decisions and outcomes;
- outcomes with respect to legal proceedings, including arbitration;
- counterparty performance;
- changes in environmental and other laws and regulations;
- competitive factors in the pipeline and energy sectors;
- construction and completion of capital projects;
- labour, equipment and material costs;
- access to capital markets;
- interest and currency exchange rates;
- weather;
- technological developments; and
- economic conditions in North America.

Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC).

Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this MD&A or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this MD&A or otherwise, whether as a result of new information, future events or otherwise, except as required by law.

NON-GAAP MEASURES

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, EBITDA, Comparable EBITDA, EBIT, Comparable EBIT, Comparable Interest Expense and Comparable Interest Income and Other, Comparable Income Taxes and Funds Generated from Operations in this MD&A. These measures do not have any standardized meaning as prescribed by CGAAP. They are, therefore, considered to be non-GAAP measures and may not be comparable to similar measures presented by other entities. Management of TransCanada uses these non-GAAP measures to improve its ability to compare financial results among reporting periods and to enhance its understanding of operating performance, liquidity and ability to generate funds to finance operations. These non-GAAP measures are also provided to readers as additional information on TransCanada's operating performance, liquidity and ability to generate funds to finance operations.

EBITDA is an approximate measure of the Company's pre-tax operating cash flow and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, net income attributable to non-controlling interests and preferred share dividends.

Comparable Earnings, Comparable EBITDA, Comparable EBIT, Comparable Interest Expense, Comparable Interest Income and Other and Comparable Income Taxes comprise Net Income Applicable to Common Shares, EBITDA, EBIT, Interest Expense, Interest Income and Other and Income Taxes, respectively, and are adjusted for specific items that are significant but are not reflective of the Company's underlying operations in the period. Specific items are subjective, however, management uses its judgement and informed decision-making when identifying items to be excluded in calculating these non-GAAP measures, some of which may recur. Specific items may include but are not limited to certain fair value adjustments relating to risk management activities, income tax refunds and adjustments, gains or losses on sales of assets, legal and bankruptcy settlements, and write-downs of assets and investments.

The Company engages in risk management activities to reduce its exposure to certain financial and commodity price risks by utilizing derivatives. The risk management activities which TransCanada excludes from Comparable Earnings provide effective economic hedges but do not meet the specific criteria for hedge accounting treatment and, therefore, changes in their fair values are recorded in Net Income each year. The unrealized gains or losses from changes in the fair value of these derivative contracts and natural gas inventory in storage are not considered to be representative of the underlying operations in the current period or the positive margin that will be realized upon settlement. As a result, these amounts have been excluded in the determination of Comparable Earnings.

The Reconciliation of Non-GAAP Measures table in this MD&A presents a reconciliation of these non-GAAP measures to Net Income Attributable to Common Shares. Comparable Earnings per Common Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the year.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. A reconciliation of Funds Generated from Operations to Net Cash Provided by Operations is presented in the Summarized Cash Flow table in the Liquidity and Capital Resources section in this MD&A.

OUTLOOK

TransCanada's corporate strategy is to maximize the full-life value of its existing assets and commercial positions, and to pursue long-term growth opportunities that add long-term shareholder value while focusing on its core strengths in its pipelines and energy businesses in North America. In 2012 and beyond, TransCanada expects that its net income and operating cash flow combined with a strong balance sheet and its proven ability to access capital markets will provide the financial resources needed to complete its current $12 billion capital expenditure program, which includes Keystone XL and the Bruce Power restarts, to continue pursuing additional long-term growth opportunities and to create additional value for its shareholders. This strategy will be executed with the same discipline and deliberate manner that characterized TransCanada's capital expenditure program in previous years.

TransCanada expects a positive impact on its 2012 earnings from assets that were placed in service in 2011 such as the Guadalajara natural gas pipeline, the Coolidge power facility and two Cartier Wind farm projects, from Keystone's Wood River/Patoka and Cushing Extension sections that began recording earnings in 2011, and from assets that are expected to be placed in service in 2012, such as Bruce Power Units 1 and 2. TransCanada expects that as these assets are placed in service, its consolidated earnings for the year will be somewhat offset by a corresponding reduction in capitalized interest.

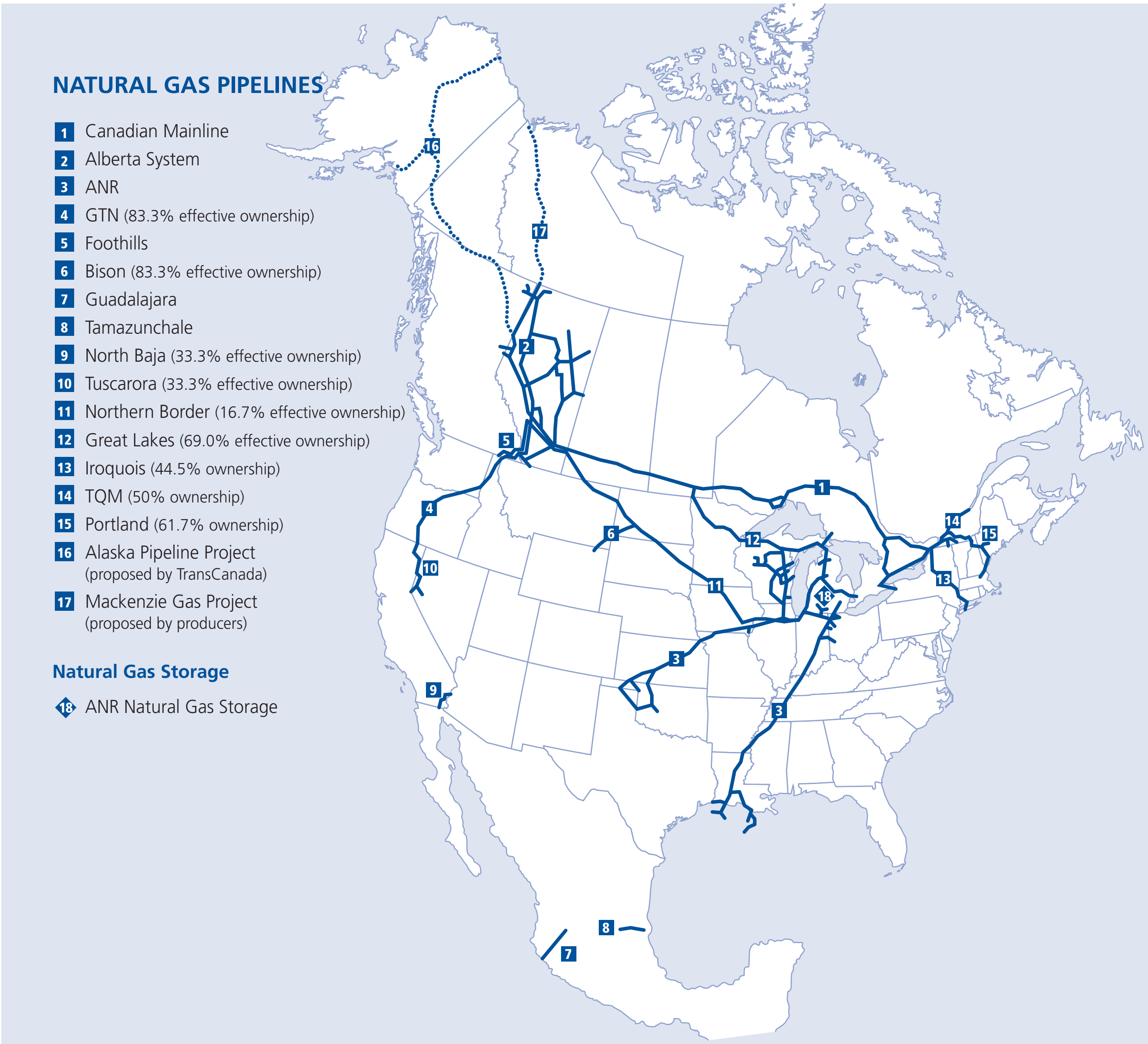
Natural Gas Pipelines' EBIT in 2012 will be affected by decisions made by applicable regulatory authorities, and the timing thereof, including the Canadian Mainline 2012 Tolls Application and Restructuring Proposal (Restructuring Proposal), as well as the establishment and expiry of long-term contracts, other variances in throughput volume, and rate settlements on its U.S. pipelines. Absent an NEB decision in 2012 with respect to Canadian Mainline 2012 tolls, EBIT from the Canadian Mainline will reflect the last approved rate of return on common equity (ROE) of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years.

Oil Pipelines EBIT in 2012 is expected to be higher than in 2011, primarily due to the impact of a full year of earnings being recorded on the Wood River/Patoka and Cushing Extension sections of Keystone compared to eleven months in 2011.

Energy's EBIT in 2012 is expected to be positively affected by assets that were placed in service during 2011 and assets that are expected to be placed in service in 2012. Energy's EBIT in 2012 could also be affected by the uncertainty and ultimate resolution of the capacity pricing issues in New York and outcome of the Sundance A PPA arbitration. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by fluctuations in commodity prices.

TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy businesses in the U.S. are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's Net Income. As new assets are placed in service in the U.S., this exposure is expected to increase as EBIT from U.S. operations increases. This impact will be partially offset by corresponding changes in the value of U.S. dollar-denominated interest expense. In addition, the Company expects to continue to use derivatives to manage its resultant net exposure to changes in U.S. dollar exchange rates.

The Company's results in 2012 may be affected by a number of factors and developments as discussed throughout this MD&A including, without limitation, the factors and developments discussed in the Forward-Looking Information and Business Risks sections for Natural Gas Pipelines, Oil Pipelines and Energy. Refer to the Outlook sections in this MD&A for further discussion on the outlook for Natural Gas Pipelines, Oil Pipelines and Energy.



NATURAL GAS PIPELINES

The following pipelines are owned 100 per cent by TransCanada unless otherwise stated.

CANADIAN MAINLINE The Canadian Mainline is a 14,101 km (8,762 miles) natural gas transmission system in Canada that extends from the Alberta/Saskatchewan border east to the Québec/Vermont border and connects with other natural gas pipelines in Canada and the U.S.

ALBERTA SYSTEM The Alberta System is a 24,373 km (15,145 miles) natural gas transmission system in Alberta and Northeast B.C. that connects with the Canadian Mainline and Foothills natural gas pipelines and with third-party natural gas pipelines.

ANR ANR is a 16,656 km (10,350 miles) natural gas transmission system that extends from producing fields located in the Texas and Oklahoma panhandle regions, from the offshore and onshore regions of the Gulf of Mexico, and from the U.S. midcontinent region to markets located mainly in Wisconsin, Michigan, Illinois, Indiana and Ohio. ANR also owns and operates regulated underground natural gas storage facilities in Michigan with a total working capacity of 250 Bcf.

GTN Owned 75 per cent by TransCanada and 25 per cent by TC PipeLines, LP, GTN is a 2,178 km (1,353 miles) natural gas transmission system that transports WCSB and Rocky Mountain-sourced natural gas to third-party natural gas pipelines and markets in Washington, Oregon and California, and connects with Tuscarora. TransCanada operates GTN and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

FOOTHILLS Foothills is a 1,241 km (771 miles) transmission system in Western Canada carrying natural gas for export from central Alberta to the U.S. border to serve markets in the U.S. Midwest, Pacific Northwest, California and Nevada.

BISON Owned 75 per cent by TransCanada and 25 per cent by TC PipeLines, LP, Bison is a 487 km (303 miles) natural gas pipeline that was placed in service in January 2011 and connects supply from the Powder River Basin in Wyoming to Northern Border in North Dakota. TransCanada operates Bison and effectively owns 83.3 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

GUADALAJARA Guadalajara is a 310 km (193 miles) natural gas pipeline from Manzanillo to Guadalajara in Mexico.

TAMAZUNCHALE Tamazunchale is a 130 km (81 miles) natural gas pipeline in east central Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi.

NORTH BAJA Owned 100 per cent by TC PipeLines, LP, North Baja is a natural gas transmission system extending 138 km (86 miles) from Ehrenberg, Arizona to Ogilby, California and connecting with a third-party natural gas pipeline system in Mexico. TransCanada operates North Baja and effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

TUSCARORA Owned 100 per cent by TC PipeLines, LP, Tuscarora is a 491 km (305 miles) pipeline system transporting natural gas from GTN at Malin, Oregon to Wadsworth, Nevada, with delivery points in northeastern California and northwestern Nevada. TransCanada operates Tuscarora and effectively owns 33.3 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

NORTHERN BORDER Owned 50 per cent by TC PipeLines, LP, Northern Border is a 2,265 km (1,407 miles) natural gas transmission system serving the U.S. Midwest. TransCanada operates Northern Border and effectively owns 16.7 per cent of the system through its 33.3 per cent interest in TC PipeLines, LP.

GREAT LAKES Owned 53.6 per cent by TransCanada and 46.4 per cent by TC PipeLines, LP, Great Lakes is a 3,404 km (2,115 miles) natural gas transmission system serving markets in Eastern Canada and the U.S. Northeast and Midwest regions. TransCanada operates Great Lakes and effectively owns 69.0 per cent of the system through the combination of its direct ownership interest and its 33.3 per cent interest in TC PipeLines, LP.

IROQUOIS Owned 44.5 per cent by TransCanada, Iroquois is a 666 km (414 miles) pipeline system that connects with the Canadian Mainline near Waddington, New York and delivers natural gas to customers in the northeastern U.S.

TQM Owned 50 per cent by TransCanada, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline near the Québec/Ontario border, transports natural gas to markets in Québec, and connects with Portland. TQM is operated by TransCanada.

PORTLAND Owned 61.7 per cent by TransCanada, Portland is a 474 km (295 miles) pipeline that connects with TQM near East Hereford, Québec and delivers natural gas to customers in the northeastern U.S. Portland is operated by TransCanada.

TRANSGAS Owned 46.5 per cent by TransCanada, TransGas is a 344 km (214 miles) natural gas pipeline system extending from Mariquita to Cali in Colombia.

GAS PACIFICO/INNERGY Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada also has a 30 per cent ownership interest in INNERGY, an industrial natural gas marketing company based in Concepción that markets natural gas transported on Gas Pacifico.

ALASKA PIPELINE PROJECT The Alaska Pipeline Project is a proposed natural gas pipeline and a proposed treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the treatment plant at Prudhoe Bay, Alaska to Alberta. TransCanada also commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the LNG option, that would extend from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska. TransCanada has entered into an agreement with ExxonMobil to jointly advance these projects.

MACKENZIE GAS PROJECT The Mackenzie Gas Project is a proposed natural gas pipeline extending 1,196 km (743 miles) that would connect northern onshore natural gas fields with North American markets. TransCanada has the right to acquire an equity interest in the project.

NATURAL GAS PIPELINES – HIGHLIGHTS

- Comparable EBIT from Natural Gas Pipelines was $2.0 billion in 2011, an increase of $0.1 billion from $1.9 billion in 2010.
- The Company invested $0.9 billion in Natural Gas Pipelines capital projects in 2011 primarily related to growth on the Alberta System and construction of the Guadalajara pipeline.
- In January 2011, the Bison natural gas pipeline was placed in service.
- In June 2011, the Company's US$360 million, 307 km (191 miles) Guadalajara natural gas pipeline went into service. This pipeline has capacity to transport 500 million cubic feet per day (MMcf/d) of natural gas to a power plant and 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara.
- The Alberta System growth continues through new connections of supply primarily in the Horn River and Montney shale basins in B.C. as well as the Deep Basin in Alberta. In 2011, the NEB approved the construction of natural gas pipeline projects for the Alberta System with a capital cost of approximately $910 million, including the approval to construct the Horn River pipeline with an estimated capital cost of $275 million and an in-service date of second quarter 2012. In addition, Pipeline projects with a total capital cost of approximately $810 million are still awaiting NEB decisions. The Company executed new agreements to further extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of $230 million. Subject to regulatory approval this extension is projected to commence service in 2014.
- In September 2011, TransCanada filed, with the NEB, the Restructuring Proposal, a comprehensive application to change the business structure and the terms and conditions of service for the Canadian Mainline including a 7.0 per cent after-tax weighted average cost of capital (ATWACC) fair return, revised depreciation rates and other parameters to address tolls for 2012 and 2013. The application also includes components that affect the Alberta System and Foothills. The NEB decision for this filing is expected in late 2012 or early 2013.
- In November 2011, TransCanada refiled an application with the NEB including supplemental information to construct $130 million of new pipeline infrastructure on the Canadian Mainline to receive Marcellus shale basin natural gas from the U.S. at the Niagara Falls receipt point for further transportation to Eastern markets.
- In May 2011, TransCanada closed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$605 million plus closing adjustments, which included US$81 million or 25 per cent of GTN LLC debt outstanding.

NATURAL GAS PIPELINES – RESULTS

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Canadian Natural Gas Pipelines			
Canadian Mainline	**1,058**	1,054	1,133
Alberta System	**742**	742	728
Foothills	**127**	135	132
Other (TQM, Ventures LP)	**50**	50	59
Canadian Natural Gas Pipelines Comparable EBITDA(1)	**1,977**	1,981	2,052
Depreciation and amortization	**(722)**	(715)	(714)
Canadian Natural Gas Pipelines Comparable EBIT(1)	**1,255**	1,266	1,338
U.S. Natural Gas Pipelines (in U.S. dollars)			
ANR	**312**	314	300
GTN(2)	**131**	171	170
Great Lakes(3)	**101**	109	120
TC PipeLines, LP(2)(4)(5)	**101**	99	90
Iroquois	**67**	67	68
Bison(5)	**49**	–	–
Portland(6)	**22**	22	22
International (Tamazunchale, Guadalajara, TransGas, Gas Pacifico/INNERGY)(7)	**77**	42	52
General, administrative and support costs(8)	**(9)**	(31)	(17)
Non-controlling interests(9)	**202**	173	153
U.S. Natural Gas Pipelines Comparable EBITDA(1)	**1,053**	966	958
Depreciation and amortization	**(267)**	(256)	(276)
U.S. Natural Gas Pipelines Comparable EBIT(1)	**786**	710	682
Foreign exchange	**(8)**	24	105
U.S. Natural Gas Pipelines Comparable EBIT(1) (in Canadian dollars)	**778**	734	787
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT(1)	**(52)**	(62)	(62)
Natural Gas Pipelines Comparable EBIT(1)	**1,981**	1,938	2,063
Summary:			
Natural Gas Pipelines Comparable EBITDA(1)	**2,967**	2,915	3,093
Depreciation and amortization	**(986)**	(977)	(1,030)
Natural Gas Pipelines Comparable EBIT(1)	**1,981**	1,938	2,063
Specific items:			
Valuation provision for MGP(10)	**–**	(146)	–
Dilution gain from reduced interest in TC PipeLines, LP(11)	**–**	–	29
Natural Gas Pipelines EBIT(1)	**1,981**	1,792	2,092

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT and EBIT.

(2) Results reflect TransCanada's direct ownership of 75 per cent of GTN effective May 2011 when 25 per cent was sold to TC PipeLines, LP, and 100 per cent prior to that date. GTN's results also include North Baja until July 2009, when North Baja was sold to TC PipeLines, LP.

(3) Represents TransCanada's 53.6 per cent direct ownership interest.

(4) Effective May 2011, TransCanada's ownership interest in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent. Results reflect TransCanada's indirect effective ownership interest of 8.3 per cent in each of GTN and Bison effective May 2011. Effective November 18, 2009, TC PipeLines, LP's results reflected TransCanada's effective ownership in TC PipeLines, LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in TC PipeLines, LP was 42.6 per cent. From January 1, 2009 to June 30, 2009, TransCanada's ownership interest in TC PipeLines, LP was 32.1 per cent.

(5) Results reflect TransCanada's direct ownership of 75 per cent of Bison effective May 2011 when 25 per cent was sold to TC PipeLines, LP and 100 per cent since January 2011 when Bison went into service.

(6) Portland's results reflect TransCanada's 61.7 per cent ownership interest.

(7) Includes Guadalajara effective June 2011.

(8) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines, including $17 million for the start up of Keystone in 2010.

(9) Non-controlling interests reflects Comparable EBITDA for the 66.7 per cent and 38.3 per cent portions of TC PipeLines, LP and Portland, respectively, not owned by TransCanada.

(10) In 2010, the Company recorded a valuation provision of $146 million for its advances to the APG for the MGP.

(11) As a result of TC PipeLines, LP issuing common units to the public in July 2009, the Company's ownership interest in TC PipeLines, LP was reduced to 38.2 per cent from 42.6 per cent and a dilution gain of $29 million was realized.

Natural Gas Pipelines' Comparable EBIT was $1,981 million in 2011 compared to $1,938 million in 2010. Comparable EBIT in 2010 excluded a $146 million valuation provision for the Company's advances to the APG for the MGP. Comparable EBIT in 2009 was $2,063 million excluding the $29 million dilution gain resulting from TransCanada's reduced interest in TC PipeLines, LP, which occurred as a result of the public issuance of common units by TC PipeLines, LP in November 2009.

Wholly Owned Canadian Natural Gas Pipelines Net Income

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Canadian Mainline	**246**	267	273
Alberta System	**200**	198	168
Foothills	**22**	27	23

NATURAL GAS PIPELINES – FINANCIAL ANALYSIS

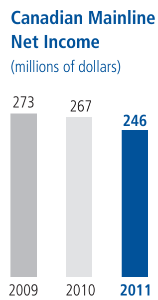
Canadian Mainline The Canadian Mainline is regulated by the NEB under the *National Energy Board Act (Canada)*. The NEB sets tolls that provide TransCanada with the opportunity to recover the costs of transporting natural gas, including a return on average investment base. The Canadian Mainline's EBITDA and net income are affected by changes in investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

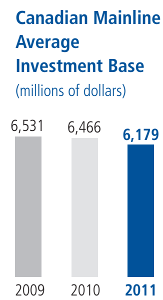
The Canadian Mainline operated under a five-year tolls settlement from 2007 through 2011. The cost of capital reflected an ROE as determined by the NEB's ROE formula on deemed common equity of 40 per cent. The tolls settlement established certain elements of the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. All other cost elements of the revenue requirement were treated on a flow-through basis. The settlement also allowed for performance-based incentive arrangements that the Company believes were mutually beneficial to TransCanada and its customers.

The Canadian Mainline's net income of $246 million in 2011 was $21 million lower compared to 2010 as a result of a lower ROE of 8.08 per cent in 2011 compared to 8.52 per cent in 2010 and a lower average investment base, partially offset by higher incentive earnings. Net income in 2010 was $6 million lower compared to 2009. This decrease was primarily due to lower OM&A incentive earnings as a result of cost-sharing with customers and an ROE of 8.52 per cent in 2010 compared to 8.57 per cent in 2009.

The Canadian Mainline's Comparable EBITDA was $1,058 million in 2011 compared to $1,054 million and $1,133 million in 2010 and 2009, respectively. EBITDA variances reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Capital Expenditures for the Canadian Mainline were $65 million in 2011 compared with $50 million and $61 million in 2010 and 2009, respectively.





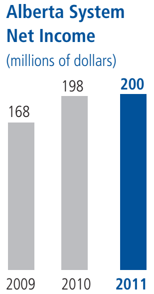
Alberta System The Alberta System is also regulated by the NEB, which approves the Alberta System's tolls and revenue requirement. The Alberta System's EBITDA and net income are affected by changes in the investment base, the ROE, the level of deemed common equity, potential incentive earnings and changes in the level of depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis.

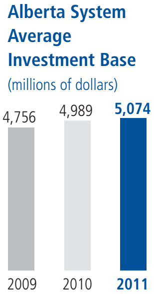
The Alberta System currently operates under the 2010 - 2012 Revenue Requirement Settlement approved by the NEB in September 2010. The 2010 - 2012 Revenue Requirement Settlement established an ROE of 9.70 per cent on deemed common equity of 40 per cent and included an annual fixed amount of $174 million for certain OM&A costs. Variances between actual and agreed-to OM&A costs accrue to TransCanada. All other cost elements of the revenue requirement are treated on a flow-through basis. In 2009, the Alberta System operated under the 2008 - 2009 Revenue Requirement Settlement approved by the Alberta Utilities Commission (AUC) in December 2008. The Alberta System was regulated by the AUC until April 2009.

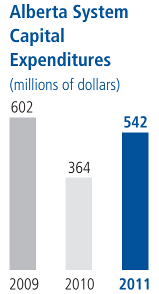
The 2008 - 2009 Revenue Requirement Settlement established fixed amounts for ROE, income taxes and certain OM&A costs. Variances between actual costs and those agreed to in the settlement accrued to TransCanada, subject to an ROE and income tax adjustment mechanism that accounted for variances between actual and settlement rate base, and income tax assumptions. The other cost elements of the settlement were treated on a flow-though basis.

The Alberta System's net income of $200 million in 2011 was $2 million higher compared to 2010. The increase is primarily due to higher earnings as a result of a growing average investment base. Net income in 2010 was $30 million higher than in 2009. This increase reflected an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 compared to the earnings achieved under the settlement in place in 2009 and a higher average investment base, partially offset by lower incentive earnings. The increase in average investment base from 2009 to 2011 reflects capital expenditures to expand capacity in response to growing customer demand for service.

The Alberta System's Comparable EBITDA of $742 million in 2011 was consistent with 2010. Comparable EBITDA in 2010 was $14 million higher than 2009. EBITDA variances from the Alberta System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.







Foothills The Foothills System's net income of $22 million in 2011 was $5 million lower compared to 2010. The decrease was primarily due to lower earnings from a lower average investment base and lower OM&A incentive earnings. Net income in 2010 was $4 million higher than 2009, due to a Foothills 2010 settlement agreement, which established an ROE of 9.70 per cent on deemed common equity of 40 per cent for 2010 through 2012. Results in 2009 were based on the NEB ROE formula of 8.57 per cent on deemed common equity of 36 per cent.

The Foothills System's Comparable EBITDA of $127 million in 2011 was $8 million lower compared to 2010. Comparable EBITDA in 2010 was $3 million higher than 2009. EBITDA variances from the Foothills System reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes recovered in revenue on a flow-through basis.

Other Canadian Natural Gas Pipelines Comparable EBITDA from Other Canadian Natural Gas Pipelines of $50 million in 2011 was consistent with 2010 and was $9 million lower than 2009 primarily due to an adjustment in 2009 as a result of the NEB's decision with respect to TQM cost of capital for 2007 and 2008.

ANR ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company, which is a FERC regulated entity that owns and operates certain storage fields in Michigan, has rates that were established pursuant to a settlement approved by the FERC that were effective beginning in 1990. ANR Storage Company is currently subject to a review, initiated by the FERC in late 2011, of its existing rates.

ANR's EBITDA is affected by the contracting and pricing of its existing transportation and storage capacity, expansion projects, delivered volumes and incidental commodity sales, as well as by costs for providing various services, which include OM&A costs and property taxes. Due to the seasonal nature of its business, ANR's volumes and revenues are generally higher in the winter months.

ANR's Comparable EBITDA in 2011 was US$312 million, a decrease of US$2 million compared to 2010. The decrease was primarily due to higher OM&A costs partially offset by higher transportation revenues, a settlement with a counterparty and incidental commodity sales. Comparable EBITDA in 2010 of US$314 million increased US$14 million compared to 2009, primarily due to lower OM&A costs, partially offset by lower contracted firm long-haul transportation sales and storage revenues.

GTN GTN is regulated by the FERC and is operated in accordance with tariffs that establish maximum and minimum rates for various services. GTN is permitted to discount or negotiate rates on a non-discriminatory basis. In 2011, GTN negotiated a settlement for new rates with its customers in lieu of filing a rate case. The FERC approved the settlement agreement in November 2011 for new rates effective January 1, 2012. The settlement includes a four-year moratorium during which GTN and the settling parties are prohibited from taking certain actions, including making any filings to adjust rates prior to December 31, 2015. The settlement also requires GTN to file for new rates that are to be effective January 1, 2016.

GTN's EBITDA is affected by variations in contracted volume levels, volumes delivered and prices charged under the various service types as well as by variations in the costs of providing services, which include OM&A costs and property taxes.

GTN's Comparable EBITDA from TransCanada's direct investment was US$131 million in 2011, a decrease of US$40 million compared to 2010. The decrease was primarily due to TransCanada's May 2011 sale of a 25 per cent interest in GTN to TC PipeLines, LP and decreased revenue. Comparable EBITDA in 2010 increased US$1 million compared to 2009, primarily due to lower OM&A costs and incremental proceeds accrued in 2010 relating to bankruptcy distributions from Calpine, partially offset by the impact of selling North Baja to TC PipeLines, LP in July 2009 and the write-off of costs in 2010 related to an unsuccessful information systems project.

Other U.S. Natural Gas Pipelines Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US$610 million in 2011 compared to $481 million in 2010. The increase was primarily due to the start of commercial operations of Bison and Guadalajara pipelines in January 2011 and June 2011, respectively, as well as the 25 per cent sale of TransCanada's ownership interest in GTN to TC PipeLines, LP in May 2011. Other contributing factors were lower general, administrative and support costs in 2011, partially offset by lower Great Lakes revenues in 2011. Comparable EBITDA in 2010 decreased US$7 million from 2009, primarily due to lower Great Lakes revenues.

Business Development Natural Gas Pipelines' Business Development Comparable EBITDA loss from business development expenses was $52 million in 2011 compared to $62 million in 2010. This improvement of $10 million was primarily due to lower business development costs associated with the Alaska Pipeline Project as a result of increased reimbursement by the State of Alaska to 90 per cent from 50 per cent effective July 31, 2010. Comparable EBITDA loss of $62 million in 2010 was consistent with 2009.

Depreciation and Amortization Depreciation and Amortization for Natural Gas Pipelines was $986 million in 2011, an increase of $9 million from 2010. The increase was primarily due to the start-up of Bison and Guadalajara partially offset by lower depreciation for Great Lakes as a result of the lower depreciation rate in Great Lakes' 2010 rate settlement. Depreciation and Amortization decreased $53 million in 2010 from 2009 primarily due to a weaker U.S. dollar in 2010 and lower depreciation for Great Lakes as a result of its 2010 rate settlement.

NATURAL GAS PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Introduction Opportunities for North American natural gas pipeline infrastructure are impacted by the developments in the natural gas exploration and production sector. Rapidly increasing supply of hydrocarbons from shale and other tight or low permeability resource plays, particularly in the past five years, are transforming the domestic natural gas market. These resource plays are being further developed due to the recent wide-spread application of horizontal drilling together with multi-stage hydraulic fracturing (fracking) that is reshaping the natural gas industry. For example, North America has evolved from having numerous projects and proposals in various stages of development for liquefied natural gas (LNG) import facilities as recently as five years ago to the current situation where both the Canadian and U.S. regulators have issued and are considering additional LNG export licenses due to the significant increase in North American natural gas supply.

The abundance of supply resulting in relatively low natural gas prices across North America is supportive of increased reliance on natural gas to meet growing energy demands. A shift to increased natural gas fired power generation is also emerging in the U.S. and Canada. Numerous proposals for development of LNG export facilities from North America is another example of the evolution of the natural gas industry. Persistently high oil prices, particularly relative to North America natural gas prices, have resulted in increased deployment of capital for the exploration and production of liquid-rich hydrocarbon basins, which also tend to produce associated natural gas. A recent announcement by the Mexican government to change its procurement strategy away from LNG imports to infrastructure improvements that facilitate increased access to natural gas supply from the U.S. is further evidence of the increased confidence in the availability of supply at stable prices across North America.

The evolution of the natural gas market is also driving changes to traditional flow patterns across the continental pipeline grid resulting in reassessment of the use and repurposing of existing assets. TransCanada's portfolio of North American natural gas pipeline infrastructure is well positioned to capture investment opportunities from growing natural gas supply as well as opportunities to connect new markets while satisfying increasing demand for natural gas within existing markets.

The following are significant initiatives by TransCanada to capture opportunities in the evolving natural gas industry in North America:

Canadian Mainline In September 2011, TransCanada filed the Restructuring Proposal, a comprehensive application with the NEB to change the business structure and the terms and conditions of service for the Canadian Mainline. The application included the following components:

- Extension of the Alberta System footprint to points on the Canadian Mainline in Saskatchewan, and on the Foothills System in Saskatchewan and B.C., thereby reducing the cost to transport gas from the Western Canada Sedimentary Basin (WCSB) to markets served by the Canadian Mainline.
- Lower depreciation expense and therefore lower tolls resulting from adjustments to the economic planning horizons for the three Canadian Mainline segments and a reallocation of accumulated depreciation to better match consumed service value for each segment.
- Changes to toll design, services, and pricing resulting in higher revenues and lower overall tolls.
- A 7.0 per cent ATWACC fair return which is equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent.

In October 2011, TransCanada filed supplementary information on cost of service and the proposed tolls for 2012 and 2013. These applied-for tolls result in a 2012 toll of $1.29 per gigajoule for transportation from Nova Inventory Transfer to the Dawn, Ontario delivery point, which is 38 per cent lower than the comparable toll charged in 2011.

The Restructuring Proposal was developed by TransCanada as an innovative and balanced response to recent and dramatic changes in the business environment of natural gas supply, demand and transportation in North America. The application is intended to enhance the long-term economic viability and sustainability of the Canadian Mainline and the WCSB. A decision regarding the Restructuring Proposal is expected in late 2012 or early 2013.

TransCanada re-filed an application with the NEB in November 2011 that included supplemental information for approval to construct $130 million of new pipeline infrastructure on the Canadian Mainline, to receive Marcellus shale basin gas at the Niagara Falls receipt point for further transportation to Eastern markets. Subject to regulatory approval to construct the facilities, deliveries from Niagara Falls are expected to begin at a rate of 230 MMcf/d in November 2012 and then increase to 350 MMcf/d by November 2013, which may require a subsequent application for additional facilities.

Alberta System The Alberta System's Horn River natural gas pipeline project was approved by the NEB in January 2011 and commenced construction in March 2011, with a targeted completion date of second quarter 2012 and an estimated capital cost of $275 million. In addition, the Company executed an agreement to extend the Horn River pipeline by approximately 100 km (62 miles) at an estimated cost of $230 million. As a result of the extension, additional contractual commitments of 100 MMcf/d are expected to commence in 2014 with volumes increasing to 300 MMcf/d by 2020. An application requesting approval to construct and operate this extension was filed with the NEB in October 2011. The total contracted volumes for Horn River, including the extension, are expected to be approximately 900 MMcf/d by 2020.

In June 2011, the NEB approved the construction and operation of a 24 km (15 miles) extension of the Groundbirch natural gas pipeline. Construction commenced in August 2011 with an expected in-service date of April 1, 2012 and an estimated cost of approximately $60 million. The project is required to serve 250 MMcf/d of new transportation contracts.

TransCanada continues to advance pipeline development projects in B.C. and Alberta to transport new natural gas supply. The Company has filed applications with the NEB requesting approval for expansions of the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. TransCanada has incremental firm commitments to transport approximately 3.4 billion cubic feet per day (Bcf/d) from western Alberta and northeast B.C. by 2014. Further requests for additional volumes on the Alberta System from the northwest portion of the WCSB have been received. In 2011, including the projects discussed above, the NEB has approved natural gas pipeline projects with capital costs of approximately $910 million. Further pipeline projects with a total capital cost of approximately $810 million are awaiting NEB decision. In addition, infrastructure to connect WCSB supply to markets continues to be pursued particularly to support further development of Alberta oil sands production and to supply proposed LNG export facilities on the Pacific Coast.

The Alberta System filed an application in October 2011 with the NEB to implement a new business model to restructure the commercial terms applied to existing natural gas liquids entering the Alberta System. The Natural Gas Liquids Extraction Model (NEXT) implementation date is proposed to be effective November 1, 2013. NEXT is designed to address the inequities caused by the current extraction convention, and improve the competitiveness of the Alberta System and the WCSB.

Commercial integration of the Alberta System and ATCO Pipelines system commenced in October 2011. Under the Agreement, the combined facilities of the two systems are commercially operated as a single transmission system and transportation service is provided to customers by NOVA Gas Transmission Ltd. (NGTL) pursuant to NGTL's Tariff and suite of rates and services. This agreement further identifies distinct geographic areas within Alberta for the construction of new facilities by each of NGTL and ATCO Pipelines. The final stage in this integration project is the swapping of certain pipeline assets of equal value. An application to the NEB for approval of the asset swaps is anticipated in the first quarter 2012.

Canadian Mainline, Alberta System and Foothills 2012 Tolls TransCanada filed for and received approval to implement interim 2012 tolls on the Canadian Mainline effective January 1, 2012, at the same level as the currently approved 2011 final tolls. In addition, TransCanada filed for interim 2012 tolls on the Alberta System and annual tolls for Foothills to be effective January 1, 2012. These tolls have also been approved on an interim basis pending the outcome of the NEB's decision on the Restructuring Proposal.

U.S. Pipelines In May 2011, TransCanada closed the sale of a 25 per cent interest in each of GTN and Bison to TC PipeLines, LP for an aggregate purchase price of US$605 million, which included US$81 million or 25 per cent of GTN's debt plus customary closing adjustments.

GTN GTN executed a settlement agreement with its shippers for new transportation rates to be effective January 2012 through December 2015. The settlement agreement was filed in August 2011 and approved by the FERC in November 2011.

Northern Border Northern Border operates pursuant to maximum long-term mileage-based rates and seasonal short-term transportation rates approved by the FERC in a January 2007 rate case settlement. A moratorium on the filing of future rate cases under National Gas Act Sections 4 or 5 expired on January 1, 2010. Northern Border is required to file a rate case on or before December 31, 2012.

Tuscarora Tuscarora Gas Transmission filed a settlement agreement with the FERC in December 2011 that concluded a review of Tuscarora's currently effective rates. The agreement, subject to the FERC approval, will lower shippers' reservation and transportation charges, and preclude another rate case until 2014.

ANR In September 2011, ANR Pipeline Company filed an application with the FERC to sell its offshore Gulf of Mexico assets and certain related onshore facilities to its wholly-owned subsidiary, TC Offshore LLC. At the same time, TC Offshore LLC requested authorization from the FERC to acquire, own and operate those facilities under the FERC's regulations. These filings are currently pending before the FERC and a decision is expected in second or third quarter 2012.

Alaska Pipeline Project The Alaska Pipeline Project team continues to work with shippers to resolve conditional bids received as part of the project's open season and is working toward the FERC application deadline of October 2012 for the Alberta option that would extend from Prudhoe Bay to points near Fairbanks and Delta Junction, and then to the Alaska-Canada border, where the pipeline would connect with a new pipeline in Canada. The pipeline in Canada would extend from the Alaska-Canada border to link up with pipeline systems near Boundary Lake, Alberta, providing the capability of transporting natural gas into the continental U.S. TransCanada has commenced initial discussions with Alaska North Slope producers regarding an alternative pipeline route, the LNG option, that would require a pipeline from Prudhoe Bay to LNG facilities, to be built by third parties, located in south-central Alaska. TransCanada has entered into an agreement with Exxon Mobil Corporation (ExxonMobil) to jointly advance the project.

The Mackenzie Gas Project The MGP received its Certificate of Public Convenience and Necessity in March 2011, marking the end of the Federal regulatory process. The proponents of the 1,196 km, 30 inch pipeline, with an initial capacity of 1.2 Bcf/d, continue to seek the Canadian government's support for an acceptable fiscal framework which would allow the project to progress.

Mexico The Guadalajara Pipeline in Mexico began commercial operations in June 2011. The US$360 million, 310 km (193 miles) project has capacity to transport 500 MMcf/d of natural gas to a power plant and 320 MMcf/d to the Pemex-owned national pipeline system near Guadalajara. The pipeline is secured under 25-year contracts with the Comisión Federal de Electricidad (CFE), Mexico's federal government owned electrical power company. In 2011, natural gas shipments were limited to support testing and commissioning efforts at the power plant. TransCanada and the CFE have agreed to add a US$60 million compressor station to the pipeline that is expected to be operational in early 2013.

NATURAL GAS PIPELINES – BUSINESS RISKS

Natural Gas Supply, Markets and Competition TransCanada faces competition at both the supply and market ends of its natural gas pipeline systems. This competition comes from other natural gas pipelines accessing supply basins, including the WCSB, and markets served by TransCanada's pipelines as well as from natural gas supplies produced in certain basins not directly served by the Company. Growth in supply and pipeline infrastructure has increased competition throughout North America. Production has increased in the U.S., driven primarily by shale gas, as well as in the WCSB. After declining over the past four years, WCSB production showed signs of recovery in 2011. Lower-cost shale gas in the U.S. has resulted in an increase in competition between supply basins, changes to traditional flow patterns and an increase in supply choices for customers. This change has contributed to a trend of continued reduction in long-haul, long-term firm contracted capacity and a shift to shorter-distance, short-term firm and interruptible contracts on many natural gas pipelines.

Although TransCanada has diversified its natural gas supply sources, many of its North American natural gas pipelines and its transmission infrastructure remain dependent on supply from the WCSB. TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Western Canada to domestic and export markets. The Alberta System, however, faces competition for connection to supply, particularly in northeast B.C., where the largest new source of natural gas has access to two existing pipeline companies with infrastructure in the area.

The Canadian Mainline, with its primary source of supply being the WCSB, also seeks opportunities to increase market share in Canadian domestic markets. However, TransCanada expects to continue to face competition for both the eastern domestic markets and in particular, the northeastern U.S export markets. Consumers in the northeastern U.S. generally have access to natural gas through numerous delivery and supply options. Eastern markets that historically received Canadian supplies only from TransCanada's systems are now able to receive supplies from new natural gas pipelines that source U.S. and Atlantic Canada supplies. In recent years, the Canadian Mainline has experienced reductions in volumes originating at the Alberta border and in Saskatchewan, which have been partially offset by increases in volumes originating at points east of Saskatchewan. These reductions in both volumes and distance transported have resulted in an increase in Canadian Mainline tolls per unit that adversely affects its competitive position.

ANR's directly connected natural gas supply is primarily sourced from the U.S. Gulf Coast and midcontinent regions which are also served by competing interstate and intrastate natural gas pipelines. The sale of pipeline transportation capacity in the U.S. Gulf Coast region is highly competitive given the extensive natural gas pipeline network in this region. ANR must also compete for supply from interconnects with pipelines originating within the growing U.S. midcontinent shale gas formations and the U.S. Rockies production regions. Lower natural gas prices could result in reduced drilling activity and slow the rate of supply growth that has been fuelling investments in pipeline infrastructure additions in the U.S. midcontinent which could limit the number of incremental pipeline investment opportunities in the future.

ANR competes for market share with other natural gas pipelines and storage operators in its primary markets in the U.S. Midwest. As transportation capacity has become more abundant due to major pipeline additions over the past few years, lower natural gas prices that result in less available supply could negatively affect the value of pipeline capacity. The value of ANR's natural gas storage services is based on market conditions, which could become unfavourable resulting in reduced rates and terms.

GTN is primarily supplied with natural gas from the WCSB and competes with other interstate pipelines providing natural gas transportation services to markets in the U.S. Pacific Northwest, California and Nevada. These markets also have access to supplies from natural gas basins in the Rocky Mountains and the U.S. Southwest. Historically, natural gas supplies from the WCSB have been competitively priced against supplies from the other regions serving these markets. Increased competing supply sources could negatively affect the transportation value on GTN. Pacific Gas and Electric Company, GTN's largest customer, received California Public Utilities Commission approval to commit to capacity on a competing pipeline out of the U.S. Rockies basin to the California border that went in service in July 2011.

Great Lakes and Northern Border are subject to annual contract renewals and can experience demand changes related to seasonal market conditions. To the extent the capacity on these pipelines is contracted, utilization does not impact revenue significantly. Both pipelines compete for natural gas transportation customers with pipelines that transport gas exiting the WCSB. An increase in competition in the key markets served by TransCanada's pipeline systems could arise from new ventures or expanded operations from existing competitors. For Great Lakes, the combination of growing supply from the Rockies, Mid-Continent and Marcellus shale developments reaching Dawn, Ontario through both new and available pipeline capacity, as well as reduced demand due to the economic environment, has the potential to maintain competitive pressures on WCSB supply into the Midwest. For example, if the transport of natural gas from those other supply basins to Dawn becomes more economical on competitive pipeline routes, then those supplies could reach the eastern zone of Great Lakes' market area and displace Great Lakes' long-haul volumes.

Demand for Pipeline Capacity Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Demand and supply in new locations often creates opportunities for new infrastructure, but it may also change flow patterns and potentially impact utilization of existing assets. For example, the proposed LNG export facilities on the west coast of B.C. have the potential to reduce demand for capacity on pipelines that transport WCSB supply to other markets. TransCanada's pipelines may be challenged to sell available transportation capacity as transportation contracts expire on its existing pipeline assets, as they have, for example, on the Great Lakes system in fourth quarter 2011. TransCanada expects its U.S. natural gas pipelines to become more exposed to the potential for revenue variability due to rapidly evolving supply dynamics, competition and trends toward shorter term contracting by shippers.

Demand for a pipeline's capacity is ultimately the key driver that enables the transportation services to be sold. There are four key factors that influence demand for pipeline capacity. They are the price of gas that influences the amount of supply, basin on basin competition that influences where the supply will be developed, technology that influences the cost and pace of development of the resource play, and price basis differentials that drive what markets the supply will flow to. The risks associated with each of these four factors are considered below.

Gas Price
The price of natural gas is a key driver for development and exploration of the resource. The current low gas prices in North America may slow drilling activities that in turn diminishes production levels, particularly in dry gas fields where the extra revenue generated from the entrained liquids is not available.

Basin on Basin Competition
Large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of the necessary pipeline infrastructure. Therefore, basin on basin competition impacts the extent and timing of a resource play development that in turn drives changing dynamics for demand of pipeline capacity.

Technology
The increased supply of natural gas in North America is primarily due to the application of technology to shale and tight gas plays that include both horizontal drilling and fracking. There is growing regulatory and public scrutiny over the impacts of fracking. Changes to the practices of fracking through changes in regulations could impact the costs and pace of development of natural gas plays.

Basis Differentials
In the period 2008 to 2011, there was more capacity added to the continental pipeline network than in any prior period in the history of the industry. Gas supply basins that were once constrained such as the U.S. Rockies and East Texas now have an overabundance of export capacity. As well, the recent focus on the development of shale gas basins has led to declines in conventional supply basins and unutilized capacity on many pipelines. These factors have led to contraction of regional basis differentials, the differences in market prices paid for natural gas between different gas receipt and delivery points, which has led to changes in the way many pipeline systems are being used. As a result, many pipeline companies are moving to restructure their business models, rate designs and services to adapt to the changing flow dynamics.

Regulatory Risk Regulatory decisions continue to have an impact on the financial returns from existing investments in TransCanada's natural gas pipelines and are expected to have a similar impact on financial returns from future investments. TransCanada manages this risk through rate applications and negotiated settlements, where possible.

Regulations and decisions issued by U.S. regulatory bodies, particularly the FERC, the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Transportation, may also have an impact on the financial performance of TransCanada's U.S. pipelines. TransCanada continually monitors existing as well as proposed regulations to manage potential impacts to its U.S. pipelines.

Pipeline Abandonment Cost Risk Through the Land Matters Consultation Initiative (LMCI), the NEB is addressing several significant issues relating to future pipeline abandonment costs for Canadian regulated pipelines. During the LMCI process, the NEB provided several key guiding principles including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the system. Based on the NEB's direction, the earliest that collection of funds for future pipeline abandonment costs through cost-of-service tolls on Canadian regulated pipelines could begin would be 2015.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and management of risks in the Natural Gas Pipelines business.

NATURAL GAS PIPELINES – OUTLOOK

The WCSB remains an important supply basin for TransCanada's pipeline infrastructure, however, the Company's portfolio of pipelines across North America has broadened its supply source to include many other prolific and emerging supply areas.

TransCanada expects there will be excess natural gas pipeline capacity from the WCSB to markets outside Western Canada for the foreseeable future as a result of capacity expansions on natural gas pipelines over the past 15 years, competition from other pipelines and supply basins, and significant growth in natural gas consumption within Alberta driven primarily by oil sands development and electricity generation requirements.

The WCSB has an ultimate remaining conventional resource estimate of 126 trillion cubic feet. In addition, the ultimate potential of the basin has been vastly improved due to the advent of economic access to shale gas and tight gas. Over its history, the WCSB's ultimate potential has primarily reflected the economic productivity of the conventional resource base. The recent additions of unconventional resources together with the increasing economic viability of low quality conventional resources as a result of new drilling and completion technology, has in TransCanada's view, more than doubled the technically accessible resource base of the WCSB.

WCSB production is expected to increase slightly in 2012. Despite reduced overall drilling levels across the WCSB, the dramatic increases in initial productivity resulting from horizontally drilled wells, in combination with a renewed focus on associated natural gas liquids, has significantly offset the anticipated negative supply impact associated with reduced levels of conventionally drilled vertical wells. Drilling activity has increased in northwestern Alberta and northeastern B.C. as producers develop projects to access deeper multi-zone gas plays, shales and tight sands utilizing horizontally-drilled wells in combination with fracking techniques. Recently, shale gas production in northeastern B.C. has emerged as a significant natural gas supply source. TransCanada forecasts approximately 5 Bcf/d of total production from the Montney and Horn River shale gas sources by 2020, however, achieving this level will depend on natural gas prices as well as producer economics in the basin. The production from these two natural gas supply regions is currently approximately 1.5 Bcf/d.

The outlook for demand driven infrastructure for WCSB supply within Western Canada remains positive with continued growth expected in Alberta oil sands development and coal conversion to natural gas for power generation. In addition, in the second half of this decade, there is also potential for additional new markets in the Asia-Pacific region for WCSB gas, connecting to new LNG terminals which are proposed along the west coast of B.C. to export Canadian gas.

Demand for WCSB-sourced natural gas in Eastern Canada and the U.S. Northeast decreased in 2011, largely as a result of a diversification of supply sources. However, demand for natural gas in TransCanada's key eastern markets served by the Canadian Mainline is expected to increase over time, particularly to meet the expected growth in natural gas-fired power generation.

In the U.S., TransCanada expects that unconventional production will continue to grow from established shale gas plays in eastern Texas, northwestern Louisiana, Arkansas, southwestern Oklahoma and the Appalachian region. The Marcellus shale basin continues to grow and with new pipeline infrastructure coming on-stream, is changing the dynamics for gas flows into and out of the U.S. Northeast. In addition, development of the Utica shale basin (predominantly in Ohio) is in its infancy. This basin has significant potential to become another major natural gas supply source. Production focus has shifted in the near term toward more oil and liquids-rich hydrocarbon production, which is expected to increase associated natural gas supply in Texas, North Dakota and other areas. Supply from coalbed methane and tight gas sands in the U.S. Rockies is also expected to grow. The resulting anticipated growth in U.S. supply should provide additional opportunities for TransCanada's U.S. pipelines. U.S. demand growth is expected to be driven primarily by increased use of natural gas for power generation and industrial growth, as well as LNG exports in the second half of the decade.

TransCanada continues to seek opportunities in Mexico to further develop natural gas infrastructure opportunities. TransCanada will leverage the experience and expertise gained on its Guadalajara and Tamazunchale pipelines and intends to participate in the $10 billion program recently announced by the Mexican government to expand its natural gas transmission infrastructure.

TransCanada will continue to focus on operational excellence and collaboration with all stakeholders to achieve negotiated settlements and provision of services that will increase the value of the Company's business.

Earnings Canadian Natural Gas Pipelines' earnings are affected by changes in investment base, ROE, capital structure and terms of toll settlements or other toll proposals as approved by the NEB, with the most significant variables being ROE, capital structure and investment base. Absent an NEB decision in 2012 with respect to Canadian Mainline 2012 tolls, earnings from the Canadian Mainline will be lower than in 2011 as results will reflect the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years. The Company expects continued growth of the Alberta System investment base as new supply in northeastern B.C. and western Alberta continues to be developed and connected to the Alberta System. TransCanada also anticipates a modest level of investment in its other Canadian natural gas pipelines but expects a continued net decline in the average investment bases of these pipelines as annual depreciation outpaces capital investment, the result of which would have the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian natural gas pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

The ability to recontract unsold capacity on TransCanada's U.S. pipelines and to sell capacity at attractive rates is influenced by prevailing market conditions and competitive factors, including competing natural gas pipelines and supply from other natural gas sources in these markets. EBIT from U.S. Natural Gas Pipelines' operations is also affected by the level of OM&A costs, regulatory decisions and changes in foreign currency exchange rates.

In addition, Natural Gas Pipelines' EBIT is expected to be affected by costs to develop new pipeline projects, including the Alaska Pipeline Project.

Capital Expenditures Total capital spending for natural gas pipelines was $0.9 billion in 2011. Capital spending for the Company's wholly owned pipelines is expected to be approximately $1.0 billion in 2012.

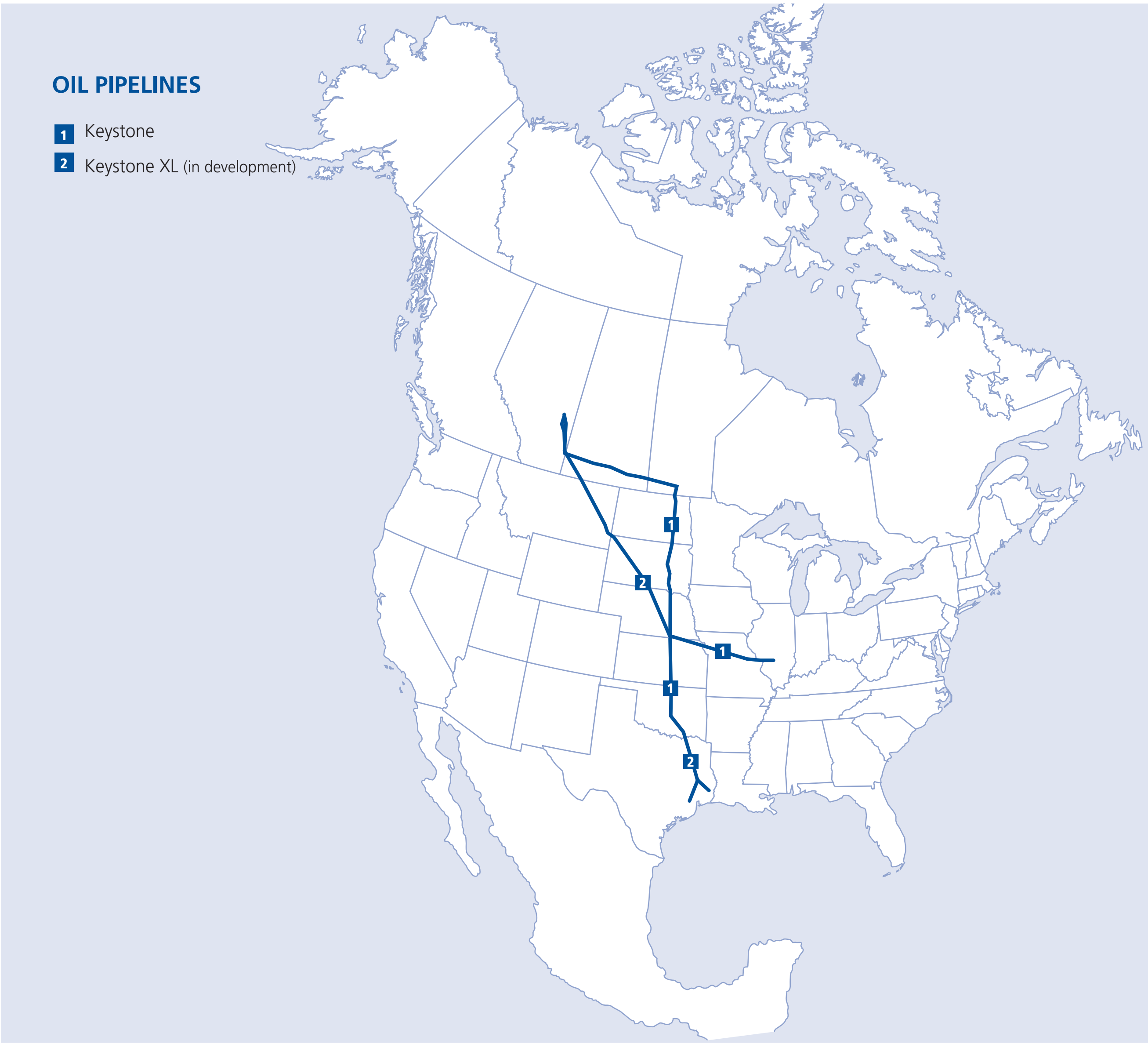
NATURAL GAS THROUGHPUT VOLUMES

(Bcf)	**2011**	2010	2009
Canadian Mainline[1]	**1,887**	1,666	2,030
Alberta System[2]	**3,517**	3,447	3,538
ANR	**1,706**	1,589	1,575
Foothills	**1,289**	1,446	1,205
Northern Border	**971**	902	706
Great Lakes	**830**	804	727
GTN	**679**	802	797
Iroquois	**317**	343	355
TQM	**154**	151	164
Ventures LP	**150**	144	145
Bison[3]	**105**	–	–
North Baja	**92**	60	96
Tamazunchale	**57**	52	54
Gas Pacifico	**46**	51	62
Portland	**36**	36	37
Tuscarora	**33**	35	34
TransGas	**26**	30	28

(1) Canadian Mainline's throughput volumes reflect physical deliveries to domestic and export markets. Customer contracting patterns have changed in recent years therefore the Company uses physical deliveries to measure system utilization. Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2011 were 1,160 Bcf (2010 – 1,228 Bcf; 2009 – 1,579 Bcf).

(2) Field receipt volumes for the Alberta System in 2011 were 3,622 Bcf (2010 – 3,471 Bcf; 2009 – 3,578 Bcf) and includes three months of ATCO Pipelines receipts consistent with the commercial integration of NGTL and ATCO Pipelines effective October 1, 2011.

(3) Effective January 14, 2011.



OIL PIPELINES

KEYSTONE

Keystone is a 3,467 km (2,154 miles) wholly owned and operated crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Company plans to expand and extend the oil pipeline system to the U.S. Gulf Coast (Keystone XL) which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

OIL PIPELINES – HIGHLIGHTS

- Wood River/Patoka and Cushing Extension sections of Keystone achieved full commercial operations in February 2011. The Company recorded EBITDA of $587 million in its first eleven months of operations.
- In August 2011, a favourable FEIS was received from the DOS for Keystone XL.
- The Company secured commercial support for an extension and expansion of Keystone XL to provide crude oil transportation service from Hardisty, Alberta to Houston, Texas, increasing total long-term firm contracts on Keystone to in excess of 1.1 million bbl/d for an average term of approximately 18 years.
- In January 2012, the DOS denied TransCanada's application requesting a Presidential Permit to construct Keystone XL based on the DOS's position that they did not have sufficient time to receive and review additional information necessary to assess alternative routes that would avoid the Sandhills region of Nebraska. The Company will reapply for a Presidential Permit for Keystone XL.

OIL PIPELINES – RESULTS

Year ended December 31[1] *(millions of dollars)*	**2011**
Canadian Oil Pipelines Comparable EBITDA[2]	**210**
Depreciation and amortization	**(49)**
Canadian Oil Pipelines Comparable EBIT[2]	**161**
U.S. Oil Pipelines Comparable EBITDA[2] (in U.S. dollars)	**383**
Depreciation and amortization	**(82)**
U.S. Oil Pipelines Comparable EBIT[2]	**301**
Foreign exchange	**(3)**
U.S. Oil Pipelines Comparable EBIT[2] (in Canadian dollars)	**298**
Oil Pipelines Business Development Comparable EBITDA and EBIT[2]	**(2)**
Oil Pipelines Comparable EBIT[2]	**457**
Summary:	
Oil Pipelines Comparable EBITDA[2]	**587**
Depreciation and amortization	**(130)**
Oil Pipelines Comparable EBIT[2]	**457**

(1) Results reflect eleven months of operations.

(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

OIL PIPELINES – FINANCIAL ANALYSIS

Keystone is a 3,467 km (2,154 miles) wholly owned and operated crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Company plans to expand and extend the existing system through Keystone XL which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone. The completion of Keystone XL is expected to increase total system capacity to approximately 1.4 million bbl/d.

The Marketlink projects would transport crude oil sourced from U.S. basins to refining markets in the Cushing, Oklahoma region and the U.S. Gulf Coast on facilities that form part of Keystone XL. The proposed Bakken Marketlink project would transport U.S. crude oil from Baker, Montana to Cushing and the proposed Cushing Marketlink project would transport crude oil from Cushing to Port Arthur and Houston, Texas.

Oil Pipelines Comparable EBIT for the year ended 2011 was $457 million. EBITDA from Keystone is primarily generated from payments received under long-term commercial arrangements for committed capacity that are not dependent on actual throughput. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental EBITDA. In February 2011, the Company began recording EBITDA for the Wood River/Patoka and Cushing Extension sections.

Although the Wood River/Patoka section commenced commercial operations in June 2010, cash flows other than general, administrative and support costs were capitalized until February 2011. As a condition of the NEB's approval to begin operations, the Wood River/Patoka section operated at a reduced maximum operating pressure (MOP) on the Canadian conversion segment of the pipeline, which did not allow the pipeline to run at design pressure and reduced throughput capacity below the initial nominal capacity of 435,000 bbl/d. After additional in-line inspections were completed, the NEB removed the MOP restriction in December 2010 and the required operational modifications were completed in late January 2011 allowing the system to operate at its design pressure and throughput capacity.

Operating Statistics

Year ended December 31[1]	2011
Delivery volumes (thousands of barrels)[2]	
Total	**137,384**
Average	**411**

(1) Results reflect eleven months of operations.

(2) Delivery volumes reflect physical deliveries.

OIL PIPELINES – OPPORTUNITIES AND DEVELOPMENTS

Wood River/Patoka and Cushing Extension In late January 2011, work was completed to allow the Wood River/Patoka section of the system to operate at its design pressure following the NEB's decision to remove the MOP restriction in December 2010. In February 2011, the Cushing Extension commenced commercial operations, extending the pipeline system to Cushing, Oklahoma and increasing nominal design capacity to 591,000 bbl/d.

In May 2011, revised fixed tolls came into effect for the Wood River/Patoka section of the system that reflected the final project costs for this section.

In June 2011, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a corrective action order on Keystone as a result of two above-ground incidents in second quarter 2011 at pump stations in North Dakota and Kansas, both of which involved the release of crude oil. Following the incidents, TransCanada took immediate action to contain the crude oil releases and repair the facilities. The corrective action order required TransCanada to develop and submit a written restart plan which included steps to facilitate the proper clean up, investigation, and system improvements and modifications. The restart plan was approved by PHMSA in June 2011. In July and August 2011, work was performed on the Keystone system to improve system reliability. The work was completed as planned and resulted in reduced pipeline capacity during those two months, however, it did not have a significant impact on EBIT.

In 2010, three entities, each of which had entered into Transportation Service Agreements for the Cushing Extension, had filed separate Statements of Claim against certain of TransCanada's Keystone subsidiaries in the Alberta Court of

Queen's Bench, seeking declaratory relief, or alternatively, damages in varying amounts. All of the claims have been discontinued on a without-cost and without-liability basis.

Keystone XL The regulatory approval process for the U.S. portion of Keystone XL continued throughout 2011 and early 2012. Following an extensive environmental review process, the DOS, the lead agency for U.S. federal regulatory approvals, released its FEIS in August 2011. The FEIS found that the project would have no significant impact on the environment and that the proposed route would have the least environmental impact of the alternatives considered.

Following the issuance of the FEIS, the DOS initiated a 90-day National Interest Determination (NID) process. During the NID process, concern about the pipeline's impact on the Sandhills region of Nebraska was raised and on November 10, 2011, the DOS determined it necessary to identify and assess alternative routes that would avoid the Sandhills region in Nebraska in order to move forward with a decision on the Presidential Permit. The DOS indicated that the additional environmental review process including a public comment period on a supplement to the FEIS could be completed as early as first quarter 2013. In December 2011, the *Temporary Payroll Tax Cut Continuation Act* was approved by the U.S. Senate and the U.S. House of Representatives and signed into law by U.S. President Obama on December 23, 2011. The legislation required a final decision on the Keystone XL Presidential Permit by February 21, 2012.

On January 18, 2012, the DOS denied the Presidential Permit for Keystone XL, based on the DOS's position that it did not have sufficient time to receive and review additional information necessary to assess alternative routes that would avoid the Sandhills region of Nebraska. The DOS noted that its decision did not preclude TransCanada from submitting a subsequent Presidential Permit application for Keystone XL.

TransCanada is continuing to work with the State of Nebraska to determine the preferred route that avoids the Sandhills region in Nebraska. The Company will submit a revised Presidential Permit application to the DOS. Assuming regulatory approval is received by first quarter 2013, TransCanada believes it could have Keystone XL in service by early 2015. The Company continues to monitor political developments in the U.S. and the potential impact they may have on commencing construction of Keystone XL.

In December 2011, TransCanada announced that it had secured additional commercial support for Keystone XL following the successful conclusion of a binding open season offering long-term firm service for crude oil transportation from Hardisty, Alberta to Houston, Texas (Houston Lateral) increasing total long-term contracts on Keystone XL to in excess of 1.1 million bbl/d for an average term of approximately 18 years. The approximate US$600 million Houston Lateral project would involve the expansion of capacity through additional pump units increasing the capacity of Keystone XL to 830,000 bbl/d and the construction of an approximately 80 km (50 miles) pipeline extension from the proposed Keystone XL system. The Houston Lateral is expected to more than double the U.S. Gulf Coast refining market capacity directly accessible from the Keystone pipeline system to over four million bbl/d and is expected to be in service by early 2015, subject to regulatory approvals.

The capital cost of Keystone XL, including the Houston Lateral, is estimated to be approximately US$7.6 billion, with US$2.4 billion having been invested at December 31, 2011. Of the amount invested to date, approximately 60 per cent of the total represents purchased equipment and materials. The remaining capital cost amount is expected to be invested between now and the in-service date of the expansion, which is expected by early 2015. Capital costs related to the construction of Keystone XL are subject to capital cost risk and reward sharing mechanisms with Keystone's long-term committed shippers.

Marketlink Projects The Company is pursuing opportunities to transport growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to major U.S. refining markets. In 2010, the Company secured firm, five-year shipper contracts totalling 65,000 bbl/d for its proposed Bakken Marketlink project, which would transport U.S. crude oil from Baker, Montana to Cushing on facilities that form part of Keystone XL. The capital cost of the incremental facilities is expected to be approximately US$140 million and, pending regulatory approvals, commercial in service is anticipated in early 2015.

In fourth quarter 2011, TransCanada secured additional contractual support for the Cushing Marketlink project, which would transport crude oil from Cushing, Oklahoma to Port Arthur and Houston, Texas. The approximate US$50 million Cushing Marketlink project would use a portion of the Keystone XL facilities including the Houston Lateral. Pending regulatory approvals, Cushing Marketlink is expected to begin shipping crude oil to Port Arthur and Houston in early 2015.

OIL PIPELINES – BUSINESS RISKS

Crude Oil Supply, Markets and Competition Alberta produces the majority of the crude oil in the WCSB and is the primary source of crude oil supply for Keystone. In 2011, the WCSB produced an estimated 2.7 million bbl/d, consisting of 1.1 million bbl/d of conventional crude oil and condensate, and 1.6 million bbl/d of Alberta oil sands crude oil. The production of conventional crude oil has been declining but has been offset by increases in production from new shale oil production including the Bakken and Cardium formations and from the oil sands. The Alberta Energy Resources Conservation Board estimated, in its June 2010 report, that there are approximately 170 billion barrels of remaining established reserves in the Alberta oil sands.

In June 2011, the Canadian Association of Petroleum Producers (CAPP) forecasted WCSB crude oil supply would increase to 3.5 million bbl/d by 2015 and to 4.5 million bbl/d by 2020, indicating future growth in Alberta crude oil production. CAPP estimated spending in the oil sands totalled $19 billion in 2011 and is expected to increase from that level in 2012.

Keystone has contracted a significant portion of its capacity under long-term commercial arrangements. Keystone will compete for spot market throughput with other crude oil pipelines from Alberta and for new long-term contracts as supply from the WCSB increases.

The Williston Basin, located primarily in North Dakota and Montana, is the primary source of crude oil supply for the Bakken Marketlink project. In 2011, the Williston Basin achieved production rates of nearly 530,000 bbl/d. TransCanada expects production levels will reach approximately 840,000 bbl/d by 2015 due to growth in Bakken shale oil production.

The Permian Basin, located primarily in western Texas, is the primary source of crude oil for the Cushing Marketlink project. Production in the Permian Basin connected to crude oil storage facilities at Cushing is more than 1.0 million bbl/d and has been growing since 2006.

The Bakken Marketlink and Cushing Marketlink projects have contracted a significant amount of capacity. Both projects would compete for spot market throughput with other crude oil pipelines in the Williston Basin, Rocky Mountain and U.S. midcontinent regions and for new long-term contracts as supply from connected basins increases.

The markets for crude oil served by TransCanada's Keystone pipeline system are primarily refiners in the U.S. Midwest, midcontinent and Gulf Coast regions. TransCanada competes with pipelines that deliver WCSB, Williston Basin and Permian Basin crude oil to these refiners through interconnections with other pipelines. Keystone also competes with U.S. domestically-produced crude oil and imported crude oil for refining markets in the U.S. Midwest, Midcontinent and Gulf Coast regions.

Regulatory Risk Regulations and decisions issued by Canadian and U.S. regulatory bodies, including the NEB, FERC, EPA, Army Corps of Engineers, various state regulators, U.S. Department of Transportation, PHMSA and DOS, may have a significant impact on the approval, construction, operational and financial performance of TransCanada's crude oil pipelines. TransCanada continuously monitors existing and proposed regulations to determine their possible impact on its Oil Pipelines business.

Pipeline Abandonment Cost Risk Keystone's Canadian facilities are subject to the NEB's LMCI process previously discussed in the Natural Gas Pipelines – Business Risks section in this MD&A. Future pipeline abandonment costs for Keystone's Canadian facilities are expected to be recovered in transportation tolls.

Throughput Risk TransCanada has secured long-term transportation contracts for most of Keystone's capacity. Payments received for this committed capacity are not dependent on actual throughput. Uncontracted capacity is offered to the market on a spot basis. Uncontracted throughput is dependent primarily on crude oil production levels, market competition for crude oil, refinery activity and variations in economic activity.

Plant Availability Optimizing and maintaining plant availability is essential to the success of the Oil Pipelines business. TransCanada has a proven history of achieving high levels of performance through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment and a skilled workforce. Unexpected plant outages will impact throughput capacity and may result in reduced contracted capacity payments and lower uncontracted transportation sales revenue.

Execution and Capital Cost Risk Capital costs related to the construction of Keystone are subject to a capital cost risk-and reward-sharing mechanism with Keystone's long-term committed shippers. This mechanism allows Keystone to adjust its tolls by a factor based on the percentage change in the capital cost of the project. Tolls on Keystone XL would be adjusted by a factor equal to 75 per cent of the percentage change in capital costs. Capital costs related to the construction of the Bakken Marketlink and Cushing Marketlink projects would not be subject to a capital cost risk-and reward-sharing mechanism with the shippers.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Oil Pipelines business.

OIL PIPELINES – OUTLOOK

North American crude oil demand is expected to remain relatively unchanged in the long term while the availability of foreign sources of supply to North America declines. TransCanada's Oil Pipelines business will continue to focus on contracting and delivering growing North American crude oil supply to key U.S. markets.

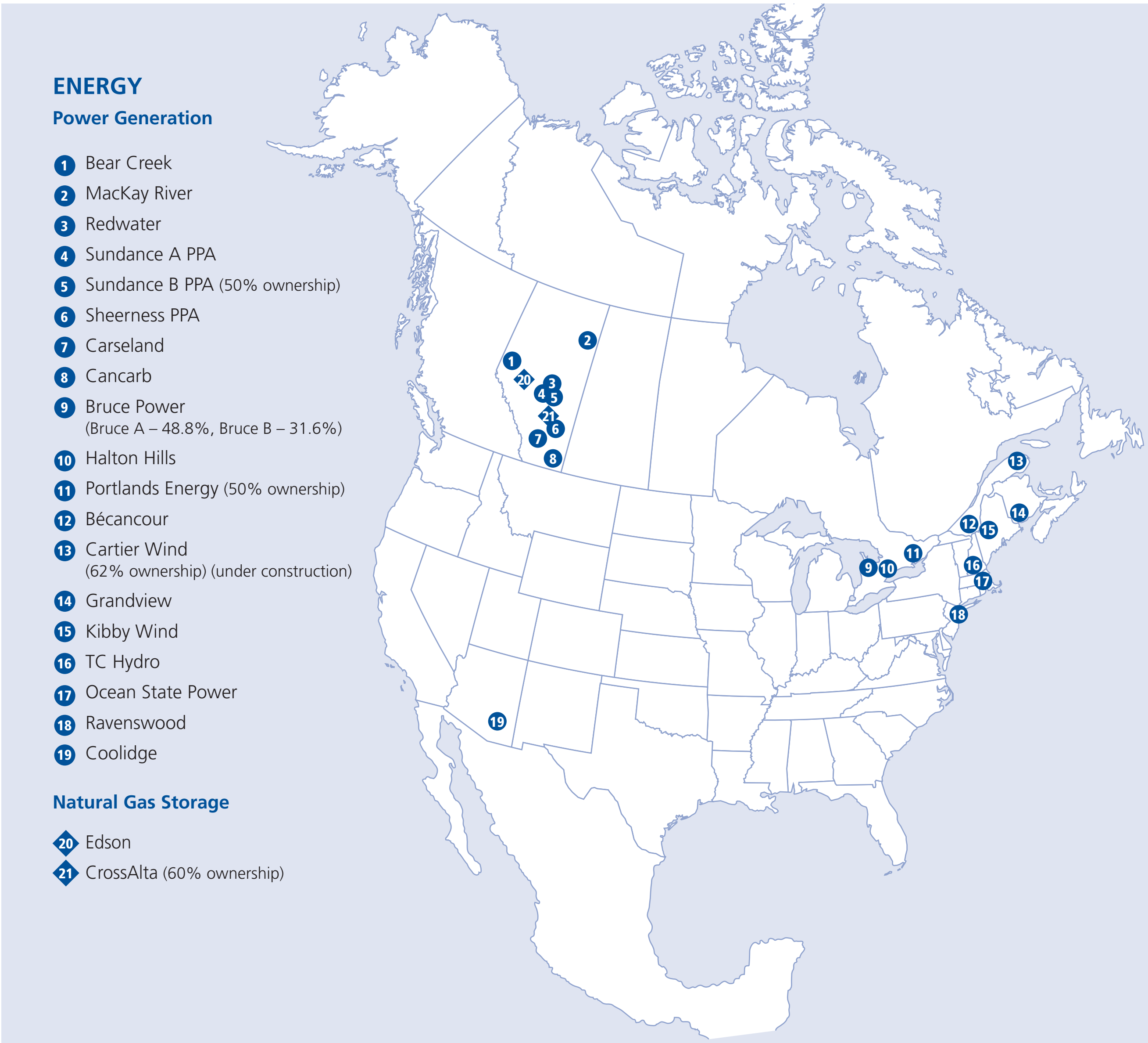
Producers continue to develop new crude oil supply in Western Canada. Several Alberta oil sands projects recently completed or under construction will begin to produce crude oil or will increase crude oil production in 2012 and 2013. Alberta oil sands production is forecast to increase to 2.3 million bbl/d by 2016 from 1.6 million bbl/d in 2011 and total Western Canada crude oil supply is projected to grow over the same period to 3.7 million bbl/d from 2.7 million bbl/d. The primary market for new crude oil production extends from the U.S. Midwest to the U.S. Gulf Coast and contains a large number of refineries that are capable of handling Canadian light and heavy crude oil blends. Incremental western Canadian crude oil production is expected to replace declining U.S. imports of crude oil from other countries.

The increase in WCSB crude oil exports from Alberta requires access to new markets, including international markets and markets in the U.S., that are currently served by foreign imports. TransCanada will continue to pursue additional opportunities to transport crude oil from Alberta to new markets.

Production in the Williston Basin is also growing and pipeline capacity in the region is constrained. Major markets for Williston Basin crude oil include the U.S. midcontinent and Midwest, and the U.S. Gulf Coast. TransCanada is competing with several other proposals to build pipeline capacity to transport crude oil supply from this region to U.S. refining centres. Capacity is constrained on the pipelines serving the crude oil storage facilities at Cushing. This situation periodically causes the price of West Texas Intermediate crude oil to be depressed relative to world prices. There are several competitive proposals to build pipeline capacity to transport oil supply from this region to the U.S. Gulf Coast. TransCanada will continue to compete for additional opportunities to transport Cushing crude oil to U.S. refining centres.

Earnings Oil Pipelines earnings in 2012 are expected to be higher than in 2011, primarily due to the impact of a full year of earnings being recorded for the Wood River/Patoka and Cushing Extension sections of Keystone compared to eleven months in 2011. Earnings are primarily generated by contractual arrangements for committed capacity that are not dependent on actual throughput. Uncontracted capacity offered to the market on a spot basis provides additional earnings opportunities. TransCanada expects earnings from its crude oil pipelines to increase as the proposed Keystone XL and Marketlink projects begin delivering crude oil. Once fully completed, TransCanada expects to record annual EBITDA of approximately US$1.7 billion, based on contracted volumes in place and assuming a full year of commercial operations servicing both the U.S. Midwest and Gulf Coast markets.

Capital Expenditures Total capital spending for Oil Pipelines in 2011 was $1.2 billion. Capital spending for Oil Pipelines in 2012 is expected to be approximately $0.9 billion, primarily due to contractual commitments associated with Keystone XL and expansion of Keystone's Hardisty, Alberta facilities.



ENERGY

The following Energy assets are owned 100 per cent by TransCanada unless otherwise stated.

BEAR CREEK An 80 MW natural gas-fired cogeneration plant located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant located near Redwater, Alberta.

SUNDANCE A&B TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA that expires in 2017. TransCanada also has a 50 per cent interest in ASTC Power Partnership, which has a PPA that expires in 2020, in place for 100 per cent of the production from the 706 MW Sundance B power facility. The Sundance facilities are located in south-central Alberta.

SHEERNESS TransCanada has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA that expires in 2020. The Sheerness plant is located in southeastern Alberta.

CARSELAND An 80 MW natural gas-fired cogeneration plant located near Carseland, Alberta.

CANCARB A 27 MW facility located in Medicine Hat, Alberta fuelled by waste heat from TransCanada's adjacent facility, which produces thermal carbon black (a natural gas by-product).

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.8 per cent of Bruce A, which has four 750 MW reactors. Two of these reactors are currently operating and two are being refurbished. TransCanada owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired, combined-cycle power plant in Halton Hills, Ontario.

PORTLANDS ENERGY A 550 MW natural gas-fired, combined-cycle power plant located in Toronto, Ontario. The plant is 50 per cent owned by TransCanada.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant located near Trois-Rivières, Québec.

CARTIER WIND The 590 MW Cartier Wind farm consists of five wind power projects located in Québec and is 62 per cent owned by TransCanada. Baie-des-Sables, Anse-à -Valleau, Carleton, Montagne-Sèche and phase one of Gros-Morne wind farms are in service and have a total generating capacity of 479 MW. Construction continues on the 111 MW second phase of the Gros-Morne wind farm which is expected to be operational in December 2012.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant located in Saint John, New Brunswick.

KIBBY WIND A 132 MW wind farm located in Kibby and Skinner Townships in Maine.

TC HYDRO TC Hydro has a total generating capacity of 583 MW and comprises 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OCEAN STATE POWER A 560 MW natural gas-fired, combined-cycle facility located in Burrillville, Rhode Island.

RAVENSWOOD A 2,480 MW multiple-unit generating facility located in Queens, New York, employing dual fuel-capable steam turbine, combined-cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power facility in Coolidge, Arizona, which was placed in service in second quarter 2011.

EDSON An underground natural gas storage facility connected to the Alberta System near Edson, Alberta. Edson's central processing system is capable of maximum injection and withdrawal rates of 725 MMcf/d of natural gas, and has a working storage capacity of approximately 50 Bcf.

CROSSALTA A 68 Bcf underground natural gas storage facility connected to the Alberta System near Crossfield, Alberta. CrossAlta's central processing system is capable of maximum injection and withdrawal rates of 550 MMcf/d of natural gas. TransCanada owns 60 per cent of CrossAlta and, through an agreement made effective July 1, 2011, is now the operator of the facility.

ENERGY – HIGHLIGHTS

- Energy's Comparable EBIT was $940 million in 2011, an increase of $192 million from $748 million in 2010.
- In 2011, the Company invested $1.1 billion in Energy capital projects which are all supported by long-term contracts, including:
  - the 575 MW Coolidge generating facility, which was placed in service in May 2011;
  - construction of the two remaining wind farms at Cartier Wind, including completion of the 58 MW Montagne-Sèche project and the 101 MW phase one of the Gros-Morne project; and
  - the restart of Bruce Power Units 1 and 2.
- Refurbishment work on Bruce Power Units 1 and 2 reached significant milestones in 2011. Fuelling of both Units 1 and 2 has now been completed and the final phases of commissioning for Unit 2 are underway.
- In December 2011, an agreement was executed for the purchase of nine Ontario solar projects with a combined capacity of 86 MW, for approximately $470 million. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. It is anticipated that the projects will be placed in service between late 2012 and mid-2013.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Canadian Power		
Western Power		
Sheerness	756	Coal
Coolidge	575	Natural gas
Sundance A	560	Coal
Sundance B[1]	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Halton Hills	683	Natural gas
Bécancour	550	Natural gas
Cartier Wind[2]	365	Wind
Portlands Energy[3]	275	Natural gas
Grandview	90	Natural gas
	1,963	
Bruce[4]	2,480	Nuclear
	7,079	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
Ocean State Power	560	Natural gas
Kibby Wind	132	Wind
	3,755	
Total Nominal Generating Capacity	10,834	

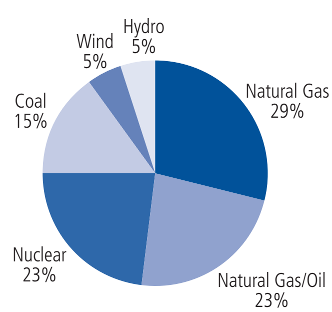
(1) Represents TransCanada's 50 per cent share of the Sundance B power plant output.

(2) Represents TransCanada's 62 per cent share of the total 590 MW project, including 111 MW under construction.

(3) Represents TransCanada's 50 per cent share of the total 550 MW facility.

(4) Represents TransCanada's 48.8 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B, including 733 MW for Bruce A Units 1 and 2.

Power by Fuel Source



ENERGY – RESULTS

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Canadian Power			
Western Power[(1)]	**489**	220	279
Eastern Power[(2)]	**314**	231	220
Bruce Power	**252**	298	352
General, administrative and support costs	**(43)**	(38)	(39)
Canadian Power Comparable EBITDA[(3)]	**1,012**	711	812
Depreciation and amortization	**(276)**	(242)	(227)
Canadian Power Comparable EBIT[(3)]	**736**	469	585
U.S. Power (in U.S. dollars)			
Northeast Power[(4)]	**314**	335	210
General, administrative and support costs	**(41)**	(32)	(40)
U.S. Power Comparable EBITDA[(3)]	**273**	303	170
Depreciation and amortization	**(109)**	(116)	(92)
U.S. Power Comparable EBIT[(3)]	**164**	187	78
Foreign exchange	**(4)**	7	8
U.S. Power Comparable EBIT[(3)] (in Canadian dollars)	**160**	194	86
Natural Gas Storage			
Alberta Storage	**89**	140	173
General, administrative and support costs	**(6)**	(8)	(9)
Natural Gas Storage Comparable EBITDA[(3)]	**83**	132	164
Depreciation and amortization	**(14)**	(15)	(14)
Natural Gas Storage Comparable EBIT[(3)]	**69**	117	150
Energy Business Development Comparable EBITDA and EBIT[(3)]	**(25)**	(32)	(37)
Energy Comparable EBIT[(3)]	**940**	748	784
Summary:			
Energy Comparable EBITDA[(3)]	**1,338**	1,125	1,131
Depreciation and amortization	**(398)**	(377)	(347)
Energy Comparable EBIT[(3)]	**940**	748	784

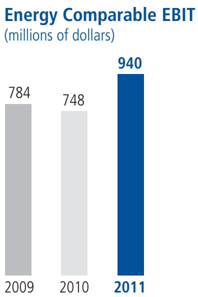
(1) Includes Coolidge effective May 2011.

(2) Includes Montagne-Sèche and phase one of Gros-Morne, Halton Hills, and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(3) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(4) Includes phase one and two of Kibby Wind effective October 2009 and October 2010, respectively.

ENERGY – FINANCIAL ANALYSIS



Energy's Comparable EBIT was $940 million in 2011 compared to $748 million in 2010 and $784 million in 2009.

Western Power As at December 31, 2011, Western Power owned or had the rights to approximately 2,600 MW of power supply in Alberta and the western U.S. from its three long-term PPAs, five natural gas-fired cogeneration facilities and a simple-cycle, natural gas peaking facility in Arizona.

The current operating power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, baseload, coal-fired generation through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration power plants with capacity ranging from 27 MW to 165 MW. This supply portfolio includes some of the lowest cost and most competitive power generation in the Alberta market area. The Sheerness and Sundance B PPAs expire in 2020, while the Sundance A PPA expires in 2017. As described further in the Energy – Opportunities and Developments section of this MD&A, no volumes were delivered under the Sundance A PPA in 2011. A portion of the expected output from the Western Power facilities is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas.

Western Power in Alberta relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced through the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is critical for optimizing Energy's return from its portfolio of power supply and managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market to ensure supply in case of unexpected plant outages. The overall amount of spot market volumes is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where TransCanada would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices in Alberta, as at December 31, 2011, Western Power had entered into fixed-price power sales contracts to sell approximately 8,400 gigawatt hours (GWh) in 2012 and 6,200 GWh in 2013.

Western U.S. power assets consist of the 575 MW Coolidge Generating Station which was placed in service in May 2011. Coolidge power output is fully contracted under a 20 year PPA with the Salt River Project, a local Arizona utility.

Eastern Power Eastern Power owns approximately 2,000 MW of power generation capacity, including facilities under construction. Eastern Power's current operating power generation assets are Halton Hills, Bécancour, the in-service Cartier Wind farms, Portlands Energy and Grandview.

Halton Hills was placed in service in September 2010 and is fully contracted under a 20-year Clean Energy Supply contract with the OPA.

Bécancour's entire power output is supplied to Hydro-Québec under a 20-year power purchase contract expiring in 2026. Steam produced from this facility is sold to an industrial customer for use in commercial processes. Electricity generation at the Bécancour power plant has been suspended since January 2008 as a result of an agreement entered into with Hydro-Québec. Under the agreement, while energy production and payments are suspended, TransCanada continues to receive capacity payments similar to those that would have been received under the normal course of operation.

The Montagne-Sèche and phase one of Gros-Morne Cartier Wind farms were placed in service November 2011, bringing the total generating capacity of the in-service Cartier Wind farms to 479 MW. Output from these wind farms is supplied to Hydro-Québec under 20-year power purchase contracts.

Portlands Energy was placed in service in April 2009. This facility is fully contracted under a 20-year Accelerated Clean Energy Supply contract with the OPA.

Grandview is located on the site of the Irving Oil refinery in Saint John, New Brunswick. TransCanada and Irving Oil are under a 20-year tolling arrangement, which expires in 2025, through which Irving Oil supplies fuel for the 90 MW plant and is contracted to purchase 100 per cent of the plant's heat and electricity output.

Eastern Power is focused on selling power under long-term contracts. Eastern Power sales volumes were 100 per cent sold under contract in 2011 and are expected to be fully contracted going forward.

Western and Eastern Canadian Power Comparable EBIT(1)(2)(3)

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Revenues			
Western power(2)	**1,081**	714	788
Eastern power(3)	**475**	330	281
Other(4)	**70**	84	86
	1,626	1,128	1,155
Commodity purchases resold			
Western power	**(538)**	(431)	(451)
Other(4)(5)	**(9)**	(26)	(26)
	(547)	(457)	(477)
Plant operating costs and other	**(276)**	(220)	(179)
General, administrative and support costs	**(43)**	(38)	(39)
Comparable EBITDA(1)	**760**	413	460
Depreciation and amortization	**(163)**	(140)	(138)
Comparable EBIT(1)	**597**	273	322

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(2) Includes Coolidge effective May 2011.

(3) Includes Montagne-Sèche and phase one of Gros-Morne, Halton Hills, and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(4) Includes sales of excess natural gas purchased for generation and sales of thermal carbon black. The net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues.

(5) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics

Year ended December 31	2011	2010	2009
Sales Volumes (GWh)			
Supply			
Generation			
Western Power[1]	2,606	2,373	2,334
Eastern Power[2]	3,714	2,359	1,550
Purchased			
Sundance A & B and Sheerness PPAs[3]	7,909	10,785	10,603
Other purchases	1,112	429	529
	15,341	15,946	15,016
Sales			
Contracted			
Western Power	9,245	10,211	9,944
Eastern Power	3,714	2,375	1,588
Spot			
Western Power	2,382	3,360	3,484
	15,341	15,946	15,016
Plant Availability[4]			
Western Power[1][5]	97%	95%	93%
Eastern Power[2][6]	93%	94%	97%

(1) Includes Coolidge effective May 2011.

(2) Includes Montagne-Séche and phase one of Gros-Morne, Halton Hills and Portlands Energy effective November 2011, September 2010 and April 2009, respectively.

(3) No volumes were delivered under the Sundance A PPA in 2011.

(4) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(5) Excludes facilities that provide power to TransCanada under PPAs.

(6) Bécancour has been excluded from the availability calculation, as power generation at the facility has been suspended since 2008.

Western Power's Comparable EBITDA of $489 million and Power Revenues of $1,081 million in 2011 increased $269 million and $367 million, respectively, compared to 2010 primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year PPA in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 51 per cent to $77 per megawatt hour (MWh) in 2011 compared to $51 per MWh in 2010. Approximately 20 per cent of Western Power's sales volumes were sold in the spot market in 2011 compared to 25 per cent in 2010.

Western Power's Comparable EBITDA in 2011 included $156 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 are interruptions of supply in accordance with the terms of the PPA. Refer to the Opportunities and Developments section in this MD&A for further discussion on the dispute regarding the Sundance A outage.

Eastern Power's Comparable EBITDA of $314 million and Power Revenues of $475 million in 2011 increased $83 million and $145 million, respectively, compared to 2010. These increases were primarily due to the full year impact of incremental earnings from Halton Hills, which was placed in service in September 2010.

Western Power's commodity purchases resold of $538 million increased $107 million compared to 2010 due to increased direct sales to customers, higher PPA costs per MWh and higher volumes at Sheerness.

Plant Operating Costs and Other, which includes natural gas fuel consumed in power generation, of $276 million in 2011 increased $56 million from 2010 primarily due to incremental fuel consumed at Halton Hills.

Depreciation and amortization of $163 million increased $23 million in 2011 compared to 2010 primarily due to incremental depreciation from Halton Hills and Coolidge.

Western Power's Comparable EBITDA of $220 million and Power Revenues of $714 million in 2010 decreased $59 million and $74 million, respectively, compared to 2009 primarily due to lower overall realized power prices. Approximately 25 per cent of Western Power's sales volumes were sold in the spot market in 2010 compared to 26 per cent in 2009.

Eastern Power's Comparable EBITDA of $231 million and Power Revenues of $330 million in 2010 increased $11 million and $49 million, respectively, compared to 2009. These increases were primarily due to incremental earnings from Halton Hills and Portlands Energy, which went in service September 2010 and April 2009, respectively, partially offset by lower contracted revenue from the Bécancour facility.

Plant Operating Costs and Other of $220 million in 2010 increased $41 million from 2009 primarily due to incremental fuel consumed at Portlands Energy and Halton Hills.

Bruce Power Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and comprises Bruce A and Bruce B. Bruce A has four 750 MW reactors, two of which are being refurbished. The two units being refurbished are expected to resume commercial operations in first and third quarter 2012. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2011, TransCanada and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System (OMERS), each owned a 48.8 per cent interest in Bruce A (2010 and 2009 – 48.8 per cent). The remaining 2.4 per cent interest in Bruce A is owned by the Power Workers' Union Trust (PWU), the Society of Energy Professionals Trust (SEP) and the Bruce Power Employee Investment Trust. Bruce A subleases Units 1 to 4 from Bruce B. TransCanada, OMERS and Cameco Corporation each own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure. The remaining interest in Bruce B is owned by PWU and SEP.

The following Bruce Power financial results reflect TransCanada's proportionate share of the eight Bruce Power units, six of which were operating:

Bruce Power Results

(TransCanada's proportionate share) Year ended December 31 *(millions of dollars unless otherwise indicated)*	**2011**	2010	2009
Revenues[1]	**817**	862	883
Operating expenses	**(565)**	(564)	(531)
Comparable EBITDA[2]	**252**	298	352
Bruce A Comparable EBITDA[2]	**98**	91	48
Bruce B Comparable EBITDA[2]	**154**	207	304
Comparable EBITDA[2]	**252**	298	352
Depreciation and amortization	**(113)**	(102)	(89)
Comparable EBIT[2]	**139**	196	263
Bruce Power – Other Information			
Plant availability[3]			
Bruce A	**90%**	81%	78%
Bruce B	**88%**	91%	91%
Combined Bruce Power	**89%**	88%	87%
Planned outage days			
Bruce A	**60**	60	56
Bruce B	**135**	70	45
Unplanned outage days			
Bruce A	**16**	64	82
Bruce B	**24**	34	47
Sales volumes (GWh)			
Bruce A	**5,475**	5,026	4,894
Bruce B	**7,859**	8,184	7,767
	13,334	13,210	12,661
Results per MWh			
Bruce A power revenues	**$66**	$65	$64
Bruce B power revenues[4]	**$54**	$58	$64
Combined Bruce Power revenues	**$57**	$60	$64

(1) Revenues include Bruce A fuel cost recoveries of $24 million in 2011 (2010 – $29 million; 2009 – $34 million).

(2) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(3) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(4) Includes revenues received under the floor price mechanism, from contract settlements as well as volumes and revenues associated with deemed generation.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased $46 million to $252 million in 2011 compared to 2010, primarily due to lower results at Bruce B. Comparable EBITDA in 2010 also included the net positive impact of a payment made in 2010 by Bruce B to Bruce A related to amendments made in 2009 to the agreements with the OPA. The net positive impact to TransCanada from the payment reflected TransCanada's higher percentage ownership in Bruce A.

TransCanada's proportionate share of Bruce A's Comparable EBITDA increased $7 million to $98 million in 2011 compared to 2010 primarily due to higher volumes as a result of a decrease in unplanned outage days, partially offset by the above-noted payment in 2010 from Bruce B.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $53 million to $154 million in 2011 compared to 2010. The decrease was primarily due to lower realized prices resulting from expiration of fixed-price contracts at higher prices, higher operating costs and lower volumes due to an increase in planned outage days. Bruce B results for 2010 included the above-noted payment to Bruce A.

Bruce Power's Depreciation and Amortization increased $11 million in 2011 compared to 2010 and $13 million in 2010 compared to 2009 primarily due to capital additions.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA of $298 million in 2010 decreased $54 million compared to 2009 due to lower realized prices and higher annual lease expense in 2010 for Bruce B, partially offset by higher volumes at both Bruce A and Bruce B and the positive net impact of the payment made in 2010 by Bruce B to Bruce A.

The Independent Electricity System Operator (IESO) periodically requires the curtailment of certain units at Bruce Power to address surplus baseload generation in Ontario. During these unit curtailments, Bruce power receives deemed generation payments at OPA contract prices. Lower sales volumes in 2009 compared to 2010 and 2011 reflected the impact of higher unit curtailments in 2009.

The overall plant availability percentage in 2012 is expected to be in the mid 70s for Bruce A Units 3 and 4. Bruce A commenced the approximate six month West Shift Plus outage on Unit 3 on November 6, 2011. Additional planned maintenance on one of the units at Bruce A is scheduled for the summer of 2012. Bruce B's overall plant availability is expected to be in the mid 90s for the four units in 2012. Planned maintenance on one of the units at Bruce B commenced in January 2012.

Bruce A

Under a contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh, adjusted annually for inflation on April 1. In addition, fuel costs are recovered from the OPA.

Bruce A Fixed Price

	per MWh
April 1, 2011 – March 31, 2012	$66.33
April 1, 2010 – March 31, 2011	$64.71
April 1, 2009 – March 31, 2010	$64.45

Bruce B

As part of Bruce Power's contract with the OPA, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1. Payments received under the floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. No amounts recorded in revenues were subject to repayment in 2011, 2010 or 2009.

Bruce B Floor Price

	per MWh
April 1, 2011 – March 31, 2012	$50.18
April 1, 2010 – March 31, 2011	$48.96
April 1, 2009 – March 31, 2010	$48.76

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price. Bruce B's realized price decreased by $4 per MWh to $54 per MWh in 2011 compared to 2010, and by $6 per MWh to $58 per MWh in 2010 compared to 2009, and reflected revenues recognized from the floor price mechanism, contract settlements as well as volumes and revenues associated with deemed generation. The decreases reflected the expiration of higher-priced contracts entered into in previous years.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, consisting of Ravenswood, TC Hydro, Ocean State Power, and Kibby Wind. Ravenswood, located in Queens, New York, is a 2,480 MW natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts with total generating capacity of 583 MW. Ocean State Power, a 560 MW natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island and Kibby Wind is a 132 MW wind farm located in Maine. The first 66 MW phase of Kibby Wind was placed in service in October 2009 and the second 66 MW phase went in service in October 2010.

U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the New England, New York and PJM Interconnection area (PJM) power markets. Exposure to fluctuations in spot prices on these power sales commitments are hedged with a combination of forward purchases of power, forward purchases of fuel to generate power and through the use of financial contracts.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. At present, a series of voluntary forward auctions and a mandatory spot demand curve price setting process are used to determine the price paid to capacity suppliers. There are two annual six-month strip forward auctions and 12 monthly forward auctions in which buyer and seller participation is optional. All remaining available capacity is required to participate in a monthly spot auction in the final week prior to each capacity month. The spot auction clears at a price based on a downward-sloping demand curve, the parameters of which are determined by the NYISO and approved by the FERC. There are separate demand curves for each of three defined capacity zones: Long Island, New York City and Rest of State. The Ravenswood capacity is located in the New York City capacity zone. Refer to the Energy – Opportunities and Development section of this MD&A for more information.

The New England Power Pool relies on a Forward Capacity Market (FCM) to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. This capacity market operated on a transition basis from 2007 to 2009. During this period, Ocean State Power and TC Hydro received capacity transition payments under this mechanism as specified in the FERC-approved FCM settlement. Beginning in June 2010, the price paid for capacity was determined by annual competitive FCM auctions, which are held three years in advance of the applicable capacity year. Future auction results will be affected by actual versus projected demand, the pace of progress in developing new qualifying resources that bid into the auctions and other factors.

U.S. Power Comparable EBIT(1)(2)

Year ended December 31 *(millions of U.S. dollars)*	**2011**	2010	2009
Revenues			
Power(3)	**919**	1,090	742
Capacity	**227**	231	169
Other(3)(4)	**80**	78	79
	1,226	1,399	990
Commodity purchases resold(3)	**(398)**	(543)	(309)
Plant operating costs and other(4)	**(514)**	(521)	(471)
General, administrative and support costs	**(41)**	(32)	(40)
Comparable EBITDA(1)	**273**	303	170
Depreciation and amortization	**(109)**	(116)	(92)
Comparable EBIT(1)	**164**	187	78

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA and Comparable EBIT.

(2) Includes phases one and two of Kibby Wind as of October 2009 and October 2010, respectively.

(3) Realized gains and losses from financial derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in Power Revenues.

(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

U.S. Power Operating Statistics(1)

Year ended December 31	**2011**	2010	2009
Physical Sales Volumes (GWh)			
Supply			
Generation	**6,880**	6,755	5,993
Purchased	**6,018**	8,899	5,310
	12,898	15,654	11,303
Plant Availability(2)	**87%**	86%	79%

(1) Includes phases one and two of Kibby Wind as of October 2009 and October 2010, respectively.

(2) Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

U.S. Power's Comparable EBITDA of US$273 million in 2011 decreased US$30 million compared to 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes, partially offset by new sales activity in PJM, an increase in the New York commercial customer base and incremental earnings from phase two of Kibby Wind which was placed in service in October 2010.

Physical sales volumes in 2011 have decreased compared to 2010 due to decreased demand as a result of unseasonable weather and reduced opportunities for wholesale contracts. As well, fewer physical transactions were used to cover power sales commitments during 2011, in favour of financial transactions, compared to 2010.

U.S. Power's Power Revenues of US$919 million in 2011 decreased US$171 million compared to 2010 primarily due to lower physical sales volumes and lower prices, partially offset by new sales activity in New York and PJM.

Capacity Revenue of US$227 million in 2011 decreased US$4 million compared to 2010. New York capacity revenues in the second half of 2011 were negatively impacted by low spot prices as a result of the price mitigation issue described further in the Energy – Opportunities and Developments section in this MD&A. Reduced capacity prices were partially offset by lower forced outage rates at Ravenswood.

Commodity Purchases Resold of $398 million in 2011 decreased US$145 million compared to 2010 primarily due to a decrease in the quantity of physical power purchased for resale under U.S. Power's power sales commitments to wholesale and industrial customers in New England, partially offset by higher realized prices on purchased power as well as new activity in the New York and PJM markets.

U.S. Power's Comparable EBITDA of US$303 million in 2010 increased US$133 million compared to 2009 primarily due to higher capacity revenues resulting from higher capacity prices partially offset by higher forced outage rates at Ravenswood, higher volumes of power sold in the New England and New York markets, higher realized prices on power sold and incremental earnings from Kibby Wind.

U.S. Power achieved plant availability of 87 per cent in 2011 compared to 86 per cent in 2010 and 79 per cent in 2009. Lower availability in 2009 was primarily due to an unplanned outage at Ravenswood Unit 30 from September 2008 to May 2009.

As at December 31, 2011, approximately 3,600 GWh or 30 per cent and 1,000 GWh or 10 per cent of U.S. Power's planned generation is contracted for 2012 and 2013, respectively. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage TransCanada owns or has rights to 129 Bcf of non-regulated natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta. TransCanada also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (MMcf/d)
Edson	50	725
CrossAlta(1)	41	550
Third-party storage	38	630
	129	1,905

(1) Represents TransCanada's 60 per cent ownership interest in CrossAlta. Working gas storage capacity can vary due to the amount of base gas in the facility.

The Company's natural gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Alberta-based storage will continue to serve market needs and could play an important role as additional gas supplies are connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TransCanada's Natural Gas Pipelines segment.

TransCanada manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

Market volatility creates arbitrage opportunities and TransCanada's storage facilities provide customers with the ability to capture value from short-term price movements. At December 31, 2011, TransCanada had contracted approximately 60 per cent of the total 129 Bcf of working gas storage capacity in 2012 and 20 per cent of storage capacity in 2013. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions are comprised of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TransCanada locks in future positive margins, effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in revenues. TransCanada records its proprietary natural gas inventory in storage at its fair value using a weighted average of forward prices for natural gas for the following four months, less selling costs. Changes in the fair value of inventory are recorded in revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings, as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage's Comparable EBITDA of $83 million in 2011 decreased $49 million compared to 2010 primarily due to decreased third party storage and proprietary revenues as a result of lower realized natural gas price spreads.

Natural Gas Storage's Comparable EBITDA of $132 million in 2010 decreased $32 million compared to 2009 primarily due to decreased proprietary and third party storage revenues as a result of lower realized natural gas price spreads.

Business Development Business Development Comparable EBITDA losses from business development expenses of $25 million in 2011 decreased $7 million compared to 2010 and decreased $5 million in 2010 compared to 2009 primarily due to decreased development activity in 2011.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Bruce Power In accordance with terms of the Bruce Power Refurbishment Implementation Agreement (BPRIA) between Bruce Power and the OPA, Bruce A committed to refurbish and restart Units 1 and 2.

Refurbishment work on Units 1 and 2 reached significant milestones in 2011. Fuelling of both Unit 1 and Unit 2 has now been completed and the final phases of commissioning for Unit 2 are underway. Subject to regulatory approval, Bruce Power expects to commence commercial operations of Unit 2 in first quarter 2012 and commercial operations of Unit 1 in third quarter 2012. TransCanada's share of the total net capital cost is expected to be approximately $2.4 billion of which $2.3 billion was incurred as at December 31, 2011.

In February 2011, the BPRIA was amended to extend the suspension date for Bruce A Contingent Support Payments (CSP) from December 31, 2011 to June 1, 2012. The CSP received from the OPA by Bruce A are equal to the difference between the fixed prices under the BPRIA and spot market prices. As a result of the amendment, all output from Bruce A will be subject to spot market prices effective June 1, 2012 until the restart of both Units 1 and 2 is complete.

In November 2011, Bruce Power commenced the approximately six month West Shift Plus outage as part of the life extension strategy for Unit 3. Subject to regulatory approval, Unit 3 is expected to return to service in second quarter 2012.

Sundance A In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta Corporation (TransAlta) in January 2011. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated.

TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour. The Company expects that its unamortized carrying value as at December 31, 2011, of $77 million related to the Sundance A PPA in Intangibles and Other Assets remains fully recoverable under the terms of the PPA, regardless of the outcome of the arbitration process.

Oakville In October 2010, the Government of Ontario announced that it would not proceed with the $1.2 billion Oakville generating station, a 900 MW facility that TransCanada was intending to build, own, and operate further to a previously awarded 20-year Clean Energy Supply contract with the OPA. In third quarter 2011, TransCanada, the Government of Ontario and the OPA reached a formal agreement to use an arbitration process to settle the dispute resulting from termination of this contract. Pursuant to the arbitration agreement, the parties remain in discussions. TransCanada expects to be appropriately compensated for the economic consequences associated with the contract's termination.

Coolidge The US$500 million Coolidge generating station was placed in service in May 2011. Power from the 575 MW simple-cycle, natural gas-fired peaking facility located near Phoenix, Arizona is sold to the Salt River Project Agricultural Improvement and Power District under a 20-year PPA.

Cartier Wind In November 2011, the 58 MW Montagne-Sèche and the 101 MW first phase of the Gros-Morne Wind farm projects were placed in service. The 111 MW second phase of Gros-Morne is expected to be operational in December 2012. This will complete construction of the 590 MW Cartier Wind project in Québec. All of the power produced by Cartier Wind is sold under a 20-year PPA to Hydro-Québec.

Ontario Solar In December 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately $470 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. TransCanada anticipates the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Bécancour In June 2011, Hydro-Québec notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant throughout 2012. Under the terms of the suspension agreement, Hydro-Québec has the option, subject to certain conditions, to extend the suspension on an annual basis until such time as regional electricity demand levels recover. TransCanada will continue to receive capacity payments under the agreement similar to those that would have been received under the normal course of operation while energy production and payments are suspended.

Ravenswood Since July 2011, spot prices for capacity sales in the New York Zone J market have been negatively impacted by the manner in which NYISO has applied pricing rules for a new power plant that recently began service in this market. TransCanada believes that this application of pricing rules by the NYISO is in direct contravention of a series of the FERC orders which direct how new entrant capacity is to be treated for the purpose of determining capacity prices. TransCanada and other parties have filed formal complaints with the FERC that are currently pending. The outcome of the complaints and longer-term impact that this development may have on Ravenswood is unknown.

During third quarter 2011, the demand curve reset process was completed following the FERC's acceptance of the NYISO's September 22, 2011 compliance filing. This resulted in increased demand curve rates that apply going forward to 2014. Until the above noted NYISO actions relative to new unit pricing are resolved, capacity prices are expected to remain volatile.

Subsequent to closing the acquisition of Ravenswood in August 2008, TransCanada experienced a forced outage event related to Ravenswood's 981 MW Unit 30. The unit returned to service in May 2009. TransCanada has filed claims against the insurers to enforce its rights under the insurance policies and litigation proceedings are ongoing.

Power Transmission Line Projects In June 2011, Zephyr terminated the precedent agreements with its potential shippers as the parties were unable to resolve key commercial issues. In July 2011, one of Zephyr's potential shippers exercised its contractual rights to acquire 100 per cent of the Zephyr project from TransCanada.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices TransCanada operates in competitive power and natural gas markets in North America. Power and natural gas price volatility is caused by fluctuating supply and demand, and by general economic conditions. TransCanada's power generation facilities are exposed to commodity price volatility in its Western Power operations in Alberta and in its U.S. Power operations in New England and New York. Earnings from these businesses are generally correlated to the prevailing power supply demand conditions and the price of natural gas, as power prices are set by gas-fired power supplies the majority of the time. Extended periods of low gas prices will generally place downward pressure on earnings from these facilities. Western Power's Coolidge Generating Station and TransCanada's portfolio of assets in Eastern Canada have been fully contracted, and are therefore not subject to fluctuating commodity prices. Bruce Power's exposure to fluctuating power prices is discussed further below.

Sales of uncontracted power volumes into the spot market in Alberta and the U.S. northeast can be subject to price volatility, directly affecting earnings. To mitigate this risk, TransCanada commits a portion of its supply to medium-term to long-term sales contracts while retaining an amount of unsold supply to mitigate the financial impact of unexpected plant outages and to provide flexibility in managing the Company's portfolio of wholly owned assets. This unsold supply is subsequently sold under shorter-term forward arrangements or into the spot market and is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Under an agreement with the OPA, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price for all of its output. Bruce B also enters into third party fixed-price contracts where it receives the difference between the contract price and spot price. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA. All Bruce A output will be subject to spot market pricing effective June 1, 2012 until the restart of both Units 1 and 2 is complete.

Energy's natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons.

U.S. Power Capacity Payments The parameters that drive U.S. Power capacity prices are reset periodically and are affected by a number of factors including the cost of entering the market, available supply and fluctuations in forecast demand. With the downturn in the economy in recent years, there has been a decrease in demand that, combined with increased supply in these markets, has put downward pressure on capacity prices. In September 2011, the demand curve reset process for the New York Zone J market was completed for the 2011 to 2014 capacity periods, resulting in increased demand curve rates. These increases, however, were more than offset by the unexpected capacity price treatment applied to certain new entrants by NYISO in 2011, a matter that remains subject to a pending complaint lodged with the FERC. Refer to Energy – Opportunities and Development for more information.

Plant Availability Optimizing and maintaining plant availability is essential to the continued success of the Energy business. High levels of performance are achieved through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment, and a skilled workforce. Further mitigation is provided through the contractual obligations to TransCanada of its power suppliers under the Sundance and Sheerness PPAs, including the payment of market-based penalties related to availability requirements and by certain sales contracts that share operating risks with the purchaser. In the event a PPA power supplier experiences a verified force majeure event, TransCanada is not entitled to receive market-based penalties for the duration of the verified force majeure event and the monthly capacity payments paid to the supplier are eliminated during the same period. Unexpected plant outages, including unexpected delays in ending planned outages, could result in lower plant output and sales revenue, reduced capacity payments and margins, and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TransCanada meets its contractual obligations.

Weather Extreme temperature and weather events in North America often create price volatility and variable demand for power and natural gas. These events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds impact the earnings of Energy's wind assets.

Hydrology TransCanada's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution, Capital Cost and Permitting Energy's construction programs in Québec and Ontario, including its investment in Bruce Power, are subject to execution, capital cost and permitting risks.

Regulation of Power Markets TransCanada operates in both regulated and deregulated power markets. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, unfair cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. TransCanada is an active participant in formal and informal regulatory proceedings and takes legal action where required.

Refer to the Risk Management and Financial Instruments and Other Risks sections in this MD&A for information on additional risks related to the Energy business.

ENERGY – OUTLOOK

The power supply/demand dynamic in Alberta is rapidly tightening. The 2011 average pool price rose to $77/MWh compared to $51/MWh in 2010, driven by unexpected plant outages and increased demand, especially in the peak periods. Increases in Alberta's power demand were a function of economic growth coming from the oil sands and natural gas industries plus population increases in the province. Over the next decade, further oil sands projects and the associated development are expected to drive continued strong Alberta economic growth. The Alberta Electric System Operator's forecasts indicate power demand growth rates of 3.2 per cent per year over the next 20 years and estimates that more than 11,000 MW of new generation will be required. This backdrop will provide an opportunity for TransCanada to participate in new generation and other power infrastructure projects. The current low gas price environment provides an opportunity for gas generation sources to be a very cost-competitive option to fill these anticipated generation needs.

Ontario's 2011 average power demand was down 0.5 per cent compared to 2010. New renewable energy projects came in service in 2011 and the IESO projects a further 2,500 MW of new and refurbished power supply additions by early 2013. This increase in supply, combined with lower natural gas prices plus weak 2011 Ontario economic growth of about two per cent resulted in a decrease in the year-over-year average hourly Ontario energy price from $36/MWh in 2010 to $30/MWh in 2011. The IESO forecasts a return to power demand growth in 2012, however, future power demand growth rates are expected to be modest, as a full return of the energy intensive industries lost in the recession is not expected. TransCanada's existing energy assets in Ontario are largely insulated from changes in the market price of power through contracts with the OPA.

New England's average power demand fell slightly in 2011 while approximately 800 MW of new gas-fired power supply was added. This prevailing supply and demand environment, in addition to lower natural gas prices and weak 2011 economic growth, resulted in power prices down slightly on a year over year basis. The 2011 average ISO New England power price was US$47/MWh compared to the 2010 average of about US$50/MWh. ISO New England forecasts a return to power growth of about one per cent per year in the coming years, based on modest economic growth.

New York City's average power demand dropped slightly in 2011 while approximately 550 MW of new gas-fired power supply was added. Under this supply/demand environment, coupled with lower natural gas prices, weak 2011 economic growth and continuing high New York City unemployment rates, power prices fell slightly on a year over year basis. The 2011 average NYISO New York City power price was US$51/MWh versus the 2010 average of about US$56/MWh. The NYISO forecasts a return to power demand growth of about one per cent per year in the coming years, based on modest population and economic growth.

Earnings TransCanada expects that results from its Energy operations in 2012 will be higher than those in 2011. There will be a positive earnings impact from a full year of Coolidge, Montagne-Sèche and the first phase of Gros-Morne, which all came in service during 2011. Additional earnings from Bruce Power will also be realized with the return to service of Unit 2, which is expected in first quarter 2012, followed by Unit 1 which is expected in third quarter 2012. It is also anticipated that the nine solar projects TransCanada agreed to purchase in late 2011 will come in service between late 2012 and mid-2013 pending certain conditions and approvals. Output from these plants, as well as a significant portion of output from Energy's other assets, has been sold under long-term contracts and provides a stable earnings base for the Energy business.

The Company expects the positive impact on earnings from the new assets coming in service could be tempered by results from U.S. Power if capacity prices in New York remain at low levels, and Gas Storage, where storage spreads are expected to remain at low levels throughout 2012. In addition, earnings from Bruce A will be impacted by the West Shift Plus outage on Unit 3, which commenced on November 6, 2011 and is expected to last six months. Energy earnings in 2012 will also be impacted by fluctuations in Alberta power prices.

Certain regulatory and arbitration outcomes that are expected to be resolved in 2012 may also have a significant impact on Energy results. Specifically, actions taken by the FERC related to New York capacity prices, and resolution to the arbitration processes underway on Sundance A and Oakville may have a material financial impact on Energy earnings in 2012.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2012 EBIT. Refer to the Energy – Business Risks section in this MD&A for a complete discussion of these and other factors affecting the Energy Outlook.

CORPORATE

Corporate had a Comparable EBIT loss of $100 million in 2011 compared to losses of $99 million and $117 million in 2010 and 2009, respectively. The losses in 2011 were consistent with 2010 and the decrease in the loss in 2010 compared to 2009 was primarily due to lower support services and other corporate costs.

OTHER INCOME STATEMENT ITEMS

COMPARABLE INTEREST EXPENSE

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Comparable Interest on long-term debt[1]			
Canadian dollar-denominated	**490**	514	548
U.S. dollar-denominated	**734**	680	645
Foreign exchange	**(7)**	20	92
	1,217	1,214	1,285
Other interest and amortization	**24**	74	27
Capitalized interest	**(302)**	(587)	(358)
Comparable Interest Expense	**939**	701	954

(1) Includes interest on Junior Subordinated Notes.

Comparable Interest Expense increased in 2011 by $238 million to $939 million compared to 2010. This increase was primarily due to decreased capitalized interest upon placing Keystone and Coolidge in service in 2011 and Halton Hills in service in the latter part of 2010. Comparable Interest on long-term debt increased in 2011 compared to 2010 primarily due to new debt issues of US$1.0 billion in September 2010 and US$1.25 billion in June 2010. This was offset by the impact of a weaker U.S. dollar and the decrease in interest expense on Canadian dollar-denominated debt from debt maturities. Other Interest and Amortization Expense in 2011 was positively affected by increased gains from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates.

Comparable Interest Expense in 2010 decreased $253 million to $701 million from $954 million in 2009. Interest on Canadian dollar-denominated debt decreased in 2010 compared to 2009 primarily due to debt maturities. Interest on U.S. dollar-denominated debt increased in 2010 compared to 2009 due to new debt issues of US$1.0 billion in September 2010, US$1.25 billion in June 2010 and US$2.0 billion in January 2009, partially offset by the impact of a weaker U.S. dollar. Other Interest and Amortization Expense in 2010 was negatively affected by additional financing charges on committed credit facilities and increased losses from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates. Interest Expense was positively impacted by higher capitalization of interest in 2010 relating to the Company's larger capital spending program primarily for the construction of Keystone and refurbishment and restart of Bruce A Units 1 and 2.

Comparable Interest Income and Other was $60 million in 2011 compared to $94 million and $121 million in 2010 and 2009, respectively. The decrease in 2011 compared to 2010 was primarily due to lower gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuations. The decrease in 2010 compared to 2009 was primarily due to the positive impact of a weakening U.S. dollar on the translation of U.S. dollar working capital balances throughout each year and gains in 2010 on derivatives used to manage foreign exchange fluctuations.

Comparable Income Taxes were $595 million, $400 million and $406 million in 2011, 2010, and 2009, respectively. The increase of $195 million in 2011 compared to 2010 was primarily due to increased pre-tax earnings and higher positive income tax adjustments in 2010 compared to 2011. In 2011 and 2010, the Company recorded a benefit in Current

Income Taxes with an offsetting provision in Future Income Taxes as a result of bonus depreciation for U.S. income tax purposes on the Bison pipeline which was placed in service in January 2011 and the Wood River/Patoka and Cushing Extension sections of Keystone which were placed in operational service in June 2010 and February 2011, respectively. The decrease of $6 million in 2010 compared to 2009 was primarily due to increased pre-tax earnings offset by higher positive income tax adjustments in 2010.

Non-Controlling Interests were $129 million in 2011 compared to $115 million and $96 million in 2010 and 2009, respectively. The $14 million increase in 2011 compared to 2010 was primarily due to the sale of a 25 per cent interest in GTN and Bison to TC PipeLines, LP and reduction in the Company's ownership interest in TC PipeLines, LP in May 2011 partially offset by the impact of a weaker US dollar in 2011. The increase in 2010 compared to 2009 was primarily due to increased TC PipeLines, LP earnings as a result of higher revenues from Northern Border and the acquisition by TC PipeLines, LP of North Baja, partially offset by the impact of a weaker US dollar in 2010.

LIQUIDITY AND CAPITAL RESOURCES

TransCanada believes that its financial position remains sound as does its ability to generate cash in the short and long term to provide liquidity, maintain financial capacity and flexibility, and provide for planned growth. TransCanada's liquidity is underpinned by predictable cash flow from operations, available cash balances and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion, US$1.0 billion and US$300 million, maturing in November 2012, October 2016, October 2012 and February 2013, respectively. These facilities also support the Company's three commercial paper programs. In addition, at December 31, 2011, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada-operated affiliates was $0.1 billion with maturity dates in 2012 and 2016. As at December 31, 2011, TransCanada had capacity of $2.0 billion, $1.25 billion and US$4.0 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

SUMMARIZED CASH FLOW

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Funds generated from operations[1]	**3,663**	3,331	3,080
Decrease/(Increase) in operating working capital	**310**	(249)	(90)
Net Cash Provided by Operations	**3,973**	3,082	2,990

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Funds Generated from Operations.

HIGHLIGHTS

Investing Activities

- Capital expenditures and acquisitions, including assumed debt, totalled approximately $15 billion over the three-year period ending December 31, 2011.

Dividends

- TransCanada's Board of Directors declared a $0.44 per common share dividend for the quarter ending March 31, 2012, an increase of five per cent over the previous dividend amount. The Board of Directors also declared regular quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2012 and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2012.

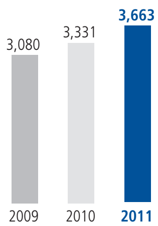
CASH FLOW AND CAPITAL RESOURCES

Cash Generated from Operations

Net Cash Provided by Operations was $4.0 billion in 2011 compared to $3.1 billion and $3.0 billion in 2010 and 2009, respectively. Net Cash Provided by Operations reflects Funds Generated from Operations, net of changes in operating working capital.

Funds Generated from Operations

Funds Generated from Operations (millions of dollars)

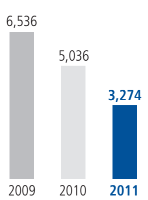


Funds Generated from Operations were $3.7 billion in 2011 compared to $3.3 billion and $3.1 billion in 2010 and 2009, respectively. The increase in 2011 compared to 2010 was primarily due to increased cash from earnings. This increase was net of lower current income tax benefits from bonus depreciation for U.S. tax purposes recognized in 2011 compared to 2010. The increase in 2010 compared to 2009 was primarily due to the current income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed in service in June 2010.

As at December 31, 2011, TransCanada's current liabilities were $5.9 billion and current assets were $3.6 billion resulting in a working capital deficiency of $2.3 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations, access to the unutilized committed revolving bank lines in excess of $4.0 billion, discussed above, as well as its ongoing access to capital markets.

Investing Activities

Capital Expenditures and Acquisitions, including Assumed Debt (millions of dollars)



Capital expenditures totalled $3.3 billion in 2011 compared to $5.0 billion in 2010 and $5.4 billion in 2009. Expenditures in 2011, 2010 and 2009 related primarily to the completion of the Wood River/Patoka and Cushing Extension Sections of Keystone, advancement of Keystone XL, the refurbishment and restart of Units 1 and 2 at Bruce A, construction of other new pipeline and power facilities, and the expansion and maintenance of existing pipelines.

In August 2009, the Company purchased ConocoPhillips' remaining interest of approximately 20 per cent in Keystone for US$553 million plus the assumption of US$197 million of short-term debt. In the first seven months of 2009, TransCanada solely funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an incremental increase in ownership of approximately 18 per cent for $313 million.

Financing Activities

In 2011, TransCanada issued Medium-Term Notes of $500 million and $250 million maturing in 2021 and 2041, respectively, and US$350 million of Senior Notes due in 2021. The Company also made draws totalling US$0.5 billion on existing facilities and retired or repaid $1.3 billion of long-term debt.

In 2011, the Company's proportionate share of joint venture long-term debt issued and repaid was $48 million and $102 million, respectively. In addition, Notes Payable decreased by $218 million in 2011.

At December 31, 2011, total committed revolving and demand credit facilities of $5.1 billion were available to support the Company's commercial paper programs and for general corporate purposes. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving, extendible TransCanada PipeLines Limited (TCPL) credit facility, maturing October 2016. The facility was fully available at December 31, 2011 and supports TCPL's Canadian commercial paper program;

- a US$300 million committed, syndicated, revolving credit facility maturing February 2013. At December 31, 2011, this facility was fully available. This facility is part of an initial US$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility established in 2007 which has since been reduced through term loan repayments of US$200 million in August 2011 and US$500 million in January 2012;
- a US$1.0 billion committed, syndicated, revolving, extendible TransCanada Keystone Pipeline, LP credit facility, maturing November 2012. The facility was fully available at December 31, 2011 and supports a TCPL USA U.S. dollar commercial paper program dedicated to funding a portion of capital expenditures for Keystone;
- a US$1.0 billion committed, syndicated, revolving, extendible TCPL USA credit facility, maturing October 2012. The facility was fully available at December 31, 2011 and supports a TCPL U.S. dollar commercial paper program that was established in December 2011; and
- demand lines totalling $802 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2011, the Company had used approximately $468 million of these demand lines for letters of credit.

In May 2011, TransCanada sold a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for a total transaction value of US$605 million, which included US$81 million of long-term debt, or 25 per cent of GTN LLC debt outstanding. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively. Subsequent to the transaction, TransCanada's ownership in TC PipeLines, LP decreased to 33.3 per cent due to TC PipeLines, LP's public issuance of common units as discussed under the heading 2011 Equity Financing Activities in this section.

The Company believes it has the capacity to fund its existing capital program through internally-generated cash flow, continued access to capital markets and liquidity underpinned by in excess of $4 billion of committed credit facilities. TransCanada's financial flexibility is further bolstered by opportunities for portfolio management, including an ongoing role for TC PipeLines, LP.

2011 Long-Term Debt Financing Activities

In November 2011, the Company issued Medium-Term Notes of $500 million and $250 million maturing in 2021 and 2041, respectively, and in June 2011, TC Pipelines, LP issued US$350 million of Senior Notes due in 2021. The Company also made draws totalling US$0.5 billion on existing facilities and retired or repaid $1.3 billion of long-term debt.

2011 Equity Financing Activities

In November 2011, TransCanada filed a base shelf prospectus in Canada and the U.S. qualifying the issuance of up to $2.0 billion of common shares, preferred shares and/or subscription receipts until December 2013. The shelf replaced the base shelf prospectus filed in September 2009. No securities have been issued under the November 2011 base shelf prospectus.

In May 2011, TC PipeLines, LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. As part of this offering, TransCanada made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in TC PipeLines, LP and did not purchase any other units. As a result of the common units offering, TransCanada's ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent.

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The Company reserves the right to satisfy its DRP obligations by issuing common shares from treasury at a discount of up to five per cent or by purchasing shares on the open market. Commencing with the dividends declared in April 2011, common shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. In 2011, dividends of $202 million were paid (2010 – $378 million; 2009 – $254 million) through the issuance of 5 million (2010 – 11 million; 2009 – 8 million) common shares from treasury in accordance with the DRP.

Dividends

Cash dividends on common shares of $961 million were paid in 2011 (2010 – $710 million; 2009 – $722 million). In addition, cash dividends of $55 million were paid on preferred shares in 2011 (2010 – $44 million). The increase in common share cash dividends paid in 2011 was primarily due to the Company's decision to satisfy its DRP obligations with market purchased shares instead of treasury shares effective April 2011, as discussed above, and an increase in the per share dividend amount in 2011. The decrease in common share dividends paid in cash in 2010 from 2009 was primarily due to increased participation in the DRP in lieu of cash dividends, which grew to $378 million in 2010 from $254 million in 2009, partially offset by a greater number of shares outstanding and an increase in the per share dividend amount in 2010.

The increase in preferred share dividends paid in 2011 from 2010 was primarily due to a full year of preferred share dividend payments in 2011 on preferred shares issued in March and June 2010. The increase in preferred share dividends paid in 2010 from 2009 was primarily due to a full year of preferred share dividend payments in 2010 on preferred shares issued in September 2009 and the preferred share issuances in 2010.

In February 2012, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.44 per share from $0.42 per share for the quarter ending March 31, 2012. This was the twelfth consecutive year in which the dividend was increased, resulting in a per share dividend that has more than doubled since 2000. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2012 and $0.275 per Series 5 preferred share for the three-month period ended April 30, 2012.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2011, the Company had $18.6 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes, compared to $17.9 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes at December 31, 2010. TransCanada's share of the total long-term debt of joint ventures, including capital lease obligations, was $0.8 billion at December 31, 2011, compared to $0.9 billion at December 31, 2010. Total Notes Payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $1.9 billion at December 31, 2011 and $2.1 billion at December 31, 2010. TransCanada has also provided certain pro-rata guarantees related to the capital lease and performance obligations of Bruce Power and certain other partially owned entities.

CONTRACTUAL OBLIGATIONS

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	20,204	950	1,926	2,467	14,861
Capital lease obligations	194	18	42	57	77
Operating leases[2]	735	79	152	143	361
Purchase obligations	9,152	1,650	2,905	1,568	3,029
Other long-term liabilities reflected on the balance sheet	911	17	35	39	820
	31,196	2,714	5,060	4,274	19,148

(1) Includes Junior Subordinated Notes and Long-Term Debt of Joint Ventures, excluding capital lease obligations.

(2) Represents future annual payments, net of sub-lease receipts, for various premises, services and equipment. The operating lease agreements for premises, services and equipment expire at various dates through 2052 with an option to renew certain lease agreements for one to 10 years.

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability among other factors. TransCanada's share of power purchased under the PPAs in 2011 was $394 million (2010 – $363 million; 2009 – $384 million).

At December 31, 2011, scheduled principal repayments and interest payments related to long-term debt and the Company's proportionate share of the long-term debt of joint ventures were as follows:

PRINCIPAL REPAYMENTS

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009	–	–	–	1,009
Long-term debt of joint ventures	628	15	52	156	405
	20,204	950	1,926	2,467	14,861

INTEREST PAYMENTS

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes[1]	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

(1) Payments were calculated assuming the notes would be redeemed after 10 years.

At December 31, 2011, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]

Year ended December 31 *(millions of dollars)*	Total	Payments Due by Period Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Natural Gas Pipelines					
Transportation by others[2]	482	130	133	108	111
Capital expenditures[3][4]	250	248	2	–	–
Other	1	1	–	–	–
Oil Pipelines					
Capital expenditures[3][5]	992	98	894	–	–
Other	48	4	8	8	28
Energy					
Commodity purchases[6]	5,121	666	1,201	1,221	2,033
Capital expenditures[3][7]	290	234	56	–	–
Other[8]	1,928	254	587	231	856
Corporate					
Information technology and other	40	15	24	–	1
	9,152	1,650	2,905	1,568	3,029

(1) The amounts in this table exclude funding contributions to pension plans.

(2) Rates are based primarily on known 2011 levels. Beyond 2011, demand rates are subject to change. The purchase obligations in the table are based on known or contracted demand volumes only and exclude commodity charges incurred when volumes flow.

(3) Amounts are estimates and are subject to variability based on timing of construction and project enhancements. The Company expects to fund capital projects with cash from operations, the issuance of senior debt and, if required, subordinated capital, and through portfolio management.

(4) Capital expenditures primarily relate to the construction costs of the Alberta System expansion, Guadalajara and other natural gas pipeline projects.

(5) Capital expenditures primarily relate to Keystone XL.

(6) Commodity purchases include fixed and variable components and excludes derivatives. The variable components are estimates and are subject to variability in plant production, market prices and regulatory tariffs.

(7) Capital expenditures primarily relate to TransCanada's share of the construction and development costs of Bruce Power and Cartier Wind.

(8) Includes estimates of certain amounts that are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation. This includes the purchase obligation for Ontario Solar.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Potential future commitments are discussed in the Opportunities and Developments sections for Natural Gas Pipelines, Oil Pipelines and Energy in this MD&A.

In 2012, TransCanada expects to make funding contributions of approximately $119 million to its defined benefit pension plans (DB Plan) and approximately $31 million to the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. In addition to these contributions, the Company expects to provide a

$48 million letter of credit in 2012 to the DB Plan. In 2011, the Company made total cash funding contributions of $93 million and provided a $27 million letter of credit to the DB Plan. TransCanada's proportionate share of cash funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2012 is approximately $73 million and $7 million, respectively, compared to total contributions of $59 million in 2011.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2013. Based on current market conditions, TransCanada expects funding requirements for these plans to continue at the anticipated 2012 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2012 net benefit cost is expected to increase from 2011 primarily due to a lower projected discount rate. However, future net benefit costs and the amount of funding contributions will be dependent on various factors, including investment returns achieved on plan assets, the level of interest rates, changes to plan design and actuarial assumptions, actual plan experience versus projections and amendments to pension plan regulations and legislation. Increases in the level of required plan funding are not expected to have a material impact on the Company's liquidity.

Bruce Power

Bruce A has signed commitments to third-party suppliers related to refurbishing and restarting Units 1 and 2. TransCanada's share of these signed commitments is $95 million. The Company expects $88 million and $7 million to be paid in 2012 and 2013, respectively.

Ontario Solar

In December 2011, an agreement was announced for the purchase of nine Ontario solar projects with a combined capacity of 86 MW, for approximately $470 million. TransCanada will purchase each project once construction and acceptance testing are completed and operations have begun under 20-year PPAs with the OPA under the Feed-In Tariff program in Ontario. It is anticipated that the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2011, the Company had accrued approximately $49 million (2010 – $59 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by TransAlta in January 2011. In February 2011, TransAlta notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated. TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012. TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe TransAlta's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of EBITDA for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

Guarantees

TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC, have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $863 million at December 31, 2011. The fair value of these Bruce Power guarantees at December 31, 2011 is estimated to be $29 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these assurances was estimated at December 31, 2011 to range from $182 million to a maximum of $498 million. The fair value of these guarantees at December 31, 2011 is estimated to be $7 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with financial risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity and natural gas. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate operational and price risks in its asset portfolio.

- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk
TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and on these forward contracts are not representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk
Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's net income. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated interest expense.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the foreign exchange rate exposures of the Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations
The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10 billion (US$9.8 billion) (2010 – $9.8 billion (US$9.8 billion)) and a fair value of $12.7 billion (US$12.5 billion) (2010 – $11.3 billion (US$11.4 billion)). At December 31, 2011, $79 million (December 31, 2010 – nil)

was included in Other Current Assets, $66 million (December 31, 2010 – $181 million) was included in Intangibles and Other Assets, $15 million (December 31, 2010 – nil) was included in Accounts Payable, and $41 million (December 31, 2010 – nil) was included in Deferred Amounts for the fair value of the forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability)

December 31 *(millions of dollars)*	**2011** Fair Value(1)	**2011** Notional or Principal Amount	2010 Fair Value(1)	2010 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2018)	**93**	**US 3,850**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2012)	**(4)**	**US 725**	2	US 100
	89	**US 4,575**	181	US 2,900

(1) Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open positions will not exceed the reported VaR. The VaR methodology is a statistically calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the regulated natural gas pipelines as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2011 (2010 – $12 million).

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using contract netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts receivable and other, and Available for sale assets in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2011, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2011, the Company had a credit risk concentration of $274 million (2010 – $317 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

In August 2011, the Company received final distributions of 2.1 million common shares, as a result of previous claims in the 2005 Calpine Corporation bankruptcy. These shares were sold into the open market resulting in total pre-tax gains of $30 million, of which the Company had accrued pre-tax gains of $15 million in 2010. In 2008, the Company had received 15.5 million common shares which were sold into the open market for $279 million. Claims by NGTL and Foothills PipeLines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in 2008 and 2009 and were passed onto the shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section of this note.

At December 31, 2011, the Company had unutilized committed revolving bank lines of US$1.0 billion, US$1.0 billion, US$300 million and $2.0 billion maturing in October 2012, November 2012, February 2013 and October 2016, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms and recently initiated a commercial paper program in the U.S.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2011, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Equity. Net debt comprises Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 *(millions of dollars)*	**2011**	2010
Notes payable	**1,863**	2,081
Long-term debt	**18,567**	17,922
Junior subordinated notes	**1,009**	985
Cash and cash equivalents	**(654)**	(660)
Net Debt	**20,785**	20,328
Equity attributable to non-controlling interests	**1,465**	1,157
Equity attributable to controlling interests	**17,324**	16,727
Total Equity	**18,789**	17,884
	39,574	38,212

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates and applying a discounted cash flow valuation model. The fair value of power and natural gas derivatives, and of available for sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2011		2010	
December 31 *(millions of dollars)*	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets(1)				
Cash and cash equivalents	765	765	764	764
Accounts receivable and other(2)(3)	1,576	1,620	1,555	1,595
Available for sale assets(2)	23	23	20	20
	2,364	2,408	2,339	2,379
Financial Liabilities(1)(3)				
Notes payable	1,880	1,880	2,092	2,092
Accounts payable and deferred amounts(4)	1,536	1,536	1,436	1,436
Accrued interest	373	373	367	367
Long-term debt	18,567	23,757	17,922	21,523
Junior subordinated notes	1,009	1,027	985	992
Long-term debt of joint ventures	822	940	866	971
	24,187	29,513	23,668	27,381

(1) Consolidated Net Income in 2011 included losses of $13 million (2010 – losses of $8 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At December 31, 2011, the Consolidated Balance Sheet included financial assets of $1,265 million (2010 – $1,271 million) in Accounts Receivable, $41 million (2010 – $40 million) in Other Current Assets and $293 million (2010 – $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for $350 million (2010 – $250 million) of Long-Term Debt that is adjusted to fair value.

(4) At December 31, 2011, the Consolidated Balance Sheet included financial liabilities of $1,494 million (2010 – $1,406 million) in Accounts Payable and $42 million (2010 – $30 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2011:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Notes payable	1,880	1,880	–	–	–
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009	–	–	–	1,009
Long-term debt of joint ventures	822	33	94	213	482
	22,278	2,848	1,968	2,524	14,938

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2011, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2011			
December 31 *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$213	$176	$3	$22
Liabilities	$(212)	$(212)	$(14)	$(22)
Notional Values				
Volumes[3]				
Purchases	23,500	103	–	–
Sales	23,158	82	–	–
Canadian dollars	–	–	–	684
U.S. dollars	–	–	US 1,269	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year[4]	$(3)	$(50)	$(4)	$1
Net realized gains/(losses) in the year[4]	$58	$(74)	$10	$10
Maturity dates	2012-2018	2012-2016	2012	2012-2016
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	$42	$3	$–	$13
Liabilities	$(277)	$(22)	$(38)	$(1)
Notional Values				
Volumes[3]				
Purchases	17,188	8	–	–
Sales	9,217	–	–	–
U.S. dollars	–	–	US 91	US 600
Cross-currency	–	–	136/US 100	–
Net realized losses in the year[4]	$(150)	$(17)	$–	$(16)
Maturity dates	2012-2017	2012-2013	2012-2014	2012-2015

(1) All derivative financial instruments in the held for trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on held for trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million. In 2011, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2011, Net Income included losses of $3 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2011, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2011. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Derivative financial instruments held for trading					
Assets	414	282	123	9	–
Liabilities	(460)	(292)	(151)	(17)	–
Derivative financial instruments in hedging relationships					
Assets	217	121	91	5	–
Liabilities	(408)	(208)	(135)	(50)	(15)
	(237)	(97)	(72)	(53)	(15)

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2010			
December 31 (all amounts in millions unless otherwise indicated)	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values				
Volumes[3]				
Purchases	15,610	158	–	–
Sales	18,114	96	–	–
Canadian dollars	–	–	–	736
U.S. dollars	–	–	US 1,479	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year[4]	$(32)	$27	$4	$43
Net realized gains/(losses) in the year[4]	$77	$(42)	$36	$(74)
Maturity dates	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	$112	$5	$–	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values				
Volumes[3]				
Purchases	16,071	17	–	–
Sales	10,498	–	–	–
U.S. dollars	–	–	US 120	US 1,125
Cross-currency	–	–	136/US 100	–
Net realized losses in the year[4]	$(9)	$(35)	$–	$(33)
Maturity dates	2011-2015	2011-2013	2011-2014	2011-2015

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2010, Net Income included a gain of $1 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2010, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 *(millions of dollars)*	**2011**	2010
Current		
Other current assets	**404**	273
Accounts payable	**(502)**	(337)
Long Term		
Intangibles and other assets *(Note 9)*	**213**	374
Deferred amounts *(Note 11)*	**(352)**	(282)

Derivative Financial Instruments of Joint Ventures

Included in the Derivative Financial Instruments Summary tables are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power derivatives was $35 million at December 31, 2011 (2010 – $48 million). These contracts mature from 2012 to 2018. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 2,979 GWh at December 31, 2011 (2010 – 3,772 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 1,595 GWh at December 31, 2011 (2010 – 2,322 GWh).

Derivatives in Cash Flow Hedging Relationships

Information about how derivatives and hedging activities affect the Company's financial position, financial performance and cash flows is as follows:

	Cash Flow Hedges							
	Power		Natural Gas		Foreign Exchange		Interest	
Year ended December 31 *(millions of Canadian dollars, pre-tax)*	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Change in fair value of derivative instruments recognized in OCI (effective portion)	**(252)**	(79)	**(59)**	(26)	**5**	10	**(1)**	(137)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**61**	(7)	**100**	(21)	**–**	–	**43**	32

Credit Risk Related Contingent Features

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2011, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2010 – $92 million), for which the Company has provided collateral of $28 million (2010 – $4 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2011, the Company would have been required to provide additional collateral of $82 million (2010 – $88 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative financial instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets are included in this category. Long-dated commodity prices are derived with a third-party modelling tool that uses market fundamentals to derive long-term prices.

There were no transfers between Level I and Level II in 2011 or 2010. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 *(millions of dollars, pre-tax)*	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Natural Gas Inventory	**–**	–	**29**	49	**–**	–	**29**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**–**	–	**35**	28	**–**	–	**35**	28
Foreign exchange contracts	**11**	10	**131**	179	**–**	–	**142**	189
Power commodity contracts	**–**	–	**244**	269	**2**	5	**246**	274
Gas commodity contracts	**124**	93	**55**	56	**–**	–	**179**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**–**	–	**(23)**	(47)	**–**	–	**(23)**	(47)
Foreign exchange contracts	**(13)**	(11)	**(89)**	(54)	**–**	–	**(102)**	(65)
Power commodity contracts	**–**	–	**(465)**	(299)	**(15)**	(8)	**(480)**	(307)
Gas commodity contracts	**(208)**	(178)	**(26)**	(15)	**–**	–	**(234)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**23**	20	**–**	–	**–**	–	**23**	20
	(63)	(66)	**(109)**	166	**(13)**	(3)	**(185)**	97

The following table presents the net change in the Level III fair value category:

(millions of dollars, pre-tax)	Derivatives[1]
Balance at December 31, 2009	(2)
New contracts[2]	(16)
Settlements	(3)
Transfers into Level III[3]	3
Transfers out of Level III[3][4]	(38)
Change in unrealized gains recorded in Net Income	14
Change in fair value of derivative instruments recorded in OCI	39
Balance at December 31, 2010	(3)
New contracts[2]	**1**
Settlements	**1**
Transfers out of Level III[3][4]	**(1)**
Change in unrealized gains recorded in Net Income	**1**
Change in fair value of derivative instruments recorded in OCI	**(12)**
Balance at December 31, 2011	**(13)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) At December 31, 2011, the total amount of net gains included in Net Income attributable to derivatives that were entered into during the year and still held at the reporting date was nil (2010 – $1 million).

(3) Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable.

(4) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2011.

OTHER RISKS

Development Projects and Acquisitions

TransCanada continues to focus on growing its Natural Gas Pipelines, Oil Pipelines and Energy operations through greenfield development projects and acquisitions. TransCanada capitalizes costs incurred on certain of its projects during the development period prior to construction when the project meets specific criteria and is expected to proceed through to completion. The related capital costs of a project that does not proceed through to completion are expensed at the time it is discontinued to the extent that these costs and underlying materials cannot be utilized on another project. There is a risk with respect to TransCanada's acquisition of assets and operations that certain commercial opportunities and operational synergies may not materialize as expected and that the assets would subsequently be subject to an impairment write-down.

Asset Commissioning

Although each of TransCanada's newly-constructed assets goes through rigorous acceptance testing prior to being placed in service, there is a risk that these assets will have lower than expected availability or performance, especially in their first year of operations.

Operational and Other Business Risks
There are a number of operating risks associated with TransCanada's pipelines and energy businesses including: labour disputes; the breakdown or failure of equipment; acts of terror; and catastrophic events such as natural disasters. The occurrence or continuance of any of these events could impact earnings through the costs associated with remediation or a reduction in revenues.

The Company has established emergency response plans to address certain unplanned events, which include an ongoing program to provide local emergency responders with the information and training necessary to ensure their preparedness for responding to events. TransCanada maintains a comprehensive insurance program to mitigate the risk of potential losses arising from operational risks and other potential losses related to its business. In certain circumstances, not all events will be covered by insurance, which may have an adverse effect on the Company's operations, earnings, cash flow and financial position.

Health, Safety and Environment Risk Management
Health, safety and environment (HSE) are top priorities in all of TransCanada's operations and business activities. These areas are guided by the Company's HSE Commitment Statement, which outlines guiding principles for a safe and healthy environment for TransCanada's employees, contractors and the public, and for TransCanada's commitment to protect the environment. All employees are responsible for the Company's HSE performance. The Company is committed to being an industry leader in conducting its business so that it meets or exceeds all applicable laws and regulations, and minimizes risk to the public and the environment. The Company is committed to continually improving its HSE performance, and to promoting safety on and off the job in the belief that all occupational injuries and illnesses are preventable. TransCanada endeavours to do business with companies and contractors that share its perspective and expectation on HSE performance and will influence them to improve their collective performance and culture. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to supporting open communication with its stakeholders.

The HSE Committee of TransCanada's Board of Directors monitors compliance with the Company's HSE corporate policy through regular reporting. TransCanada's integrated HSE management system is modeled after the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001; and the Occupational Health and Safety Assessment Series (OHSAS 18001) for occupational health and safety. TransCanada's HSE management system conforms to external industry consensus standards and voluntary regulatory programs and complies with applicable legislated requirements and various other internal management systems. Resources are focused on the areas of significant risk to the organization's HSE business activities. Management is informed regularly of all important and/or significant HSE operational issues and initiatives through formal reporting and incident management processes. TransCanada's HSE management system and performance are assessed by an independent outside firm every three years. The most recent assessment occurred in 2009 and did not identify any material issues. The HSE management system is subject to ongoing internal and external review to ensure that it remains effective as circumstances change.

As one of TransCanada's priorities, safety is an integral part of the way its employees work. In 2011, one of the Company's objectives was to sustain health and safety performance year over year. Overall, the Company's safety frequency rates in 2011 continued to be better than most industry benchmarks.

The safety and integrity of the Company's existing and newly-developed infrastructure is also a top priority. All new assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. The Company expects to spend approximately $322 million in 2012 for pipeline integrity on the pipelines it operates, an increase of approximately $78 million over 2011 primarily due to increased levels of in-line pipeline inspection on all systems. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are treated on a flow-through basis and, as a result, these expenditures have no impact on TransCanada's earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on TransCanada's earnings. TransCanada's pipeline safety record in 2011 continued to be better than industry benchmarks. TransCanada experienced two pipeline breaks in 2011 on its operated pipelines. The first break occurred in a remote part of Northern Ontario on the Canadian Mainline pipeline system. The second break occurred in a remote part of Wyoming on the Bison pipeline system.

Spending associated with public safety on the Energy assets is focused primarily on the Company's hydro dams and associated equipment, and is slightly higher than previous years due to increased spending to repair damage from the high flow events of 2011 caused by Hurricane Irene.

Environment

TransCanada's facilities are subject to stringent federal, state, provincial, and local environmental statutes and regulations governing environmental protection, including, but not limited to, air emissions, water quality, wastewater discharges and waste management. Such laws and regulations generally require facilities to obtain or comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements and/or the issuance of orders respecting future operations. TransCanada has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements.

At December 31, 2011, TransCanada recorded liabilities of approximately $69 million (2010 – $84 million) for remediation obligations and compliance costs associated with certain environmental regulations. The Company believes it has considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring the Company to set aside additional amounts.

The Company owns assets in four regions, Alberta, Québec, B.C., and the Northeastern U.S., where regulations exist to address industrial greenhouse gas (GHG) emissions. TransCanada has procedures in place to comply with these regulations.

In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHG emissions over an intensity threshold level are required to reduce the intensity of GHG emissions by 12 per cent below an average baseline. TransCanada's Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TransCanada has certain rights under the PPAs. TransCanada has a program in place to manage the compliance costs incurred by these assets as a result of the regulation. Compliance costs on the Alberta System are recovered through tolls paid by customers. Some of the compliance costs from the Company's power generation facilities in Alberta are recovered through market pricing and contract flow-through provisions. TransCanada has estimated and recorded GHG emissions related costs of $13 million for 2011 (2010 – $22 million), after contracted cost recovery.

In Québec, the natural gas distributor collects the hydrocarbon royalty on behalf of the provincial government through a green fund contribution charge on gas consumed. In 2011, the cost pertaining to the Bécancour facility arising from the hydrocarbon royalty was less than $1 million as a result of an agreement between TransCanada and Hydro-Québec to temporarily suspend the facility's power generation.

The carbon tax in B.C., which came into effect in mid-2008, applies to carbon dioxide (CO_2) emissions from fossil fuel combustion. Compliance costs for fuel combustion at the Company's compressor and meter stations in B.C. are recovered through tolls paid by customers. Costs related to the carbon tax in 2011 were approximately $3 million (2010 – $4 million). The cost per tonne of CO_2 will be increased in July 2012 to $30 from $25.

States in the northeastern U.S. that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators effective in January 2009. Under the RGGI, both the Ravenswood and OSP generation facilities were required to submit allowances following the end of the first compliance period on December 31, 2011. TransCanada participated in the quarterly auctions of allowances for the Ravenswood and Ocean

State Power generation facilities and incurred related costs of $4 million in 2011 (2010 – $5 million). These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

TransCanada is not aware of any material outstanding orders, claims or lawsuits against it in relation to the release or discharge of any material into the environment or in connection with environmental protection.

Environmental risks from TransCanada's operating facilities typically include: air emissions, GHG emissions; potential impacts on land, including land reclamation or restoration following construction; the use, storage and release of hydrocarbons or other chemicals; the generation, handling and disposal of wastes and hazardous wastes; and water impacts such as uncontrolled water discharge.

The Company's operations are subject to various environmental laws and regulations that establish compliance and remediation obligations. Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties. It is not possible for the Company to estimate the amount and timing of all future expenditures related to environmental matters due to:

- uncertainties in estimating pollution control and clean up costs, including at sites where only preliminary site investigation or agreements have been completed;
- the potential discovery of new contaminated sites or additional information at existing contaminated sites;
- the uncertainty in quantifying the Company's liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the evolving nature of environmental laws and regulations, including the interpretation and enforcement of them; and
- the potential for litigation on existing or discontinued assets.

The impact of new or proposed federal, state, and/or provincial safety and environmental laws, regulations, guidelines and enforcement in Canada and the U.S. on TransCanada's business is not yet certain. TransCanada makes assumptions about possible expenditures for safety and environmental matters based on current laws and regulations and interpretations thereof. If the laws or regulations or the interpretation thereof changes, the Company's assumptions may change. Incremental costs may or may not be recoverable under existing rate structures or commercial agreements. Proposed changes in environmental policy, legislation or regulation are routinely monitored by TransCanada, and where the risks are potentially large or uncertain, the Company works independently or through industry associations to comment on proposals.

Regulation of air pollutant emissions under the *U.S. Clean Air Act* and state regulations continue to evolve. A number of EPA initiatives could lead to impacts ranging from requirements to install enhanced emissions control equipment, to additional administrative and reporting requirements. At this time, there is insufficient detail to accurately determine the potential impacts of these initiatives. While the majority of the proposals are not expected to be material to TransCanada, the Company anticipates additional future costs related to the monitoring and control of air emissions.

In addition to those climate change policies already in place, there are also federal, regional, state, and provincial initiatives currently in development. While recent political and economic events may significantly affect the scope and timing of new policies, TransCanada anticipates that most of the Company's facilities in Canada and the U.S. are or will be subject to federal and/or regional climate change regulations to manage industrial GHG emissions.

In August 2011, the Canadian government published the first sector specific draft regulation that will impact industrial GHG emissions. This proposed regulation is focused on the coal-fired generation of electricity and requires a natural gas performance standard for all coal-fired facilities reaching the end of their economic life. The draft regulation is expected to come into effect in July 2015. This process is not expected to pose a significant risk or financial impact to TransCanada's existing facilities and may present opportunities for new power generation investment. Additional sectors, including the natural gas-fired generation of electricity and upstream oil and gas facility sectors, are expected to begin consultations with Environment Canada.

The Western Climate Initiative (WCI) continues to work toward implementing a regional cap-and-trade program. California and Québec are the only WCI members with cap and trade regulations. In December 2011, the Government of Québec adopted the "Regulation respecting the cap-and-trade system for greenhouse gas emission allowances". The initial phase of the cap and trade system will begin January 1, 2013. The regulation will have a limited impact on TransCanada's Bécancour power generation facility and natural gas pipeline assets. With respect to California, the Air Resources Board adopted a cap and trade regulation in October 2011. The regulation is divided into two phases: the first, beginning in 2013, will include all major industrial sources and electricity utilities; the second, starting in 2015, will cover distributors of transportation fuels, natural gas and other fuels. The regulation may impact the Company's importation of electricity into the state.

Future Abandonment Costs

Depending on specific operating jurisdictions, the Company may have obligations to abandon its facilities in accordance with applicable laws and regulations.

To the extent legal obligations exist and can be reasonably estimated, the Company recognizes the fair value of a liability for asset retirement obligations (ARO), which is accreted through changes to operating expenses. The Company recorded ARO associated with the retirement of certain power generation facilities, natural gas pipelines and transportation facilities, and natural gas storage systems. The estimates or assumptions required to calculate ARO include scope of abandonment and reclamation activities, inflation rates, discount rates and timing of asset retirements. By their nature, these assumptions are subject to measurement uncertainty. The Company has determined that the scope and timing of asset retirements related to its U.S. regulated natural gas pipelines, oil pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded amounts for ARO related to these assets, with the exception of certain abandoned facilities.

The NEB's LMCI deals with pipeline abandonment, including related financial issues. The goal of this initiative is for all pipeline companies regulated under the *National Energy Board Act* (Canada) to begin collecting and setting aside funds to cover future abandonment costs by mid-2014. In its May 2009 decision, the NEB established several filing deadlines relating to the financial issues, including deadlines for preparing and filing an estimate of the abandonment costs to be used to begin collecting funds, developing a proposal for collecting these funds through tolls or some other satisfactory method and developing a proposed process to set aside the funds collected. TransCanada filed its estimates of abandonment costs for its Canadian oil and natural gas pipelines in November 2011, as required by the NEB decision. These costs would be recovered from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The specific toll impacts have not yet been determined as they will be the subject of a subsequent NEB filing in late 2012. In addition, as the actual timing of retirements for the assets is indeterminable, the Company has not recorded amounts for ARO.

For the foreseeable future, the Company intends to operate and maintain these assets as long as supply and demand exists for hydroelectric power generation, natural gas and oil. The Company continues to evaluate its obligations related to future abandonment costs and to monitor developments that could impact the amounts it records.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As at December 31, 2011, an evaluation of the effectiveness of TransCanada's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that, as at December 31, 2011, the design and operation of TransCanada's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in reports filed with, or submitted to, securities regulatory authorities is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure and were effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's Annual Report on Internal Control over Financial Reporting

Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with CGAAP, including a reconciliation to U.S. generally accepted accounting principles (U.S. GAAP).

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting was effective as at December 31, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2011, there was no change in TransCanada's internal control over financial reporting that materially affected or is reasonably likely to materially affect TransCanada's internal control over financial reporting.

CEO and CFO Certifications

TransCanada's President and Chief Executive Officer and Chief Financial Officer have filed with the SEC and the Canadian securities regulators certifications regarding the quality of TransCanada's public disclosures relating to its fiscal 2011 reports filed with the SEC and the Canadian securities regulators.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

To prepare financial statements that conform with CGAAP, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses, since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. TransCanada regularly assesses the assets and liabilities associated with these estimates and assumptions. A summary of TransCanada's significant accounting policies can be found in Note 2 to the Consolidated Financial Statements. The Company believes the following accounting policies and estimates require it to make assumptions about highly uncertain matters and changes in these estimates could have a material impact on the Company's financial information.

Rate-Regulated Accounting

The Company accounts for the impacts of rate regulation in accordance with CGAAP. The following three criteria must be met to use these accounting principles:

- the rates for regulated services or activities must be established by or subject to approval by a regulator;
- the regulated rates must be designed to recover the cost of providing the services or products; and

- it must be reasonable to assume that rates set at levels to recover the cost can be charged to and collected from customers in view of the demand for services or products and the level of direct and indirect competition.

The Company's management believes all three of these criteria have been met with respect to each of the regulated natural gas pipelines accounted for using rate-regulated accounting (RRA) principles. The most significant impact from the use of these accounting principles is that the timing of recognition of certain Natural Gas Pipelines expenses and revenues in the regulated businesses may differ from that otherwise expected under CGAAP in order to appropriately reflect the economic impact of the regulators' decisions regarding the Company's revenues and tolls. At December 31, 2011, the Company reported regulatory assets of $0.2 billion and $1.4 billion in Other Current Assets and Regulatory Assets, respectively (2010 – $0.3 billion and $1.5 billion, respectively), and regulatory liabilities of $0.1 billion and $0.3 billion in Accounts Payable and Regulatory Liabilities, respectively (2010 – $0.1 billion and $0.3 billion, respectively).

Financial Instruments and Hedges

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at fair value. Subsequent measurement of the financial instruments is based on their classification as held for trading, available for sale, held-to-maturity investments, loans and receivables, and other financial liabilities.

Held for trading derivative financial assets and liabilities consist of swaps, options, forwards and futures with changes in the fair value recorded in Net Income. The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications with changes in the fair value recorded in Other Comprehensive (Loss)/Income (OCI). Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as loans and receivables and are measured at amortized cost using the effective interest method, net of any impairment. The Company does not have any held-to-maturity investments. Other financial liabilities consist of liabilities not classified as held for trading and are recognized at amortized cost using the effective interest method.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination or cancellation.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item. Changes in fair value of the hedged and hedging items are recognized in Net Income.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive (Loss)/Income (AOCI) are reclassified to Net Income during the periods when the variability in cash flows of the hedged item affects Net Income. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it is probable the anticipated transaction will not occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation in Canada. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities on behalf of the ratepayers. When the hedges are settled, the realized gains and losses are refunded to or collected from the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its investment in a foreign operation.

The fair value of financial instruments and hedges, where fair value does not approximate carrying value, is primarily derived from market values adjusted for credit risk, which can fluctuate widely from period to period. Since the changes in fair value are recorded through earnings in certain circumstances, fluctuations can result in variability in Net Income.

Depreciation and Amortization Expense

TransCanada's Plant, Property and Equipment are depreciated on a straight-line basis over their estimated useful lives once they are ready for their intended use. The estimation of useful lives requires management's judgement regarding the period of time the assets will be in use based on third-party engineering studies, experience and industry practice. The initial payment for the Company's PPAs is deferred and amortized on a straight-line basis over the terms of the contracts, which expire in 2017 and 2020.

Natural gas pipeline and compression equipment is depreciated at annual rates ranging from one per cent to six per cent. Oil pipeline and pumping equipment is depreciated at annual rates ranging from approximately two per cent to 2.5 per cent. Metering and other plant equipment are depreciated at various rates. Major power generation and natural gas storage plant, equipment and structures in the Energy business are depreciated by major component on a straight-line basis over estimated service lives at average annual rates ranging from two per cent to 20 per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other Energy equipment is depreciated at various rates. Corporate Plant, Property and Equipment are depreciated on a straight-line basis over estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Depreciation and Amortization Expense in 2011 was $1,528 million (2010 – $1,354 million; 2009 – $1,377 million) and was recorded in Natural Gas Pipelines, Oil Pipelines, Energy and Corporate. In Natural Gas Pipelines, depreciation rates are approved by regulators when applicable and depreciation expense is recoverable based on the cost of providing the services or products. If regulators permit recovery of depreciation through rates charged to customers, a change in the estimate of the useful lives of plant, property and equipment in the Natural Gas Pipelines segment will have no material impact on TransCanada's Net Income but will directly affect Funds Generated from Operations. PPA amortization expense of $58 million was included in Energy's Depreciation and Amortization expense for 2009 through 2011.

Impairment of Long-Lived Assets and Goodwill

The Company reviews long-lived assets such as plant, property and equipment, as well as intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

At December 31, 2011, the Company reported Goodwill of $3.7 billion (2010 – $3.6 billion). Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. An initial test is done by comparing the fair value of the operations, which includes goodwill, to the book value of each reporting unit. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

These valuations are based on management's projections of future cash flows and, therefore, require estimates and assumptions with respect to:

- discount rates;
- commodity and capacity prices;
- market supply and demand assumptions;
- growth opportunities;
- output levels;
- competition from other companies; and
- regulatory changes.

Significant changes in these assumptions could affect the Company's requirement to record an impairment charge. In addition to the above noted estimates and assumptions used by the Company in its fair value determinations, the realization of Ravenswood's fair value is partially dependent on a favourable resolution of the NYISO actions relating to capacity prices as described further in Energy – Opportunities and Developments. An unfavourable outcome could have a negative effect on the estimated fair value and may, in future periods, result in an impairment of a portion of the US$834 million Goodwill balance relating to Ravenswood at December 31, 2011 (2010 – US$834 million).

ACCOUNTING CHANGES

CHANGES IN ACCOUNTING POLICIES FOR 2011

Business Combinations
Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, expensing of acquisition costs, and increased disclosure. Adoption of this standard had no effect on the financial statements as at and for the year ended December 31, 2011.

Consolidated Financial Statements and Non-Controlling Interests
Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of net income between the controlling and non-controlling interests. Changes resulting fromt he adoption of Sections 1601 and 1602 were applied retrospectively.

FUTURE ACCOUNTING CHANGES

U.S. GAAP
The CICA's Accounting Standards Board previously announced that Canadian publicly accountable enterprises were required to adopt International Financial Reporting Standards (IFRS) effective January 1, 2011, with the exception of certain qualifying entities historically using RRA that were given a one year deferral from adopting IFRS. TransCanada is a qualifying entity for these purposes and has deferred the adoption of IFRS. The Company has prepared its consolidated financial statements for 2011 in accordance with CGAAP in order to continue using RRA.

In the application of CGAAP, TransCanada follows specific accounting guidance under U.S. GAAP unique to rate-regulated businesses. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under CGAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The International Accounting Standards Board has concluded that the development of RRA under IFRS requires further analysis and TransCanada does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As a registrant with the SEC, TransCanada has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The financial reporting impact of TransCanada adopting U.S. GAAP is disclosed in Note 25 of the Consolidated Financial Statements. The differences between CGAAP and U.S. GAAP are consistent with those reported by the Company in its annual "Reconciliation to United States GAAP" as filed in prior years. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting framework.

Fair Value Measurement

In May 2011, the Financial Accounting Standards Board (FASB) issued amended guidance on fair value measurements, which updated some of the existing measurement guidance and included enhanced disclosure requirements under U.S. GAAP. This guidance is effective for interim and annual periods beginning after December 15, 2011. Adoption of these amendments is expected to result in an increase in the qualitative and quantitative disclosures regarding Level 3 measurements, however, the Company expects no material effect on the financial statements.

Intangibles – Goodwill and Other

In September 2011, the FASB issued new guidance on testing goodwill for impairment which simplifies an entity's testing for goodwill impairment under U.S. GAAP by permitting an entity to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount, as a basis for determining whether it is required to proceed to the two-step quantitative goodwill impairment test. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Adoption is not expected to impact the financial statements.

Balance Sheet Offsetting/Netting

In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting agreement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosures regarding financial instruments which are subject to offsetting as described in this amendment.

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA[1]

(unaudited) (millions of dollars except per share amounts)	2011 Fourth	 Third	 Second	 First
Revenues	2,360	2,393	2,143	2,243
Net Income Attributable to Common Shares	375	384	353	415
Share Statistics				
Net income per share – basic and diluted	$0.53	$0.55	$0.50	$0.59
Dividend declared per common share	$0.42	$0.42	$0.42	$0.42

(unaudited) (millions of dollars except per share amounts)	2010 Fourth	 Third	 Second	 First
Revenues	2,057	2,129	1,923	1,955
Net Income Attributable to Common Shares	269	377	285	296
Share Statistics				
Net income per share – basic and diluted	$0.39	$0.54	$0.41	$0.43
Dividend declared per common share	$0.40	$0.40	$0.40	$0.40

(1) The selected quarterly consolidated financial data has been prepared in accordance with GAAP.

Factors Affecting Quarterly Financial Information

In Natural Gas Pipelines, which consists primarily of the Company's investments in regulated pipelines and regulated natural gas storage facilities, annual revenues and net income fluctuate over the long term based on regulators' decisions and negotiated settlements with shippers. Generally, quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from adjustments being recorded due to regulatory decisions and negotiated settlements with shippers, seasonal fluctuations in short-term throughput volumes on U.S. pipelines, acquisitions and divestitures, and developments outside of the normal course of operations.

In Oil Pipelines, which consists of the Company's investment in a regulated crude oil pipeline, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable with fluctuations resulting from changes in the amount of spot volumes transported and the associated rate charged. Spot volumes transported are affected by customer demand, market pricing, planned and unplanned outages of refineries, terminals and pipeline facilities, and developments outside of the normal course of operations.

In Energy, which consists primarily of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities, quarter-over-quarter revenues and net income are affected by seasonal weather conditions, customer demand, market prices, capacity prices and payments, planned and unplanned plant outages, acquisitions and divestitures, certain fair value adjustments and developments outside of the normal course of operations.

Significant developments that affected EBIT and Net Income in 2011 and 2010 were as follows:

- ***Fourth Quarter 2011*** EBIT excluded net unrealized after-tax gains of $9 million ($9 million pre-tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

- ***Third Quarter 2011*** Energy's EBIT included the positive impact of higher prices for Western Power. EBIT included net unrealized losses of $47 million pre-tax ($33 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Second Quarter 2011*** Natural Gas Pipelines' EBIT included incremental earnings from Guadalajara, which was placed in service in June 2011. Energy's EBIT included incremental earnings from Coolidge, which was placed in service in May 2011. EBIT included net unrealized losses of $5 million pre-tax ($4 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***First Quarter 2011*** Natural Gas Pipelines' EBIT included incremental earnings from Bison, which was placed in service in January 2011. Oil Pipelines began recording EBIT for the Wood River/Patoka and Cushing Extension sections of Keystone in February 2011. EBIT included net unrealized losses of $17 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Fourth Quarter 2010*** Natural Gas Pipelines' EBIT decreased as a result of recording a $146 million pre-tax ($127 million after-tax) valuation provision for advances to the APG for the MGP. Energy's EBIT included contributions from the second phase of Kibby Wind, which was placed in service in October 2010, and net unrealized gains of $22 million pre-tax ($12 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Third Quarter 2010*** Natural Gas Pipelines' EBIT increased as a result of recording nine months of incremental earnings related to the Alberta System 2010 - 2012 Revenue Requirement Settlement, which resulted in a $33 million increase to Net Income. Energy's EBIT included contributions from Halton Hills, which was placed in service in September 2010, and net unrealized gains of $4 million pre-tax ($3 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.
- ***Second Quarter 2010*** Energy's EBIT included net unrealized gains of $15 million pre-tax ($10 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. Net Income reflected a decrease of $58 million after tax due to losses in 2010 compared to gains in 2009 for interest rate and foreign exchange rate derivatives that did not qualify as hedges for accounting purposes and the translation of U.S. dollar-denominated working capital balances.
- ***First Quarter 2010*** Energy's EBIT included net unrealized losses of $49 million pre-tax ($32 million after tax) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

FOURTH QUARTER 2011 HIGHLIGHTS

Reconciliation of Non-GAAP Measures

Three months ended December 31 *(unaudited)* *(millions of dollars)*	Natural Gas Pipelines 2011	Natural Gas Pipelines 2010	Oil Pipelines 2011	Oil Pipelines 2010	Energy 2011	Energy 2010	Corporate 2011	Corporate 2010	Total 2011	Total 2010
Comparable EBITDA	**739**	737	**179**	–	**295**	301	**(29)**	(33)	**1,184**	1,005
Depreciation and amortization	**(251)**	(241)	**(35)**	–	**(100)**	(103)	**(4)**	–	**(390)**	(344)
Comparable EBIT	**488**	496	**144**	–	**195**	198	**(33)**	(33)	**794**	661
Other Income Statement Items										
Comparable interest expense									**(251)**	(173)
Interest expense of joint ventures									**(15)**	(15)
Comparable interest income and other									**8**	61
Comparable income taxes									**(123)**	(103)
Net income attributable to non-controlling interests									**(33)**	(33)
Preferred share dividends									**(14)**	(14)
Comparable Earnings									**366**	384
Specific items (net of tax):										
Valuation provision for MGP									**–**	(127)
Risk management activities(1)									**9**	12
Net Income Attributable to Common Shares									**375**	269

Three months ended December 31 *(unaudited)(millions of dollars except per share amounts)*	2011	2010
Comparable Interest Income and Other	**8**	61
Specific item:		
Risk management activities(1)	**35**	–
Interest Income and Other	**43**	61
Comparable Income Taxes	**(123)**	(103)
Specific items:		
Valuation provision for MGP	**–**	19
Risk management activities(1)	**–**	(10)
Income Taxes Expense	**(123)**	(94)
Comparable Earnings per Common Share	**$0.52**	$0.55
Specific items (net of tax):		
Valuation provision for MGP	**–**	(0.18)
Risk management activities(1)	**0.01**	0.02
Net Income per Common Share	**$0.53**	$0.39

(1) Three months ended December 31

(unaudited)(millions of dollars)	2011	2010
Risk Management Activities Gains/(Losses):		
U.S. Power derivatives	**(33)**	24
Natural Gas Storage proprietary inventory and derivatives	**7**	(2)
Foreign exchange derivatives	**35**	–
Income taxes attributable to risk management activities	**–**	(10)
Risk Management Activities	**9**	12

Comparable Earnings in fourth quarter 2011 were $366 million or $0.52 per share compared to $384 million or $0.55 per share for the same period in 2010. Comparable Earnings in fourth quarter 2011 excluded net unrealized after-tax gains of $9 million ($9 million pre-tax) (2010 – $12 million after-tax gains; $22 million pre-tax) resulting from changes in the fair value of certain risk management activities. Comparable Earnings in fourth quarter 2010 also excluded the $127 million after tax ($146 million pre-tax) valuation provision on advances to the APG for the MGP.

Comparable Earnings decreased $18 million or $0.03 per share in fourth quarter 2011 compared to the same period in 2010 and included the following:

- decreased Comparable EBIT from Natural Gas Pipelines reflecting lower incentive earnings from the Canadian Mainline and the Alberta System and lower revenues from certain U.S. Pipelines partially offset by incremental earnings from Bison and Guadalajara which were placed in service in January and June 2011, respectively;
- Oil Pipelines Comparable EBIT as the Company commenced recording earnings from Keystone in February 2011;
- decreased Comparable EBIT from Energy reflecting lower Bruce A and B volumes and higher operating costs as well as lower realized prices at Bruce B, lower contributions from U.S. Power and lower Natural Gas Storage revenues partially offset by higher realized prices in Western Power and incremental earnings from the start-up of Coolidge in May 2011;
- increased Comparable Interest Expense primarily due to decreased capitalized interest upon placing Keystone and other new assets in service in 2011;
- decreased Comparable Interest Income and Other, reflecting higher realized losses in 2011 on derivatives used to manage the Company's exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income compared to gains in 2010; and
- increased Comparable Income Taxes due to higher positive income tax adjustments which reduced income taxes in fourth quarter 2010.

TransCanada's Net Income Attributable to Common Shares was $375 million or $0.53 per share in fourth quarter 2011 compared to $269 million or $0.39 per share in fourth quarter 2010.

Natural Gas Pipelines' Comparable EBIT was $488 million in fourth quarter 2011 compared to $496 million for the same period in 2010. Comparable EBIT in 2010 excluded a $146 million pre-tax valuation provision on advances to the APG for the MGP.

Canadian Mainline's net income in fourth quarter 2011 decreased $11 million to $60 million compared to the same period in 2010. This decrease was primarily due to lower incentive earnings, a lower ROE as determined by the NEB of 8.08 per cent in 2011 compared to 8.52 per cent in 2010, as well as a lower average investment base.

The Alberta System's net income of $51 million in fourth quarter 2011 decreased $2 million compared to the same period in 2010. The lower net income was primarily due to lower incentive earnings, partially offset by the positive impact of a higher average investment base.

Canadian Mainline's Comparable EBITDA of $262 million in fourth quarter 2011 decreased $7 million compared to the same period in 2010. The Alberta System's Comparable EBITDA was $185 million in fourth quarter 2011 compared to $194 million for the same period in 2010. EBITDA from the Canadian Mainline and the Alberta System includes net income variances discussed above as well as flow through items which do not affect net income.

ANR's Comparable EBITDA in fourth quarter 2011 was US$73 million compared to US$76 million for the same period in 2010. The decrease in fourth quarter 2011 was primarily due to higher OM&A costs.

GTN's Comparable EBITDA in fourth quarter 2011 from TransCanada's direct investment was US$26 million compared to US$45 million for the same period in 2010. The decrease was primarily due to TransCanada's sale of a 25 per cent interest in GTN to TC PipeLines, LP in May 2011 and lower revenues.

The Bison pipeline was placed in service on January 14, 2011. TransCanada's portion of Comparable EBITDA from its direct investment was US$14 million in fourth quarter 2011. EBITDA reflects TransCanada's 75 per cent direct interest in Bison subsequent to the sale of a 25 per cent interest in Bison to TC PipeLines, LP in May 2011 and 100 per cent prior to that date.

Comparable EBITDA from the remainder of the U.S. Natural Gas Pipelines was US$145 million in fourth quarter 2011 compared to US$128 million for the same period in 2010. The increases were primarily due to incremental earnings from the Guadalajara pipeline, which was placed in service in June 2011. In addition, lower general, administrative and support costs increased EBITDA in fourth quarter 2011, offset by lower earnings from Great Lakes and Portland.

Natural Gas Pipelines' Depreciation and Amortization increased $10 million in fourth quarter 2011 compared to the same period in 2010 primarily due to the Guadalajara and Bison pipelines being placed in service in 2011.

Natural Gas Pipelines' Business Development Comparable EBITDA losses, resulting from business development expenses, decreased $6 million in fourth quarter 2011 compared to the same period in 2010 primarily due to decreased business development costs related to the Alaska Pipeline Project. Project applicable expenses and reimbursements are shared proportionately with ExxonMobil, TransCanada's joint venture partner in developing the Alaska Pipeline Project.

Oil Pipelines Comparable EBIT in fourth quarter 2011 was $144 million. At the beginning of February 2011, the Company commenced recording EBITDA for the Wood River/Patoka section of Keystone following the NEB's decision to remove the MOP restriction along the conversion section of the system and completion of the required operational modifications. The Cushing Extension was also placed in service at that time.

Energy's Comparable EBIT was $195 million in fourth quarter 2011 compared to $198 million for the same period in 2010.

Western Power's Comparable EBITDA of $143 million and Power revenues of $294 million in fourth quarter 2011 increased $95 million and $114 million, respectively, compared to the same period in 2010, primarily due to higher overall realized power prices in Alberta and incremental earnings from Coolidge, which went in service under a 20-year PPA in May 2011. Plant outages and higher demand resulted in average spot market power prices in Alberta increasing 65 per cent to $76 per MWh in fourth quarter 2011 compared to $46 per MWh in fourth quarter 2010.

Western Power's Comparable EBITDA in fourth quarter 2011 included $57 million of accrued earnings from the Sundance A PPA, the revenues and costs of which have been recorded as though the outages of Sundance A Units 1 and 2 were interruptions of supply in accordance with the terms of the PPA.

Eastern Power's Comparable EBITDA of $87 million and Power Revenues of $125 million in fourth quarter 2011 increased $10 million and $12 million, respectively, compared to the same period in 2010 primarily due to higher Bécancour contractual earnings.

TransCanada's proportionate share of Bruce A's Comparable EBITDA decreased $34 million to a loss of $1 million in fourth quarter 2011 compared to EBITDA of $33 million in fourth quarter 2010. The decrease was primarily due to lower volumes reflecting the November 6, 2011 commencement of the approximate six-month West Shift Plus planned outage as part of the life extension strategy for Unit 3.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $32 million to $34 million in fourth quarter 2011 compared to $66 million in fourth quarter 2010 due to higher operating costs, lower volumes due to increased planned outage days and lower realized prices resulting from the expiry of fixed-price contracts at higher prices.

U.S. Power's Comparable EBITDA in fourth quarter 2011 of US$32 million decreased US$27 million compared to the same period in 2010 primarily due to the negative impact of lower commodity and capacity prices and lower physical sales volumes partially offset by new sales activity in PJM.

Natural Gas Storage's Comparable EBITDA in fourth quarter 2011 was $23 million compared to $37 million for the same period in 2010. The decrease of $14 million in Comparable EBITDA in fourth quarter 2011 was primarily due to decreased proprietary natural gas and third party storage revenues as a result of lower realized natural gas price spreads.

Comparable Interest Expense in fourth quarter 2011 increased $78 million to $251 million from $173 million in fourth quarter 2010. The increase primarily reflected lower capitalized interest upon placing Keystone and other new assets in service in 2011.

Comparable Interest Income and Other in fourth quarter 2011 decreased $53 million to $8 million from income of $61 million in fourth quarter 2010. The decrease in fourth quarter reflected realized losses in 2011 compared to gains in 2010 on derivatives used to manage the Company's net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable Income Taxes were $123 million in fourth quarter 2011 compared to $103 million for the same period in 2010. The increase was primarily due to higher positive income tax adjustments that reduced income taxes in fourth quarter 2010 compared to 2011.

SHARE INFORMATION

At February 8, 2012, TransCanada had 704 million issued and outstanding common shares, and had 22 million Series 1, 14 million Series 3 and 14 million Series 5 issued and outstanding first preferred shares that are convertible to 22 million Series 2, 14 million Series 4 and 14 million Series 6 preferred shares, respectively. In addition, there were seven million outstanding options to purchase common shares, of which five million were exercisable as at February 8, 2012.

OTHER INFORMATION

Additional information relating to TransCanada, including the Company's Annual Information Form and other continuous disclosure documents, is available on SEDAR at www.sedar.com under TransCanada Corporation.

Other selected consolidated financial information for 2007 to 2011 is found under the heading "Five Year Financial Highlights" in the Supplementary Information section of the Company's Annual Report.

GLOSSARY OF TERMS

AFUDC	Allowance for funds used during construction
Alaska Pipeline Project	A proposed natural gas pipeline extending from Prudhoe Bay, Alaska to either Alberta or Valdez, Alaska
Alberta System	A natural gas transmission system in Alberta and B.C.
AOCI	Accumulated Other Comprehensive (Loss)/Income
ANR	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and U.S. midcontinent region to markets located primarily in Wisconsin, Michigan, Illinois, Indiana and Ohio, and regulated underground natural gas storage facilities in Michigan
APG	Aboriginal Pipeline Group
ARO	Asset retirement obligation
ATWACC	After-tax weighted average cost of capital
AUC	Alberta Utilities Commission
B.C.	British Columbia
bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bear Creek	A natural gas-fired cogeneration plant near Grande Prairie, Alberta
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A natural gas pipeline extending from the Powder River Basin in Wyoming to Northern Border in North Dakota
Bison LLC	Bison Pipeline LLC
BPC	BPC Generation Infrastructure Trust
BPRIA	Bruce Power Refurbishment Implementation Agreement
Bruce A	A partnership interest in a nuclear power generation facility consisting of Units 1 to 4 of Bruce Power
Bruce B	A partnership interest in a nuclear power generation facility consisting of Units 5 to 8 of Bruce Power
Bruce Power	A nuclear power generation facility located northwest of Toronto, Ontario (Bruce A and Bruce B, collectively)
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Cancarb	A waste-heat fuelled power plant and the Cancarb thermal carbon black facility in Medicine Hat, Alberta
CAPP	Canadian Association of Petroleum Producers
Carseland	A natural gas-fired cogeneration plant near Carseland, Alberta
Cartier Wind	Five wind farms in Gaspé, Québec, four plus the first phase of the fifth which are operational and phase two of the fifth under construction
CFE	Comisión Federal de Electricidad
CGAAP	Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
Coolidge	A simple-cycle, natural gas-fired peaking power generation station in Coolidge, Arizona
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CrossAlta	An underground natural gas storage facility near Crossfield, Alberta
CSP	Contingent Support Payments
Cushing Extension	A crude oil pipeline extending from Steele City, Nebraska to Cushing, Oklahoma
DB Plans	Defined benefit pension plans
DC Plans	Defined contribution pension plans
DOS	U.S. Department of State
DRP	Dividend Reinvestment and Share Purchase Plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization

Edson	An underground natural gas storage facility near Edson, Alberta
EPA	Environmental Protection Agency (U.S.)
ExxonMobil	Exxon Mobil Corporation
FASB	Financial Accounting Standards Board
FCM	Forward Capacity Market
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
Fracking	Multi-stage hydraulic fracturing
Gas Pacifico	A natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile
GHG	Greenhouse gas
Grandview	A natural gas-fired cogeneration plant in Saint John, New Brunswick
Great Lakes	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the northeastern and midwestern U.S.
GTN	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
GTN LLC	Gas Transmission Northwest LLC
Guadalajara	A natural gas pipeline in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
GWh	Gigawatt hours
Halton Hills	A natural gas-fired, combined-cycle power plant in Halton Hills, Ontario
HOEP	Hourly Ontario energy price
HSE	Health, safety and environment
IASB	International Accounting Standards Board
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
INNERGY	An industrial natural gas marketing company based in Concepción, Chile
Iroquois	A natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to the northeastern U.S.
ISO	International Organization for Standardization
Keystone	The crude oil pipeline system which extends from Hardisty, Alberta to the U.S. markets and includes the Wood River/Patoka, the Cushing Extension and Keystone XL
Keystone XL	A proposed extension and expansion of the Keystone oil pipeline to the U.S. Gulf Coast, which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the expansion of existing facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometre(s)
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
MacKay River	A natural gas-fired cogeneration plant near Fort McMurray, Alberta
MD&A	Management's Discussion and Analysis
Mackenzie Gas Project (MGP)	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
MMcf/d	Million cubic feet per day
MOP	Maximum operating pressure
MW	Megawatt(s)
MWh	Megawatt hours
NCC	North Central Corridor
NEB	National Energy Board
NEXT	Natural Gas Liquids Extraction Model
NGTL	NOVA Gas Transmission Ltd.
NID	National Interest Determination

North Baja	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
Northern Border	A natural gas transmission system extending from a point near Monchy, Saskatchewan to the U.S. Midwest
NYISO	New York Independent System Operator
OCI	Other Comprehensive (Loss)/Income
OM&A	Operating, maintenance and administration
OMERS	Ontario Municipal Employees Retirement System
OPA	Ontario Power Authority
Ocean State Power	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
PHMSA	Pipeline and Hazardous Materials Safety Administration
PJM Interconnection (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
Portland	A natural gas transmission system extending from a point near East Hereford, Québec to the northeastern U.S.
Portlands Energy	A natural gas-fired, combined-cycle power plant in Toronto, Ontario
PPA	Power purchase arrangement
PWU	Power Workers' Union Trust
Ravenswood	A natural gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology located in Queens, New York
Redwater	A natural gas-fired cogeneration plant near Redwater, Alberta
Restructuring Proposal	Canadian Mainline 2012 Tolls Application and Restructuring Proposal
RGGI	Regional Greenhouse Gas Initiative
ROE	Rate of return on common equity
RRA	Rate-regulated accounting
SEC	Securities and Exchange Commission (U.S.)
SEP	Society of Energy Professionals Trust
Sheerness	A coal-fired power generating facility near Hanna, Alberta
Sundance A	A coal-fired power generating facility near Wabamun, Alberta
Sundance B	A coal-fired power generating facility near Wabamun, Alberta
Tamazunchale	A natural gas pipeline in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi
TC Hydro	Hydroelectric generation assets in New Hampshire, Vermont and Massachusetts
TC Keystone	TransCanada Keystone Pipeline, LP
Tcf	Trillion cubic feet
TCPL	TransCanada PipeLines Limited
TCPL USA	TransCanada PipeLine USA Ltd.
TQM	A natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with Portland
TransAlta	TransAlta Corporation
TransCanada or the Company	TransCanada Corporation
TransGas	A natural gas transmission system extending from Mariquita to Cali in Colombia
Tuscarora	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S.	United States
U.S. GAAP	U.S. generally accepted accounting principles
VaR	Value-at-Risk
Ventures LP	A natural gas transmission system in Alberta supplying natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta
WCI	Western Climate Initiative
WCSB	Western Canada Sedimentary Basin
Wood River/Patoka	A crude oil pipeline extending from Hardisty, Alberta to U.S. markets at Wood River and Patoka in Illinois
Zephyr	A proposed power transmission line project originating in Wyoming and terminating in Nevada

Report of Management

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP) and include amounts that are based on estimates and judgements. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2011 to that in 2010, and highlights significant changes between 2010 and 2009. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal controls over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting are effective as of December 31, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with CGAAP. The report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Russell K. Girling
President and
Chief Executive Officer

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 13, 2012

Independent Auditors' Report

To the Shareholders of TransCanada Corporation

We have audited the accompanying consolidated financial statements of TransCanada Corporation, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, the consolidated statements of income, comprehensive income, accumulated other comprehensive income, equity and cash flows for each of the years in the three-year period ended December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our 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, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

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

KPMG LLP

Chartered Accountants
Calgary, Canada

February 13, 2012

TRANSCANADA CORPORATION
CONSOLIDATED INCOME

Year ended December 31 *(millions of dollars except per share amounts)*	**2011**	2010	2009
Revenues	**9,139**	8,064	8,181
Operating and Other Expenses			
Plant operating costs and other	**3,449**	3,114	3,213
Commodity purchases resold	**941**	1,017	831
Depreciation and amortization	**1,528**	1,354	1,377
Valuation provision for MGP (Note 9)	**–**	146	–
	5,918	5,631	5,421
Financial Charges/(Income)			
Interest expense (Note 13)	**937**	701	954
Interest expense of joint ventures (Note 14)	**55**	59	64
Interest income and other	**(55)**	(94)	(121)
	937	666	897
Income before Income Taxes	**2,284**	1,767	1,863
Income Tax Expense/(Recovery) (Note 12)			
Current	**209**	(141)	30
Future	**364**	521	357
	573	380	387
Net Income	**1,711**	1,387	1,476
Net Income Attributable to Non-Controlling Interests (Note 16)	**129**	115	96
Net Income Attributable to Controlling Interests	**1,582**	1,272	1,380
Preferred Share Dividends (Note 18)	**55**	45	6
Net Income Attributable to Common Shares	**1,527**	1,227	1,374
Net Income per Common Share (Note 17)			
Basic	**$2.18**	$1.78	$2.11
Diluted	**$2.17**	$1.77	$2.11

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

TRANSCANADA CORPORATION

CONSOLIDATED COMPREHENSIVE INCOME

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Net Income	**1,711**	1,387	1,476
Other Comprehensive Income/(Loss), Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations(1)	**113**	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations(2)	**(73)**	89	258
Change in fair value of derivative instruments designated as cash flow hedges(3)	**(203)**	(141)	75
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges(4)	**127**	(7)	(15)
Other Comprehensive Loss	**(36)**	(239)	(153)
Comprehensive Income	**1,675**	1,148	1,323
Comprehensive Income Attributable to Non-Controlling Interests	**140**	121	103
Comprehensive Income Attributable to Controlling Interests	**1,535**	1,027	1,220
Preferred Share Dividends	**55**	45	6
Comprehensive Income Attributable to Common Shares	**1,480**	982	1,214

(1) Net of income tax recovery of $29 million in 2011 (2010 – $65 million expense; 2009 – $92 million expense).

(2) Net of income tax recovery of $28 million in 2011 (2010 – $37 million expense; 2009 – $124 million expense).

(3) Net of income tax recovery of $104 million in 2011 (2010 – $95 million recovery; 2009 – $7 million expense).

(4) Net of income tax expense of $77 million in 2011 (2010 – $21 million expense; 2009 – $9 million expense).

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

TRANSCANADA CORPORATION
CONSOLIDATED CASH FLOWS

Year ended December 31 *(millions of dollars)*	**2011**	2010	2009
Cash Generated from Operations			
Net income	**1,711**	1,387	1,476
Depreciation and amortization	**1,528**	1,354	1,377
Future income taxes (Note 12)	**364**	521	357
Employee future benefits funding in excess of expense (Note 20)	**(3)**	(69)	(111)
Valuation provision for MGP (Note 9)	**–**	146	–
Other	**63**	(8)	(19)
	3,663	3,331	3,080
Decrease/(increase) in operating working capital (Note 22)	**310**	(249)	(90)
Net cash provided by operations	**3,973**	3,082	2,990
Investing Activities			
Capital expenditures (Note 4)	**(3,274)**	(5,036)	(5,417)
Deferred amounts and other	**(14)**	(384)	(594)
Acquisitions, net of cash acquired (Note 23)	**–**	–	(902)
Net cash used in investing activities	**(3,288)**	(5,420)	(6,913)
Financing Activities			
Dividends on common and preferred shares (Notes 17 and 18)	**(1,016)**	(754)	(728)
Distributions paid to non-controlling interests	**(131)**	(112)	(100)
Notes payable (repaid)/issued, net	**(218)**	474	(244)
Long-term debt issued, net of issue costs	**1,622**	2,371	3,267
Repayment of long-term debt	**(1,272)**	(494)	(1,005)
Long-term debt of joint ventures issued	**48**	177	226
Repayment of long-term debt of joint ventures	**(102)**	(254)	(246)
Common shares issued, net of issue costs	**58**	26	1,820
Preferred shares issued, net of issue costs	**–**	679	539
Partnership units of subsidiary issued, net of issue costs (Note 23)	**321**	–	193
Net cash (used in)/provided by financing activities	**(690)**	2,113	3,722
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**6**	(8)	(110)
Increase/(Decrease) in Cash and Cash Equivalents	**1**	(233)	(311)
Cash and Cash Equivalents			
Beginning of year	**764**	997	1,308
Cash and Cash Equivalents			
End of year	**765**	764	997

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

TRANSCANADA CORPORATION

CONSOLIDATED BALANCE SHEET

December 31 *(millions of dollars)*	**2011**	2010
ASSETS		
Current Assets		
Cash and cash equivalents	**765**	764
Accounts receivable	**1,265**	1,271
Inventories	**416**	425
Other	**1,194**	870
	3,640	3,330
Plant, Property and Equipment (Note 5)	**38,262**	36,244
Goodwill (Note 6)	**3,650**	3,570
Regulatory Assets (Note 7)	**1,405**	1,512
Intangibles and Other Assets (Note 9)	**2,038**	2,138
	48,995	46,794
LIABILITIES		
Current Liabilities		
Notes payable (Note 10)	**1,880**	2,092
Accounts payable	**2,659**	2,272
Accrued interest	**373**	367
Current portion of long-term debt (Note 13)	**935**	894
Current portion of long-term debt of joint ventures (Note 14)	**33**	65
	5,880	5,690
Regulatory Liabilities (Note 7)	**303**	314
Deferred Amounts (Note 11)	**805**	694
Future Income Taxes (Note 12)	**3,788**	3,398
Long-Term Debt (Note 13)	**17,632**	17,028
Long-Term Debt of Joint Ventures (Note 14)	**789**	801
Junior Subordinated Notes (Note 15)	**1,009**	985
	30,206	28,910
EQUITY		
Controlling interests	**17,324**	16,727
Non-controlling interests (Note 16)	**1,465**	1,157
	18,789	17,884
	48,995	46,794

Commitments, Contingencies and Guarantees (Note 24)

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

On behalf of the Board:

Russell K. Girling
Director

Kevin E. Benson
Director

TRANSCANADA CORPORATION

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE (LOSS)/INCOME

(millions of dollars)	Currency Translation Adjustments	Cash Flow Hedges and Other	Total
Balance at January 1, 2009	(379)	(93)	(472)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(471)	–	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	258	–	258
Change in fair value of derivative instruments designated as cash flow hedges[3]	–	77	77
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	–	(24)	(24)
Balance at December 31, 2009	(592)	(40)	(632)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	(180)	–	(180)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	89	–	89
Change in fair value of derivative instruments designated as cash flow hedges[3]	–	(137)	(137)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4]	–	(17)	(17)
Balance at December 31, 2010	(683)	(194)	(877)
Change in foreign currency translation gains and losses on investments in foreign operations[1]	**113**	**–**	**113**
Change in fair value of derivative instruments to hedge the net investments in foreign operations[2]	**(73)**	**–**	**(73)**
Change in fair value of derivative instruments designated as cash flow hedges[3]	**–**	**(204)**	**(204)**
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[4][5]	**–**	**117**	**117**
Balance at December 31, 2011	**(643)**	**(281)**	**(924)**

(1) Net of income tax recovery of $29 million in 2011 (2010 – $65 million expense; 2009 – $92 million expense).

(2) Net of income tax recovery of $28 million in 2011 (2010 – $37 million expense; 2009 – $124 million expense).

(3) Net of income tax recovery of $104 million in 2011 (2010 – $95 million recovery; 2009 – $7 million expense).

(4) Net of income tax expense of $77 million in 2011 (2010 – $21 million expense; 2009 – $9 million expense).

(5) Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net Income in 2012 are estimated to be $181 million ($116 million, net of tax). These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

TRANSCANADA CORPORATION
CONSOLIDATED EQUITY

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Common Shares			
Balance at beginning of year	**11,745**	11,338	9,264
Shares issued under dividend reinvestment plan (Note 17)	**202**	378	254
Shares issued on exercise of stock options (Note 17)	**64**	29	28
Proceeds from shares issued under public offering, net of issue costs (Note 17)	**–**	–	1,792
Balance at end of year	**12,011**	11,745	11,338
Preferred Shares			
Balance at beginning of year	**1,224**	539	–
Shares issued under public offering, net of issue costs (Note 18)	**–**	685	539
Balance at end of year	**1,224**	1,224	539
Contributed Surplus			
Balance at beginning of year	**331**	328	279
Issuance of stock options, net of exercises	**1**	3	2
Increased ownership in TC PipeLines, LP (Note 23)	**–**	–	47
Dilution gain from TC PipeLines, LP units issued (Note 23)	**30**	–	–
Balance at end of year	**362**	331	328
Retained Earnings			
Balance at beginning of year	**4,304**	4,186	3,827
Net income attributable to controlling interests	**1,582**	1,272	1,380
Common share dividends	**(1,180)**	(1,109)	(1,015)
Preferred share dividends	**(55)**	(45)	(6)
Balance at end of year	**4,651**	4,304	4,186
Accumulated Other Comprehensive (Loss)/Income			
Balance at beginning of year	**(877)**	(632)	(472)
Other comprehensive loss	**(47)**	(245)	(160)
Balance at end of year	**(924)**	(877)	(632)
Equity Attributable to Controlling Interests	**17,324**	16,727	15,759
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,157**	1,174	1,194
Net income attributable to non-controlling interests			
TC PipeLines, LP	**101**	87	66
Preferred share dividends of subsidiary	**22**	22	22
Portland	**6**	6	8
Other comprehensive income attributable to non-controlling interests	**11**	6	7
Sale of TC PipeLines, LP units			
Proceeds, net of issue costs	**321**	–	193
Decrease in TransCanada's ownership	**(50)**	–	(29)
Distributions to non-controlling interests	**(131)**	(112)	(100)
Foreign exchange and other	**28**	(26)	(187)
Balance at end of year	**1,465**	1,157	1,174
Total Equity	**18,789**	17,884	16,933

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

TRANSCANADA CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy company which operates in three business segments, Natural Gas Pipelines, Oil Pipelines and Energy, each of which offers different products and services.

Natural Gas Pipelines
The Natural Gas Pipelines segment consists of the Company's investments in regulated natural gas pipelines and regulated natural gas storage facilities. Through its Natural Gas Pipelines segment, TransCanada owns and operates:

- a natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec (Canadian Mainline);
- a natural gas transmission system in Alberta and northeastern British Columbia (B.C.) (Alberta System);
- a natural gas transmission system extending from producing fields primarily located in Texas, Oklahoma, the Gulf of Mexico and Louisiana to markets primarily located in Wisconsin, Michigan, Illinois, Ohio and Indiana, and to regulated natural gas storage facilities in Michigan (ANR);
- a natural gas transmission system extending from central Alberta to the B.C./Idaho border and to the Saskatchewan/Montana border (Foothills);
- natural gas transmission systems in Alberta that supply natural gas to the oil sands region of northern Alberta and to a petrochemical complex at Joffre, Alberta (Ventures LP);
- a natural gas transmission system in Mexico extending from Naranjos, Veracruz to Tamazunchale, San Luis Potosi (Tamazunchale); and
- a natural gas transmission system in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco (Guadalajara).

Through its Natural Gas Pipelines segment, TransCanada operates and has ownership interests in natural gas pipeline systems as follows:

- a 53.6 per cent direct ownership interest in a natural gas transmission system that connects to the Canadian Mainline and serves markets in eastern Canada and the northeastern and midwestern United States (U.S.) (Great Lakes);
- a 75 per cent direct ownership interest in a natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border (GTN);
- a 75 per cent direct ownership interest in a natural gas transmission system extending from the Powder River Basin in Wyoming to Northern Border in North Dakota (Bison);
- a 61.7 per cent interest in a natural gas transmission system that extends from a point near East Hereford, Québec, to the northeastern U.S. (Portland);
- a 50 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec and to the Portland system (TQM); and
- a 33.3 per cent controlling interest in TC PipeLines, LP, which has the following ownership interests in pipelines operated by TransCanada:
  - a 46.4 per cent interest in Great Lakes, in which TransCanada has a combined 69 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 50 per cent interest in a natural gas transmission system extending from a point near Monchy, Saskatchewan, to the U.S. Midwest (Northern Border), in which TransCanada has a 16.7 per cent effective ownership interest through TC PipeLines, LP;
  - a 25 per cent interest in GTN, in which TransCanada has a combined 83.3 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 25 per cent interest in Bison, in which TransCanada has a combined 83.3 per cent effective ownership interest through TC PipeLines, LP and a direct interest described above;
  - a 100 per cent interest in a natural gas transmission system extending from Arizona to Baja California at the Mexico/California border (North Baja), in which TransCanada has a 33.3 per cent effective ownership interest through TC PipeLines, LP; and
  - a 100 per cent interest in a natural gas transmission system extending from Malin, Oregon, to Wadsworth, Nevada (Tuscarora), in which TransCanada has a 33.3 per cent effective ownership interest through TC PipeLines, LP.

TransCanada does not operate but has ownership interests in natural gas pipelines and natural gas marketing activities as follows:

- a 44.5 per cent interest in a natural gas transmission system that connects with the Canadian Mainline near Waddington, New York, and delivers natural gas to customers in the northeastern U.S. (Iroquois);
- a 46.5 per cent interest in a natural gas transmission system extending from Mariquita to Cali in Colombia (TransGas); and
- a 30 per cent interest in a natural gas transmission system extending from Loma de la Lata, Argentina to Concepción, Chile (Gas Pacifico), and in an industrial natural gas marketing company based in Concepción (INNERGY).

Oil Pipelines
The Oil Pipelines segment consists of a wholly owned and operated crude oil pipeline system extending from Hardisty, Alberta to U.S. markets at Wood River and Patoka in Illinois (Wood River/Patoka), and from Steele City, Nebraska to Cushing, Oklahoma (Cushing Extension). The Company plans to expand and extend this oil pipeline system to the U.S. Gulf Coast (Keystone XL) which includes the construction of a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast, the addition of operational storage facilities at Hardisty, Alberta and the construction of a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska. The expanded oil pipeline system is collectively referred to as Keystone.

The proposed Marketlink projects will connect additional oil supply sourced from U.S. basins to facilities which form part of Keystone XL and provide transportation services accessing refining markets in the Cushing, Oklahoma region and the U.S. Gulf Coast. The proposed Bakken Marketlink project would transport U.S. crude oil from Baker, Montana to Cushing and the proposed Cushing Marketlink project would transport crude oil from Cushing to Port Arthur and Houston, Texas.

Energy
The Energy segment primarily consists of the Company's investments in electrical power generation plants and non-regulated natural gas storage facilities. Through its Energy segment, the Company owns and operates:

- a natural gas and oil-fired generating facility in Queens, New York, consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology (Ravenswood);
- a natural gas-fired, combined-cycle power plant in Halton Hills, Ontario (Halton Hills);
- hydroelectric generation assets located in New Hampshire, Vermont and Massachusetts (TC Hydro);
- a natural gas-fired peaking facility located near Phoenix, Arizona (Coolidge);
- a natural gas-fired, combined-cycle plant in Burrillville, Rhode Island (Ocean State Power);
- a natural gas-fired cogeneration plant near Trois-Rivières, Québec (Bécancour);
- natural gas-fired cogeneration plants in Alberta at Carseland, Redwater, Bear Creek and MacKay River;
- a wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine (Kibby Wind);
- a natural gas-fired cogeneration plant near Saint John, New Brunswick (Grandview);
- a waste-heat fuelled power plant and the Cancarb thermal carbon black facility in Medicine Hat, Alberta (Cancarb);
- a natural gas storage facility near Edson, Alberta (Edson); and
- a 60 per cent interest in an underground natural gas storage facility near Crossfield, Alberta (CrossAlta).

TransCanada does not operate but has ownership interests in power generation plants as follows:

- a 48.8 per cent partnership interest and a 31.6 per cent partnership interest in the nuclear power generation facilities of Bruce A and Bruce B (collectively Bruce Power), respectively, located near Tiverton, Ontario;
- a 62 per cent interest in the Baie-des-Sables, Anse-à-Valleau, Carleton, Montagne-Sèche and Gros-Morne wind farms in Gaspé, Québec (Cartier Wind). All wind farms are in service with the exception of the second phase of Gros-Morne, which is currently under construction; and
- a 50 per cent interest in a natural gas-fired, combined-cycle plant in Toronto, Ontario (Portlands Energy).

TransCanada also has long-term power purchase arrangements (PPA) in place for:

- 756 megawatts (MW) of generating capacity from the Sheerness power facility near Hanna, Alberta;
- a 50 per cent interest in ASTC Power Partnership, which has a PPA in place for 100 per cent of the production from the Sundance B power facilities near Wabamun, Alberta; and
- 100 per cent of the production of the Sundance A power facilities near Wabamun, Alberta.

NOTE 2 ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles as defined in Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook (CGAAP) as discussed further in Note 3. Amounts are stated in Canadian dollars unless otherwise indicated. Certain comparative figures have been reclassified to conform with the current year's presentation.

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies summarized below.

Basis of Presentation

The consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-Controlling Interests. TransCanada proportionately consolidates its share of the accounts of joint ventures in which the Company is able to exercise joint control. TransCanada uses the equity method of accounting for investments over which the Company is able to exercise significant influence.

Regulation

In Canada, regulated natural gas pipelines and oil pipelines are subject to the authority of the National Energy Board (NEB) of Canada. In the U.S., natural gas pipelines, oil pipelines and regulated storage assets are subject to the authority of the U.S. Federal Energy Regulatory Commission (FERC). The Company's natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in these rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses under CGAAP to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls.

The NEB and the FERC regulate construction and operations of Keystone; however, RRA is not applicable to Keystone and, as a result, the regulators' decisions regarding operations and tolls on Keystone generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Canadian Natural Gas Pipelines

Revenues from Canadian natural gas pipelines subject to rate regulation are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include an appropriate return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are periodically subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than otherwise required to account for the incentives. Revenues are recognized on firm contracted capacity over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to the NEB's decision on rates for a specified period reflect the NEB's last approved return on equity. Adjustments to revenue are recorded when the NEB decision is received.

U.S. Natural Gas Pipelines

Revenues from U.S. natural gas pipelines subject to rate regulation are recorded in accordance with FERC rules and regulations. The Company's U.S. natural gas pipeline revenues are generally based on quantity of gas delivered or contracted capacity. Revenues are recognized on firm contracted capacity over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made.

Oil Pipelines

The Company's oil pipeline revenues are generated from the transportation of crude oil and contractual arrangements for committed capacity. Transportation revenues are recognized in the period the product is delivered. Transportation revenues are based on actual volumes and reflect adjustments to rates to reflect under-recovery or over-recovery of certain transportation costs. Revenues earned from contracted capacity arrangements are recognized in the period in which the capacity is made available.

Energy

i) Power

Revenues from the Company's power business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, which are earned monthly, and revenues earned through the use of energy derivative contracts. The accounting for energy derivative contracts is described in the Financial Instruments section of this note.

ii) Natural Gas Storage

Revenues earned from providing natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Forward contracts for the purchase or sale of natural gas, as well as proprietary natural gas inventory in storage, are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's Cash and Cash Equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories
Inventories primarily consist of materials and supplies, including spare parts and fuel, and are carried at the lower of average cost and net realizable value. The Company values its proprietary natural gas inventory in storage at fair value, measured using a weighted average of forward prices for the following four months, which represents the estimated withdrawal period, less selling costs. To record inventory at fair value, TransCanada has designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. The Company records its net proprietary natural gas storage sales and purchases in Revenues. All changes in the fair value of proprietary natural gas inventory in storage are reflected in Inventories and in Revenues.

Plant, Property and Equipment

Natural Gas Pipelines
Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates. The cost of overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. This allowance is reflected as an increase in the cost of the assets in Plant, Property and Equipment. The equity component of AFUDC is a non-cash item. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Oil Pipelines
Plant, property and equipment for oil pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from approximately two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction. When oil pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy
Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Nuclear power generation assets under capital lease are recorded initially at the present value of minimum lease payments at the inception of the lease and amortized on a straight-line basis over the shorter of their useful life and the remaining lease term. Other equipment is depreciated at various rates. The cost of overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When Energy retires plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Corporate
Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Impairment of Long-Lived Assets
The Company reviews long-lived assets, such as plant, property and equipment, and intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows is less than the carrying value of the assets, an impairment loss is recognized for the excess of the carrying value over the fair value of the assets.

Acquisitions and Goodwill
The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are recorded at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate the asset might be impaired. An initial test is done by comparing the fair value of the reporting unit to its book value, which includes goodwill. If the fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded.

Power Purchase Arrangements

A PPA is a long-term contract for the purchase or sale of power on a predetermined basis. The PPAs under which TransCanada buys power are accounted for as operating leases. The initial payments for the Company's PPAs were recognized in Intangibles and Other Assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. A portion of these PPAs has been subleased to third parties under terms and conditions similar to the PPAs. The subleases are accounted for as operating leases and TransCanada records the margin earned from the subleases as a component of Revenues.

Stock Options

TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. The contractual life of options granted in 2003 and thereafter and of options granted prior to 2003 is seven years and 10 years, respectively. The Company uses the Black-Scholes model to determine fair value of the options on their grant date. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration, and if not previously vested, upon resignation or retirement of the option holder or upon termination of the option holder's employment. Stock options become null and void upon forfeiture. The Company records compensation expense over the three-year vesting period, assuming a 15 per cent forfeiture rate, with an offset to Contributed Surplus. This charge is reflected in the Corporate segment. Upon exercise of stock options, amounts originally recorded against Contributed Surplus are reclassified to Common Shares.

Income Taxes

The Company uses the liability method of accounting for income taxes. This method requires the recognition of future income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Foreign Currency Translation

The Company's foreign operations are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated at the period-end exchange rates and revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. Translation adjustments are reflected in Other Comprehensive Income/(Loss) (OCI).

Exchange gains and losses on monetary assets and liabilities are recorded in income except for exchange gains and losses on the foreign currency debt related to the Canadian Mainline, Alberta System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Financial Instruments

The Company initially records all financial instruments on the Balance Sheet at fair value. Where possible, fair value is determined by reference to quoted market prices. In the absence of quoted prices, other pricing and valuation techniques are used that maximize the use of observable data. The entity's own credit risk and the credit risk of its counterparties are taken into consideration when measuring the fair value of financial assets and financial liabilities. Subsequent measurement of financial instruments is based on their classification. Financial assets are classified into the following categories: held for trading, available for sale, held-to-maturity investments, and loans and receivables. Financial liabilities are classified as held for trading or as other financial liabilities.

Held for trading derivative financial assets and liabilities consist of swaps, options, forwards and futures. A financial asset or liability may be designated as held for trading when it is entered into with the intention of generating a profit. The Company has not designated any of its non-derivative financial assets or liabilities as held for trading. Commodity held for trading financial instruments are initially recorded at their fair value and changes to fair value are included in Revenues. Realized gains and losses on derivatives used to manage the Company's operating assets are presented on a net basis in Revenues. Changes in the fair value of interest rate held for trading instruments are recorded in Interest Expense and changes in the fair value of foreign exchange rate held for trading instruments are recorded in Interest Income and Other. Realized gains and losses are included in the same financial statement category as their underlying position upon settlement of the financial instrument.

The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in any of the other three classifications. TransCanada's available for sale financial instruments include fixed-income securities held for self-insurance.

These instruments are accounted for initially at their fair value and changes to fair value are recorded through OCI. Gains and losses from the settlement of available for sale financial assets is included in Interest Income and Other.

The held-to-maturity classification consists of non-derivative financial assets that are accounted for at their amortized cost using the effective interest method. The Company does not have any held-to-maturity financial assets.

Trade receivables, loans and other receivables with fixed or determinable payments that are not quoted in an active market are classified as loans and receivables and are measured at amortized cost using the effective interest method, net of any impairment. The Company's loans and receivables include trade accounts receivable, interest-bearing and non-interest-bearing third-party loans, and notes receivable. Interest and other income earned from these financial assets are recorded in Interest Income and Other.

Other financial liabilities consist of liabilities not classified as held for trading. Items in this financial instrument category are recognized at amortized cost using the effective interest method. Interest costs are included in Interest Expense and in Interest Expense of Joint Ventures.

The Company uses derivatives and other financial instruments to manage its exposure to changes in foreign currency exchange rates, interest rates and energy commodity prices. The Company also uses a combination of derivatives and U.S. dollar-denominated debt to manage the foreign currency exposure of its foreign operations.

All derivatives are recorded on the balance sheet at fair value, with the exception of non-financial derivatives that were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected normal purchase, sale or usage requirements. Derivatives used in hedging relationships are discussed further in the Hedges section of this note.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are recorded separately, they are included in Net Income.

The recognition of gains and losses on the derivatives used to manage the Canadian natural gas regulated pipelines exposures is determined through the regulatory process. The gains and losses on derivatives accounted for as part of RRA are deferred in Regulatory Assets or Regulatory Liabilities.

Transaction costs are defined as incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. The Company offsets long-term debt transaction costs against the associated debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of tolling mechanisms.

The Company records the fair value of its portion of material joint and several guarantees. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees. Guarantees are recorded as an increase to an investment account, Plant, Property and Equipment, or a charge to Net Income, and a corresponding liability is recorded in Deferred Amounts.

Hedges

The Company applies hedge accounting to arrangements that qualify for hedge accounting treatment, which include fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in self-sustaining foreign operations. Documentation is prepared at the inception of each hedging arrangement in order to qualify for hedge accounting treatment. In addition, the Company performs an assessment of effectiveness at the inception of the contract and at each reporting date. Hedge accounting is discontinued prospectively when the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination or cancellation.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net Income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net Income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest Income and Other and Interest Expense, respectively. When hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net Income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net Income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in Accumulated Other Comprehensive (Loss)/Income (AOCI) are reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net Income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net Income from AOCI when the hedged item is sold or terminated early, or when it is probable the anticipated transaction will not occur.

The Company also enters into cash flow hedges and fair value hedges for activities subject to rate regulation in Canada. The gains and losses arising from changes in the fair value of these hedges can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory Assets or Regulatory Liabilities. When the hedges are settled, the realized gains or losses are refunded to or collected from the ratepayers in subsequent years.

In hedging the foreign currency exposure of a net investment in a self-sustaining foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net Income. The amounts recognized previously in AOCI are reclassified to Net Income in the event the Company reduces its net investment in a foreign operation.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Balance Sheet at historical cost and expensed when they are utilized. Compliance payments are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Balance Sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and recorded in Revenues.

Employee Benefit and Other Plans

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a Savings Plan and other post-employment benefit plans. Contributions made by the Company to the DC Plans and Savings Plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-employment benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized over the average remaining service period of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Certain of the Company's joint ventures sponsor DB Plans. The Company records its proportionate share of expenses, funding contributions and accrued benefit assets and liabilities related to these plans.

NOTE 3 ACCOUNTING CHANGES

Changes in Accounting Policies for 2011

Business Combinations

Effective January 1, 2011, the Company adopted CICA Handbook Section 1582 "Business Combinations", which is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, expensing of acquisition costs, and increased disclosure. Adoption of this standard had no effect on the financial statements as at and for the year ended December 31, 2011.

Consolidated Financial Statements and Non-Controlling Interests
Entities adopting Section 1582 were also required to adopt CICA Handbook Sections 1601 "Consolidated Financial Statements" and 1602 "Non-Controlling Interests". Sections 1601 and 1602 require Non-Controlling Interests to be presented as part of Equity on the balance sheet. In addition, the income statement of the controlling parent now includes 100 per cent of the subsidiary's results and presents the allocation of net income between the controlling and non-controlling interests. Changes resulting from the adoption of Sections 1601 and 1602 were applied retrospectively.

Future Accounting Changes

United States Generally Accepted Accounting Principles
The CICA's Accounting Standards Board (AcSB) previously announced that Canadian publicly accountable enterprises were required to adopt International Financial Reporting Standards (IFRS) effective January 1, 2011, with the exception of certain qualifying entities historically using RRA that were given a one year deferral from adopting IFRS. TransCanada is a qualifying entity for these purposes and has deferred the adoption of IFRS. The Company has prepared its consolidated financial statements for 2011 in accordance with CGAAP in order to continue using RRA.

In the application of CGAAP, TransCanada follows specific accounting guidance under United States generally accepted accounting principles (U.S. GAAP) unique to rate-regulated businesses. These RRA standards allow the timing of recognition of certain revenues and expenses to differ from the timing that may otherwise be expected in a non-rate-regulated business under CGAAP in order to appropriately reflect the economic impact of regulators' decisions regarding the Company's revenues and tolls. The International Accounting Standards Board has concluded that the development of RRA under IFRS requires further analysis and TransCanada does not expect a final RRA standard under IFRS to be effective in the foreseeable future.

As a registrant with the U.S. Securities and Exchange Commission, TransCanada has the option under Canadian disclosure rules to prepare and file its consolidated financial statements using U.S. GAAP. As a result of the developments noted above, the Company's Board of Directors has approved the adoption of U.S. GAAP effective January 1, 2012. The financial reporting impact of TransCanada adopting U.S. GAAP is disclosed in Note 25 "United States Accounting Principles and Reporting". The differences between CGAAP and U.S. GAAP are consistent with those reported by the Company in its annual "Reconciliation to United States GAAP" as filed in prior years. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company's primary accounting framework.

Fair Value Measurement
In May 2011, the Financial Accounting Standards Board (FASB) issued amended guidance on fair value measurements, which updated some of the existing measurement guidance and included enhanced disclosure requirements under U.S. GAAP. This guidance is effective for interim and annual periods beginning after December 15, 2011. Adoption of these amendments is expected to result in an increase in the qualitative and quantitative disclosures regarding Level 3 measurements, however, the Company expects no material effect on the financial statements.

Intangibles – Goodwill and Other
In September 2011, the FASB issued new guidance on testing goodwill for impairment which simplifies an entity's testing for goodwill impairment under U.S. GAAP by permitting an entity to first assess qualitative factors affecting the fair value of a reporting unit in comparison to the carrying amount, as a basis for determining whether it is required to proceed to the two-step quantitative goodwill impairment test. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Adoption is not expected to impact the financial statements.

Balance Sheet Offsetting/Netting
In December 2011, the FASB issued amended guidance to enhance disclosures that will enable users of the financial statements to evaluate the effect, or potential effect, of netting arrangements on an entity's financial position. The amendments result in enhanced disclosures by requiring additional information regarding financial instruments and derivative instruments that are either offset in accordance with current U.S. GAAP or subject to an enforceable master netting agreement. This guidance is effective for annual periods beginning on or after January 1, 2013. Adoption of these amendments is expected to result in an increase in disclosures regarding financial instruments which are subject to offsetting as described in this amendment.

NOTE 4 SEGMENTED INFORMATION

Commencing in February 2011, TransCanada began recording earnings related to the Wood River/Patoka and Cushing Extension sections of Keystone.

During 2010, the Company began recognizing a separate segment, Oil Pipelines. Also during that period, Wood River/Patoka began delivering oil but at reduced operating pressure due to regulatory restrictions. As a result, the Company continued to classify Wood River/Patoka as under construction along with the Cushing Extension and Keystone XL. At December 31, 2010, Keystone capital costs were net of $99 million of operating cash flows relating to Wood River/Patoka.

Year ended December 31, 2011 (millions of dollars)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**4,500**	**827**	**3,812**	**–**	**9,139**
Plant operating costs and other	**(1,533)**	**(240)**	**(1,590)**	**(86)**	**(3,449)**
Commodity purchases resold	**–**	**–**	**(941)**	**–**	**(941)**
Depreciation and amortization	**(986)**	**(130)**	**(398)**	**(14)**	**(1,528)**
	1,981	**457**	**883**	**(100)**	**3,221**
Interest expense					**(937)**
Interest expense of joint ventures					**(55)**
Interest income and other					**55**
Income tax expense					**(573)**
Net Income					**1,711**
Net Income Attributable to Non-Controlling Interests					**(129)**
Net Income Attributable to Controlling Interests					**1,582**
Preferred Share Dividends					**(55)**
Net Income Attributable to Common Shares					**1,527**

Year ended December 31, 2010 (millions of dollars)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Revenues	4,373	–	3,691	–	8,064
Plant operating costs and other[1]	(1,458)	–	(1,557)	(99)	(3,114)
Commodity purchases resold	–	–	(1,017)	–	(1,017)
Depreciation and amortization	(977)	–	(377)	–	(1,354)
Valuation provision for MGP	(146)	–	–	–	(146)
	1,792	–	740	(99)	2,433
Interest expense					(701)
Interest expense of joint ventures					(59)
Interest income and other					94
Income tax expense					(380)
Net Income					1,387
Net Income Attributable to Non-Controlling Interests					(115)
Net Income Attributable to Controlling Interests					1,272
Preferred Share Dividends					(45)
Net Income Attributable to Common Shares					1,227

(1) In 2010, Natural Gas Pipelines included $17 million of general, administrative and support costs relating to Keystone.

Year ended December 31, 2009 (millions of dollars)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Revenues	4,729	–	3,452	–	8,181
Plant operating costs and other	(1,607)	–	(1,489)	(117)	(3,213)
Commodity purchases resold	–	–	(831)	–	(831)
Depreciation and amortization	(1,030)	–	(347)	–	(1,377)
	2,092	–	785	(117)	2,760
Interest expense					(954)
Interest expense of joint ventures					(64)
Interest income and other					121
Income tax expense					(387)
Net Income					1,476
Net Income Attributable to Non-Controlling Interests					(96)
Net Income Attributable to Controlling Interests					1,380
Preferred Share Dividends					(6)
Net Income Attributable to Common Shares					1,374

TOTAL ASSETS

December 31 (millions of dollars)	**2011**	2010
Natural Gas Pipelines	**23,669**	23,629
Oil Pipelines	**9,439**	8,501
Energy	**14,276**	12,966
Corporate	**1,611**	1,698
	48,995	46,794

GEOGRAPHIC INFORMATION

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Revenues[(1)]			
Canada – domestic	**4,836**	4,368	5,079
Canada – export	**1,087**	838	756
United States and other	**3,216**	2,858	2,346
	9,139	8,064	8,181

(1) Revenues are attributed based on the country in which the product or service originated.

December 31 (millions of dollars)	**2011**	2010
Plant, Property and Equipment		
Canada	**22,349**	21,561
United States and other	**15,913**	14,683
	38,262	36,244

CAPITAL EXPENDITURES

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Natural Gas Pipelines	**935**	1,196	965
Oil Pipelines	**1,204**	2,696	2,939
Energy	**1,127**	1,129	1,487
Corporate	**8**	15	26
	3,274	5,036	5,417

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

	2011			2010		
December 31 (millions of dollars)	**Cost**	**Accumulated Depreciation**	**Net Book Value**	Cost	Accumulated Depreciation	Net Book Value
Natural Gas Pipelines[1]						
Canadian Mainline						
Pipeline	**8,785**	**4,958**	**3,827**	8,768	4,730	4,038
Compression	**3,362**	**1,765**	**1,597**	3,385	1,651	1,734
Metering and other	**383**	**175**	**208**	381	167	214
	12,530	**6,898**	**5,632**	12,534	6,548	5,986
Under construction	**28**	**–**	**28**	14	–	14
	12,558	**6,898**	**5,660**	12,548	6,548	6,000
Alberta System						
Pipeline	**6,701**	**3,062**	**3,639**	6,528	2,917	3,611
Compression	**1,778**	**1,109**	**669**	1,707	1,045	662
Metering and other	**931**	**409**	**522**	909	378	531
	9,410	**4,580**	**4,830**	9,144	4,340	4,804
Under construction	**368**	**–**	**368**	71	–	71
	9,778	**4,580**	**5,198**	9,215	4,340	4,875
ANR						
Pipeline	**858**	**47**	**811**	858	96	762
Compression	**510**	**72**	**438**	507	74	433
Metering and other	**576**	**81**	**495**	548	74	474
	1,944	**200**	**1,744**	1,913	244	1,669
Under construction	**20**	**–**	**20**	7	–	7
	1,964	**200**	**1,764**	1,920	244	1,676
Joint Ventures and Others						
GTN	**1,612**	**370**	**1,242**	1,557	319	1,238
Great Lakes	**1,581**	**741**	**840**	1,540	698	842
Foothills	**1,630**	**1,005**	**625**	1,650	975	675
Northern Border	**1,288**	**644**	**644**	1,252	608	644
Other[2]	**3,132**	**720**	**2,412**	2,913	633	2,280
	9,243	**3,480**	**5,763**	8,912	3,233	5,679
	33,543	**15,158**	**18,385**	32,595	14,365	18,230
Oil Pipelines						
Keystone						
Pipeline	**4,904**	**80**	**4,824**	–	–	–
Pumping equipment	**1,502**	**38**	**1,464**	–	–	–
Tanks and other	**548**	**15**	**533**	–	–	–
	6,954	**133**	**6,821**	–	–	–
Under construction[3]	**2,433**	**–**	**2,433**	8,184	–	8,184
	9,387	**133**	**9,254**	8,184	–	8,184
Energy						
Nuclear[4]	**1,712**	**630**	**1,082**	1,586	536	1,050
Natural Gas – Ravenswood	**1,799**	**220**	**1,579**	1,710	144	1,566
Natural Gas – Other[5]	**3,337**	**708**	**2,629**	2,767	588	2,179
Hydro	**620**	**90**	**530**	599	69	530
Wind[6]	**843**	**88**	**755**	659	65	594
Natural Gas Storage	**454**	**78**	**376**	423	67	356
Other	**163**	**94**	**69**	160	96	64
	8,928	**1,908**	**7,020**	7,904	1,565	6,339
Under construction – Nuclear[7]	**3,217**	**–**	**3,217**	2,678	–	2,678
Under construction – Other[8]	**308**	**–**	**308**	728	–	728
	12,453	**1,908**	**10,545**	11,310	1,565	9,745
Corporate	**129**	**51**	**78**	125	40	85
	55,512	**17,250**	**38,262**	52,214	15,970	36,244

(1) In 2011, the Company capitalized $23 million (2010 – $35 million) relating to the equity portion of AFUDC for natural gas pipelines with a corresponding amount recorded in Interest Income and Other.

(2) Includes in service assets of Bison, Tamazunchale, Portland, Iroquois, TQM, North Baja, Guadalajara, Tuscarora and Ventures LP, and under construction amounts of $33 million (2010 – $899 million). Bison went in service in January 2011 and Guadalajara went in service in June 2011.

(3) Includes $2.4 billion at December 31, 2011 (2010 – $1.4 billion) relating to Keystone XL which remains subject to regulatory approvals.

(4) Includes assets under capital lease relating to Bruce Power.

(5) Includes facilities with long-term PPAs that are accounted for as operating leases, including Coolidge which went in service in May 2011. The cost and accumulated depreciation of these facilities were $605 million and $34 million, respectively, at December 31, 2011 (2010 – $89 million and $19 million, respectively). Revenues of $53 million were recognized in 2011 (2010 and 2009 – $15 million) through the sale of electricity under the related PPAs.

(6) Includes Montagne-Sèche and phase one of Gros-Morne effective November 2011.

(7) Nuclear assets under construction primarily includes expenditures for the refurbishment and restart of Bruce A.

(8) Other Energy assets under construction at December 31, 2011 includes amounts for the second phase of the Gros-Morne wind farm (Cartier Wind).

NOTE 6 GOODWILL

The Company has recorded the following goodwill on its acquisitions in the U.S.:

(millions of dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2010	2,891	872	3,763
Foreign exchange rate changes	(144)	(49)	(193)
Balance at December 31, 2010	2,747	823	3,570
Foreign exchange rate changes	**62**	**18**	**80**
Balance at December 31, 2011	**2,809**	**841**	**3,650**

NOTE 7 RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian and U.S. natural gas pipelines and regulated U.S. natural gas storage. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the applicable regulatory authorities.

Rates charged by TransCanada's Canadian regulated pipelines are typically set through a process that involves filing an application with the regulators for a change in rates. Regulated rates are underpinned by the total annual revenue requirement, which comprises a specified annual return on capital, including debt and equity, and all necessary operating expenses, taxes and depreciation.

TransCanada's Canadian regulated natural gas pipelines have generally been subject to a cost-of-service model wherein forecasted costs, including a return on capital, determine the revenues for the upcoming year. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they are incurred.

The Canadian Mainline, Alberta System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act* (Canada). The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

In October 2009, the NEB issued a decision that its RH-2-94 Decision, which established a rate of return on common equity (ROE) formula that had formed the basis of determining tolls for natural gas pipelines under NEB jurisdiction since 1995, would no longer be in effect. The decision meant a company's cost of capital will now be determined by negotiations between pipeline companies and their shippers or by the NEB if a pipeline company files a cost of capital application. The decision has affected TransCanada's NEB regulated pipelines. However, the Canadian Mainline continues to base its return on the RH-2-94 ROE formula in accordance with the terms of the current Canadian Mainline tolls settlement, described below.

Canadian Mainline

In 2011, the Canadian Mainline operated under its five-year settlement, which was effective January 1, 2007 to December 31, 2011. The Canadian Mainline's cost of capital for establishing tolls under the settlement reflects ROE as determined by the NEB's RH-2-94 ROE formula on a deemed common equity of 40 per cent. The allowed ROE in 2011 for the Canadian Mainline was 8.08 per cent (2010 – 8.52 per cent). The balance of the capital structure is comprised of short and long-term debt.

The settlement also established the Canadian Mainline's fixed operating, maintenance and administration (OM&A) costs for each of the five years. Variances between actual OM&A costs and those agreed to in the settlement accrued fully to TransCanada from 2007 to 2009. Variances in OM&A costs were shared equally between TransCanada and its customers in 2010 and 2011. All other cost elements of the revenue requirement are treated on a flow-through basis. The settlement also allows for performance-based incentive arrangements. In 2009, the NEB approved an adjustment account, which was established to reduce tolls in 2010 under a settlement with stakeholders. In accordance with the terms of the settlement, balances in the adjustment account are to be amortized at the composite depreciation rate and included in tolls beginning in 2011.

In September 2011, the NEB approved the Canadian Mainline's interim tolls as final for 2011, including TransCanada's proposal to carry forward any revenue variances into the determination of 2012 tolls. However, the NEB determined that TransCanada's inclusion of certain elements in the proposed 2011 revenue requirement derived in accordance with the 2007-2011 settlement will be examined with TransCanada's 2012-2013 Tolls Application before a final decision is rendered on the 2011 revenue requirement.

Alberta System

In September 2010, the NEB approved the Alberta System's 2010-2012 Revenue Requirement Settlement Application. The settlement provides for a 9.70 per cent ROE on a deemed common equity of 40 per cent and fixes certain annual OM&A costs during the term. Any variances between actual costs and those agreed to in the settlement accrue to TransCanada. All other costs are treated on a flow-through basis.

Foothills

In June 2010, TransCanada reached an agreement to establish a cost of capital for Foothills that reflects a 9.70 per cent ROE on a deemed common equity of 40 per cent for 2010 to 2012. A component of OM&A is fixed, subject to the terms of the B.C System/Foothills Integration Settlement, and variances between actual and fixed amounts were shared with customers up to and including June 2011 when the OM&A savings cap was reached.

TQM

In November 2010, the NEB approved TQM's multi-year settlement with its interested parties regarding its annual revenue requirements for 2010 to 2012. As part of the settlement, the annual revenue requirement comprises fixed and flow-through components. The fixed component includes certain OM&A costs, return on rate base, depreciation and municipal taxes. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations

TransCanada's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the *Natural Gas Act of 1938,* the *Natural Gas Policy Act of 1978* (NGA) and the *Energy Policy Act of 2005*, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR

ANR's natural gas transportation and storage services are provided for under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective beginning in 1997. ANR Pipeline Company is not required to conduct a review of currently effective rates with the FERC at any time in the future but is not prohibited from filing for new rates if necessary. ANR Storage Company, which is another FERC regulated entity that owns and operates storage fields in Michigan, has rates that were established pursuant to a settlement approved by the FERC that were effective beginning in 1990. ANR Storage Company is currently subject to a review, initiated by the FERC in late 2011, of its existing rates.

In 2011, ANR Pipeline Company filed an application with the FERC to sell its offshore Gulf of Mexico assets and certain related onshore facilities to its wholly owned subsidiary, TC Offshore LLC. At the same time, TC Offshore LLC requested authorization from the FERC to acquire, own and operate those facilities under the FERC's regulations. These filings are currently pending before the FERC and a decision is expected in second or third quarter 2012.

GTN

GTN is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. GTN's rates were established pursuant to a settlement approved by the FERC in January 2008. That settlement required GTN to file a rate case within seven years of the effective date. In November 2011, the FERC approved, without modification, GTN's new settlement with its shippers regarding GTN's rates, terms and conditions of service which will become effective January 1, 2012. This new settlement provides for a four year moratorium during which GTN and the settling parties are prohibited from taking certain actions under the NGA, including filings to adjust rates. GTN is required to file for new rates to be effective January 1, 2016.

Great Lakes

Great Lakes is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for its various services and permits Great Lakes to discount or negotiate rates on a non-discriminatory basis. Great Lakes rates were established pursuant to a settlement approved by the FERC in July 2010. The settlement included a moratorium on participants and customers from initiating a NGA Section 5 rate case to adjust rates prior to November 1, 2012. In addition, Great Lakes is required to file a NGA Section 4 general rate case no later than November 1, 2013.

Bison

Bison is regulated by the FERC and operates in accordance with a FERC-approved tariff that establishes maximum and minimum rates for various services. Bison is permitted to discount or negotiate these rates on a non-discriminatory basis. Bison's rates were established pursuant to its initial certificate to construct and operate the pipeline that initiated service in January 2011.

Regulatory Assets and Liabilities

Year ended December 31 (millions of dollars)	**2011**	2010	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Future income taxes[1]	**1,178**	1,256	n/a
Operating and debt-service regulatory assets[2]	**172**	237	1
Adjustment account[3]	**82**	85	31
Other[4]	**151**	174	n/a
	1,583	1,752	
Less: Current portion included in Other Current Assets	**178**	240	
	1,405	1,512	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**184**	200	1 - 18
Operating and debt-service regulatory liabilities[2]	**135**	98	1
Other[4]	**123**	150	n/a
	442	448	
Less: Current portion included in Accounts Payable	**139**	134	
	303	314	

(1) These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

(2) Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2011 would have been $102 million higher (2010 – $51 million higher) had these amounts not been recorded as regulatory assets and liabilities.

(3) A regulatory adjustment account of $85 million was established and agreed upon by Canadian Mainline stakeholders to reduce tolls in 2010. Amortization of the adjustment account commenced in 2011 at the composite depreciation rate.

(4) Pre-tax operating results in 2011 would have been $4 million lower (2010 – $28 million higher) had these amounts not been recorded as regulatory assets and liabilities.

(5) Foreign exchange on long-term debt of the Canadian Mainline, Alberta System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, CGAAP would have required the inclusion of these unrealized gains or losses in Net Income.

NOTE 8 JOINT VENTURE INVESTMENTS

(millions of dollars)	Ownership Interest as at December 31, 2011	TransCanada's Proportionate Share – Income before Income Taxes Year Ended December 31 2011	2010	2009	Net Assets December 31 2011	2010
Natural Gas Pipelines						
Northern Border[1]		**75**	69	47	**429**	389
Iroquois	44.5%	**40**	40	44	**181**	181
TQM	50.0%	**17**	16	22	**82**	85
Other	Various	**14**	16	17	**32**	36
Energy						
Bruce A	48.8%	**33**	35	3	**3,537**	3,011
Bruce B	31.6%	**77**	138	236	**493**	505
ASTC Power Partnership	50.0%	**84**	41	34	**58**	61
Portlands Energy	50.0%	**33**	33	24	**313**	335
CrossAlta	60.0%	**23**	45	55	**81**	73
Cartier Wind[2]	62.0%	**27**	24	26	**518**	355
Other	Various	**7**	8	4	**50**	42
		430	465	512	**5,774**	5,073

(1) The results reflect a 50 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2011, TransCanada had an ownership interest in TC PipeLines, LP of 33.3 per cent (2010 and 2009 – 38.2 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 16.7 per cent (2010 and 2009 – 19.1 per cent).

(2) TransCanada proportionately consolidates its 62 per cent interest in the Cartier Wind assets. The Montagne-Sèche project and phase one of the Gros-Morne wind farm were placed in service in November 2011.

Summarized Financial Information of Joint Ventures

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Income			
Revenues	**1,668**	1,643	1,632
Plant operating costs and other	**(974)**	(913)	(856)
Depreciation and amortization	**(212)**	(208)	(196)
Interest expense and other	**(52)**	(57)	(68)
Proportionate Share of Joint Venture Income before Income Taxes	**430**	465	512

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Cash Flows			
Operating activities	**733**	678	455
Investing activities	**(827)**	(722)	(651)
Financing activities[1]	**99**	51	130
Effect of foreign exchange rate changes on cash and cash equivalents	**2**	(1)	(17)
Proportionate Share of Increase/(Decrease) in Cash and Cash Equivalents of Joint Ventures	**7**	6	(83)

(1) Financing activities included cash outflows resulting from distributions paid to TransCanada of $486 million in 2011 (2010 – $475 million; 2009 – $252 million) and cash inflows resulting from capital contributions paid by TransCanada of $633 million in 2011 (2010 – $601 million; 2009 – $864 million).

December 31 (millions of dollars)	**2011**	2010
Balance Sheet		
Cash and cash equivalents	**111**	104
Other current assets	**433**	438
Plant, property and equipment	**6,430**	5,704
Intangibles and other assets/(deferred amounts), net	**26**	14
Current liabilities	**(437)**	(387)
Long-term debt	**(789)**	(801)
Future income taxes	**–**	1
Proportionate Share of Net Assets of Joint Ventures	**5,774**	5,073

NOTE 9 INTANGIBLES AND OTHER ASSETS

December 31 (millions of dollars)	**2011**	2010
Employee benefit plans (Note 20)	**499**	473
PPAs[(1)]	**482**	539
Loans and advances[(2)]	**224**	241
Fair value of derivative contracts (Note 21)	**213**	374
Future income tax assets (Note 12)	**133**	112
Margin calls	**104**	76
Equity investments[(3)]	**41**	78
Other	**342**	245
	2,038	2,138

(1) The following amounts related to PPAs are included in Intangibles and Other Assets:

	2011			2010		
December 31 (millions of dollars)	**Cost**	**Accumulated Amortization**	**Net Book Value**	Cost	Accumulated Amortization	Net Book Value
Sheerness	**585**	**234**	**351**	585	195	390
Sundance A	**225**	**148**	**77**	224	133	91
Sundance B	**110**	**56**	**54**	110	52	58
PPAs	**920**	**438**	**482**	919	380	539

Amortization expense for the PPAs was $58 million for the year ended December 31, 2011 (2010 and 2009 – $58 million). The expected annual amortization expense in each of the next five years is $58 million. The $77 million net book value related to Sundance A is expected to remain fully recoverable under the terms of the PPA regardless of the outcome of the arbitration process discussed in Note 24 "Commitments, Contingencies and Guarantees".

(2) As at December 31, 2011, TransCanada held a $265 million (2010 – $281 million) note receivable from the seller of Ravenswood which bears interest at 6.75 per cent and matures in 2039. This represents the long–term portion of that note.

(3) The balance primarily relates to the Company's 46.5 per cent ownership interest in TransGas.

Advances to Aboriginal Pipeline Group

The Mackenzie Delta gas producers, the Aboriginal Pipeline Group (APG) and TransCanada have an agreement governing TransCanada's role in the Mackenzie Gas Project (MGP). The project, if successful, would result in a natural gas pipeline being constructed from Inuvik, Northwest Territories to the northern border of Alberta, where it would connect to the Alberta System. Under the agreement, TransCanada agreed to finance the APG for its one-third share of project pre-development costs.

The MGP proponents continue to pursue the required regulatory approvals for the project and the Canadian government's support of an acceptable fiscal framework. In December 2010, the NEB released a decision granting approval of the project's application for a Certificate of Public Convenience and Necessity. The approval contained 264 conditions including the requirement to file an updated cost estimate and report on the decision to construct by the end of 2013 and, further, that construction must commence by December 31, 2015.

At December 31, 2010, due to uncertainty with respect to the project's ultimate commercial structure and fiscal framework, the timeframes under which the project would proceed and if and when the Company's advances to the APG will be repaid, a valuation provision of $146 million was recorded on the loan to the APG. Amounts advanced to the APG in furtherance of the MGP in 2011 have been expensed.

NOTE 10 NOTES PAYABLE

	2011		2010	
	Outstanding December 31	**Weighted Average Interest Rate per Annum at December 31**	Outstanding December 31	Weighted Average Interest Rate per Annum at December 31
	(millions of dollars)		(millions of dollars)	
Canadian dollars	**483**	**1.2%**	601	1.2%
U.S. dollars (2011 – US$1,373; 2010 – US$1,499)	**1,397**	**0.5%**	1,491	0.7%
	1,880		2,092	

Notes payable consists of commercial paper issued by TransCanada PipeLines Limited (TCPL), TransCanada PipeLine USA Ltd. (TCPL USA) and TransCanada Keystone Pipeline, LP (TC Keystone) and draws on line-of-credit and demand facilities.

At December 31, 2011, total committed revolving and demand credit facilities of $5.1 billion were available. When drawn, interest on the lines of credit is charged at prime rates of Canadian chartered and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

- a $2.0 billion committed, syndicated, revolving, extendible TCPL credit facility, maturing October 2016. The facility was fully available at December 31, 2011. The cost to maintain the credit facility was $2 million in 2011 (2010 – $2 million; 2009 – $2 million);
- a US$300 million committed, syndicated, revolving TCPL USA credit facility, guaranteed by TransCanada and maturing February 2013. At December 31, 2011, this facility was fully available. This facility is part of an initial US$1.0 billion credit facility discussed in Note 13. The cost to maintain the credit facility was $1 million in 2011 (2010 – $1 million; 2009 – $1 million);
- a US$1.0 billion committed, syndicated, revolving, extendible TC Keystone credit facility, guaranteed by TCPL and TCPL USA and maturing November 2012. The facility was fully available at December 31, 2011. The cost to maintain the credit facility was $4 million in 2011 (2010 – $5 million; 2009 – $2 million);
- a US$1.0 billion committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL and maturing October 2012. At December 31, 2011, this facility was fully available. The cost to maintain the credit facility was $4 million in 2011 (2010 – $4 million); and
- demand lines totalling $802 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2011, the Company had used approximately $468 million of these demand lines for letters of credit.

NOTE 11 DEFERRED AMOUNTS

December 31 (millions of dollars)	**2011**	2010
Fair value of derivative contracts (Note 21)	**352**	282
Employee benefit plans (Note 20)	**285**	251
Asset retirement obligations (Note 19)	**68**	65
Other	**100**	96
	805	694

NOTE 12 INCOME TAXES

Provision for Income Taxes

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Current			
Canada	**211**	29	(70)
Foreign	**(2)**	(170)	100
	209	(141)	30
Future			
Canada	**138**	170	339
Foreign	**226**	351	18
	364	521	357
Income Tax Expense	**573**	380	387

Geographic Components of Income

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Canada	**1,175**	798	1,095
Foreign	**1,109**	969	768
Income before Income Taxes	**2,284**	1,767	1,863

Reconciliation of Income Tax Expense

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Income before Income Taxes	**2,284**	1,767	1,863
Federal and provincial statutory tax rate	**26.5%**	28.0%	29.0%
Expected income tax expense	**605**	495	540
Income tax differential related to regulated operations	**42**	8	39
Lower effective foreign tax rates	**(5)**	(36)	(63)
Tax rate and legislative changes	**–**	–	(30)
Income from equity investments and non-controlling interests	**(45)**	(40)	(37)
Other	**(24)**	(47)	(62)
Actual Income Tax Expense	**573**	380	387

Future Income Tax Assets and Liabilities

December 31 (millions of dollars)	**2011**	2010
Future Income Tax Assets		
Operating loss carryforwards	**905**	494
Financial instruments	**163**	108
Other post-employment benefits	**74**	75
Deferred amounts	**49**	42
Other	**141**	153
	1,332	872
Future Income Tax Liabilities		
Difference in accounting and tax bases of plant, equipment and PPAs	**4,164**	3,439
Taxes on future revenue requirement	**299**	321
Unrealized foreign exchange gains on long-term debt	**133**	161
Pension benefits	**94**	96
Other	**107**	77
	4,797	4,094
Net Future Income Tax Liabilities	**3,465**	3,222

The above future tax amounts have been classified in the Consolidated Balance Sheet as follows:

December 31 (millions of dollars)	**2011**	2010(1)
Future Income Tax Assets		
Other current assets	**265**	93
Intangibles and other assets (Note 9)	**133**	112
	398	205
Future Income Tax Liabilities		
Accounts payable	**75**	29
Future income taxes	**3,788**	3,398
	3,863	3,427
Net Future Income Tax Liabilities	**3,465**	3,222

(1) Amounts relating to deferred tax assets and liabilities as at December 31, 2010 have been reclassified to conform with current year's presentation.

At December 31, 2011, the Company has recognized the benefit of unused non-capital loss carryforwards of $450 million (2010 – $42 million) for federal and provincial purposes in Canada, which expire from 2014 to 2031.

At December 31, 2011, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,119 million (2010 – US$1,320 million) for federal purposes in the U.S., which expire from 2028 to 2031.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Future income tax liabilities would have increased at December 31, 2011 by approximately $136 million (2010 – $105 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax refunds of $84 million, net of payments made, were received in 2011 (2010 – payments, net of refunds, of $53 million; 2009 – payments, net of refunds, of $83 million).

NOTE 13 LONG-TERM DEBT

Outstanding loan amounts (millions of dollars)	Maturity Dates	2011 Outstanding December 31	2011 Interest Rate[1]	2010 Outstanding December 31	2010 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian dollars	2014 to 2020	**873**	**10.9%**	872	10.9%
U.S. dollars (2011 and 2010 – US$600)	2012 to 2021	**608**	**9.5%**	595	9.5%
Medium-Term Notes					
Canadian dollars	2013 to 2041	**4,537**	**5.9%**	4,150	6.2%
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$8,626)[2]	2013 to 2040	**8,693**	**5.7%**	8,490	5.7%
		14,711		14,107	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian dollars	2014 to 2024	**386**	**11.5%**	390	11.4%
U.S. dollars (2011 and 2010 – US$375)	2012 to 2023	**380**	**8.2%**	371	8.2%
Medium-Term Notes					
Canadian dollars	2025 to 2030	**502**	**7.4%**	502	7.4%
U.S. dollars (2011 and 2010 – US$33)	2026	**33**	**7.5%**	32	7.5%
		1,301		1,295	
TRANSCANADA PIPELINE USA LTD.					
Bank Loan					
U.S. dollars (2011 – US$500; 2010 – US$700)	2012	**509**	**0.6%**	696	0.5%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$432)	2021 to 2025	**438**	**8.9%**	429	8.9%
GAS TRANSMISSION NORTHWEST CORPORATION					
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$325)	2015 to 2035	**329**	**5.5%**	322	5.5%
TC PIPELINES, LP					
Unsecured Loan					
U.S. dollars (2011 – US$363; 2010 – US$483)	2016	**366**	**1.6%**	480	0.8%
Senior Unsecured Notes					
U.S. dollars (2011 – US$350)	2021	**356**	**4.7%**	–	–
		722		480	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. dollars (2011 – US$373; 2010 – US$392)	2018 to 2030	**379**	**7.8%**	389	7.8%
TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. dollars (2011 – US$30; 2010 – US$31)	2012 to 2017	**31**	**4.4%**	31	4.4%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. dollars (2011 – US$147; 2010 – US$164)	2018	**147**	**6.1%**	161	6.1%
OTHER					
Senior Notes					
U.S. dollars (2011 – nil; 2010 – US$12)		**–**	**–**	12	7.3%
		18,567		17,922	
Less: Current Portion of Long-Term Debt		**935**		894	
		17,632		17,028	

(1) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

(2) Includes fair value adjustments of $13 million (2010 – $8 million) for interest rate swap agreements on US$350 million of debt at December 31, 2011 (2010 – US$250 million).

(3) Senior Secured Notes are secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

Principal repayments on the long-term debt of the Company for the next five years are approximately as follows: 2012 – $935 million; 2013 – $903 million; 2014 – $971 million; 2015 – $1,084 million; and 2016 $1,227 million.

In the normal course of business, TransCanada and various wholly owned subsidiaries also provide guarantees on behalf of the Company or wholly owned subsidiaries for debt owed to third parties. This is to facilitate the extension of sufficient credit to accomplish their intended commercial activity.

TransCanada PipeLines Limited

In November 2011, TCPL issued $500 million and $250 million of Medium-Term Notes maturing November 15, 2021 and November 15, 2041, respectively, and bearing interest at 3.65 per cent and 4.55 per cent, respectively.

In May 2011, TCPL retired $60 million of 9.50 per cent Medium-Term Notes.

In January 2011, TCPL retired $300 million of 4.3 per cent Medium-Term Notes.

In September 2010, TCPL issued US$1.0 billion of Senior Notes maturing October 1, 2020, and bearing interest at 3.80 per cent.

In June 2010, TCPL issued US$500 million and US$750 million of Senior Notes maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively.

In February 2010, TCPL retired US$120 million of 6.125 per cent Medium-Term Notes and in August 2010, TCPL retired $130 million of 10.50 per cent debentures.

In October 2009, TCPL retired $250 million of 10.625 per cent debentures.

In February 2009, TCPL issued $300 million and $400 million of Medium-Term Notes maturing in February 2014 and February 2039, respectively, and bearing interest at 5.05 per cent and 8.05 per cent, respectively. Also in February 2009, TCPL retired $200 million of 4.10 per cent Medium-Term Notes.

In January 2009, TCPL issued US$750 million and US$1.25 billion of Senior Unsecured Notes maturing in January 2019 and January 2039, respectively, and bearing interest at 7.125 per cent and 7.625 per cent, respectively. Also in January 2009, TCPL retired US$227 million of 6.49 per cent Medium-Term Notes.

NOVA Gas Transmission Ltd.

Debentures issued by NOVA Gas Transmission Ltd. (NGTL) in the amount of $225 million have retraction provisions that entitle the holders to require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made to December 31, 2011.

TransCanada PipeLine USA Ltd.

TCPL USA has an initial US$1.0 billion committed, unsecured, syndicated credit facility, guaranteed by TransCanada which was reduced to a US$800 million credit facility through a US$200 million term loan repayment in August 2011. The facility consists of a US$500 million five-year term loan maturing in 2012 and a US$300 million revolving facility maturing in February 2013, described further in Note 10. Included in Long-Term Debt was an outstanding balance of US$500 million on the term loan at December 31, 2011 (2010 – US$700 million) which was fully repaid in January 2012.

TC PipeLines, LP

In July 2011, TC PipeLines, LP increased its senior syndicated revolving credit facility to US$500 million and extended the maturity date to July 2016. In December 2011, TC PipeLines, LP repaid a maturing US$300 million term loan with a draw under this facility, and at December 31, 2011, US$363 million (2010 – US$8 million) was outstanding on the facility.

In June 2011, TC PipeLines, LP issued US$350 million of 4.65 per cent Senior Notes due 2021. The proceeds from the issuance were used to partially repay TC PipeLines, LP's term loan and borrowings under its senior revolving credit facility, and repay its bridge loan facility described below.

In May 2011, TC PipeLines, LP made draws of US$61 million on a bridge loan facility and US$125 million on its senior revolving credit facility to partially fund the acquisition of a 25 per cent interest in each of Gas Transmission Northwest LLC (GTN LLC) and Bison Pipeline LLC (Bison LLC) as further described in Note 23.

Interest Expense

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Interest on long-term debt	**1,154**	1,149	1,212
Interest on junior subordinated notes	**63**	65	73
Interest on short-term debt	**16**	15	10
Capitalized interest	**(302)**	(587)	(358)
Amortization and other financial charges[1]	**6**	59	17
	937	701	954

(1) Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to rising interest rates.

The Company made interest payments of $926 million in 2011 (2010 – $652 million; 2009 – $916 million) on long-term debt and junior subordinated notes, net of interest capitalized on construction projects.

NOTE 14 LONG-TERM DEBT OF JOINT VENTURES

		2011		2010	
Outstanding loan amounts (millions of dollars)	Maturity Dates	**Outstanding December 31[1]**	**Interest Rate[2]**	Outstanding December 31[1]	Interest Rate[2]
NORTHERN BORDER PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. dollars (2011 and 2010 – US$175)	2016 to 2021	**177**	**7.1%**	174	7.1%
Bank Facility					
U.S. dollars (2011 – US$62; 2010 – US$96)	2016	**62**	**1.6%**	94	0.5%
IROQUOIS GAS TRANSMISSION SYSTEM, L.P.					
Senior Unsecured Notes					
U.S. dollars (2011 – US$169; 2010 – US$178)	2019 to 2027	**171**	**6.1%**	176	6.1%
BRUCE POWER L.P. AND BRUCE POWER A L.P.					
Capital Lease Obligations	2018	**194**	**7.5%**	207	7.5%
Term Loan	2031	**88**	**7.1%**	90	7.1%
TRANS QUÉBEC & MARITIMES PIPELINE INC.					
Bonds	2014 to 2017	**87**	**4.2%**	87	4.2%
Term Loan	2016	**30**	**2.2%**	35	1.6%
OTHER	2012 to 2016	**13**	**4.0%**	3	2.7%
		822		866	
Less: Current Portion of Long-Term Debt of Joint Ventures		**33**		65	
		789		801	

(1) Amounts outstanding represent TransCanada's proportionate share, except for Northern Border, which reflects a 50 per cent interest as a result of the Company fully consolidating TC PipeLines, LP.

(2) Interest rates are the effective interest rates except for those pertaining to long-term debt issued for TQM's regulated operations, in which case the weighted average interest rate is presented as required by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

The long-term debt of joint ventures is non-recourse to TransCanada, except that TransCanada has provided certain pro-rata guarantees related to the capital lease obligations of Bruce Power. The security provided with respect to the debt of each joint venture is limited to the rights and assets of the joint venture and does not extend to the rights and assets of TransCanada, except to the extent of TransCanada's investment. TQM has two series of bonds which mature in 2014 and 2017, respectively. The bonds are secured by the pledge of a bond and promissory note of certain affiliated entities. All security interests with respect to the TQM bonds terminate on redemption or repayment of the series of bonds maturing in 2014.

Subject to meeting certain requirements, the Bruce Power capital lease agreements provide for a series of renewals commencing January 1, 2019. The first renewal is for a period of one year and each of 12 renewals thereafter is for a period of two years.

The Company's proportionate share of principal repayments for the next five years resulting from maturities and sinking fund obligations of the non-recourse joint venture debt is approximately as follows: 2012 – $15 million; 2013 – $8 million; 2014 – $44 million; 2015 – $7 million; and 2016 – $149 million.

The Company's proportionate share of principal payments for the next five years resulting from the capital lease obligations of Bruce Power is approximately as follows: 2012 – $18 million; 2013 – $20 million; 2014 – $22 million; 2015 – $26 million; and 2016 – $31 million.

In April 2010, Iroquois retired US$200 million of Series I bonds bearing interest at 9.16 per cent and issued US$150 million of bonds maturing in April 2020 and bearing interest at 4.96 per cent.

In September 2010, TQM retired $100 million of 7.53 per cent Series I bonds and $75 million of 3.906 per cent Series J bonds. In July 2010, TQM issued $100 million of bonds maturing in September 2017 and bearing interest at 4.25 per cent.

Sensitivity

A one per cent change in interest rates would have the following effect on Net Income assuming all other variables were to remain constant:

(millions of dollars)	Increase	Decrease
Effect on interest expense of variable interest rate debt	1	(1)

Interest Expense of Joint Ventures

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Interest on long-term debt	**34**	39	51
Interest on capital lease obligations	**22**	16	17
Short-term interest and other financial charges	**(1)**	4	(4)
	55	59	64

The Company's proportionate share of the interest payments by joint ventures was $31 million in 2011 (2010 – $42 million; 2009 – $41 million), net of interest capitalized on construction projects.

The Company's proportionate share of interest payments from the capital lease obligations of Bruce Power was $15 million in 2011 (2010 – $16 million; 2009 – $17 million).

NOTE 15 JUNIOR SUBORDINATED NOTES

		2011		2010	
Outstanding loan amount (millions of dollars)	Maturity Date	**Outstanding December 31**	**Effective Interest Rate**	Outstanding December 31	Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. dollars (2011 and 2010 – US$1,000)	2017	**1,009**	**6.5%**	985	6.5%

Junior Subordinated Notes of US$1.0 billion mature in 2067 and bear interest at 6.35 per cent per year until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate plus 221 basis points. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default and without permitting acceleration of payment under the terms of the Junior Subordinated Notes. However, the Company would be prohibited from paying dividends during any such deferral period. The Junior Subordinated Notes are subordinated in right of payment to existing and future senior indebtedness and are effectively subordinated to all indebtedness and other obligations of TCPL. The Junior Subordinated Notes are callable at the Company's option at any time on or after May 15, 2017, at 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption. The Junior Subordinated Notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount of the Junior Subordinated Notes plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with the terms of the Junior Subordinated Notes.

NOTE 16 NON-CONTROLLING INTERESTS

The Company's non-controlling interests included in the Consolidated Balance Sheet were as follows:

December 31 (millions of dollars)	**2011**	2010
Non-controlling interest in TC PipeLines, LP[1]	**997**	686
Preferred shares of subsidiary	**389**	389
Non-controlling interest in Portland[2]	**79**	82
	1,465	1,157

The Company's non-controlling interests included in the Consolidated Income Statement were as follows:

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Non-controlling interest in TC PipeLines, LP[1]	**101**	87	66
Preferred share dividends of subsidiary	**22**	22	22
Non-controlling interest in Portland[2]	**6**	6	8
	129	115	96

(1) Effective May 3, 2011, the non-controlling interest in TC PipeLines, LP increased from 61.8 per cent to 66.7 per cent due to the issuance of equity to non-controlling interests in TC PipeLines, LP associated with the sale of 25 per cent interests in GTN LLC and Bison LLC pipelines from TransCanada to TC PipeLines, LP. The non-controlling interest in TC PipeLines, LP from November 18, 2009 to May 2, 2011 was 61.8 per cent, from July 1, 2009 to November 17, 2009 was 57.4 per cent, and from February 22, 2007 to June 30, 2009 was 67.9 per cent.

(2) The non-controlling interests in Portland as at December 31, 2011 represented the 38.3 per cent interest not owned by TransCanada (2010 and 2009 – 38.3 per cent).

Preferred Shares of Subsidiary

December 31	Number of Shares	Dividend Rate per Share	Redemption Price per Share	**2011**	2010
	(thousands)			(millions of dollars)	(millions of dollars)
Cumulative First Preferred Shares of Subsidiary					
Series U	4,000	$2.80	$50.00	**195**	195
Series Y	4,000	$2.80	$50.00	**194**	194
				389	389

The authorized number of preferred shares of TCPL issuable in each series is unlimited. All of the cumulative first preferred shares of TCPL are without par value.

On or after October 15, 2013, TCPL may redeem the Series U preferred shares at $50 per share, and on or after March 5, 2014, TCPL may redeem the Series Y shares at $50 per share.

Cash Dividends

Cash dividends of $22 million or $2.80 per share were paid on the Series U and Series Y preferred shares in each of 2011, 2010 and 2009.

In 2011, TransCanada received fees of $2 million from TC PipeLines, LP (2010 and 2009 – $2 million) and $7 million from Portland (2010 – $7 million; 2009 – $8 million) for services provided.

NOTE 17 COMMON SHARES

	Number of Shares	Amount
	(thousands)	(millions of dollars)
Outstanding at January 1, 2009	616,471	9,264
Issuance of common shares[1]	58,420	1,792
Dividend reinvestment and share purchase plan	8,220	254
Exercise of options	1,248	28
Outstanding at December 31, 2009	684,359	11,338
Dividend reinvestment and share purchase plan	10,670	378
Exercise of options	1,201	29
Outstanding at December 31, 2010	696,230	11,745
Dividend reinvestment and share purchase plan	**5,371**	**202**
Exercise of options	**2,260**	**64**
Outstanding at December 31, 2011	**703,861**	**12,011**

(1) Net of underwriting commissions and future income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

In June 2009, TransCanada completed a public offering of 58.4 million common shares at a purchase price of $31.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.8 billion.

Net Income per Share

Net income per share is calculated by dividing Net Income Attributable to Common Shares by the weighted average number of common shares. During the year, the weighted average number of common shares of 701.6 million and 702.8 million (2010 – 690.5 million and 691.7 million; 2009 – 651.8 million and 652.8 million) were used to calculate basic and diluted earnings per share, respectively. The increase in the weighted average number of shares for the diluted earnings per share calculation is due to the options exercisable under TransCanada's Stock Option Plan.

Stock Options

	Number of Options	Weighted Average Exercise Prices	Options Exercisable
	(thousands)		(thousands)
Outstanding at January 1, 2009	8,501	$29.10	6,461
Granted	1,191	$31.96	
Exercised	(1,248)	$21.22	
Forfeited	(170)	$35.58	
Outstanding at December 31, 2009	8,274	$30.56	6,212
Granted	1,367	$35.32	
Exercised	(1,201)	$22.04	
Forfeited	(34)	$27.35	
Outstanding at December 31, 2010	8,406	$32.57	6,458
Granted	**970**	**$38.02**	
Exercised	**(2,260)**	**$25.86**	
Forfeited	**(16)**	**$35.83**	
Outstanding at December 31, 2011	**7,100**	**$35.44**	**5,165**

Stock options outstanding were as follows:

December 31, 2011	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(thousands)		(years)	(thousands)		(years)
$21.43 to $31.93	**414**	**$26.32**	**4.3**	**379**	**$25.80**	**4.2**
$31.97 to $33.08	**1,496**	**$32.32**	**3.8**	**1,285**	**$32.38**	**3.7**
$35.08	**1,135**	**$35.08**	**5.2**	**559**	**$35.08**	**5.2**
$35.23	**1,001**	**$35.23**	**1.2**	**1,001**	**$35.23**	**1.2**
$36.26 to $38.10	**2,100**	**$37.86**	**5.2**	**1,011**	**$37.99**	**2.8**
$38.14 to $41.65	**954**	**$39.63**	**3.2**	**930**	**$39.58**	**3.1**
	7,100	**$35.44**	**3.5**	**5,165**	**$35.14**	**2.7**

An additional 4.4 million common shares were reserved for future issuance under TransCanada's Stock Option Plan at December 31, 2011. The weighted average fair value of options granted to purchase common shares under the Company's Stock Option Plan was determined to be $2.94 for the year ended December 31, 2011 (2010 – $5.76; 2009 – $4.78). The Company used the Black-Scholes model for determining the fair value of options granted applying the following weighted average assumptions for 2011: four years of expected life (2010 and 2009 – four years); 2.1 per cent interest rate (2010 – 2.0 per cent; 2009 – 1.7 per cent); 14 per cent volatility (2010 – 27 per cent; 2009 – 29 per cent); and 4.3 per cent dividend yield (2010 – 4.7 per cent; 2009 – 5.2 per cent). Volatility is derived based on the historical volatility of the Company's shares. The amount expensed for stock options, with a corresponding increase in contributed surplus, was $5 million in 2011 (2010 and 2009 – $4 million).

The total intrinsic value of options exercised in 2011 was $34 million (2010 – $17 million; 2009 – $15 million). As at December 31, 2011, the aggregate intrinsic value of the total options exercisable was $48 million and the total intrinsic value of options outstanding was $64 million. In 2011, the 0.9 million (2010 – 1.5 million; 2009 – 1.2 million) shares that vested had a fair value of $42 million (2010 – $57 million; 2009 – $43 million).

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Under certain circumstances, each common share is entitled to one right that entitles certain holders to purchase two common shares of the Company for the price of one.

Cash Dividends

Cash dividends of $961 million, net of the Dividend Reinvestment and Share Purchase Plan (DRP), or $1.66 per common share were paid in 2011 (2010 – $710 million or $1.58 per common share; 2009 – $722 million or $1.50 per common share).

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL may reinvest their dividends and make optional cash payments to obtain TransCanada common shares. The Company reserves the right to satisfy its DRP obligations by issuing common shares from treasury at a discount of up to five per cent or by purchasing shares on the open market. Commencing with the dividends declared in April 2011, common shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market at 100 per cent of the weighted average purchase price. Previously, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. In 2011, TransCanada issued 5.4 million (2010 – 10.7 million; 2009 – 8.2 million) common shares from treasury in accordance with the DRP in lieu of making cash dividend payments of $202 million (2010 – $378 million; 2009 – $254 million).

NOTE 18 PREFERRED SHARES

December 31	Number of Shares Authorized and Outstanding	Dividend Rate per Share	Redemption Price per Share	**2011**	2010
	(thousands)			(millions of dollars)[1]	(millions of dollars)[1]
Cumulative First Preferred Shares					
Series 1	22,000	$1.15	$25.00	**539**	539
Series 3	14,000	$1.00	$25.00	**343**	343
Series 5	14,000	$1.10	$25.00	**342**	342
				1,224	1,224

(1) Net of underwriting commissions and future income taxes.

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, for the initial five-and-a-half-year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter at a price of $25 per share plus all accrued and unpaid dividends.

The Series 5 preferred shareholders have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares. The preferred shares were issued at a price of $25 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, for the initial five-year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter at a price of $25 per share plus all accrued and unpaid dividends.

The Series 3 preferred shareholders have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent.

In September 2009, TransCanada completed a public offering of 22 million Series 1 cumulative redeemable first preferred shares for gross proceeds of $550 million. The holders of the Series 1 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25 per share plus all accrued and unpaid dividends.

The Series 1 preferred shareholders have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

The preferred shareholders are eligible to participate in the Company's DRP.

Cash Dividends

In 2011, the Company made cash dividend payments of $25 million, net of DRP, or $1.15 per Series 1 preferred share (2010 – $24 million or $1.15 per share; 2009 – $6 million or $0.2875 per share), $14 million, net of DRP, or $1.00 per Series 3 preferred share (2010 – $11 million or $0.8041 per share) and $16 million, net of DRP, or $1.10 per Series 5 preferred share (2010 – $9 million or $0.3707 per share).

NOTE 19 ASSET RETIREMENT OBLIGATIONS

The scope and timing of asset retirements related to regulated oil and natural gas pipelines in the U.S. and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities. The Company has not recorded an amount for ARO related to the nuclear assets, as Bruce Power leases the assets and the lessor is responsible for decommissioning liabilities under the lease agreement.

Through its Land Matters Consultation Initiative, the NEB is addressing several significant issues relating to future pipeline abandonment costs for Canadian regulated pipelines. In its May 2009 decision, the NEB established several filing deadlines relating to the financial issues, including deadlines for preparing and filing an estimate of the abandonment costs to be used to begin collecting funds. TransCanada filed its estimates of abandonment costs for its Canadian natural gas and oil pipelines on November 30, 2011, as required by the NEB decision. These estimates are expected to clarify the scope of ARO, however, the timing of retirements for these assets remains indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets.

ARO recognized in the Natural Gas Pipelines segment relates to non-regulated natural gas pipelines and regulated natural gas storage operations. The estimated undiscounted cash flows required to settle the ARO with respect to these operations were $63 million at December 31, 2011 (2010 – $62 million), calculated using an annual inflation rate ranging from 1.2 per cent to 4.0 per cent. The estimated fair value of this liability was $26 million at December 31, 2011 (2010 – $24 million) after discounting the estimated cash flows at rates ranging from 4.3 per cent to 11.0 per cent. At December 31, 2011, the expected timing of payment for settlement of the obligations ranged from 2012 to 2029.

ARO recognized in the Energy segment relates to certain power generation facilities and non-regulated natural gas storage facilities. The estimated undiscounted cash flows required to settle the ARO with respect to the Energy segment were $641 million at December 31, 2011 (2010 – $719 million), calculated using an annual inflation rate ranging from 2.0 per cent to 2.5 per cent. The estimated fair value of this liability was $43 million at December 31, 2011 (2010 – $42 million), after discounting the estimated cash flows at average rates ranging from 5.2 per cent to 6.8 per cent. During 2010, the economic life of certain Energy assets was extended after reviewing market trends and asset conditions. At December 31, 2011, the expected timing of payment for settlement of the obligations ranged from 2018 to 2061.

Reconciliation of Asset Retirement Obligations[1]

(millions of dollars)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2010	24	87	111
New obligations and revisions in estimated cash flows	(1)	(47)	(48)
Accretion expense	1	2	3
Balance at December 31, 2010	24	42	66
New obligations and revisions in estimated cash flows	**–**	**(1)**	**(1)**
Accretion expense	**2**	**2**	**4**
Balance at December 31, 2011	**26**	**43**	**69**

(1) At December 31, 2011, ARO totalling $68 million (2010 – $65 million) and $1 million (2010 – $1 million) were included in Deferred Amounts and Accounts Payable, respectively.

NOTE 20 EMPLOYEE FUTURE BENEFITS

The Company sponsors DB Plans that cover a significant majority of employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plans increase annually by a portion of the increase in the Consumer Price Index. Past service costs are amortized over the expected average remaining service life of employees, which is approximately eight years (2010 – eight years; 2009 – eight years).

The Company also provides its employees with a Savings Plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Past service costs are amortized over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2011. Contributions to the Savings Plan and DC Plans are expensed as incurred. In 2011, the Company expensed $23 million (2010 and 2009 – $21 million) for the Savings Plan and DC Plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company to the DB Plans and other benefit plans, was $93 million in 2011 (2010 – $127 million; 2009 – $168 million), including $23 million in 2011 (2010 and 2009 – $21 million) related to the Savings Plan and DC Plans. In addition to these cash payments, in 2011 the Company provided a $27 million letter of credit to the DB Plan.

The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2012, and the next required valuation will be as at January 1, 2013.

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Change in Benefit Obligation				
Benefit obligation – beginning of year	**1,622**	1,476	**159**	150
Current service cost	**54**	50	**2**	2
Interest cost	**91**	89	**9**	9
Employee contributions	**4**	4	**1**	1
Benefits paid	**(71)**	(73)	**(9)**	(9)
Actuarial loss	**131**	95	**7**	8
Transfers	**–**	(8)	**–**	–
Foreign exchange rate changes	**5**	(11)	**1**	(2)
Benefit obligation – end of year	**1,836**	1,622	**170**	159
Change in Plan Assets				
Plan assets at fair value – beginning of year	**1,636**	1,447	**29**	27
Actual return on plan assets	**21**	177	**–**	3
Employer contributions	**62**	98	**8**	8
Employee contributions	**4**	4	**1**	1
Benefits paid	**(71)**	(73)	**(9)**	(9)
Transfers	**–**	(8)	**–**	–
Foreign exchange rate changes	**4**	(9)	**–**	(1)
Plan assets at fair value – end of year	**1,656**	1,636	**29**	29
Funded status – plan (deficit)/surplus	**(180)**	14	**(141)**	(130)
Unamortized net actuarial loss	**549**	345	**50**	42
Unamortized past service costs	**15**	18	**(3)**	(3)
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**384**	377	**(94)**	(91)

The accrued benefit asset/(liability) net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Intangibles and Other Assets	**399**	380	**–**	–
Deferred Amounts	**(15)**	(3)	**(94)**	(91)
	384	377	**(94)**	(91)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Benefit obligation	**(1,836)**	(417)	**(170)**	(159)
Plan assets at fair value	**1,656**	391	**29**	29
Funded Status – Plan Deficit	**(180)**	(26)	**(141)**	(130)

The Company's expected funding contributions in 2012 are approximately $119 million for the DB Plans and approximately $31 million for the other benefit plans, Savings Plan and DC Plans. In addition to these contributions, the Company expects to provide a $48 million letter of credit in 2012 to the DB Plan.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2012	85	9
2013	90	9
2014	94	10
2015	99	10
2016	104	10
2017 to 2021	591	57

The rate used to discount pension and other post-employment benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2011. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-employment obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31	**2011**	2010	**2011**	2010
Discount rate	**5.05%**	5.55%	**5.10%**	5.65%
Rate of compensation increase	**3.15%**	3.20%		

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan cost were as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.55%**	6.00%	6.65%	**5.60%**	6.00%	6.50%
Expected long-term rate of return on plan assets	**6.95%**	6.95%	6.95%	**6.40%**	7.80%	7.75%
Rate of compensation increase	**3.10%**	3.20%	3.25%			

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

An 8.50 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2019 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-employment benefit obligation	15	(13)

The Company's net benefit cost is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2011**	2010	2009	**2011**	2010	2009
Current service cost	**54**	50	45	**2**	2	2
Interest cost	**91**	89	89	**9**	9	9
Actual return on plan assets	**(21)**	(177)	(206)	**–**	(3)	(5)
Actuarial loss	**131**	95	107	**7**	8	10
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**255**	57	35	**18**	16	16
Difference between expected and actual return on plan assets	**(93)**	68	107	**(2)**	1	3
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(110)**	(86)	(101)	**(5)**	(6)	(8)
Difference between amortization of past service costs and actual plan amendments	**3**	4	4	**–**	–	–
Amortization of transitional obligation related to regulated business	**–**	–	–	**2**	2	2
	55	43	45	**13**	13	13

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

Asset Category

	Percentage of Plan Assets		Target Allocations
December 31	**2011**	2010	**2011**
Debt securities	**39%**	37%	**35% to 60%**
Equity securities	**61%**	63%	**40% to 65%**
	100%	100%	

Debt securities included the Company's debt of $2 million (0.1 per cent of total plan assets) and $4 million (0.2 per cent of total plan assets) at December 31, 2011 and 2010, respectively. Equity securities included the Company's common shares of $3 million (0.2 per cent of total plan assets) and $3 million (0.2 per cent of total plan assets) at December 31, 2011 and 2010, respectively.

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded.

The following table presents plan assets for DB Plans and other post-employment benefits measured at fair value, which have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets. In Level II, determination of the fair value of assets includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets is based on inputs that are not readily observable and are significant to the overall fair value measurement.

Asset Category	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
December 31 (millions of Canadian dollars)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Cash and cash equivalents	**25**	19	**–**	–	**–**	–	**25**	19	**1%**	1%
Equity Securities:										
Canadian	**374**	394	**95**	93	**–**	–	**469**	487	**28%**	29%
U.S.	**251**	225	**55**	117	**–**	–	**306**	342	**18%**	21%
International	**25**	31	**231**	199	**–**	–	**256**	230	**15%**	14%
Fixed Income Securities:										
Canadian Bonds:										
Federal	**–**	–	**303**	302	**–**	–	**303**	302	**18%**	18%
Provincial	**–**	–	**158**	127	**–**	–	**158**	127	**9%**	8%
Municipal	**–**	–	**4**	4	**–**	–	**4**	4	**–**	–
Corporate	**–**	–	**47**	64	**–**	–	**47**	64	**3%**	4%
U.S. Bonds:										
State	**–**	–	**29**	28	**–**	–	**29**	28	**2%**	2%
Corporate	**–**	–	**29**	19	**–**	–	**29**	19	**2%**	1%
International:										
Corporate	**–**	–	**9**	–	**–**	–	**9**	–	**1%**	–
Mortgage Backed	**–**	–	**30**	22	**–**	–	**30**	22	**2%**	1%
Other Investments:										
Private Equity Funds	**–**	–	**–**	–	**20**	21	**20**	21	**1%**	1%
	675	669	**990**	975	**20**	21	**1,685**	1,665	**100%**	100%

The following table presents the net change in the Level III fair value category:

(millions of dollars, pre-tax)	Private Equity Funds
Balance at December 31, 2009	25
Realized and unrealized losses	(6)
Purchases and sales	2
Balance at December 31, 2010	21
Realized and unrealized losses	**(2)**
Purchases and sales	**1**
Balance at December 31, 2011	**20**

Employee Future Benefits of Joint Ventures

Certain of the Company's joint ventures sponsor DB Plans as well as post-employment benefits other than pensions, including defined life insurance and medical benefits beyond those provided by government-sponsored plans. The obligations of these plans are non-recourse to TransCanada. The following amounts in this note, including those in the accompanying tables, represent TransCanada's proportionate share with respect to these plans.

Total cash payments for employee future benefits, consisting of cash contributed by the Company's joint ventures to DB Plans and other benefit plans was $59 million in 2011 (2010 – $58 million; 2009 – $54 million).

The Company's joint ventures measure the benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuations of the pension plans for funding purposes were as at January 1, 2012, and the next required valuations will be as at January 1, 2013.

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Change in Benefit Obligation				
Benefit obligation – beginning of year	**864**	695	**208**	170
Current service cost	**27**	19	**11**	8
Interest cost	**46**	42	**11**	10
Employee contributions	**8**	7	**–**	–
Benefits paid	**(33)**	(31)	**(4)**	(5)
Actuarial loss	**73**	132	**25**	25
Benefit obligation – end of year	**985**	864	**251**	208
Change in Plan Assets				
Plan assets at fair value – beginning of year	**727**	641	**–**	–
Actual return on plan assets	**13**	57	**–**	–
Employer contributions	**53**	53	**6**	5
Employee contributions	**8**	7	**–**	–
Benefits paid	**(33)**	(31)	**(4)**	(5)
Plan assets at fair value – end of year	**768**	727	**2**	–
Funded status – plan deficit	**(217)**	(137)	**(249)**	(208)
Unamortized net actuarial loss	**317**	230	**71**	49
Unamortized past service costs	**–**	–	**2**	2
Accrued Benefit Asset/(Liability), Net of Valuation Allowance of Nil	**100**	93	**(176)**	(157)

The accrued benefit asset/(liability), net of valuation allowance of nil in the Company's Balance Sheet was as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Intangibles and Other Assets	**100**	93	**–**	–
Deferred Amounts	**–**	–	**(176)**	(157)
	100	93	**(176)**	(157)

The following amounts were included in the above benefit obligation and fair value of plan assets for plans that are not fully funded:

	Pension Benefit Plans		Other Benefit Plans	
December 31 (millions of dollars)	**2011**	2010	**2011**	2010
Benefit obligation	**(979)**	(864)	**(251)**	(208)
Plan assets at fair value	**761**	727	**2**	–
Funded Status – Plan Deficit	**(218)**	(137)	**(249)**	(208)

The expected total funding contributions of the Company's joint ventures in 2012 are approximately $73 million for the pension benefit plans and approximately $7 million for the other benefit plans.

The following are estimated future benefit payments, which reflect expected future service:

(millions of dollars)	Pension Benefits	Other Benefits
2012	37	7
2013	38	8
2014	40	8
2015	42	9
2016	44	10
2017 to 2021	310	60

The significant weighted average actuarial assumptions adopted in measuring the benefit obligations of the Company's joint ventures were as follows:

	Pension Benefit Plans		Other Benefit Plans	
December 31	**2011**	2010	**2011**	2010
Discount rate	**4.75%**	5.25%	**4.60%**	5.10%
Rate of compensation increase	**3.50%**	3.50%		

The significant weighted average actuarial assumptions adopted in measuring the net benefit plan costs of the Company's joint ventures were as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.25%**	6.00%	6.75%	**5.10%**	5.80%	6.40%
Expected long-term rate of return on plan assets	**7.00%**	7.00%	7.00%			
Rate of compensation increase	**3.50%**	3.50%	3.50%			

An 8.50 per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2019 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of dollars)	Increase	Decrease
Effect on total of service and interest cost components	4	(3)
Effect on post-employment benefit obligation	35	(28)

The Company's proportionate share of net benefit cost of joint ventures is as follows:

	Pension Benefit Plans			Other Benefit Plans		
Year ended December 31 (millions of dollars)	**2011**	2010	2009	**2011**	2010	2009
Current service cost	**27**	19	16	**11**	8	5
Interest cost	**46**	42	40	**11**	10	9
Actual return on plan assets	**(13)**	(57)	(63)	**–**	–	–
Actuarial loss/(gain)	**73**	132	68	**25**	25	27
Elements of net benefit cost prior to adjustments to recognize the long-term nature of net benefit cost	**133**	136	61	**47**	43	41
Difference between expected and actual return on plan assets	**(38)**	12	25	**–**	–	–
Difference between actuarial loss/(gain) recognized and actual actuarial loss/(gain) on accrued benefit obligation	**(62)**	(128)	(67)	**(22)**	(24)	(28)
	33	20	19	**25**	19	13

The weighted average asset allocations and target allocations by asset category in the pension plans of the Company's joint ventures were as follows:

December 31	Percentage of Plan Assets		Target Allocations
Asset Category	**2011**	2010	**2011**
Debt securities	**45%**	41%	**40%**
Equity securities	**55%**	59%	**60%**
	100%	100%	

Debt securities included the Company's debt of $1 million (0.2 per cent of total plan assets) and $1 million (0.2 per cent of total plan assets) at December 31, 2011 and 2010, respectively. Equity securities included the Company's common shares of $4 million (0.6 per cent of total plan assets) and $4 million (0.5 per cent of total plan assets) at December 31, 2011 and 2010, respectively.

The assets of the joint ventures' pension plans are managed on a going concern basis subject to legislative restrictions. The plans' investment policies are to maximize returns within an acceptable risk tolerance. Pension assets are invested in a diversified manner with consideration given to the demographics of the plans' participants.

NOTE 21 RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Risks are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by risk management and internal audit personnel. The Board of Directors' Audit Committee oversees how management monitors compliance with financial risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of risk management controls and procedures, the results of which are reported to the Audit Committee.

Market Risk

The Company constructs and invests in large infrastructure projects, purchases and sells energy commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. These activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to manage the exposure to market risk that results from these activities. Derivative contracts used to manage market risk generally consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to mitigate the impact of volatility in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements to convey the right, but not the obligation, of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to mitigate the impact of changes in interest rates, foreign exchange rates and commodity prices.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

Commodity Price Risk
The Company is exposed to commodity price movements as part of its normal business operations, particularly in relation to the prices of electricity and natural gas. A number of strategies are used to mitigate these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to mitigate operational and price risks in its asset portfolio.
- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or purchased through contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative financial instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

The Company assesses its commodity contracts and derivative instruments used to manage commodity risk to determine the appropriate accounting treatment. Contracts, with the exception of leases, have been assessed to determine whether they or certain aspects of them meet the definition of a derivative. Certain commodity purchase and sale contracts are derivatives but fair value accounting is not required, as they were entered into and continue to be held for the purpose of receipt or delivery in accordance with the Company's expected purchase, sale or usage requirements and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk
TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Fair value adjustments recorded each period on proprietary natural gas inventory in storage and on these forward contracts are not representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk
Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TransCanada's earnings from its Natural Gas Pipelines, Oil Pipelines and Energy segments is generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's net income. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada has a greater exposure to U.S. currency fluctuations than in prior years due to growth in its U.S. operations, partially offset by increased levels of U.S. dollar-denominated interest expense.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to its debt and other U.S. dollar-denominated transactions, and to manage the foreign exchange rate exposures of the Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers in accordance with the terms of the shipping agreements.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net Investment in Self-Sustaining Foreign Operations
The Company hedges its net investment in self-sustaining foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, forward foreign exchange contracts and foreign exchange options. At December 31, 2011, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $10 billion (US$9.8 billion) (2010 – $9.8 billion (US$9.8 billion)) and a fair value of $12.7 billion (US$12.5 billion) (2010 – $11.3 billion (US$11.4 billion)). At December 31, 2011, $79 million (December 31, 2010 – nil) was included in Other Current Assets, $66 million (December 31, 2010 – $181 million) was included in Intangibles and Other Assets, $15 million (December 31, 2010 – nil) was included in Accounts Payable, and $41 million (December 31, 2010 – nil) was included in Deferred Amounts for the fair value of the forwards and swaps used to hedge the Company's net U.S. dollar investment in foreign operations.

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

Asset/(Liability)	2011		2010	
December 31 (millions of dollars)	**Fair Value(1)**	**Notional or Principal Amount**	Fair Value(1)	Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2012 to 2018)	**93**	**US 3,850**	179	US 2,800
U.S. dollar forward foreign exchange contracts (maturing 2012)	**(4)**	**US 725**	2	US 100
	89	**US 4,575**	181	US 2,900

(1) Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open positions will not exceed the reported VaR. The VaR methodology is a statistically calculated, probability-based approach that takes into consideration market volatilities as well as risk diversification by recognizing offsetting positions and correlations among products and markets. Risks are measured across all products and markets, and risk measures are aggregated to arrive at a single VaR number.

There is currently no uniform industry methodology for estimating VaR. The use of VaR has limitations because it is based on historical correlations and volatilities in commodity prices, interest rates and foreign exchange rates, and assumes that future price movements will follow a statistical distribution. Although losses are not expected to exceed the statistically estimated VaR on 95 per cent of occasions, losses on the other five per cent of occasions could be substantially greater than the estimated VaR.

TransCanada's estimation of VaR includes wholly owned subsidiaries and incorporates relevant risks associated with each market or business unit. The calculation does not include the regulated natural gas pipelines, as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada's Board of Directors has established a VaR limit, which is monitored on an ongoing basis as part of the Company's risk management policy. TransCanada's consolidated VaR was $12 million at December 31, 2011 (2010 – $12 million).

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the financial instruments with the Company.

Counterparty credit risk is managed through established credit management techniques, including conducting financial and other assessments to establish and monitor a counterparty's creditworthiness, setting exposure limits, monitoring exposures against these limits, using contract netting arrangements and obtaining financial assurances where warranted. In general, financial assurances include guarantees, letters of credit and cash. The Company monitors and manages its concentration of counterparty credit risk on an ongoing basis. The Company believes these measures minimize its counterparty credit risk but there is no certainty that they will protect it against all material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, portfolio investments recorded at fair value, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts receivable and other, and Available for sale assets in the Non-Derivative Financial Instruments Summary table located in the Fair Values section of this note. The majority of counterparty credit exposure is with counterparties that are investment grade or the exposure is supported by financial assurances provided by investment grade parties. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2011, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

At December 31, 2011, the Company had a credit risk concentration of $274 million (2010 – $317 million) due from a counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

TransCanada has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, critical liquidity in the foreign exchange derivative, interest rate derivative and energy wholesale markets, and letters of credit to mitigate TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

In August 2011, the Company received final distributions of 2.1 million common shares as a result of previous claims in the 2005 Calpine Corporation bankruptcy. These shares were sold into the open market resulting in total pre-tax gains of $30 million, of which the Company had accrued pre-tax gains of $15 million in 2010. In 2008, the Company had received 15.5 million common shares which were sold into the open market for $279 million. Claims by NGTL and Foothills PipeLines (South B.C.) Ltd. for $32 million and $44 million, respectively, were received in cash in 2008 and 2009 and were passed onto the shippers on these systems in 2008 and 2009.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

Management continuously forecasts cash flows for a period of 12 months to identify financing requirements. These requirements are then managed through a combination of committed and demand credit facilities and access to capital markets, as discussed in the Capital Management section of this note.

At December 31, 2011, the Company had unutilized committed revolving bank lines of US$1.0 billion, US$1.0 billion, US$300 million and $2.0 billion maturing in October 2012, November 2012, February 2013 and October 2016, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms and recently initiated a commercial paper program in the U.S.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2011, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. The Company's management considers its capital structure to consist of net debt, Non-Controlling Interests and Equity. Net debt comprises Notes Payable, Long-Term Debt and Junior Subordinated Notes less Cash and Cash Equivalents. Net debt only includes obligations that the Company controls and manages. Consequently, it does not include Cash and Cash Equivalents, Notes Payable and Long-Term Debt of TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 (millions of dollars)	**2011**	2010
Notes payable	**1,863**	2,081
Long-term debt	**18,567**	17,922
Junior subordinated notes	**1,009**	985
Cash and cash equivalents	**(654)**	(660)
Net Debt	**20,785**	20,328
Equity attributable to non-controlling interests	**1,465**	1,157
Equity attributable to controlling interests	**17,324**	16,727
Total Equity	**18,789**	17,884
	39,574	38,212

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, Notes Payable, Accounts Payable, Accrued Interest and Deferred Amounts have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. The fair value of foreign exchange and interest rate derivatives has been calculated using year-end market rates and applying a discounted cash flow valuation model. The fair value of power and natural gas derivatives, and of available for sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2011		2010	
December 31 (millions of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**765**	**765**	764	764
Accounts receivable and other[2][3]	**1,576**	**1,620**	1,555	1,595
Available for sale assets[2]	**23**	**23**	20	20
	2,364	**2,408**	2,339	2,379
Financial Liabilities[1][3]				
Notes payable	**1,880**	**1,880**	2,092	2,092
Accounts payable and deferred amounts[4]	**1,536**	**1,536**	1,436	1,436
Accrued interest	**373**	**373**	367	367
Long-term debt	**18,567**	**23,757**	17,922	21,523
Junior subordinated notes	**1,009**	**1,027**	985	992
Long-term debt of joint ventures	**822**	**940**	866	971
	24,187	**29,513**	23,668	27,381

(1) Consolidated Net Income in 2011 included losses of $13 million (2010 – losses of $8 million) for fair value adjustments related to interest rate swap agreements on US$350 million (2010 – US$250 million) of Long-Term Debt. There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

(2) At December 31, 2011, the Consolidated Balance Sheet included financial assets of $1,265 million (2010 – $1,271 million) in Accounts Receivable, $41 million (2010 – $40 million) in Other Current Assets and $293 million (2010 – $264 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost, except for $350 million (2010 – $250 million) of Long-Term Debt that is adjusted to fair value.

(4) At December 31, 2011, the Consolidated Balance Sheet included financial liabilities of $1,494 million (2010 – $1,406 million) in Accounts Payable and $42 million (2010 – $30 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2011:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Notes payable	1,880	1,880	–	–	–
Long-term debt	18,567	935	1,874	2,311	13,447
Junior subordinated notes	1,009	–	–	–	1,009
Long-term debt of joint ventures	822	33	94	213	482
	22,278	2,848	1,968	2,524	14,938

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary in this note.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Long-term debt	16,541	1,180	2,227	1,989	11,145
Junior subordinated notes	355	65	129	129	32
Long-term debt of joint ventures	343	48	89	77	129
	17,239	1,293	2,445	2,195	11,306

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2011, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2011			
December 31 (all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	**$213**	**$176**	**$3**	**$22**
Liabilities	**$(212)**	**$(212)**	**$(14)**	**$(22)**
Notional Values				
Volumes[3]				
Purchases	**23,500**	**103**	**–**	**–**
Sales	**23,158**	**82**	**–**	**–**
Canadian dollars	**–**	**–**	**–**	**684**
U.S. dollars	**–**	**–**	**US 1,269**	**US 250**
Cross-currency	**–**	**–**	**47/US 37**	**–**
Net unrealized (losses)/gains in the year[4]	**$(3)**	**$(50)**	**$(4)**	**$1**
Net realized gains/(losses) in the year[4]	**$58**	**$(74)**	**$10**	**$10**
Maturity dates	**2012-2018**	**2012-2016**	**2012**	**2012-2016**
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	**$42**	**$3**	**$–**	**$13**
Liabilities	**$(277)**	**$(22)**	**$(38)**	**$(1)**
Notional Values				
Volumes[3]				
Purchases	**17,188**	**8**	**–**	**–**
Sales	**9,217**	**–**	**–**	**–**
U.S. dollars	**–**	**–**	**US 91**	**US 600**
Cross-currency	**–**	**–**	**136/US 100**	**–**
Net realized losses in the year[4]	**$(150)**	**$(17)**	**$–**	**$(16)**
Maturity dates	**2012-2017**	**2012-2013**	**2012-2014**	**2012-2015**

(1) All derivative financial instruments in the held for trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on held for trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $13 million and a notional amount of US$350 million. In 2011, net realized gains on fair value hedges were $7 million and were included in Interest Expense. In 2011, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2011, Net Income included losses of $3 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2011, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

The anticipated timing of settlement of the derivative contracts assumes constant commodity prices, interest rates and foreign exchange rates from December 31, 2011. Settlements will vary based on the actual value of these factors at the date of settlement. The anticipated timing of settlement of these contracts is as follows:

(millions of dollars)	Total	2012	2013 and 2014	2015 and 2016	2017 and Thereafter
Derivative financial instruments held for trading					
Assets	414	282	123	9	–
Liabilities	(460)	(292)	(151)	(17)	–
Derivative financial instruments in hedging relationships					
Assets	217	121	91	5	–
Liabilities	(408)	(208)	(135)	(50)	(15)
	(237)	(97)	(72)	(53)	(15)

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010, excluding hedges of the Company's net investment in self-sustaining foreign operations, is as follows:

	2010			
December 31 *(all amounts in millions unless otherwise indicated)*	Power	Natural Gas	Foreign Exchange	Interest
Derivative Financial Instruments Held for Trading[1]				
Fair Values[2]				
Assets	$169	$144	$8	$20
Liabilities	$(129)	$(173)	$(14)	$(21)
Notional Values				
Volumes[3]				
Purchases	15,610	158	–	–
Sales	18,114	96	–	–
Canadian dollars	–	–	–	736
U.S. dollars	–	–	US 1,479	US 250
Cross-currency	–	–	47/US 37	–
Net unrealized (losses)/gains in the year[4]	$(32)	$27	$4	$43
Net realized gains/(losses) in the year[4]	$77	$(42)	$36	$(74)
Maturity dates	2011-2015	2011-2015	2011-2012	2011-2016
Derivative Financial Instruments in Hedging Relationships[5][6]				
Fair Values[2]				
Assets	$112	$5	$ –	$8
Liabilities	$(186)	$(19)	$(51)	$(26)
Notional Values				
Volumes[3]				
Purchases	16,071	17	–	–
Sales	10,498	–	–	–
U.S. dollars	–	–	US 120	US 1,125
Cross-currency	–	–	136/US 100	–
Net realized losses in the year[4]	$(9)	$(35)	$–	$(33)
Maturity dates	2011-2015	2011-2013	2011-2014	2011-2015

(1) All derivative financial instruments in the held-for-trading classification have been entered into for risk management purposes and are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

(2) Fair values equal carrying values.

(3) Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) All hedging relationships are designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $8 million and a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6) In 2010, Net Income included a gain of $1 million for changes in the fair value of power and natural gas cash flow hedges that were ineffective in offsetting the change in fair value of their related underlying positions. In 2010, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur. No amounts have been excluded from the assessment of hedge effectiveness.

Balance Sheet Presentation of Derivative Financial Instruments

The fair value of the derivative financial instruments in the Company's Balance Sheet was as follows:

December 31 (millions of dollars)	**2011**	2010
Current		
Other current assets	**404**	273
Accounts payable	**(502)**	(337)
Long Term		
Intangibles and other assets (Note 9)	**213**	374
Deferred amounts (Note 11)	**(352)**	(282)

Derivative Financial Instruments of Joint Ventures

Included in the Derivative Financial Instruments Summary tables are amounts related to power derivatives used by one of the Company's joint ventures to manage commodity price risk. The Company's proportionate share of the fair value of these power derivatives was $35 million at December 31, 2011 (2010 – $48 million). These contracts mature from 2012 to 2018. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 2,979 gigawatt hours (GWh) at December 31, 2011 (2010 – 3,772 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 1,595 GWh at December 31, 2011 (2010 – 2,322 GWh).

Derivatives in Cash Flow Hedging Relationships

Information about how derivatives and hedging activities affect the Company's financial position, financial performance and cash flows is as follows:

	Cash Flow Hedges							
Year ended December 31	Power		Natural Gas		Foreign Exchange		Interest	
(millions of Canadian dollars, pre-tax)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Change in fair value of derivative instruments recognized in OCI (effective portion)	**(252)**	(79)	**(59)**	(26)	**5**	10	**(1)**	(137)
Reclassification of gains and losses on derivative instruments from AOCI to Net Income (effective portion)	**61**	(7)	**100**	(21)	**–**	–	**43**	32

Credit Risk Related Contingent Features

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. Based on contracts in place and market prices at December 31, 2011, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $110 million (2010 – $92 million), for which the Company has provided collateral of $28 million (2010 – $4 million) in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2011, the Company would have been required to provide additional collateral of $82 million (2010 – $88 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative financial instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant inputs are observable, directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets are included in this category. Long-dated commodity prices are derived with a third-party modelling tool that uses market fundamentals to derive long-term prices.

There were no transfers between Level I and Level II in 2011 or 2010. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 (millions of dollars, pre-tax)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Natural Gas Inventory	**–**	–	**29**	49	**–**	–	**29**	49
Derivative Financial Instrument Assets:								
Interest rate contracts	**–**	–	**35**	28	**–**	–	**35**	28
Foreign exchange contracts	**11**	10	**131**	179	**–**	–	**142**	189
Power commodity contracts	**–**	–	**244**	269	**2**	5	**246**	274
Gas commodity contracts	**124**	93	**55**	56	**–**	–	**179**	149
Derivative Financial Instrument Liabilities:								
Interest rate contracts	**–**	–	**(23)**	(47)	**–**	–	**(23)**	(47)
Foreign exchange contracts	**(13)**	(11)	**(89)**	(54)	**–**	–	**(102)**	(65)
Power commodity contracts	**–**	–	**(465)**	(299)	**(15)**	(8)	**(480)**	(307)
Gas commodity contracts	**(208)**	(178)	**(26)**	(15)	**–**	–	**(234)**	(193)
Non-Derivative Financial Instruments:								
Available-for-sale assets	**23**	20	**–**	–	**–**	–	**23**	20
	(63)	(66)	**(109)**	166	**(13)**	(3)	**(185)**	97

The following table presents the net change in the Level III fair value category:

(millions of dollars, pre-tax)	Derivatives[1]
Balance at December 31, 2009	(2)
New contracts[2]	(16)
Settlements	(3)
Transfers into Level III[3]	3
Transfers out of Level III[3][4]	(38)
Change in unrealized gains recorded in Net Income	14
Change in fair value of derivative instruments recorded in OCI	39
Balance at December 31, 2010	(3)
New contracts[2]	**1**
Settlements	**1**
Transfers out of Level III[3][4]	**(1)**
Change in unrealized gains recorded in Net Income	**1**
Change in fair value of derivative instruments recorded in OCI	**(12)**
Balance at December 31, 2011	**(13)**

(1) The fair value of derivative assets and liabilities is presented on a net basis.

(2) At December 31, 2011, the total amount of net gains included in Net Income attributable to derivatives that were entered into during the year and still held at the reporting date was nil (2010 – $1 million).

(3) Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which inputs are considered to be observable.

(4) As contracts near maturity, they are transferred out of Level III and into Level II.

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $10 million decrease or increase, respectively, in the fair value of outstanding derivative financial instruments included in Level III as at December 31, 2011.

NOTE 22 CHANGES IN OPERATING WORKING CAPITAL

Year ended December 31 (millions of dollars)	**2011**	2010	2009
(Increase)/decrease in accounts receivable	**(6)**	(305)	314
Decrease/(increase) in inventories	**27**	70	(19)
Increase in other current assets	**(20)**	(89)	(249)
Increase/(decrease) in accounts payable	**300**	84	(154)
Increase/(decrease) in accrued interest	**9**	(9)	18
Decrease/(Increase) in Operating Working Capital	**310**	(249)	(90)

NOTE 23 ACQUISITIONS AND DISPOSITIONS

Natural Gas Pipelines

TC PipeLines, LP
On May 3, 2011, TransCanada completed the sale of a 25 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$605 million which included US$81 million of long-term debt, or 25 per cent of GTN LLC's outstanding debt. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

On May 3, 2011, TC PipeLines, LP completed an underwritten public offering of 7,245,000 common units, including 945,000 common units purchased by the underwriters upon full exercise of an over-allotment option, at US$47.58 per unit. Net proceeds of approximately US$331 million from this offering were used to partially fund the acquisition. The acquisition was also funded by draws of US$61 million on TC PipeLines, LP's bridge loan facility and US$125 million on its US$250 million senior revolving credit facility.

As part of this offering, TransCanada made a capital contribution of approximately US$7 million to maintain its two per cent general partnership interest in TC PipeLines, LP and did not purchase any other units. As a result of the common units offering, TransCanada's ownership in TC PipeLines, LP decreased from 38.2 per cent to 33.3 per cent and an after-tax dilution gain of $30 million ($50 million pre-tax) was recorded in Contributed Surplus.

In November 2009, TC PipeLines, LP completed an offering of five million common units at a price of US$38.00 per unit, resulting in net proceeds to TC PipeLines, LP of US$182 million. TransCanada contributed an additional US$3.8 million to maintain its general partnership interest but did not purchase any other units. Upon completion of this offering, the Company's ownership interest in TC PipeLines, LP decreased to 38.2 per cent and the Company recognized an after-tax dilution gain of $18 million ($29 million pre-tax) in income.

In July 2009, TransCanada sold North Baja to TC PipeLines, LP. As part of the transaction, the Company agreed to amend its general partner incentive distribution rights arrangement with TC PipeLines, LP. TransCanada received aggregate consideration totalling approximately US$395 million from TC PipeLines, LP, including US$200 million in cash and 6,371,680 common units of TC PipeLines, LP. As a result of this transaction, TransCanada recorded no gain or loss and its ownership in TC PipeLines, LP increased to 42.6 per cent. The Company's increased ownership in TC PipeLines, LP also resulted in a decrease in Non-Controlling Interests and an increase in Contributed Surplus.

Oil Pipelines

Keystone

In August 2009, TransCanada purchased the remaining ownership interest in Keystone of approximately 20 per cent for US$553 million plus the assumption of US$197 million of short-term debt. The acquisition increased the Company's ownership interest in Keystone to 100 per cent and was recorded in Plant, Property and Equipment. TransCanada began fully consolidating Keystone upon this acquisition.

In 2009, prior to August, TransCanada funded $1.3 billion of cash calls for Keystone, resulting in the Company acquiring an increase in ownership from 62 per cent to 80 per cent for $313 million. The Company proportionately consolidated the Keystone partnerships prior to August 2009.

NOTE 24 COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments, net of sub-lease receipts, under the Company's operating leases for various premises, services and equipment are approximately as follows:

Year ended December 31 (millions of dollars)	Minimum Lease Payments	Amounts Recoverable under Sub-leases	Net Payments
2012	87	(8)	79
2013	85	(7)	78
2014	81	(7)	74
2015	76	(5)	71
2016	75	(3)	72
2017 and thereafter	363	(2)	361
	767	(32)	735

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 10 years. Net rental expense on operating leases in 2011 was $79 million (2010 – $80 million; 2009 – $64 million).

TransCanada's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Future payments under these PPAs have been excluded from operating leases in the above table, as these payments are dependent upon plant availability and other factors. TransCanada's share of payments under the PPAs in 2011 was $394 million (2010 – $363 million; 2009 – $384 million). The generating capacities and expiry dates of the PPAs are as follows:

	Megawatts	Expiry Date
Sundance A	560	December 31, 2017
Sundance B	353	December 31, 2020
Sheerness	756	December 31, 2020

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments
At December 31, 2011, TransCanada was committed to Natural Gas Pipelines capital expenditures totalling approximately $250 million, primarily related to construction costs of the Alberta System and Guadalajara.

At December 31, 2011, the Company was committed to Oil Pipelines capital expenditures totalling approximately $992 million, primarily related to construction costs of Keystone XL.

At December 31, 2011, the Company was committed to Energy capital expenditures totalling approximately $290 million and includes TransCanada's share of capital costs of Bruce Power and Cartier Wind.

On December 15, 2011, TransCanada agreed to purchase nine Ontario solar projects from Canadian Solar Solutions Inc., with a combined capacity of 86 MW, for approximately $470 million. Under the terms of the agreement, each of the nine solar projects will be developed and constructed by Canadian Solar Solutions Inc. using photovoltaic panels. TransCanada will purchase each project once construction and acceptance testing have been completed and operations have begun under 20-year PPAs with the Ontario Power Authority (OPA) under the Feed-in Tariff program in Ontario. TransCanada anticipates the projects will be placed in service between late 2012 and mid-2013, subject to regulatory approvals.

Contingencies
TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2011, the Company had accrued approximately $49 million (2010 – $59 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Sundance A PPA
In December 2010, Sundance A Units 1 and 2 were withdrawn from service and were subject to a force majeure claim by the PPA owner in January 2011. In February 2011, the owner notified TransCanada that it had determined it was uneconomic to replace or repair Units 1 and 2, and that the Sundance A PPA should therefore be terminated.

TransCanada has disputed both the force majeure and the economic destruction claims under the binding dispute resolution process provided in the PPA and both matters will be heard through a single binding arbitration process. The arbitration panel has scheduled a hearing in April 2012 for these claims. Assuming the hearing concludes within the time allotted, TransCanada expects to receive a decision in mid-2012.

TransCanada has continued to record revenues and costs throughout 2011 as it considers this event to be an interruption of supply in accordance with the terms of the PPA. The Company does not believe the owner's claims meet the tests of force majeure or destruction as specified in the PPA and has therefore recorded $156 million of pre-tax income for the year ended December 31, 2011. The outcome of any arbitration process is not certain, however, TransCanada believes the matter will be resolved in its favour.

Guarantees
TransCanada and its joint venture partners on Bruce Power, Cameco Corporation and BPC Generation Infrastructure Trust (BPC), have severally guaranteed one-third of certain contingent financial obligations of Bruce B related to power sales agreements, a lease agreement and contractor services. The guarantees have terms ranging from 2018 to perpetuity. In addition, TransCanada and BPC have each severally guaranteed one-half of certain contingent financial obligations related to an agreement with the OPA to refurbish and restart Bruce A power generation units. The guarantees have terms ending in 2018 and 2019. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $863 million at December 31, 2011. The fair value of these Bruce Power guarantees at December 31, 2011 is estimated to be $29 million. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. TransCanada's share of the potential exposure under these assurances was estimated at December 31, 2011 to range from $182 million to a maximum of $498 million. The fair value of these guarantees at December 31, 2011 is estimated to be $7 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

NOTE 25 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

As previously discussed in Note 3, TransCanada will be adopting U.S. GAAP effective January 1, 2012. The consolidated financial statements have been prepared in accordance with CGAAP which in some respects, differ from U.S. GAAP. The effects of significant differences between CGAAP and U.S. GAAP are described in this note.

Reconciliation of Net Income and Comprehensive Income to U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net Income – CGAAP	**1,711**	1,387	1,476
U.S. GAAP adjustments:			
Unrealized loss/(gain) on natural gas inventory held in storage[(1)]	**4**	15	(3)
Tax impact of unrealized loss/(gain) on natural gas inventory held in storage	**(1)**	(5)	1
Dilution gain[(2)]	**–**	–	(29)
Tax impact of dilution gain	**–**	–	11
Tax recovery due to a change in tax legislation substantively enacted in Canada[(4)]	**(4)**	(4)	–
Net Income – U.S. GAAP	**1,710**	1,393	1,456
Less: Net Income Attributable to Non-Controlling Interests	**(129)**	(115)	(96)
Net Income Attributable to Controlling Interests – U.S. GAAP	**1,581**	1,278	1,360
Less: Preferred Share Dividends	**(55)**	(45)	(6)
Net Income Attributable to Common Shareholders – U.S. GAAP	**1,526**	1,233	1,354
Other Comprehensive Loss – CGAAP	**(36)**	(239)	(153)
U.S. GAAP adjustments:			
Change in funded status of post-retirement plan liability[(3)]	**(106)**	(11)	7
Tax impact of change in funded status of post-retirement plan liability	**27**	4	(2)
Change in funded status of post-retirement plan liability of equity investment	**(80)**	(119)	(48)
Other Comprehensive Loss – U.S. GAAP	**(195)**	(365)	(196)
Less: Other Comprehensive Income Attributable to Non-Controlling Interests	**(11)**	(6)	(7)
Other Comprehensive Loss Attributable to Controlling Interests – U.S. GAAP	**(206)**	(371)	(203)
Comprehensive Income Attributable to Common Shares – U.S. GAAP	**1,320**	862	1,151

Information Prepared in Accordance with U.S. GAAP

The differences between CGAAP and the following information prepared in accordance with U.S. GAAP relates principally to the accounting for joint venture investments. Under CGAAP, the Company accounts for joint venture investments using the proportionate consolidation basis of accounting whereby the Company's proportionate share of assets, liabilities, revenues, expenses and cash flows are included in the Company's financial statements. U.S. GAAP requires that these joint venture investments be recorded on an equity basis of accounting. Information on the balances that have been proportionately consolidated under CGAAP is included in Note 8 to these financial statements. The effects of any additional differences between CGAAP and U.S. GAAP are described in the footnotes below.

Condensed Consolidated Statement of Income – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Revenues[1]	**7,694**	6,634	6,778
Income from Equity Investments	**415**	453	478
Operating and Other Expenses			
Plant operating costs and other[2]	**2,768**	2,434	2,621
Commodity purchases resold	**846**	960	772
Depreciation and amortization	**1,328**	1,160	1,201
Valuation provision for MGP	**–**	146	–
	4,942	4,700	4,594
Financial Charges/(Income)			
Interest expense	**937**	701	954
Interest income and other	**(55)**	(94)	(118)
	882	607	836
Income before Income Taxes	**2,285**	1,780	1,826
Income Taxes Expenses/(Recovery)			
Current[2][4]	**210**	(139)	13
Deferred[1]	**365**	526	357
	575	387	370
Net Income – U.S. GAAP	**1,710**	1,393	1,456
Net Income Attributable to Non-Controlling Interests	**129**	115	96
Net Income Attributable to Controlling Interests – U.S. GAAP	**1,581**	1,278	1,360
Preferred Share Dividends	**55**	45	6
Net Income Attributable to Common Shares – U.S. GAAP	**1,526**	1,233	1,354
Net Income per Common Share – U.S. GAAP			
Basic	**$2.17**	$1.79	$2.08
Diluted	**$2.17**	$1.78	$2.08

Consolidated Statement of Comprehensive Income – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net Income – U.S. GAAP	**1,710**	1,393	1,456
Other Comprehensive Income/(Loss), Net of Income Taxes			
Change in foreign currency translation gains and losses on investments in foreign operations[8]	**113**	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[9]	**(73)**	89	258
Change in fair value of derivative instruments designated as cash flow hedges[10]	**(212)**	(169)	(29)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[11]	**147**	53	71
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[3][12]	**(89)**	(12)	(1)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[3][13]	**10**	5	6
Other Comprehensive Loss on equity investments[14]	**(91)**	(151)	(30)
Other Comprehensive Loss – U.S. GAAP	**(195)**	(365)	(196)
Comprehensive Income – U.S. GAAP	**1,515**	1,028	1,260
Comprehensive Income Attributable to Non-Controlling Interests	**140**	121	103
Comprehensive Income Attributable to Controlling Interests – U.S. GAAP	**1,375**	907	1,157
Preferred Share Dividends	**55**	45	6
Comprehensive Income Attributable to Common Shares – U.S. GAAP	**1,320**	862	1,151

Condensed Consolidated Balance Sheet – U.S. GAAP

As at December 31 (millions of dollars)	**2011**	2010
Assets		
Current Assets(1)	**3,110**	2,799
Plant, Property and Equipment(7)	**32,467**	30,987
Equity Investments(3)(5)(6)	**5,077**	4,683
Goodwill	**3,534**	3,457
Regulatory Assets(3)	**1,684**	1,699
Intangibles and Other Assets(3)(6)	**1,466**	1,624
	47,338	45,249
Liabilities		
Current Liabilities(4)(7)	**5,522**	5,352
Regulatory Liabilities	**297**	308
Deferred Amounts(3)(5)	**929**	728
Deferred Income Tax Liabilities(1)(3)(6)	**3,591**	3,241
Long-Term Debt(6)	**17,724**	17,122
Junior Subordinated Notes(6)	**1,016**	993
	29,079	27,744
Equity		
Common shares, no par value	**12,011**	11,745
Issued and outstanding: 2011 – 704 million shares		
Issued and outstanding: 2010 – 696 million shares		
Preferred shares	**1,224**	1,224
Additional paid-in capital(2)	**380**	349
Retained earnings(1)(2)(4)	**4,628**	4,273
Accumulated other comprehensive (loss)/income(3)	**(1,449)**	(1,243)
Equity Attributable to Controlling Interests	**16,794**	16,348
Equity Attributable to Non-Controlling Interests	**1,465**	1,157
	18,259	17,505
	47,338	45,249

Consolidated Statement of Accumulated Other Comprehensive (Loss)/Income – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Balance at beginning of year	**(1,243)**	(872)	(669)
Change in foreign currency translation gains and losses on investments in foreign operations[8]	**113**	(180)	(471)
Change in fair value of derivative instruments to hedge the net investments in foreign operations[9]	**(73)**	89	258
Change in fair value of derivative instruments designated as cash flow hedges[10]	**(213)**	(165)	(27)
Reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges[11]	**137**	43	62
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans[3][12]	**(89)**	(12)	(1)
Reclassification to Net Income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans[3][13]	**10**	5	6
Other Comprehensive Loss on equity investments[14]	**(91)**	(151)	(30)
Balance at end of year	**(1,449)**	(1,243)	(872)

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

Year ended December 31 (millions of dollars)	**2011**	2010	2009
Net cash provided by operations	**3,759**	2,876	3,008
Net cash used in investing activities	**(3,127)**	(5,296)	(7,347)
Net cash (used in)/provided by financing activities	**(642)**	2,188	4,204
Effect of foreign exchange rate changes on cash and cash equivalents	**4**	(7)	(93)
Decrease in cash and cash equivalents	**(6)**	(239)	(228)
Cash and cash equivalents beginning of year	**660**	899	1,127
Cash and cash equivalents end of year	**654**	660	899

(1) Under U.S. GAAP, inventory is recorded at lower of cost or market. Under CGAAP, natural gas inventory held in storage is recorded at its fair value.

(2) Under U.S. GAAP, the dilution gain resulting from TC PipeLines, LP's 2009 equity issuance was accounted for as an equity transaction. Under CGAAP, the dilution gain was included in Net Income.

(3) Under U.S. GAAP, an employer is required to recognize the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability in its Consolidated Balance Sheet and to recognize changes in that funded status, through OCI, in the year in which the changes occur. The amounts recognized in the Company's U.S. GAAP Consolidated Balance Sheet for its DB Plans and other post-retirement benefits are as follows:

December 31 (millions of dollars)	**2011**	2010
Intangibles and other assets	**–**	40
Deferred amounts	**(321)**	(156)
	(321)	(116)

Pre-tax amounts recognized in U.S. GAAP AOCI are as follows:

	2011		2010		2009	
December 31 (millions of dollars)	**Pension Benefits**	**Other Benefits**	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Net loss	**283**	**29**	179	24	170	21
Prior service cost	**7**	**2**	9	2	10	2
	290	**31**	188	26	180	23

Pre-tax amounts recognized in U.S. GAAP OCI were as follows:

	2011		2010			2009
December 31 (millions of dollars)	**Pension Benefits**	**Other Benefits**	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Amortization of net loss from AOCI to OCI	**(10)**	**(1)**	(5)	(1)	(5)	(1)
Amortization of prior service (credit) from AOCI to OCI	**(2)**	**–**	(2)	–	(2)	–
Funded status adjustment	**113**	**6**	15	4	2	(1)
	101	**5**	8	3	(5)	(2)

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

December 31 (millions of dollars)	**2011**	2010
Accumulated benefit obligation	**1,691**	1,463
Fair value of plan assets	**1,656**	1,636
Funded status – (deficit)/surplus	**(35)**	173

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

December 31 (millions of dollars)	2011	2010
Accumulated benefit obligation	446	182
Fair value of plan assets	391	178
Funded status – (deficit)	(55)	(4)

The estimated net loss and prior service cost for the DB Plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $10 million and $1 million, respectively. The estimated net loss and prior service cost for the other post-retirement plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $1 million and $1 million, respectively.

(4) In accordance with CGAAP, the Company recorded current income tax benefits resulting from substantively enacted Canadian federal income tax legislation. Under U.S. GAAP, the legislation must be fully enacted for income tax adjustments to be recorded.

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

December 31 (millions of dollars)	2011	2010
Unrecognized tax benefits at beginning of year	62	55
Gross increases – tax positions in prior years	9	7
Gross decreases – tax positions in prior years	(7)	(1)
Gross increases – current year positions	11	9
Settlements	–	(7)
Lapses of statute of limitations	(23)	(1)
Unrecognized tax benefits at end of year	52	62

TransCanada expects the enactment of certain Canadian federal tax legislation in the next 12 months which is expected to result in a favourable income tax adjustment of approximately $20 million. Otherwise, subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next twelve months that would have a material impact on its financial statements.

TransCanada and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2006. Substantially all material U.S. federal income tax matters have been concluded for years through 2007 and U.S. state and local income tax matters through 2006.

TransCanada's continuing practice is to recognize interest and penalties related to income tax uncertainties in Income Tax Expense. Net tax expense for the year ended December 31, 2011 reflects a reversal of $12 million of interest expense and nil for penalties (2010 – $3 million for interest expense and nil for penalties; 2009 – $8 million reversal of interest expense and nil for penalties). At December 31, 2011, the Company had $7 million accrued for interest expense and nil accrued for penalties (December 31, 2010 – $19 million accrued for interest expense and nil accrued for penalties).

(5) As a consequence of using equity accounting for certain of these joint ventures under U.S. GAAP, the Company is required to reflect an additional liability of $111 million at December 31, 2011 (December 31, 2010 – $150 million) for certain guarantees related to debt and other performance commitments of the joint venture operations that were not required to be recorded when the underlying liability was reflected on the balance sheet under the proportionate consolidation method of accounting.

U.S. GAAP requires the disclosure of the difference, if any, between the carrying value of the investment and the investor's underlying equity in the net assets of the investee on an ongoing basis, rather than only at the date of purchase as required under CGAAP. At December 31, 2011, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company and Bruce Power is US$120 million (2010 – US$121 million) and $752 million (2010 – $783 million), respectively. This difference is primarily due to goodwill recorded with respect to the acquisition of Northern Border and the fair value assessment of assets at the time of acquisition of Bruce Power.

The distributed earnings from long-term investments for the year ended December 31, 2011 were $494 million (2010 – $250 million; 2009 – $265 million). The undistributed earnings from long-term investments as at December 31, 2011 were $1,283 million (2010 – $1,361 million; 2009 – $1,174 million).

(6) In accordance with U.S. GAAP, debt issue costs are recorded as a deferred asset rather than being included in Long-Term Debt as required under CGAAP.

(7) In 2009, the Company purchased the remaining 20 per cent ownership interest in Keystone, increasing its ownership interest to 100 per cent. Under CGAAP, the transaction was considered to be an asset purchase; however, under U.S. GAAP it is considered to be a business combination. The purchase price was allocated to Plant, Property and Equipment (US$734 million) and Short-term Debt (US$197 million) using fair values of the net assets at the date of acquisition. There is no Income Statement impact under U.S. GAAP as no gain or loss was created.

(8) Net of income tax recovery of $29 million in 2011 (2010 – $65 million expense; 2009 – $92 million expense).

(9) Net of income tax recovery of $28 million in 2011 (2010 – $37 million expense; 2009 – $124 million expense).

(10) Net of income tax recovery of $106 million in 2011 (2010 – $82 million recovery; 2009 – $38 million recovery).

(11) Net of income tax expense of $77 million in 2011 (2010 – $28 million expense; 2009 – $48 million expense).

(12) Net of income tax recovery of $30 million in 2011 (2010 – $7 million recovery; 2009 – nil).

(13) Net of income tax expense of $3 million in 2011 (2010 – $3 million expense; 2009 – $2 million expense).

(14) Primarily related to reclassification to Net Income of actuarial losses on pension and other post-retirement benefit plans, reclassification to Net Income of gains and losses on derivative instruments designated as cash flow hedges, offset by gains and losses on derivative instruments designated as cash flow hedges. Net of income tax recovery of $3 million in 2011 (2010 – $69 million recovery; 2009 – $17 million recovery).