MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and Consolidated Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. ("AltaGas" or "the Corporation") as at and for the year ended December 31, 2011 compared to 2010. This MD&A dated March 12, 2012, should be read in conjunction with the accompanying Consolidated Financial Statements and notes thereto of AltaGas for the year ended December 31, 2011.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or an affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements are set forth under: "Consolidated Outlook"; "Growth Capital"; "Gas Outlook"; "Power Outlook"; "Utility Outlook" and "Corporate Outlook".

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in AltaGas' public disclosure documents.

Many factors could cause AltaGas' or any of its business segment's actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other than for which it is disclosed herein.

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas and AltaGas Income Trust (the "Trust"), including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular, and Proxy Statement, material change reports and press releases, are also available through AltaGas' website or directly through the SEDAR system at www.sedar.com.

ALTAGAS ORGANIZATION

The material businesses of AltaGas Ltd. (the Corporation) are operated by the Corporation, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), and AltaGas Utility Holdings (Pacific) Inc. (collectively the operating subsidiaries).

Prior to July 1, 2010, AltaGas General Partner Inc., through its Board of Directors, the members of which were elected by AltaGas Income Trust (the Trust) at the direction of the unitholders, had been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. As of July 1, 2010, the members of the Board of Directors of AltaGas General Partner Inc. were appointed to the Board of Directors of AltaGas Ltd. in accordance with the plan of arrangement approved at the Annual and Special Meeting of Securityholders on June 3, 2010.

The annual MD&A and Consolidated Financial Statements follow the continuity of interest basis of accounting whereby the Corporation is considered a continuation of the Trust. As a result, this MD&A includes the results of operations for the period up to and including June 30, 2010, when the entity existed as a Trust and the Corporation's results of operations thereafter. At the end of 2010, the Corporation completed an internal reorganization that formally established three operating businesses – Gas, Power and Utilities. The following MD&A is based on these operating businesses.

ALTAGAS' VISION AND OBJECTIVE

AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the northern and western United States. The Corporation's overall objective is to generate superior economic returns by investing in low-risk, long-life energy assets underpinned by contracts with strong counterparties or regulated assets which provide stable returns. Over the past eighteen years AltaGas has built a portfolio of assets that provide the platform for future growth. The Corporation focuses on investing in proximity to owned assets and operations that provide stable, regulated, long-life cash flows with opportunities to grow and add additional earnings and cash flow which support further dividend and capital growth.

OVERVIEW OF THE BUSINESS

AltaGas is a diversified energy infrastructure business with an enterprise value of approximately $4 billion and a focus on natural gas, power and regulated utilities. With the physical and economic links along the energy value chain, together with its efficient, reliable and profitable assets, market knowledge and financial discipline, AltaGas has provided strong, stable and predictable returns to its investors. AltaGas focuses on maximizing the profitability of its assets, providing services that are complementary to its existing businesses, and growing through the acquisition and development of energy infrastructure.

AltaGas has three operating businesses, Gas, Power and Utilities. AltaGas' Gas business serves producers in the Western Canada Sedimentary Basin (WCSB or the Basin) and touches more than 2 Bcf/d of gas and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing. Gas gathering systems move natural gas from producing wells to processing facilities. The gas is then compressed for transportation. The Extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and NGL. The Transmission pipelines deliver natural gas and NGL to distribution systems, end users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by providing energy consulting and management services to commercial end users, buys and resells energy, provides gas transportation, storage and gas marketing for producers and sources gas supply to some of its processing assets. In 2011, the Gas business included expansions at several gas processing facilities within liquids-rich development areas as well as construction of the Harmattan Co-stream (Co-stream Project) and the Gordondale Gas Processing Facility (Gordondale), both of which have long-term contracts and are expected to be in service in 2012.

The Power business includes 555 MW of generating capacity from gas fired, coal-fired, wind, biomass and run-of-river assets. AltaGas owns 50 percent of the Sundance B Power Purchase Arrangements (PPAs), giving it the rights to power output and ancillary services from coal fired base load generation until December 31, 2020. Further generation is in various stages of construction and development including the Northwest run-of-river projects (Northwest Projects), which consist of the Forrest Kerr run-of-river project (Forrest Kerr Project), currently under construction, to come online in 2014 followed by McLymont Creek and Volcano Creek run-of-river projects (McLymont and Volcano Projects), in advanced stages of development, expected to come online in late 2015. The 277 MWs Northwest Projects are contracted with 60-year fully inflation indexed Energy Purchase Arrangements (EPAs) with BC Hydro.

The Utility business is comprised of mainly natural gas distribution utilities. The utilities are allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of capital from the capital investment base. AltaGas owns and operates utility assets that deliver natural gas to end users in Alberta, British Columbia, and Nova Scotia. AltaGas also owns a one-third interest in the utility which delivers natural gas to end-users in Inuvik, Northwest Territories. The Utility business is comprised of AltaGas Utilities Inc. (AUI), the Alberta utility business, Pacific Northern Gas Ltd. (PNG), the British Columbia utility business and Heritage Gas Limited (Heritage Gas), the Nova Scotia utility.

On February 1, 2012, AltaGas and AltaGas Utility Holdings (U.S.) LLC (AUH(US)) entered into an agreement with Continental Energy Systems LLC (Continental) and SEMCO Holding Corporation (SEMCO) pursuant to which AUH(US) agreed to acquire all of the issued and outstanding shares of SEMCO for aggregate consideration of US$1.135 billion, subject to adjustment, including approximately US$355 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy Inc. (SEMCO Energy), a privately held regulated public utility company headquartered in Port Huron, Michigan, with natural gas distribution operations in Alaska and Michigan. The closing of the acquisition is subject to receipt of required regulatory approvals and the satisfaction or waiver of certain closing conditions. The closing of the acquisition is expected to occur in third quarter 2012. On March 2, 2012, the Federal Trade Commission has granted approval of the application for early termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR).

STRATEGY

In support of its overarching goal of creating long-term shareholder value and delivering superior economic returns to investors, AltaGas' strategy has remained focused on four key themes:

- Optimize its existing businesses by focusing on safe and reliable service to its customers and capitalize on the strategic location of its current assets;
- Grow and diversify its Gas, Power and Utility infrastructure platform;
- Maintain its financial strength and flexibility; and
- Continue to evolve its organizational capability to support the strategy.

AltaGas' Board of Directors reviews the strategy annually, consistent with its mandate of overseeing and directing the Corporation's strategic direction. The Corporation continually assesses the macro-economic and micro-economic trends impacting its business and seeks opportunities to generate value for shareholders, including acquisitions, dispositions or other strategic transactions. Opportunities that AltaGas determines to pursue must meet strategic, operating and financial criteria.

Optimize, grow and diversify energy infrastructure

The Corporation has been providing gas processing and marketing services to natural gas producers since 1994. Since that time it has expanded into extraction, transmission, storage and distribution of natural gas as well as NGL and power generation. The natural gas and power supply and demand fundamentals in North America have consistently underpinned the Corporation's strategy. In recent years, the supply and demand fundamentals have been changing. AltaGas sees a growing North American gas supply as a result of new technology that has improved the economics of unconventional gas plays, including shale, tight gas and coal bed methane. New technology such as horizontal drilling and multi-stage hydraulic fracture drilling allow shale and other low productivity gas resources to be produced more economically. The crude oil, natural gas and NGL markets are presenting opportunities that the Corporation is well positioned to capitalize on as a result of its strategically located assets and its capability to add new assets to serve areas which are not yet connected to gas processing, transmission or distribution infrastructure. Increased gas supply, driven by improved drilling technology, continued low natural gas prices in North America and significant natural gas price differential between Asia and North America, have all resulted in increased activity by producers seeking natural gas markets in Asia. There are several Liquified Natural Gas (LNG) projects under development in British Columbia which could provide significant growth opportunities for each of AltaGas' Gas, Power and Utility businesses.

Abundant natural gas supply is anticipated to be positive news for North American consumers and is likely to lead to renewed interest in natural gas as an economically priced, clean burning fuel. As a result, the use of natural gas for power generation and for use as Compressed Natural Gas (CNG) is expected to increase substantially. This is a result of both economic growth and increased demand for clean sources of power to reduce greenhouse gas emissions. AltaGas expects that gas-fired power generation and renewable power generation will be instrumental in the near-term reduction of greenhouse gas emissions. Amid these changing energy supply and demand dynamics, the Corporation's strategy is to diversify and grow its energy asset portfolio with a focus on gas processing, NGL extraction, natural gas, NGL and CNG transmission and distribution, as well as power generation.

Cost management initiatives are balanced with the safe and reliable operation of the Corporation's assets and the need to ensure ongoing customer satisfaction. With respect to safety, AltaGas strives to employ the best available practices and technologies for integrity management systems and maintenance and operations in order to mitigate risks to the public, employees and the environment. Cost efficiency and operating performance is a driver of increasing value as the Corporation continues to build out its portfolio of assets. Key initiatives continue to increase proficiency in managing costs and include changes to cost tracking systems and implementing best practice procurement strategies. Superior service, safety and reliability are also integral to AltaGas' customer value proposition.

Maintain financial strength and flexibility

Financial discipline is a fundamental cornerstone of the Corporation's strategy. As a growth-oriented energy infrastructure company, AltaGas creates value for its investors through minimizing its cost of capital and maximizing its return on invested capital which ensures operating cash flows are maintained and growing. AltaGas' financing strategy is built on two key principles: ensure the Corporation has sufficient liquidity to meet its capital requirements, and do so at the lowest cost possible. The Corporation develops and executes financing plans and strategies to maintain and improve its credit ratings, diversify its funding sources and maintain ready access to capital markets.

A key element of the Corporation's low-risk business model is mitigation of exposure to certain market price risks. As a result, the Corporation has developed robust risk management processes that mitigate earnings volatility from commodity price risk. AltaGas proactively hedges interest rates, foreign exchange and commodity price exposures. As well, the continued management of counterparty credit risk remains an ongoing priority.

Continue to develop organizational capability to support the strategy

AltaGas recognizes that to be successful in operating and constructing energy infrastructure, specific core competencies are required. To that end the Corporation continues to focus on training and hiring the required competencies for executing the strategy and ensuring that the performance management processes support the long-term objective of creating shareholder value.

STRATEGY EXECUTION

The acquisition of PNG in December 2011 is an example of AltaGas' ability to grow and diversify. The transaction resulted in a 50 percent increase in AltaGas' regulated rate base to more than $500 million and increased customers from 75,000 to more than 115,000. Increased natural gas exploration taking place in areas such as the Montney and Horn River areas, and increased industrial and economic activity in northern B.C., are expected to result in rate base and customer growth in areas such as Dawson Creek and Fort St. John. The significant geographic alignment of PNG and other key AltaGas assets, such as the Bear Mountain Wind Park (Bear Mountain) and the Younger Extraction Plant (Younger), position AltaGas well to take advantage of opportunities to capitalize on the need for infrastructure in all its business segments of Gas, Power and Utilities as LNG activity materializes.

The acquisition of SEMCO announced on February 1, 2012, and anticipated to be closed in third quarter 2012, is another example of AltaGas' ability to execute its strategy to grow and diversify its businesses. The transaction is expected to provide a significant foothold in the United States. Upon closing, AltaGas is expected to increase rate base by approximately US$725 million and customers by over 418,000. Approximately 99 percent of SEMCO revenues are derived from regulated natural gas distribution and storage utilities.

During 2010 and 2011 AltaGas completed expansions at the Pouce Coupe, Ante Creek, Alder Flats and Blair Creek facilities to serve producers seeking to capitalize on liquids-rich areas and areas of growing gas supply. AltaGas has also consolidated or improved the interconnections between certain facilities in order to optimize operations and provide continued service to its customers, such as the consolidation of the Enchant and Turin gas plants and reconfiguration of the Bantry and Princess facilities. The completion of the Younger Septimus Pipeline (Septimus), in December 2011, and the expansion of the South Peace Pipeline, in late 2009, have resulted in higher volumes processed at Younger.

The Co-stream Project is a great example of AltaGas optimizing its assets. The Co-stream Project will use 250 Mmcf/d of existing spare capacity to recover ethane and other NGL from natural gas sourced from the western leg of the NOVA Gas Transmission Ltd. (NGTL) System. The Co-stream Project will expand the availability of valuable feedstock for Alberta's petrochemical industry and retain extraction revenues and value in Alberta in an economical manner. The Co-stream Project is expected to result in the full utilization of this facility, providing producers with additional capacity to increase their netbacks on the western leg of the NGTL system. Plant construction is underway, pipeline construction is substantially complete, and major plant tie-ins were completed during the plant turnaround in third quarter 2011. AltaGas entered into a 20-year definitive agreement to deliver all natural gas liquids extracted from co-stream gas on a full cost-of-service basis to NOVA Chemicals.

In 2011, AltaGas began construction of Gordondale. The Corporation has a long-term contract with a major natural gas producer to build and operate the 120 Mmcf/d facility along with a natural gas gathering system. The plant is expected to be in service in late 2012. AltaGas achieved early processing capabilities in late 2011 through the use of existing infrastructure in the area and completion of a pipeline connection to its Pouce Coupe facility. Gordondale is located in the Montney resource area, one of the largest, low-cost, liquids-rich resource plays in the WCSB. This plant will allow AltaGas to provide a midstream solution to a number of producers in the area. The addition of deep-cut gas processing facilities to the project allows producers to extract additional value for liquids from the gas processed at the plant. The ability to extract NGL allows AltaGas to expand its service offering to customers in active producing areas and to purchase gas at the plant gate and extract the value of the liquids.

The addition of a second cogeneration plant at the Harmattan Complex (Harmattan) is another example of the Corporation's ability to capitalize on the energy value chain. The second cogeneration plant will meet the power demand of the Co-stream Project.

Significant progress was made in 2011 on the Northwest Projects, consisting of three run-of-river power generation projects representing approximately $1 billion in investments - 195 MW Forrest Kerr, 66 MW McLymont Creek and 16 MW Volcano Creek. Construction is progressing on schedule and on budget at the Forrest Kerr Project. At the end of 2011, 86 percent of Forrest Kerr Project costs are contractually fixed; substantially mitigating capital cost risk. In 2011, AltaGas signed 60-year, fully indexed to the Canadian Consumer Price Index (CPI) EPAs with BC Hydro and Impact Benefit Agreements (IBAs) with the Tahltan First Nation for the McLymont and Volcano Projects. Under the terms of the EPAs, AltaGas will sell all the power generated from the Northwest Projects to BC Hydro. Together the Northwest Projects add a significant stream of stable, long-term cash flow that supports AltaGas' objective of providing shareholders with stable and predictable cash flows for generations.

The Corporation has a portfolio of 1,400 MW of wind power projects currently under development. There are approximately 260 MW in the advanced development stages, for which AltaGas is seeking contractual arrangements before moving forward. These projects will provide geographic and counterparty diversification thereby reducing overall business risk. The acquisition of Decker Energy International Inc. (DEI) on January 26, 2012, contributes to fuel source and geographic diversification with ownership interests in two operating biomass power generation facilities in the United States. The acquisition of a 50 percent interest in a wind farm project with Black Hills/Colorado Electric Utility Company, LP ("Black Hills"), expected to be in service at the end of 2012, adds to AltaGas' current wind energy portfolio in the United States.

In 2011, AltaGas completed several financing transactions demonstrating the ability to execute its strategy of maintaining financial strength and flexibility. The Corporation extended its debt maturity profile with two senior medium term note issuances for a total of $400 million and strengthened the balance sheet with a $144 million common share issuance in fourth quarter 2011. At the end of 2011, AltaGas had approximately $848.3 million of available credit facilities and debt-to-total capitalization of 49.3 percent. In fourth quarter 2011, AltaGas announced that beginning in December 2011, the monthly dividend would increase by 4.5 percent to $0.115 per share. The dividend increase reflects the significant progress AltaGas has made on its major projects as well as the strength and stability of its cash flows. The Corporation also executed a new $125 million unsecured bilateral letter of credit facility on April 26, 2011 and amended and extended the Utility Group's $200 million unsecured, extendible revolving credit facility to four years with a new maturity date of November 17, 2015.

On February 1, 2012, concurrent with the announcement to acquire SEMCO, AltaGas announced a bought deal offering of $350 million of subscription receipts plus a 15 percent overallotment. On February 1, 2012, AltaGas entered into a new US$300 million unsecured credit agreement, maturing on March 2, 2013. Concurrent with the new credit facility, AltaGas extended the term of its $600 million and $75 million credit facilities to May 30, 2016.

2011 GROWTH HIGHLIGHTS

- Acquired all the outstanding common shares of PNG for $36.75 per common share. The transaction resulted in a 50 percent increase in AltaGas' regulated rate base to more than $500 million and increased customers from 75,000 to more than 115,000;
- Signed 60-year inflation indexed EPAs with BC Hydro for its 66 MW McLymont Creek and 16 MW Volcano Creek projects. Combined the Northwest Projects are expected to cost approximately $1 billion. The Forrest Kerr Project, currently under construction, is expected to be in service in mid-2014. The McLymont and Volcano Projects are expected to be in service in late 2015;
- Commenced construction of the Co-stream Project. Pipeline construction was 95 percent complete by year-end and plant construction is proceeding as planned with the first phase of construction successfully completed before year-end;
- Commenced construction of Gordondale. The 120 Mmcf/d facility will serve producers in the Montney gas resource area and will include liquids extraction facilities to capture NGL. The facility and associated gas gathering system is expected to cost approximately $236 million and be in service in late 2012. By using existing infrastructure in the area and building the Henderson Pipeline to connect to the Pouce Coupe facility, AltaGas began providing early processing production in late 2011;
- Commenced construction of a second 15 MW cogeneration facility (Cogeneration II) at Harmattan to supply steam and power to the Co-stream Project.;
- Commenced operation of the co-owned 25-km Septimus pipeline, resulting in approximately 60 Mmcf/d of additional gas processed at Younger. AltaGas' capital contribution for the project was approximately $9 million;
- Completed multi-year rate applications for AUI and Heritage Gas. Heritage Gas' negotiated settlement was approved by the NSUARB in November 2011 with 11 percent return on equity (ROE) and 7.25 percent cost of debt and rate increases effective January 1, 2012, until December 31, 2014. The approved rate increases will allow Heritage Gas to fully recover its annual cost-of-service. AUI received a decision on the Generic Cost of Capital (GCC) hearing which awarded AUI with ROE of 8.75 percent for 2011 and 2012;
- Increased rate base at AUI and Heritage Gas by 13 percent and 23 percent, respectively;
- Completed expansions at the Alder Flats, Ante Creek and Blair Creek gas processing facilities to serve producers seeking to capitalize on liquids-rich natural gas and areas of growing gas supply;
- Acquired a 40 percent interest in the Marlboro Gas Plant. The facility has gross capacity of 40 Mmcf/d (gross) and is located in the Pine Creek area;

- Executed several agreements to support a second expansion of the Blair Creek Gas Plant for incremental processing capacity of 50 Mmcf/d, which is expected to cost approximately $42 million and will increase licensed capacity to 82 Mmcf/d;
- Signed definitive agreements with an oil sands producer to expand the Cold Lake facilities to supply the customer natural gas to operate its facilities. The expansion is expected to cost $24 million.

2011 FINANCIAL HIGHLIGHTS

- Completed the issuance of 4,910,500 common shares on November 15, 2011, resulting in gross proceeds of $144 million;
- Completed a $200 million issuance of senior unsecured medium term notes on October 17, 2011. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019;
- Extended the term of the $600 million and $75 million credit facilities to four years to May 30, 2015. Subsequently on March 2, 2012, both facilities were extended to May 30, 2016;
- Amended and extended the Utility Group's $200 million unsecured, extendible, revolving credit facility to four years with a new maturity date of November 17, 2015;
- Issued $200 million of senior unsecured medium term notes in March. The notes carry a coupon rate of 4.1 percent and mature on March 24, 2016;
- Executed a new $125 million unsecured bilateral letter of credit facility on April 26, 2011;
- Reported normalized net income[1] of $102.1 ($1.21 per share) million compared to $101.7 ($1.25 per share) million;
- Reported normalized EBITDA[1] of $282.1 million in 2011, compared to $249.6 million in 2010;
- Reported normalized funds from operations[1] of $225.7 million ($2.69 per share) in 2011, compared to $194.7 million ($2.39 per share) in 2010;
- Reported operating income of $174.8 million compared to $153.1 million;
- Reported net income applicable to common shares of $83.6 million compared to $97.2 million;
- Reported total net debt as at December 31, 2011, of $1,320.0 million, compared to $902.4 million as at December 31, 2010;
- Reported net debt-to-total capitalization ratio as at December 31, 2011, of 49.3 percent, compared to 42.7 percent as at December 31, 2010.

[1] *Includes financial measures not disclosed under Canadian GAAP. Please see discussion in Non-GAAP financial measures in this MD&A.*

CONSOLIDATED OUTLOOK

AltaGas expects to report stronger operating income from its three business segments in 2012 compared to 2011. In 2012, AltaGas expects to add approximately $1.8 billion in new assets. These additions are expected to add approximately $200 million in annualized EBITDA. Overall, assets currently in operation are expected to perform better than 2011. In the Gas business, higher throughput, continued strong frac spreads and no major turnarounds are expected to result in stronger earnings in 2012 compared to 2011. In Alberta, current forward power prices are expected to result in slightly lower earnings in 2012 compared to 2011 from the conventional power assets. Results are expected to be higher from the Utility business due to strong rate base growth at both AUI and Heritage Gas, the addition of PNG and the expected addition of SEMCO in third quarter 2012.

In the Gas business, volumes processed are expected to increase at certain gas processing and extraction facilities in service today as producers look to increase netbacks from liquids-rich gas and higher realized frac spreads based on current forward prices. AltaGas expects volume increases to offset the impact of lower volumes expected in areas with low producer activity as a result of continued depressed natural gas prices. In 2012, AltaGas estimates that 13 percent of total extraction volumes will be exposed to frac spread. For 2012, approximately 75 percent of the exposure has been hedged at an average price of $35/Bbl before deducting extraction premiums compared to 70 percent hedged at an average price of $27.78/Bbl in 2011. Extraction premiums are those fees paid by AltaGas to the producers or shippers of natural gas to acquire the NGL extraction rights. The Co-stream Project is expected to be in service in second quarter 2012 and Gordondale is expected to be in service in late 2012. On an annualized basis, these two projects are expected to add EBITDA of approximately $55 to $60 million.

AltaGas expects earnings from the conventional power assets to be slightly lower in 2012 compared to 2011 as a result of current forward power prices in Alberta which are lower than in 2011. This is expected to be partially offset by the addition of Cogeneration II, the Crowsnest Pass waste-heat facility, Gordondale peaking plant, and the recently acquired biomass facilities. For first quarter 2012, AltaGas has hedged approximately 75 percent of the expected Alberta based power generation at an average price of $80 per MWh. For the second through fourth quarters of 2012, AltaGas has hedged approximately 56 percent of the expected production at an average price of $65 per MWh. On a full year basis, AltaGas is approximately 60 percent hedged at an average price of $70 per MWh compared to approximately 62 percent hedged at $70/MWh in 2011.

AltaGas expects a stronger year from its Utility business in 2012 compared to 2011. Higher earnings are expected as a result of forecast rate base growth at AUI and Heritage Gas of 14 percent and 16 percent in 2012, respectively, the benefit of a full year ownership of PNG, the potential for an incremental $20 million payment related to PNG's sale of its interest in the Pacific Trail Pipelines (PTP) in 2011 and the SEMCO acquisition expected to close in the third quarter 2012. On an annualized basis, the Utility business is expected to contribute approximately 40 percent of overall AltaGas EBITDA. The first full year of PNG is expected to add approximately $25 million in EBITDA. AltaGas expects to close SEMCO in third quarter which is expected to add approximately $40 million in EBITDA and incur approximately $7.0 million in transaction costs. AltaGas expects to add $725 million of rate base through the SEMCO acquisition and approximately $50 million through organic growth within AUI, PNG and Heritage Gas. Total utility customers are expected to increase from approximately 115,000 in 2011 to approximately 536,000 in 2012.

On a net income basis, the Corporation expects to report higher future income tax expense based on higher taxable income. The Corporation has approximately $1.3 billion in tax pools, and based on current estimates for capital expenditures and taxable income, does not generally expect to be cash taxable until 2016. Future income taxes recoverable or payable by the Utilities are recorded as regulatory assets or liabilities until such time as the taxes are collectible or payable from or to utility customers.

On closing of the SEMCO acquisition and upon satisfaction of certain escrow release conditions, the 13,915,000 subscription receipts issued on February 22, 2012, will be converted to 13,915,000 common shares of AltaGas for gross proceeds of approximately $403 million.

GAS BUSINESS

Description of assets

AltaGas' Gas business serves customers primarily in the WCSB and touches more than 2 Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and fractionation, transmission, storage and natural gas marketing. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation. Extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and NGL. AltaGas owns 1.6 Bcf/d of extraction processing capacity and 1.2 Bcf/d of raw field gas processing capacity.

Transmission pipelines deliver natural gas and NGL to distribution systems, end users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by providing energy consulting and supply management services to commercial end users, buys and resells energy, provides gas transportation, storage and gas marketing for producers and sources gas supply to some of the processing assets. The Gas business also includes several expansion and greenfield projects under development and construction.

The Gas business includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1.6 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues;
- Five natural gas transmission systems with combined transportation capacity of approximately 0.5 Bcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d. The transmission assets provide stable take-or-pay based

revenues;

- More than 70 gathering and processing facilities in 31 operating areas in western Canada and a network of 6,500 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets. The field facilities provide fee-for-service revenues based on volumes processed. A significant portion of contracts flow through operating costs;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn hub in Eastern Canada;
- Co-stream Project under construction with expected in service date of second quarter 2012. AltaGas entered into a 20-year definitive agreement to deliver all natural gas liquids extracted from co-stream gas on a full cost-of-service basis to NOVA Chemicals;
- Gordondale with deep-cut extraction capability under construction with planned in service date of late 2012. The majority of the volumes processed are supported by a long-term natural gas supply agreement with a major producer;
- Several expansion projects to meet producer needs in the liquids-rich and solution gas formations;
- 50 percent interest in a natural gas storage project under development in Nova Scotia with potential gross storage capacity of 10 Bcf and in Michigan with potential storage capacity of approximately 50 Bcf; and
- Energy consulting, natural gas buys and sells and gas transportation services to optimize the value of the infrastructure assets and meet customer needs.

Capitalize on Opportunities

AltaGas pursues opportunities in the Gas business to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Increase throughput, utilization and efficiency of existing facilities;
- Provide the most cost effective midstream services while delivering reliable and safe operations;
- Mitigate volume risk by directly recovering operating costs from customers;
- Acquire and develop new gas infrastructure assets to meet customers' needs; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration of business lines across the energy value chain.

The Gas business provides safe and reliable natural gas and liquids gathering, processing, extraction, transportation and storage services to its customers. The strategic focus is to increase profitability of the existing infrastructure, expand and add new infrastructure, and redeploy assets to capitalize on increased exploration and drilling activities in the WCSB. AltaGas also focuses on long-term, fixed fee, take-or-pay and cost-of-service contracts with strong counterparties to mitigate the impact of volume risk and increase stability of earnings.

Until recently, the WCSB was considered to be a maturing basin. Recent technological advancements have resulted in a significant change in the cost of production of natural gas in the Basin. As a result, AltaGas remains confident that the long-term demand for natural gas, combined with improvements in exploration, drilling and completion technology, will support the long-term viability of the Basin. The emergence of unconventional gas plays in the WCSB such as Montney and Horn River, as well as increased focus on horizontal multi fracturing technology have provided renewed life to the Basin. As natural gas supply increases AltaGas expects growing demand for processing infrastructure in the WCSB. Strong NGL prices have resulted in increased producer focus on liquids-rich natural gas and oil thereby increasing the demand for processing capacity that allows producers to earn higher netbacks on liquids-rich gas and associated gas from increasing oil production.

The supply and demand fundamentals for natural gas and NGL provide significant growth opportunities in the Corporation's Gas business. AltaGas expects to capitalize on these opportunities by increasing throughput at facilities, by increasing interests in existing plants, and acquiring and constructing new facilities in areas with growing demand for natural gas processing, extraction, storage and transmission capacity. AltaGas' results within the gas processing business unit have demonstrated this market behaviour.

During fourth quarter 2011, available volumes at certain gas processing facilities grew by approximately 69 Mmcf/d, which more than offset declines of approximately 63 Mmcf/d from other facilities, when compared to the reported volumes in fourth quarter 2010. This resulted in 101 percent of the current quarter's declines being offset by the addition of new volumes, also known as the replacement factor (fourth quarter 2010 – 52 percent).

The natural gas supply to AltaGas' extraction plants, with the exception of Harmattan and Younger, depends on natural gas demand pull from residential, commercial and industrial usages inside and outside of western Canada, and gas liquids demand pull from the Alberta petrochemical, propane heating and Canadian oil and gas industries. Natural gas supply to Younger is dependent on the amount of raw natural gas processed at the McMahon Gas Plant, which is based on the robust natural gas producing region of northeast B.C. Harmattan's raw natural gas supply is based on producer activity in west-central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and increase asset utilization and profitability. Harmattan is the only deep cut and fractionation plant in the area. There is significant demand for gas processing capacity at the Harmattan plant as a result of the high volume of liquids-rich gas being produced in the area. The Co-stream Project will also increase utilization at the plant. The 20-year cost-of-service arrangement with NOVA Chemicals for the Co-stream Project adds long-life, low-risk stable cash flow that further strengthens AltaGas' business risk profile and creates significant shareholder value.

AltaGas also expects to see increased opportunities to acquire or build gathering and processing infrastructure, from or on behalf of, producers wishing to redeploy capital to exploration and production activities rather than dedicating to non-core activities such as gas processing. The Corporation also expects there to be opportunities to increase volumes by tying-in new wells and building or purchasing adjoining facilities and systems to create larger processing infrastructure to capture operating synergies and enhance its competitive advantage. The strategic location of some of its existing infrastructure is expected to allow the Corporation to capitalize on growing natural gas production in northeast B.C. and northwest Alberta, in response to the development of unconventional sources of gas, such as Montney and Duvernay shale gas plays. In addition, AltaGas is able to relocate certain units quickly and cost effectively to respond to the changing processing needs of its customers since field gas compression and processing units are mostly skid-mounted. The new Gordondale gas plant will meet liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. The contractual underpinning of Gordondale provides stable cash flows. Overall, the diverse nature of its field processing and extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

Due to the integrated nature of AltaGas' gas gathering and processing assets, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is required to meet producer and end-user demands. AltaGas pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure based businesses. These include maintaining the cost effective flow of gas through extraction plants and increasing services provided to producers. AltaGas has significant gas and power market knowledge which it employs across all its assets to enhance value along the energy value chain and more effectively serve customers' needs across Canada.

Gas Outlook

The Gas business is expected to deliver stronger results in 2012 than in 2011. Stronger results are expected due to the completion of the Co-stream Project and Gordondale, as well as expansions at other field processing and extraction assets as producers look to increase netbacks from liquids-rich gas. Stronger results are also expected as a result of not having any major turnarounds in 2012, compared to two major turnarounds in 2011. These increases are expected to be partially offset by lower volumes in areas where there are fewer opportunities for producers to benefit from liquids-rich gas and lower daily contract quantity commitment on the Suffield natural gas transmission system. Other reductions for 2012 include one-time items from 2011 of approximately $8 million comprised of the gains recorded from the sale of the Groundbirch facility and settlement of a take-or-pay contract.

Throughput at the extraction assets is expected to increase in 2012 over 2011 as a result of full year operation of the Septimus Pipeline, the addition of the Co-stream Project in second quarter of 2012, success in contracting new gas supply for this same facility and no major turnarounds scheduled during 2012. Drilling activity in northeast B.C. and west central Alberta has increased as producers continue the development of tight and shale gas plays within the area.

AltaGas expects higher volumes within the field processing business as a result of the completion of Gordondale in late 2012 and the second expansion of Blair Creek expected to commence operations in second quarter 2012. These projects, a full year of operation of the Marlboro Gas Plant, the Henderson Pipeline, expanded gas processing capabilities at the Alder Flats Gas Plant, along with higher volumes at the Bantry and Princess facilities, due to high producer activity in the area, are expected to more than offset the volume declines at other facilities. Areas experiencing higher activity levels are being driven by producers focusing on high NGL content gas plays or light oil plays which create significant solution gas, thereby increasing throughput at some of the field processing plants. In 2012, more than half of the throughput volumes for the field processing business are anticipated to be captured through facilities near or inside the Montney, Wilrich, Notikewin and other liquids-rich gas formations and associated gas from oil or solution gas production. Despite these encouraging developments, if natural gas prices remain at current pricing levels for most of 2012, management has estimated that average gas processing volumes would be 8 percent lower than expected, but still higher than 2011 due to the addition of Gordondale and other expansions mentioned above. Overall, the impact of lower natural gas processing volumes on operating income is not expected to be material based on additional revenues that would be earned from frac exposed NGL volumes which benefit from lower natural gas prices.

Based on management's analysis of historical NGL prices, along with NGL published commodity prices and the current forward curve, management expects spot NGL frac spread prices for AltaGas to average approximately $35/Bbl before deducting extraction premiums. In 2012, the Corporation estimates that 13 percent of total extraction volumes will be exposed to frac spread. For 2012, approximately 75 percent of the exposure has been hedged at an average price of $35/Bbl compared to 70 percent hedged at $27.78/Bbl in 2011.

Gas Risk Management

AltaGas' Gas assets process and transport natural gas and NGL produced in the WCSB. Utilization of the assets is dependent on a number of factors including natural gas supply and demand, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the long-term price of natural gas, the level of demand for ethane and NGL and the regulatory environment for market participants. The utilization of extraction plants is influenced by natural gas composition and the difference between the value of the ethane, propane, butane and condensate as separate marketable commodities versus their value in a heat content basis within the natural gas stream.

In the Energy Services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies, as well as other energy consulting firms. The most significant risk in this aspect of the Gas business is counterparty credit risk. The credit intensive nature of this business requires balance sheet support to enable the execution of fixed price natural gas purchase and sale agreements. Storage spreads that support the economic fundamentals of the Corporation's storage business are also a risk.

Construction of the Gordondale project, Co-stream Project and other gas plant expansions are currently underway, which is subject to capital cost increases from equipment cost increases and labour productivity risks.

AltaGas manages its exposure to risk in the Gas business using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term volume declines	• Contract provisions underpin capital commitments • Long-term contracts such as take-or-pay, area of mutual interest, geographic franchise with economic out • Increase market share by expanding existing facilities or acquiring or constructing new facilities	• In 2011, the majority of extraction ethane production was sold under long-term cost-of-service or fee-for-service contracts • Progressed engineering, procurement, and construction for Gordondale and Co-stream Projects as planned • Executed Harmattan Co-stream agreement

	• Increase geographic and customer diversity to reduce exposure to individual customer or area of the WCSB • Strategically locate facilities to provide secure access to gas supply • Capitalize on integrated aspects of AltaGas' businesses to increase volumes through its processing facilities	with NOVA Chemicals • Success in contracting additional gas supply and the new Septimus Pipeline connection will result in additional gas supply at Younger • 98 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed fee • Executed definitive agreements with OSUM to contract gas supply pipelines in Cold Lake • New Field Gathering and Processing (FG&P) facilities and expansions underpinned by take-or-pay contracts • Executed definitive agreements to expand the processing capacity of the Blair Creek Gas Plant by 50 Mmcf/d received regulatory approval and initiated construction • Expanded or debottlenecked Alder Flats, Bantry/Princess gathering system and Blair Creek gas plants to capture new volumes • Ongoing work to develop storage capacity in Nova Scotia with potential for 10 Bcf of storage capacity • Over 290 customers with no customer representing more than 3 percent of the Gas Division's net revenue during 2011 • Top 10 FG&P customers represented 9 percent of consolidated net revenues in 2011 • More than 70 FG&P facilities in 30 operating areas in three provinces within the WCSB • Interest in six of Canada's 10 NGL extraction facilities • Empress extraction facilities maintained high capacity utilization due to gas supply contracted by Energy Services • Co-stream Project to increase utilization and extract liquids-rich gas from the western leg of the NGTL system
Increasing operating costs	• Acquire large working interests to control and optimize operations and maximize efficiencies • Contractual provisions provide for recovery of operating costs • Centralized procurement strategy to reduce costs	• Major turnarounds at Harmattan moved to four-year cycle from a three-year cycle • Approximately 40 percent of operating costs were recovered through contract provisions in 2011 • Operate and control the majority of FG&P facilities • Operate and control all transmission assets • Operate and control four of six extraction facilities • Average FG&P working interest of 95 percent and average E&T working interest of 82 percent • Maintenance management and centralized purchasing programs ensure tight cost controls and equipment reliability
Operational	• Maintain control over operational decisions, operating cost and capital expenditures by operating facilities • Maintain written standard operating practices,	• Operated and controlled the majority of FG&P facilities at 98 percent reliability during 2011 • Operate and control all transmission assets

	assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs	• Operate and control four of six extraction facilities • Successful operator competency program closely monitored and improved • Successful maintenance management program to ensure facility integrity
Commodity price	• Contracting terms, processing, storage and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions • Employ hedging practices to reduce exposure to frac and storage spread volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility • Commodity Risk Policy prohibits transactions for speculative purposes • Employ strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy • In depth knowledge of transportation systems, natural gas and NGL markets	• Less than 13 percent of total extraction production was exposed to frac spreads in 2011 • Most ethane production sold under long-term, cost-of-service or fee-for-service • 56 percent of NGL production under long-term, fixed-fee arrangements • 99 percent of revenue in transmission business is underpinned by take-or-pay contracts • Approximately three-quarters of volumes exposed to frac spread for 2012 and one-third for 2013 have been hedged • NGL is re-injected or extraction operations are reduced or suspended when uneconomical to produce • Majority of FG&P contracts are volumetric service fee structures, based on a rate per Mcf of throughput reducing direct commodity price risk compared to a percentage of price arrangement • All gas marketing transactions are back to back with locked-in margins • In majority of energy management business, AltaGas acts as agent, taking no direct commodity price risk
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty credit • Establish credit thresholds using conservative credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base • Agency arrangements in energy management whereby counterparty credit risk for commodity is between the supplier and end user • Active accounts receivable monitoring and collections processes in place • Credit terms included in gas processing contracts	• Over 290 FG&P customers with no customer representing more than 3 percent of the Gas division's net revenue during 2011 • Majority of the exposures are to investment grade counterparties • In energy management business, some customers are aggregated into groups with joint and several liability for payment of fees • No energy services customer represented more than 10 percent of consolidated revenues during 2011 • AltaGas purchases natural gas from a wide array of investment grade suppliers • Liens placed on natural gas volumes owned by customers, but processed by AltaGas to collect accounts receivable in accordance with contractual terms
Construction	• Major Projects Group manages and monitors significant construction projects • Strong project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and	• Approximately 80 percent and two thirds of capital costs are contractually fixed for Co-stream Project and Gordondale, respectively • Practiced effective procurement policies and procedures and vendor selection • Fixed price quotes for most major equipment components • Redeploying equipment from underutilized plants

	schedule risks	• Major Projects Group include representation from senior executives and experienced project staff • Steering committees provide strong project governance
Reputation	• Maintain active corporate and regulatory affairs department	• Held several events to inform and educate the communities in which AltaGas is operating, constructing and developing projects
Regulatory	• Regulatory and commercial personnel monitor and react to regulatory issues • Proactive government relations group • Build risk mitigation into contracts where possible	• AltaGas continued active participation in industry committees and regulatory forums in 2011 • Improved communication in communities in which we operate • Received full regulatory approval for Gordondale in June
Environment and safety	• Strong safety and environmental management systems, which AltaGas continually strives to improve	• Audits resulted in AltaGas maintaining its Certification of Recognition from Alberta Human Resources and Employment • In 2011, AltaGas received its highest scores since inception for safety and environment audits, despite the implementation of higher benchmark standards • Participated in industry programs, including the annual Safety Stand Down

POWER BUSINESS

Description of assets

The Power business includes 555 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. 1,754 MW of further power generation is in various stages of construction and development including 277 MWs for the Northwest Projects.

The Power business includes:

- 353 MW of coal-fired generating capacity in Alberta through the Sundance PPAs. AltaGas employs a hedging strategy to mitigate the exposure to spot power prices;
- 102 MW Bear Mountain Wind Farm and a further 1,400 MW in various stages of development. Bear Mountain has a 25-year 50 percent inflation indexed EPA with BC Hydro and owns the Renewable Energy Credits (RECs) it generates;
- 39 MW of gas-fired peaking plants and a further 3.4 MW under construction. The gas-fired facilities in Alberta provide partial backstopping to the Sundance PPA;
- 35 MW of biomass generation. The plants have long-term EPAs with strong counterparties;
- 15 MW of cogeneration capacity and a further 15 MW under construction. The gas-fired facilities in Alberta provide partial backstopping to the Sundance PPA;
- 11.2 MW of operating run-of-river generation, a further 195 MW under construction, 82 MW in advanced stages of development and 56 MW under development. All run-of-river have long-term EPAs. 277 MW of the generation has 60-year EPAs;
- 3.4 MW waste-heat recovery project under construction. The project has a 25-year EPA with BC Hydro; and
- Commercial and Industrial (C&I) power sales in Alberta which provides further opportunities to hedge power prices in Alberta for periods of one to five years.

At the end of 2011, the Power business comprised 407 MW of power generation capacity in Alberta. AltaGas' 50 percent ownership of the Sundance B PPAs represents the majority of generation in Alberta. The PPAs provide AltaGas with the rights to power output and ancillary services from 353 MW of coal-fired base load generation until December 31, 2020. PPAs were established in 1999 under Alberta's program of power industry deregulation in order to separate ownership of the physical power generation assets from marketing of output.

In addition, AltaGas has 39 MW of gas-fired peaking power capacity in southern Alberta (Peaking Plants). In late 2010 the Corporation commissioned the 15 MW gas-fired cogeneration facility at Harmattan (Cogeneration I). This 54 MW of gas-fired capacity provides fuel diversity to AltaGas' Power business and partially backstops outages at Sundance. Cogeneration I provides steam to the gas processing facility as well as base-load power to the Alberta electric grid. The peaking plants also provide revenue from the sale of energy and ancillary services due to their quick ramp-up capability. Currently under construction is Cogeneration II, a second 15 MW cogeneration unit at Harmattan, and the 3.4 MW gas-fired peaking plant at Gordondale, both expected to be in service in second quarter 2012.

The Corporation employs a power hedging strategy which is designed to balance market and operational risk related to the Sundance PPAs, thereby reducing the exposure to Alberta spot power prices and providing earnings stability in the Power business. Hedges are executed with industry participants. AltaGas also sells power to C&I end-users in Alberta, providing further earnings stability. Counterparties are subject to credit reviews and credit thresholds in the normal course of business.

AltaGas recognizes that climate change concerns give rise to opportunities to create value. The Corporation is committed to capturing and retaining that value for its shareholders. AltaGas tracks and maintains its inventory of emission credits and offsets and pursues opportunities to generate emissions credits or offsets through efficient and environmentally responsible operations of existing or new assets. Lower emissions costs are also achieved by sourcing third party emissions credits at costs that are lower than paying into the fund established by the Specified Gas Emitters Regulations (SGER) in Alberta.

AltaGas owns 113 MW in British Columbia. Bear Mountain near Dawson Creek, British Columbia generates green attributes and RECs which AltaGas has retained. These credits have been certified by the California Energy Commission, enabling AltaGas to sell them in the California market. In addition, Bear Mountain has qualified for the Federal Government of Canada's ecoEnergy renewable initiative (eRPI), which grants $10/MWh generated by Bear Mountain for 10 years beginning on October 31, 2009. AltaGas has entered into a long-term service agreement with the manufacturer of the wind turbines to operate and maintain the turbines. Also included in the portfolio of power generation assets in British Columbia is a 25 percent effective interest in a 7 MW run of river power generation facility and a 97 percent interest in a 9.8 MW of run of river facility. All power generation assets in British Columbia are underpinned by long-term EPAs with BC Hydro.

Growth in the Power business aligns with AltaGas' strategy of increasing earnings and cash flow stability and predictability. AltaGas' most significant undertaking to date is the construction of 277 MW Northwest Projects. The Northwest Projects, estimated to cost $1.0 billion, are underpinned by 60-year EPAs, fully indexed to CPI and have signed IBAs with the Tahltan Nation. The 195 MW Forrest Kerr project is under construction and is expected to be in service in mid-2014. The 66 MW McLymont and 16 MW Volcano projects are in advanced stages of development, and expected to be in service in late 2015. AltaGas also owns a 60% interest in a 6 MW waste heat recovery project, with a long-term EPA with BC Hydro, in Sparwood, British Columbia which is expected to be in service in third quarter 2012.

AltaGas recently expanded its footprint into the U.S. with the acquisition of a 50 percent interest in the Busch Ranch Wind project (Busch Ranch) and DEI. Busch Ranch is a 29 MW wind farm in Colorado with a 25 year PPA with the local utility, Black Hills Energy. DEI's primary assets are a 30 percent working interest in the 37 MW wood biomass power facility in Grayling, Michigan and a 50 percent working interest in the 48 MW wood biomass power facility in Craven County, North Carolina. AltaGas bears no construction risk and expects to close the acquisition of the wind farm in late 2012. Both biomass facilities have long-term PPAs.

Capitalize on Opportunities

AltaGas pursues opportunities in the Power business to enhance long-term shareholder value. The Corporation's objectives are to:

- Execute power hedges to balance operational and market risk and to increase earnings stability from its Alberta power assets;
- Operate and dispatch the gas-fired peaking capacity to maximize revenue from both energy sales and ancillary services and minimize operating costs across its entire fleet of power generating assets;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Acquire and develop power infrastructure backstopped by long-term power sales arrangements or supported by strong power supply and demand fundamentals; and
- Grow and diversify the power generation portfolio by geography and fuel source.

AltaGas' strategy is to build, own and operate long-life, low-risk power infrastructure assets to deliver strong, stable returns for investors. Growth is focused on clean and renewable sources of energy as the Corporation seeks to capitalize on increasing demand for clean power while reducing its carbon footprint.

The demand for renewable and clean generating capacity continues to be strong across North America, as industry addresses climate change legislation and utilities are faced with renewable portfolio standards. However, the poor economic environment over the past several years resulted in slowed demand growth for power and reduced focus on increasing clean power generation sources. In Alberta specifically, average power demand remained unchanged in 2008 and 2009, but showed renewed growth in 2010 and 2011 at a rate of approximately 2.5 percent and 3 percent respectively. AltaGas expects power demand growth to follow suit with a broader economic recovery. The potential retirement of a 560 MW coal-fired generator announced in early February 2011 and continued low reserve margins are expected to result in continued strong and volatile power prices in Alberta.

The Sundance B facility is among the lowest cost producers of power in the province, uniquely positioning AltaGas to maintain profitable operations during difficult economic conditions. The evolution of the Rate Regulated Option (RRO) has changed the wholesale power market dynamics in Alberta. As of July 1, 2010, the RRO is based entirely on the month-ahead market price for electricity. RRO providers submit their regulated rate proposals to the appropriate regulatory body for approval. The Alberta Utilities Commission (AUC) regulates investor-owned utilities and approves RRO rates for the cities of Calgary and Edmonton and rural Alberta. Before July 1, 2010, the RRO was calculated using a combination of both short-term and long-term market prices for electricity. The new RRO pricing mechanism has resulted in lower liquidity in the long-term market. While the changing market dynamics have presented opportunities for AltaGas to capitalize on the short-term price volatility, this results in fewer opportunities to enter into long-term hedges.

AltaGas' primary means of securing long-term power sales is through its Commercial and Industrial (C&I) power retail business. AltaGas actively markets electricity and gas directly to end-users, enabling the Corporation to secure fixed-price sales at competitive market prices while earning fees associated with the administration of the metered data and billing. These C&I sales are typically for 3 to 5 year terms, offering AltaGas price certainty and a source of liquidity that has decreased in the wholesale market. Currently, AltaGas has approximately 70 MW of fixed price sales to C&I customers for 2012, 60 MW for 2013, 50 MW for 2014 and 2015 all with average prices in the low $60's per MWh, excluding retail fees.

Power generated from Bear Mountain is not currently exposed to power price volatility as the power generated is sold to BC Hydro at a fixed price with 50 percent escalated by CPI for 25 years. The British Columbia power market is established by the government's strategy to increase its green footprint and enter into EPAs with independent power producers. While the BC power market is linked to some of the northwest electric regions, namely Mid-Columbia and the California Oregon Border the price received by AltaGas for power generated by Bear Mountain is driven by the contractual arrangement with BC Hydro. AltaGas also receives eRPI funding of $10 per MWh from the Federal government of Canada. In addition to the price received for power generated, AltaGas receives the economic benefit of any RECs produced as a result of power generated from Bear Mountain. There is significant opportunity to capitalize on the demand for RECs as North America moves forward on its climate change policies and establishes renewable portfolio standards for utilities.

Opportunities to develop and own additional power generation are also likely to arise with the growing North American demand for cleaner energy sources such as natural gas, hydroelectric and wind. The Federal government's stated policy to have coal-fired generators retire at the end of their useful economic lives may prompt additional opportunities to develop new clean power generation capacity. The Bear Mountain Wind Park, Forrest Kerr Project under construction and McLymont and Volcano Projects under development are all examples of AltaGas' strategy in action.

AltaGas has approximately 1,730 MW of renewable power under development, including 1,400 MW of wind power developments, 137 MW of run-of-river hydroelectric developments and 195 MW run-of-river hydroelectric under construction. The wind projects are geographically dispersed in western North America, with 500 MW in Canada and 900 MW in the northern and western United States, while the run-of-river projects are located in British Columbia.

In 2011 there was considerable progress made in the natural gas industry in developing LNG projects in western Canada. The potential addition of 1.7 to 3.4 Bcf of LNG export facilities is expected to require an additional 300 to 600 MW of power generation to support the LNG facilities and the increased economic and industrial activity expected to occur in the region. The strategic location of AltaGas' assets and operational expertise, along with a track record of collaborating with the First Nations in British Columbia, provide AltaGas a significant competitive advantage in its ability to capitalize on opportunities to increase its power generation portfolio to support LNG activities as they materialize.

Power Outlook

The Power business is expected to report stronger earnings in 2012 from the addition of approximately 70 MWs of new power generation assets in 2012. In Canada, the addition of Cogeneration II, the gas-fired peaker at Gordondale and the waste heat recovery plant are all expected to add to earnings in 2012. The addition of biomass power generation assets and the acquisition of the 50 percent interest in a wind farm in Colorado in the United States, all with long-term PPAs, are also expected to increase earnings. On an annualized basis, EBITDA from these new assets is expected to be approximately $10 million. The increased earnings from new assets is expected to be more than offset by the impact of lower power prices in Alberta in 2012 compared to 2011 based on the current forward spot prices.

For first quarter 2012, AltaGas has hedged approximately 75 percent of the expected Alberta based power generation at an average price of $80 per MWh. For the second through fourth quarters of 2012, AltaGas has hedged approximately 57 percent of the expected production at an average price of $65 per MWh. On a full year basis, AltaGas is approximately 60 percent hedged at an average price of $70 per MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to long-term averages.

According to AESO, if the demand for power and the rate of growth in Alberta continues as forecast, the addition of up to 13,000 MW of new generation may be required over the next 20 years. Improved economic conditions in Alberta are expected to bring increased power demand to the province and provide further support to prices over the long-term.

Power Risk Management

In Alberta, the main risks faced in the Power business are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risk related to the deregulation of power, market regulation and environmental legislation. Power results are generally driven by volumes of power generated, hedge prices, spot power prices, the cost of power and transmission. Power prices in Alberta are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, and economic activity. The cost of power is driven by operating costs, changes in transmission rates and power available for sale, mainly due to outage and force majeure events. In British Columbia, the risks impacting the financial performance of operating assets are weather and operational performance of the turbines. AltaGas is constructing the Forrest Kerr Project which is subject to capital cost increases from equipment cost increases and labour productivity risks.

AltaGas mitigates these risks through the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Power price volatility	• Disciplined hedging strategy with hedge targets approved by the Board of Directors • Monitor hedge transactions through Risk Management Committee • In-depth Alberta power market knowledge and experience • Hedge own electrical demand requirements • Direct marketing to end use customers • Own and operate gas-fired peaking capacity to backstop PPAs and sell energy and ancillary services • Increase base-load natural gas-fired generating capacity • Execute long-term inflation adjusted electricity purchase arrangements with power buyers	• Average sales price received in 2011 was $75.94 per MWh, compared to average monthly Alberta Power Pool spot price of $76.22 per MWh • Hedged 62 percent of generation in 2011 • Supplied approximately 9 MW for own use in 2011 • Supplied approximately 75 MW to Alberta commercial and industrial customers under one to five year contracts • Peaking plants contributed $11.3 million to net revenue in 2011 through sales of ancillary services and energy • Full year of operating the Harmattan cogeneration facility that increased the volume of low cost efficient base-load power generated in Alberta • Power generated from Bear Mountain sold under 25-year EPA with BC Hydro; power price is inflation adjusted for 50 percent of CPI • Entered 60-year EPAs fully indexed to CPI with BC Hydro for power generated from Forrest Kerr, McLymont Creek, and Volcano Creek
Volume of power generated	• PPAs include specified target availability levels • Diversification of fuel sources and geography • Hedging strategy to balance price and operating risk • Undertake extensive wind and hydrology studies to support investment decisions	• The operator of the Sundance B plant is obligated to provide AltaGas financial compensation for shortfalls below the specified target availability level, which was 86 percent of rated capacity in 2011. Payment is based on the difference between actual and target availability and the 30 day rolling average power price (RAPP) • 54 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs • Continue to monitor and study wind power development projects; at the end of 2011, had 29 met towers installed • Forrest Kerr Project is supported by 40 years of hydrology data and analysis • Continued to evaluate expected performance of Forrest Kerr using 40:1 working model
Cost of power	• Hedge power costs • Avoid commodity price exposure on electricity energy sources	• Cost of power from the coal-fired generation based on PPA indices not market price of coal
Operational	• Long-term maintenance contract with wind turbine manufacturer (Enercon) • Fixed price O&M contracts with equipment manufacturers • PPAs include specified target availability levels	• Bear Mountain turbines under warranty • Power curve and reliability guarantees provided by turbine manufacturer • Revenue from Sundance B PPA based on target availability

	• Hedging strategy used to balance price and operating risk; deliveries of certain hedge contracts are suspended if there is an outage at Sundance B • Backstop Sundance B PPA operations by adding new power generation capacity • Develop standard operating procedures to maximize reliability, safety and output	• Active hedging program during 2011 for Sundance B PPA power generation in Alberta balancing operational risk with market risk • Operating synergies with the Gas business, increase efficiency of Harmattan cogeneration plant • Balance availability and production from gas-fired peakers to maximize revenue and minimize operating costs • Gas-fired peakers dispatched from central location
Counterparty	• Strong credit policies • Continuous review of counterparty credit worthiness • Establish credit thresholds using conservative credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Contracts with strong counterparties	• All relevant policies and processes were enforced in 2011 • All wholesale financial hedge counterparties are investment grade • No wholesale counterparty defaulted in 2011 • Alberta retail credit risk has little impact on hedge portfolio on an individual basis. In the event of a default, AltaGas can sell the power on the spot market • Bear Mountain contracted with BC Hydro • Entered 60-year EPAs with BC Hydro for Northwest Projects
Construction	• Major Projects Group manages and monitors significant construction projects • Strong project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost overruns and schedule risks	• Qualified and experienced team engaged to construct Northwest Projects • All Northwest Projects are in close proximity, allowing AltaGas to use same camp and support infrastructure and leverage purchasing power • Significant internal project and construction management expertise • Procurement strategy balances cost certainty with project risks • Built a 40:1 scale model of the intake structure for Forrest Kerr to mitigate engineering risk • Strong engineering expertise provided by key service provider • Strong working relationship with BC Hydro • At the end of 2011, approximately 86 percent of the cost for the Forrest Kerr Project had been fixed; expect to have 90 percent of the project cost contractually committed to fixed price contracts by December 31, 2012. • Construction of the 15 MW Harmattan cogeneration facility is 30 percent complete at the end of 2011 and expected to be on time and under budget • Construction of Gordondale peaking plant is 5 percent complete at the end of 2011
Reputation	• Active corporate and regulatory affairs departments	• Continued to strengthen the relationship with the Tahltan through their participation in the construction of the Forrest Kerr Project. 91 percent of staff at site is Tahltan • Tahltan nation voted in favour of the IBAs in

		support of the McLymont and Volcano Projects. IBAs provide significant economic and educational benefits to the Tahltan Nation • Held several events to inform and educate the communities in which AltaGas is constructing and developing projects
Regulatory	• Regulatory and commercial personnel monitor and react to regulatory issues • Build risk mitigation into contracts where possible	• AltaGas' Sundance B PPAs have provisions for financial relief in the event that policies and regulations render PPAs uneconomic • AltaGas personnel participate in industry policy and oversight committees
Environment and Safety	• Strong safety and environmental management systems, which AltaGas continually strives to improve • Focus on mitigating the impact of the SGER	• Bear Mountain generates renewable energy certificates • Bantry and Parkland gas-fired peaking plants use compressed natural gas to drive the peaking plant starter motors; compressed gas is then captured and cycled through the peaking plants rather than vented into the environment • Generate offsets and emissions performance credits from existing AltaGas operating facilities

UTILITY

Description of assets

AltaGas owns and operates utility assets that deliver natural gas to end users in Alberta, British Columbia, and Nova Scotia. AltaGas also owns a one-third interest in the utility which delivers natural gas to end users in Inuvik, Northwest Territories.

The stable, long-life energy infrastructure is underpinned by regulated returns and cost-of-service recovery that provide stable and predictable earnings and cash flows. The Utility business enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Corporation's business risk profile, thus allowing the Corporation to meet its objective of generating superior economic returns by investing in regulated, long-life assets with stable earnings.

AUI in Alberta, PNG in British Columbia and Heritage Gas in Nova Scotia operate in regulated marketplaces where they are allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on capital from the capital investment base. Return on rate base comprises regulator allowed financing costs and return on equity. Inuvik Gas in the Northwest Territories operates a natural gas distribution franchise in a "light handed" regulatory environment where delivery service and natural gas pricing are market based.

Earnings in the Utility business are highly seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. In Alberta and Nova Scotia, earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. Increases in the number of customers or changes in customer usage are other factors that might typically affect volumes and hence actual earned returns.

Regulatory Process Delivery Tariffs

AUI's, PNG's and Heritage Gas' delivery tariffs are designed to recover their approved cost-of-service and their approved return on equity. Tariffs are generally determined through General Rate Applications (GRA) to establish the revenue requirement and set the rates to be charged to various customer classes.

The utilities seek approval of their revenue requirements through either a negotiated settlement process with interested parties or through an administrative hearing before the AUC, the British Columbia Utilities Commission (BCUC) and the Nova Scotia Utility and Review Board (NSUARB), respectively. The regulators monitor the respective negotiated settlement processes and regulatory approval is required for any settlement the utilities negotiate with interested parties. Factors affecting the utilities' revenue requirements include forecasts for customer usage, rate base, distribution and other revenue, operating costs, depreciation, financing costs, income taxes and return on rate base.

Although the approved revenue requirement and subsequent approved rates are based on forecasts, and actual results can differ from these forecasts, generally no adjustment is made to either the revenue requirement or rates for actual results varying from forecast. Other than certain circumstances where a regulator approves the use of a deferral account, once the rates are approved for a period, all risks and benefits from differences in actual versus forecast energy units delivered, capital expenditures, numbers of service sites billed, operating costs, debt servicing costs and taxes are borne by AltaGas' shareholders. Actual returns achieved can therefore differ from allowed returns.

PNG has a rate stabilization adjustment mechanism approved by the BCUC which allows PNG to record the after-tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates.

Utilities key metrics:

	2011 Rate Base ($ million)	Return on Equity (%)	Debt rate (%)	Deemed Capital structure (Debt % / Equity %)	2011 Customers
AUI(1)	153.5	8.75	6.69	57/43	71,850
PNG(2)	174.1	10.09	6.61	56/44	39,400
HGL(3)	174.6	13.00	8.75	55/45	3,600
SEMCO(4)(5)					
Michigan	425.0	10.35	5.17	51.4/48.6	286,000
ENSTAR	200.0	12.55	5.75	50/50	132,000
CINGSA	100.0	12.55	7.00	50/50	n/a

(1) *AUI's 2010-2012 GRA decision expected in first quarter 2012. ROE and Capital Structure approved for 2011.*

(2) *PNG's 2012 GRA decision expected in second quarter 2012. ROE approved for 2011 and 2012.*

(3) *Heritage Gas 2011 rate base, ROE, debt rate and capital structure approved by NSUARB. 2012 ROE and debt rate approved at 11.0 percent and 7.25 percent respectively on 55 percent /45 percent debt/equity capital structure.*

(4) *Acquisition expected to close in third quarter 2012*

(5) *Expected approved rate base at the transaction close*

AltaGas Utilities Inc.

AUI serves approximately 71,850 customers (2010 – 70,788), through its 20,380 km distribution system. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. The growth of AUI's service sites and business generally occurs through infill growth in established franchises. Growth for space and water heating in AUI's service areas continues to be concentrated in town distribution systems and relates to servicing new homes and commercial developments with natural gas. AUI serves almost all of the potential market in its existing service areas. New service site installations during 2011 were 1,331 compared to 1,592 in 2010. In addition to capital expansion for new business and general plant, AUI spent $12.5 million in 2011 on its multi-year system rejuvenation program. This program is being undertaken to maintain public and worker safety and to ensure reliable and efficient long-term operation of AUI's gas delivery systems, many of which are in their fifth and sixth decade of service. AUI's capital investments grew its 2011 mid-year rate base by $18.1 million or 13 percent to $153.5 million.

For 2011, AUI's approved regulated ROE was 8.75 percent (2010 – 9.0 percent) on a prescribed capital structure of 43 percent equity and 57 percent debt. AUI is operating in regulatory lag for a number of items, including all of AUI's debt recovery rates and its full 2010 to 2012 GRA including cost-of-service and capital programs. The 2010 and 2011 capital incurred and plan for 2012 are subject to regulatory approval which is not expected until March 2012. Currently, AUI has interim refundable rates in place.

Pacific Northern Gas Ltd.

On December 20, 2011, AltaGas closed the acquisition of PNG for total consideration of $224 million including $86 million of assumed debt. The acquisition increased AltaGas' regulated rate base by 50 percent to more than $500 million. The acquisition is consistent with AltaGas' strategy of building one of North America's leading energy infrastructure companies underpinned by stable, long-life assets. PNG operates a transmission and distribution system in the west central portion of northern British Columbia (Western System) and in the areas of Dawson Creek and Fort St. John of northeast British Columbia (Northeast System). PNG operates over 3,500 km of transmission and distribution pipelines and serve a base of more than 39,000 residential, commercial and industrial customers. PNG's regulated rate based was $174.1 million in 2011.

For 2011 and 2012, PNG's weighted average approved regulated ROE is 10.09 percent on a weighted average prescribed capital structure of 44 percent equity and 56 percent debt. On November 30, 2011, PNG filed its 2012 GRA and on December 7, 2011, the BCUC approved interim rates as per the application. PNG is required to update the GRA by March 15, 2012, to reflect its new forecast of 2012 costs based on its new ownership by AltaGas.

Heritage Gas Limited

Heritage Gas has the exclusive rights to distribute natural gas to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality (HRM). Heritage Gas is a relatively new energy alternative in the province and will continue to require significant capital investment as the natural gas distribution infrastructure is constructed to provide new services to consumers in its franchise areas. Heritage Gas provides Nova Scotia consumers with the opportunity to switch heating fuel sources, mainly from oil or electricity to natural gas.

Potential customers are those with direct access to natural gas service. At the end of 2011, Heritage Gas had approximately 10,000 potential customers with access to its distribution system. Of these potential customers, Heritage Gas has installed approximately 3,800 service lines of which approximately 3,600 were activated before the end of 2011. Heritage Gas' rate base growth during 2011 was $33 million, or 23 percent, increasing average rate base to $174.6 million.

In Heritage Gas' current development stage, the actual revenues billed to customers are less than the revenue required to earn the regulated rate of return. Heritage Gas has approval from the NSUARB to accumulate, up to a maximum of $50 million, a revenue deficiency account (RDA) for this shortfall. The RDA changes based on the difference between the actual revenue billed and the revenue required to earn the rate of return approved by the NSUARB. In Heritage Gas' early development stage, it was expected that the actual revenue billed would be less than the revenue required to earn the approved rate of return and therefore an RDA asset will accumulate. As the distribution network matures, the actual revenue billed is expected to exceed the revenue required to earn the approved rate of return, and the RDA will be drawn down. The RDA is a component of Heritage Gas' rate base upon which it earns a return.

For 2011, Heritage Gas' approved regulated ROE was 13 percent (2010 – 13 percent) and debt recovery rate of 8.75 percent on a prescribed capital structure of 45 percent equity and 55 percent debt. On November 24, 2011 Heritage Gas received NSUARB approval of its negotiated settlement for rates beginning January 1, 2012, which included increases in rates charged to customers over the years 2012 to 2014. These increases in rates charged to customers are expected to reduce the RDA beginning 2012. The settlement included ROE of 11 percent and a debt recovery rate of 7.25 percent on a prescribed capital structure of 45 percent equity and 55 percent debt.

Inuvik Gas Ltd. (Inuvik Gas) & Ikhil Joint Venture (Ikhil)

AltaGas has a one third interest in Inuvik Gas, a distribution company serving the Town of Inuvik in the Northwest Territories and Ikhil, a joint venture holding natural gas reserves and related assets at Ikhil near the Town of Inuvik. In December 2010, Inuvik Gas and Ikhil announced their intention to perform repairs on a natural gas well as a result of natural gas deliverability issues. Repair work, which was concluded in March 2011, was not successful and the well was shut in.

During 2011 Inuvik Gas installed a propane air system to provide short-term, back-up energy supply to the Town of Inuvik in the event of a natural gas outage. When activated, the propane air system uses the existing natural gas system to deliver continued service to Inuvik Gas' customers.

At the end of 2011 Inuvik Gas provided service to 921 (2010 – 932) residential and commercial customers.

Capitalize on Opportunities

The Utility business pursues opportunities to enhance long-term shareholder value and deliver value to its customers. The Corporation's objectives for the Utility business are to:

- Grow its existing utility infrastructure through infill and expansion of services within current franchise areas;
- Continue the multi-year system rejuvenation program in Alberta to maintain public and worker safety, and to ensure reliable and efficient long-term operation of its gas delivery systems;
- Develop compressed natural gas (CNG) opportunities within its current utility franchise areas;
- Continue to work within regulatory processes to ensure fair returns are earned for shareholders; and
- Develop or acquire assets in new market areas in Canada and in the United States.

AUI

AUI will continue to pursue growth in its existing franchise areas and is well positioned to capture opportunities arising in its service areas. The years leading up to 2008 were of exceptional growth and the largest in AUI's history with over four percent and three percent growth in service sites in 2007 and 2008, respectively. New service site installations in the year ended December 31, 2011, were 1,331, compared to 1,592 in the same period in 2010. AltaGas expects that new business growth in 2012 will continue at the historic growth levels of approximately two percent in its Alberta utility.

2012 will mark the third year of AUI's system rejuvenation program. The program is being undertaken to maintain public and worker safety and to ensure reliable and efficient long-term operation of AUI's gas delivery systems, many of which are in their fifth or sixth decade of service. In 2012 AUI will continue the system rejuvenation program, including PVC and non-certified pipe replacement projects, steel pipe replacement, station upgrades as well as routine system betterment projects.

PNG

PNG will continue to pursue customer growth within its Northeast System as increased natural gas exploration in areas such as the Montney and Horn River drives the local economies. PNG's Western System is well positioned to capitalize on the growing demand for additional pipeline capacity along the Summit Lake to Kitimat/Prince Rupert corridor. Increased economic and industrial activity occurring in the Kitimat and Prince Rupert areas are also expected to result in increased demand for natural gas.

Heritage Gas

Heritage Gas offers strong growth potential in its franchise areas such as the continued expansion of its system in the HRM and through ongoing conversion of customers to natural gas service.

In addition to expansion of its pipeline infrastructure in 2012, Heritage Gas plans to pursue the development of CNG opportunities. There are a number of energy users in Heritage Gas' franchise area who do not have direct access to Heritage Gas' pipeline infrastructure, however could be accessed with CNG trucking. The large pricing differential between natural gas and alternative fuel sources has made CNG trucking a viable expansion opportunity for Heritage Gas.

SEMCO

On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.135 billion including US$355 million in assumed debt. SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through ENSTAR Natural Gas Company (ENSTAR) and a 65 percent interest in a regulated natural gas storage utility in Alaska under construction called Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA). SEMCO also indirectly holds a regulated natural gas distribution utility and an interest in an unregulated natural gas storage facility in Michigan (SEMCO Michigan). The acquisition of SEMCO is expected to close in third quarter 2012.

ENSTAR delivers natural gas to approximately 132,000 customers, primarily residential and is the largest natural gas distributor in Alaska. ENSTAR has experienced 2.5 percent compounded annual growth over the past 10 years in customer and net plant growth. Growth is expected to continue as Alaska continues to benefit from the significant activity in the natural resource sector. Regulated rate base in Alaska, including SEMCO's interest in CINGSA, is expected to be approximately $300 million.

SEMCO Michigan delivers natural gas to approximately 286,000 customers. The customer base of SEMCO Michigan has remained stable through the recent economic downturn and is anticipated to have stable growth of approximately 1 to 2 percent over the long-term as the Michigan economy, and in particular the local economies in SEMCO Michigan's service areas, improve. Regulated rate base in Michigan is expected to be approximately $425 million.

Utility Outlook

Results in 2012 are expected to be stronger than 2011, driven by rate base growth of 14 percent and 16 percent at AUI and Heritage Gas, respectively. The addition of PNG and SEMCO are also expected to result in a significant increase in earnings and cash flow from the Utility segment. The first full year of PNG is expected to add approximately $25 million in EBITDA and SEMCO upon close in third quarter is expected to add approximately $40 million in EBITDA in fourth quarter 2012. Utility results will also be impacted by the one-time charge of approximately $7.0 million of transaction costs related to the SEMCO acquisition. AltaGas expects regulated rate base at the utilities to increase from approximately $505 million in 2011 to $1.3 billion in 2012. This growth will come from the addition of $725 million of rate base through the SEMCO acquisition and approximately $70 million through organic growth within AUI, PNG, Heritage Gas as well as spending in fourth quarter at SEMCO. AltaGas expects total utility customers to increase from approximately 115,000 in 2011 to approximately 536,000 in 2012. AltaGas has a $20 million contingent payment receivable related to PNG's 2011 sale of its interest in PTP. Receipt of the payment is contingent on the purchasers of PTP making a decision to proceed with construction of the Kitimat LNG facility.

AUI

AltaGas expects AUI to perform in line with expectations as filed in its 2010 to 2012 GRA. In 2012, AUI is forecast to spend approximately $29 million, growing mid-year rate base by 14 percent to approximately $174 million. For 2012, AUI's approved regulated ROE is 8.75 percent on a prescribed equity of 43 percent.

AUI is operating in regulatory lag for a number of items, including all of AUI's debt recovery rates and its full 2010 to 2012 GRA including costs of service and capital programs. The 2010 and 2011 capital incurred and plan for 2012 are subject to regulatory approval which is not expected until March 2012.

AUI filed its Incentive Regulation (IR) application in July 2011 which will change the basis of AUI's regulation from a cost-of-service recovery model to an incentive based model. A hearing for AUI's IR application is scheduled for April 2012 with a decision expected in the third quarter of 2012. IR will be effective January 1, 2013, and the initial term is expected to be five years.

PNG

AltaGas expects PNG to perform in line with its 2012 GRA. In 2012, PNG is forecast to spend approximately $8 million on its regulated business, to grow rate base to approximately $177 million. For 2012, PNG's approved weighted average regulated ROE is 10.09 percent on a weighted average prescribed equity of 44 percent.

On November 30, 2011, PNG filed its 2012 GRA and on December 7, 2011, the BCUC approved interim rates as requested in the application. PNG is required to update the GRA by March 15, 2012 to reflect its new forecast of 2012 costs based on the December 20, 2011, acquisition by AltaGas. A decision on the application is not expected until summer 2012.

PNG has a $20 million contingent payment receivable related to PNG's 2011 sale of its interest in PTP. Receipt of the payment is contingent on the purchasers of PTP making a decision to proceed with construction of the Kitimat LNG facility.

Heritage Gas

AltaGas expects Heritage Gas to perform in line with the first year of its 2012 to 2014 GRA settlement. In 2012, Heritage Gas is forecast to spend approximately $26 million to continue the expansion of service to the Bedford, Dartmouth, Halifax Mainland, Halifax Peninsula - regions of the Halifax Regional Municipality along with the Amherst/Airport region with the installation of approximately 50 km of mains and the connection of 600 new customers. The RDA, a component of rate base, is expected to decrease slightly in 2012. Through the net combination of capital expenditures and RDA changes, mid-year rate base is expected to grow by 16 percent to approximately $202 million. For 2012, Heritage Gas' approved ROE is 11 percent and the debt recovery rate is 7.25 percent on a prescribed capital structure of 45 percent equity and 55 percent debt.

Inuvik Gas Ltd. (Inuvik Gas) & Ikhil Joint Venture (Ikhil)

Ikhil and Inuvik Gas are evaluating short and long-term strategies for maintaining gas supply and are currently taking steps to mitigate the impact of a shortage of gas supply from the currently producing well. These steps have included the decision by the Northwest Territories Power Corporation (NWTPC) to convert to 90 percent diesel for its power generation from natural gas. The conversion commenced in early 2012. Natural gas production from the second well at Ikhil currently meets the demands of Inuvik Gas, the gas supplier for the Town of Inuvik. A report on the estimated life of reserves has been finalized which indicates that as at December 31, 2011, there are approximately 1.2 to 2.3 years remaining at current and anticipated usage rates. The Ikhil Joint Venture operator, on behalf of the joint venture partners, continues to work with consultants and other parties to evaluate alternative gas supply production options for meeting future requirements.

Utility Risk Management

AltaGas manages its exposure to risk in the Utility business using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Weather	• Earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated • Anticipated volumes are determined based on the 20 year rolling average for weather • PNG has a weather normalization account which means variations in weather to not affect PNG's earnings	• AUI 2011 weather was at normal levels (2010 1.6 percent warmer than normal) • Heritage Gas was 12.7 percent warmer than normal in 2011 (2010 – 13.2 percent warmer than normal)
Rate Regulated Environment	• Skilled regulatory department retained at AUI, PNG, Heritage Gas and AltaGas head office • Maintain strong working relationship with the respective regulators and their staff • Use of expert consultants when needed	• Received AUC decision on the 2011 Generic Cost of Capital on December 8, 2011 approving ROE of 8.75 percent with no change to financing structure. • Negotiated a settlement agreement with the active interveners for all matters related to Heritage Gas' 2012 to 2014 GRA. The settlement agreement was approved by NSUARB on November 24, 2011. Settlement included 11 percent ROE, 7.25 percent debt rate and recovery of all applied for operating and administrative costs. • Received BCUC approval for the change of

		control application for the acquisition of PNG.
Construction	• Appropriate internal management structure and processes • Strong project cost control and project management framework • Engage specialists in designing and building major projects	• Practiced effective procurement policies and procedures and vendor selection • AUI successfully completed the second year of system betterment projects in 2011 on time and on budget.
Environment and safety	• Strong safety and environmental management systems, which AltaGas continually strives to improve	• AUI conducted its first organization-wide Safety Stand Down to acknowledge safety as the most important corporate value. • AUI operated throughout 2011 in full compliance with all environmental regulations related to its business. • AUI continued its significant investment in infrastructure rejuvenation to ensure reliable and safe natural gas system operations. • Heritage Gas continues to promote safe excavation practices via participation in an initiative to create an Atlantic Region Common Ground Alliance chapter.

CONSOLIDATED FINANCIAL RESULTS

($ millions) Years ended December 31	**2011**	2010	2009
Revenue	**1,563.8**	1,354.1	1,268.3
Net revenue[(1)]	**526.7**	485.5	456.6
Normalized EBITDA[(1)]	**282.1**	249.6	242.0
Operating income[(1)]	**174.8**	153.1	170.6
Net income applicable to common shares	**83.6**	97.2	141.3
Normalized net income[(1)]	**102.1**	101.7	132.7
Total assets	**3,542.4**	2,752.5	2,628.9
Total long-term liabilities	**1,609.7**	1,217.4	719.1
Net additions to property, plant and equipment	**642.6**	211.7	486.4
Dividends declared[(2)]	**112.2**	54.1	-
Distributions declared[(3)]	-	87.0	170.2
Cash flows			
Normalized funds from operations[(1)]	**225.7**	194.7	202.3

($ per share)	**2011**	2010	2009
Normalized EBITDA[(1)]	**3.36**	3.06	3.08
Net income - basic	**0.99**	1.19	1.80
Net income - diluted	**0.98**	1.19	1.79
Normalized net income[(1)]	**1.21**	1.25	1.69
Dividends declared[(2)]	**1.33**	0.66	-
Distributions declared[(3)]	-	1.08	2.16
Cash flows			
Normalized funds from operations[(1)]	**2.69**	2.39	2.58
Shares outstanding - basic (millions)			
During the period[(4)]	**84.0**	81.5	78.5
End of period	**89.2**	82.5	80.3

(1) *Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of this MD&A.*
(2) *Dividends declared of $0.11 per common share per month commencing July 2010 and $0.115 commencing October 27, 2011*
(3) *Distributions declared of $0.18 per trust unit and exchangeable unit per month for the first six months of 2010.*
(4) *Weighted average.*

FULL YEAR 2011 CONSOLIDATED FINANCIAL REVIEW

In 2011, AltaGas delivered stronger results from its operating businesses compared to 2010. Normalized operating income reported by the three business segments was higher at $221.0 million; a 19 percent increase over $185.0 million in 2010. The results reflect the higher natural gas volumes processed at extraction and field gathering facilities processing higher liquids-rich gas, higher frac spreads, higher power generated and higher rate base at the utilities. The increases were partially offset by the scheduled turnarounds at Harmattan and Younger, as well as lower daily contract quantities on the Suffield pipeline and lower volumes at some field facilities as a result of the impact of low natural gas prices in areas producing dry gas.

Normalized net income before taxes in 2011 was 25 percent higher at $136.5 million compared to $108.7 million in 2010. In 2011, AltaGas reported transaction costs primarily related to the acquisition of PNG of $5.7 million (pre-tax) and mark-to-market losses of $17.4 million (pre-tax).

Normalized net income for 2011 was $102.1 million ($1.21 per share) compared to $101.7 million ($1.25 per share) for 2010. Net income applicable to common shares for 2011 was $83.6 million ($0.99 per share) compared to $97.2 million

($1.19 per share) in 2010. In 2011, AltaGas reported future income taxes of $18.6 million, based on a full year as a corporation, compared to $1.9 million in 2010, based on being a corporation for six months.

On a cash flow basis, normalized funds from operations was $225.7 million ($2.69 per share) in 2011 compared to $194.7 million ($2.39 per share) in 2010. Normalized EBITDA in 2011 was $282.1 million compared to $249.6 million in 2010. For the year ended December 31, 2011, AltaGas declared dividends to common shareholders of approximately 50 percent of normalized funds from operations.

The Gas segment reported higher operating income of $104.9 million in 2011, compared to $86.9 million in 2010. Results in the Gas business were stronger despite the $12 million impact of two major scheduled turnarounds in 2011. Increased earnings were due to higher realized frac spreads, higher frac exposed volumes, sale of the Groundbirch facility, higher fees earned from increased extraction volumes, contributions from new and expanded gas processing facilities, lower amortization, lower administration costs as a result of cost cutting measures, settlement of a take-or-pay contract, increased revenues from gas services provided and lower provision for doubtful customer receivables. These increases were partially offset by lower volumes processed at some gas processing facilities, the impact of scheduled major turnarounds, lower daily contract quantity on the Suffield system, increased variable operating costs associated with more extraction volumes and lower margins realized in the natural gas storage business.

The Power segment reported operating income for 2011 of $86.0 million, a 15 percent increase, compared to $74.7 million in 2010. Operating income increased as a result of higher realized power prices, higher generation from the Cogeneration I, higher run time of the gas-fired peaking plants, and higher generation from Bear Mountain. These increases were partially offset by higher PPA costs, higher general and administrative expenses, amortization resulting from the recent growth and transaction costs related to the acquisition of power assets in the U.S.

The Utility segment reported higher operating income of $24.4 million in 2011 compared to $23.4 million in 2010. The increase was mainly due to growth in rate base of 13 percent and 23 percent at AUI and Heritage Gas, respectively, and the addition of the PNG assets, partially offset by transaction costs related to the acquisition of PNG, higher depletion rate related to the Ikhil assets and higher unrecoverable corporate expenses.

The Corporate segment reported a higher loss of $40.5 million in 2011 compared to $31.9 million in 2010. The increase was due to the mark-to-market loss related to an equity investment in a publicly traded company. Adjusting for the impact of mark-to-market accounting, the Corporate segment reported an operating loss of $31.3 million compared to $27.4 million in 2010. In 2010, AltaGas recorded approximately $7.1 million in realized gains from an equity investment.

On a consolidated basis, net revenue for 2011, was $526.7 million compared to $485.5 million in 2010. The Gas segment reported higher net revenue compared to the prior year due to higher frac exposed volumes, higher frac spreads, the sale of Groundbirch, settlement of a take-or-pay contract, contributions from new and expanded gas processing facilities and higher fees earned from increased extraction volumes. The higher net revenue was partially offset by lower throughput at some processing facilities, lower transmission revenues and lower margins realized in the natural gas storage business. Net revenue in the Power segment was higher due to increased generation from Bear Mountain, the addition of Cogeneration I and higher generation from the gas-fired peaking plants, partially offset by higher environmental compliance costs and higher transmission costs. The Utilities reported higher net revenue mainly due to growth in rate base, including the addition of PNG, and higher recoverable costs at AUI and Heritage Gas. The Corporate segment recorded lower net revenue due to lower realized investment income, higher mark-to-market losses on risk management contracts and an equity investment.

Operating and administrative expense for 2011 was $267.7 million, up from $241.5 million in 2010. The increase was primarily due to incremental costs at extraction facilities from higher volumes processed and expenses incurred during turnarounds, transaction costs primarily related to the acquisition of PNG, partially offset by lower general and administrative expenses.

Amortization expense for 2011 was $90.1 million compared to $89.2 million in 2010. Accretion expense for 2011 was $2.4 million compared to $2.9 million in 2010.

Interest expense for 2011 was $52.7 million compared to $48.8 million in 2010. The increase was due to a higher average borrowing rate of 6.2 percent (2010 - 5.4 percent) and a higher average debt balances of $1,032.6 million (2010 - $988.0 million).

Capitalized interest for 2011 was $11.0 million compared to $4.4 million in 2010.

In 2011, an income tax expense of $18.8 million was reported compared to an income tax expense of $1.7 million in 2010. The increase was due to higher income subject to taxation as a result of the conversion to a corporate structure in July 2010. The increased income tax expense was partially offset by a decrease of $6.8 million to future income tax liabilities. The Corporation has followed the practice of determining its future taxes provision utilizing an estimated future tax rate of 26 percent, applied to the difference between the book carrying values and the tax bases of assets and liabilities. In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflected the substantively enacted tax rates anticipated to be in effect in the periods in which the differences are expected to reverse.

GROWTH CAPITAL

Based on projects currently under review, development or construction and the cash to close the pending acquisition of SEMCO, AltaGas expects capital expenditure for 2012 to be approximately $1.5 billion allocated approximately 20 percent for Gas, 25 percent for Power and 55 percent for Utilities.

AltaGas is well positioned to fund its committed capital program through its growing internally-generated cash flow, its dividend reinvestment plan, its available credit on bank lines and its continued strong access to capital markets. On closing of the SEMCO acquisition and upon satisfaction of certain escrow release conditions, the 13,915,000 subscription receipts issued on February 22, 2012, will be converted to 13,915,000 common shares of AltaGas for gross proceeds of approximately $403 million. As at December 31, 2011, the Corporation had $848.3 million of available credit facilities. On March 2, 2012, AltaGas closed a new US$300 million credit facility which expires March 2, 2013, and extended the term of its $600 million and $75 million credit facilities to May 30, 2016.

SEMCO Acquisition

On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.135 billion including US$355 million in assumed debt. SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through ENSTAR and a 65 percent interest in a regulated natural gas storage utility in Alaska under construction called CINGSA. SEMCO also indirectly holds a regulated natural gas distribution utility and an interest in an unregulated natural gas storage facility in Michigan. The acquisition of SEMCO is expected to close in third quarter 2012.

Forrest Kerr Hydroelectric Project

Construction of the Forrest Kerr Project is progressing well. The project includes approximately 4,879 major linear meters of tunneling. Excavation of the tunnels has advanced as expected due to a stable and consistent rock formation. As at December 31, 2011, a total of 2,270 linear meters have been excavated and approximately 86 percent of the project costs have been contractually committed to fixed price contracts. Five of eight tunnels were completed and excavation of the power tunnel and power house began. In 2011, manufacturing of the turbines began and work progressed on the desander, intake structure and the 37 km transmission line to the Bob Quinn station. The Forrest Kerr Project is expected to be completed and operational by July 2014 for a total cost of approximately $725 million. AltaGas has a 60-year EPA with BC Hydro which is fully indexed to CPI.

McLymont Creek and Volcano Creek Hydroelectric Projects

AltaGas signed 60-year inflation indexed EPAs with BC Hydro and Impact Benefit Agreements with the Tahltan First Nation for its 66 MW McLymont Creek and 16 MW Volcano Creek run-of-river projects. Subject to environmental assessment and permitting, construction is expected to begin in the latter half of 2012 and 2013 for McLymont Creek and Volcano Creek, respectively. Combined the two projects are estimated to cost approximately $300 million and are scheduled to be in service in late 2015.

Harmattan Co-stream Project

The Co-stream Project will use 250 Mmcf/d of existing spare capacity to recover ethane and other NGL from natural gas sourced from the NOVA Gas Transmission Ltd. (NGTL) Western System. The project costs are expected to be slightly over the budgeted costs of $130 million plus 20 percent contingency and is expected to commence operations in second quarter 2012. Costs have increased as a result of higher engineering costs, rock formations along the pipeline route, increased equipment costs and in-plant construction costs. The project timeline is delayed slightly due to an additional National Energy Board ("NEB") process that was not anticipated. The NEB approval to connect the AltaGas pipeline to the TransCanada pipeline has been obtained. AltaGas has experienced the impact of labour and engineering shortages but has managed to mitigate some of those increases by employing smaller, local contractors. Management will continue to look for ways of managing the rising costs of construction in Alberta. Based on current capital cost estimates, AltaGas expects the annual EBITDA contribution to be slightly over $25 million.

AltaGas had $146 million of committed capital costs by the end of 2011. Pipeline construction was 95 percent complete by year-end and plant construction is proceeding as planned with the first phase of construction successfully completed before year-end. As at December 31, 2011, 70 percent of expected costs were incurred.

On March 4, 2011, AltaGas entered into a definitive agreement with NOVA Chemicals for the project. The agreement is for an initial term of 20 years whereby AltaGas will deliver all natural gas liquids extracted from co-stream gas on a full cost-of-service basis to NOVA Chemicals. The agreement provides that all capital expenditures and operating costs related to the project will be fully recovered through fees under normal operations.

In early January 2011, two of initial interveners in AltaGas' Energy Resources Conservation Board (ERCB) application filed notices of motion for leave to appeal the ERCB decision to approve the Co-stream Project at the Court of Appeal of Alberta. In late January, one of those parties filed an application with the ERCB for a Review and Variance of the ERCB Decision. The application was dismissed by the ERCB on May 27, 2011. The leave to appeal applications were heard on June 8, 2011 and the appealing parties were granted leave to appeal on August 8, 2011. The appealing parties filed their notices of appeal with the Alberta Court of Appeal on September 7, 2011, and the hearing date has been set for April 5, 2012. AltaGas continues to believe that the grounds set forth by the intervening parties for appeal are without merit. AltaGas remains committed to the construction schedule as outlined above. One of the parties applied to the ERCB for a stay of the ERCB decision approving the Co-stream Project, which was rejected by the ERCB on September 9, 2011.

Gordondale Gas Plant

In 2011, construction proceeded on AltaGas' 120 Mmcf/d Gordondale facility in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The plant will be equipped with liquids extraction facilities. The facility is supported by a long-term gathering and processing agreement with a major natural gas producer to supply natural gas to the facility. AltaGas expects the annual EBITDA contribution to be $30 million to $35 million. The facility and associated gas gathering system is expected to cost approximately $236 million and be in service late 2012. The project is experiencing cost pressures primarily related to the shortage of labour and engineering expertise. Management continues to manage construction to mitigate rising costs, for example by moving to shop manufacturing of modules that require less field labour for on-site construction. Management will continue to look for ways of managing the rising costs of construction in Alberta.

AltaGas had approximately $180 million of committed capital costs by the end of 2011. In total, approximately two-thirds of costs are expected to be contractually fixed over the course of construction. The remainder will be subject to cost and labour productivity risk.

Harmattan Cogeneration II

In 2011 AltaGas began construction of a second 15 MW cogeneration unit at Harmattan to supply steam and power to the Co-stream Project. Cogeneration II is estimated to cost $24 million and be in service during second quarter 2012.

$20 million of costs have been committed for this project. The application to the Alberta Utilities Commission (AUC) was approved in fourth quarter 2011, as was the Alberta Environment application license.

Busch Ranch Project

AltaGas has acquired a 50 percent interest in a wind farm project with Black Hills in southern Colorado. Black Hills received approval from the Colorado Public Utilities Commission to construct a 29 MW wind farm in Huerfano County, just south of Pueblo, Colorado. The project is planned for completion in late 2012 and has a 25-year PPA.

Under the arrangement, AltaGas has no construction risk. The wind farm has abundant wind resources and is in close proximity to an existing transmission system that serves the 94,000 customers of Black Hills in southern Colorado.

Blair Creek

The approximate $42 million expansion of the Blair Creek began construction in late 2011. The expansion will increase production capacity by 50 Mmcf/d and raise the licensed capacity to 82 Mmcf/d. The expansion is expected to be completed in second quarter 2012. The expansion is contractually supported by three active producers in the area.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and its capacity to fund dividends, capital expenditures and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

Net revenue

Years ended December 31 ($ millions)		**2011**	2010	2009
Net revenue		**526.7**	485.5	456.6
Add:	Cost of sales	**1,037.1**	868.6	811.7
Revenue (GAAP financial measure)		**1,563.8**	1,354.1	1,268.3

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of natural gas and power affect both revenue and cost of sales.

Normalized Operating Income

Years ended December 31 ($ millions)		**2011**	2010	2009
Normalized operating income		**189.6**	157.5	164.8
Add (deduct):	Unrealized gain (loss) on held-for-trading	**(9.1)**	(4.4)	5.8
	Transaction costs	**(5.7)**	-	-
Operating income		**174.8**	153.1	170.6
Add (deduct):	Unrealized gain (loss) on risk management contracts	**(8.3)**	(1.3)	3.7
	Interest expense	**(52.7)**	(48.8)	(31.8)
	Foreign exchange (loss)	**(0.4)**	(0.1)	-
	Income tax (expense) recovery	**(18.8)**	(1.7)	(1.2)
	Preferred share dividend (net of tax)	**(11.0)**	(4.0)	-
Net income applicable to common shares (GAAP financial measure)		**83.6**	97.2	141.3

Operating income is a measure of AltaGas' profitability from its principal operating activities prior to how these activities are financed, how the results are taxed, or the impact of unrealized gains or losses on risk management contracts. The measure is used by management to assess operating performance since it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, interest expense, foreign exchange loss, income tax (expense) recovery and preferred share dividend (net of tax).

Normalized operating income represents operating income adjusted for non-operating related expenses such as transaction costs related to acquisitions and mark-to-market gains and losses related to equity investments.

Normalized EBITDA
Years ended December 31

($ millions)		**2011**	2010	2009
Normalized EBITDA		**282.1**	249.6	242.0
Add (deduct):	Unrealized gain (loss) on held-for-trading	**(9.1)**	(4.4)	5.8
	Transaction costs	**(5.7)**		
EBITDA		**267.3**	245.2	247.8
Add (deduct):	Unrealized (loss) on risk management contracts	**(8.3)**	(1.3)	3.7
	Amortization	**(90.1)**	(89.2)	(74.1)
	Accretion of asset retirement obligations	**(2.4)**	(2.9)	(3.1)
	Interest expense	**(52.7)**	(48.8)	(31.8)
	Foreign exchange (loss)	**(0.4)**	(0.1)	-
	Income tax (expense)	**(18.8)**	(1.7)	(1.2)
	Preferred share dividends (net of tax)	**(11.0)**	(4.0)	-
Net income applicable to common shares (GAAP financial measure)		**83.6**	97.2	141.3

EBITDA is a measure of AltaGas' operating profitability without the impact of risk management contracts and prior to how business activities are financed, assets are amortized or how earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, and therefore evaluates company performance excluding unrealized gains or losses from risk management contracts. EBITDA is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, amortization, accretion of asset retirement obligations, interest expense, income tax (expense) recovery, and preferred share dividends (net of tax).

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as transaction costs related to acquisitions and mark-to-market gains and losses related to equity investments.

Normalized Net Income

Years ended December 31 ($ millions)	**2011**	2010	2009
Normalized net income	**102.1**	101.7	132.7
Add (deduct):			
Unrealized (loss) gain on risk management contracts	**(6.2)**	(0.7)	3.5
Unrealized (loss) gain on held for trading assets	**(8.0)**	(3.8)	5.1
Transaction costs after taxes	**(4.3)**	-	-
Net Income applicable to common shares (GAAP financial measure)	**83.6**	97.2	141.3

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related (expenses) recoveries, such as transaction costs related to acquisitions.

Normalized Funds from Operations

Years ended December 31 ($ millions)	**2011**	2010	2009
Normalized funds from operations	**225.7**	194.7	202.3
Add (deduct): Transaction costs	**(5.7)**	-	-
Funds from operations	**220.0**	194.7	202.3
Add (deduct): Net change in non-cash working capital	**(9.3)**	(0.8)	(17.8)
Asset retirement obligations settled	**(0.9)**	(0.5)	(0.4)
Cash from operations (GAAP financial measure)	**209.8**	193.3	184.1

Normalized funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in non-cash working capital in the period and non-operating related expenses (recoveries) such as transaction costs related to acquisitions. Funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP. Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash from operations before net changes in non-cash working capital, expenditures incurred to settle asset retirement obligations and non-operating related expenses, such as transaction costs related to acquisitions.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income

Years ended December 31 ($ millions)	**2011**	2010
Gas	**104.9**	86.9
Power	**86.0**	74.7
Utility	**24.4**	23.4
Sub-total: Operating Businesses	**215.3**	185.0
Corporate[1]	**(40.5)**	(31.9)
	174.8	153.1

[1] Includes mark-to-market loss on equity investments, excludes mark-to-market losses on risk management contracts.

GAS

OPERATING STATISTICS

Years ended December 31	**2011**	2010
E&T		
Extraction inlet gas processed (Mmcf/d)(1)	**883**	798
Extraction ethane volumes (Bbls/d)(1)	**26,565**	25,453
Extraction NGL volumes (Bbls/d)(1)	**14,513**	12,654
Total extraction volumes (Bbls/d)(1)	**41,078**	38,107
Frac spread - realized ($/Bbl)(1) (2)	**33.67**	27.27
Frac spread - average spot price ($/Bbl)(1) (3)	**42.88**	31.95
FG&P		
Processing throughput (gross Mmcf/d)(1)	**391**	423
Capacity utilization (%)(4)	**33**	35
Energy Services		
Average volumes transacted (GJ/d)(5)	**369,603**	386,004

(1) *Average for the period.*

(2) *Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from sales recorded by the business during the period on frac exposed volumes plus the settlement value of frac hedges settled in the period divided by the total frac exposed volumes produced during the period.*

(3) *Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, and derived from the average sales price at AltaGas' facilities received for propane, butane and condensate and the daily AECO natural gas price.*

(4) *As at the end of the reporting period.*

(5) *Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.*

In 2011, average ethane and NGL volumes in the extraction business increased by 1,112 Bbls/d and 1,859 Bbls/d, respectively compared to 2010. Volumes were higher at most extraction facilities as a result of higher inlet volumes, successful contracting efforts for Empress extraction facilities, commencement of the Septimus Pipeline in December 2011, partially offset by Harmattan and Younger turnarounds.

In 2011, throughput in FG&P averaged 391 Mmcf/d compared to 423 Mmcf/d in 2010. Volumes were lower, despite the addition of the Marlboro plant in May and an expansion of the Alder Flats facility completed at the end of April. The lack of producer activity in response to low natural gas prices has resulted in overall lower average processing volumes of approximately 70 Mmcf/d from natural declines or well shut-ins during 2011 compared to the same period in 2010. These reductions were offset by increased production at certain FG&P facilities that saw higher throughput on average of 39 Mmcf/d over the prior year. This equates to an annual average replacement factor, (the ratio of higher volumes at certain facilities compared to facilities recording lower volumes) of more than 50 percent during 2011 compared to 33 percent in 2010.

2011 Financial Results

The Gas segment reported operating income of $104.9 million for 2011, a 21 percent increase compared to $86.9 million in 2010.

The financial impact of scheduled major turnarounds at Younger and Harmattan was approximately $12 million in 2011. Operating income increased due to higher realized frac spreads, higher frac exposed volumes, sale of Groundbirch, higher fees earned from increased extraction volumes, contributions from new and expanded gas processing facilities, lower amortization, settlement of a take-or-pay contract, increased revenues from gas services provided and lower provision for doubtful customer receivables. These increases were partially offset by lower volumes processed at some gas processing facilities, the impact of scheduled turnarounds, lower daily contract quantity at the Suffield system, increased variable operating costs associated with more extraction volumes and lower margins realized in the natural gas storage business.

Excluding one-time items in 2011 and 2010, the Gas segment increased operating income by more than 20 percent during 2011 compared to 2010. Operating income earned from unhedged frac spreads was approximately 18 percent in 2011 compared to 20 percent in 2010 when compared to the overall operating income for the Gas segment.

Net revenue increased $22.1 million due to higher realized frac spreads and higher frac exposed volumes, $4.7 million from higher operating expense recoveries, $5.3 million from higher fees earned from increased extraction volumes, contributions from new and expanded gas processing facilities of $1.8 million, increased contributions of $1.6 million from gas services and lower provision for doubtful accounts of $1.0 million. In addition, net revenue increased due to one-time items that included the sale of Groundbirch for a gain of $6.2 million and the settlement of a take-or-pay contract for $2.0 million. These increases were partially offset by lost revenue impact from Younger and Harmattan turnarounds of $5.9 million, lower transmission revenues of $5.4 million which was driven largely by lower daily contract quantity on the Suffield system, lower volumes processed at certain gas processing facilities of $4.0 million and lower natural gas storage margins of $2.3 million.

Operating and administrative expense for 2011 was $177.4 million compared to $163.8 million in 2010. Operating costs during the period increased as a result of Younger and Harmattan turnarounds of approximately $6 million and increased variable costs associated with more extraction volumes. These increases were partially offset by lower administration costs as a result of increased efficiencies and full-year cost saving measures implemented in 2010.

Amortization expense for 2011 was $55.0 million compared to $59.1 million in 2010. Accretion expense for 2011 was $2.4 million compared to $2.8 million in 2010. The decreases were due to revisions in estimates in the lives of certain facilities, partially offset by additional amortization expenses associated with new or expanded facilities.

POWER

OPERATING STATISTICS

Years ended December 31	**2011**	2010
Volume of power sold (GWh)(1)(2)	**3,003**	2,828
Average price realized on the sale of power ($/MWh)(1)(2)	**75.94**	66.79
Alberta Power Pool average spot price ($/MWh)(1)	**76.22**	50.76

(1) Average for the period.

(2) Includes both Alberta and British Columbia sale of power.

2011 Financial Results

Operating income for 2011 was $86.0 million, a 15 percent increase compared to $74.7 million in 2010. Overall results in power were driven by the addition of new power generating assets and higher generation from Bear Mountain. While power prices in Alberta were significantly higher in 2011 compared to 2010, the net contribution to operating income from the Sundance PPA was similar to 2010 due to the hedging strategy as well as the RAPP mechanism of the PPA which resulted in higher PPA costs. Operating income increased as a result of higher realized power prices, higher generation from Cogeneration I and Bear Mountain, and higher run-time of the gas-fired peaking plants, partially offset by higher PPA costs, higher general and administrative costs and higher amortization resulting from the recent growth. For 2011, AltaGas hedged 62 percent of power sold in Alberta at an average price of $70/MWh compared to 63 percent hedged at $64.50/MWh in 2010.

Net revenue for 2011 was $120.0 million compared to $101.8 million in 2010. $19.5 million was primarily due to higher realized power prices, $6.6 million from higher generation from Cogeneration I, $6.0 million from higher run-time of the gas-fired peaking plants, $6.7 million from higher generation at Bear Mountain, $0.9 million from the C&I activity, partially offset by higher PPA costs of $21.5 million.

Operating and administrative expense was $17.6 million for 2011 compared to $11.8 million in 2010. This increase was primarily due to the full year operation of Cogeneration I, higher run times of the peaking facilities, higher general and administrative costs and transaction costs associated with recent acquisitions. Amortization expense was $16.3 million for 2011 compared to $15.3 million in 2010. This increase was primarily due to the addition of Cogeneration I.

UTILITIES

OPERATING STATISTICS

Years ended December 31	**2011**	2010
Natural gas deliveries - end-use (PJ)[1]	**21.8**	19.9
Natural gas deliveries - transportation (PJ)[1]	**4.6**	5.3
Service sites [2]	**115,932**	74,664
Degree day variance from normal - AUI (%) [3]	**-**	(1.6)
Degree day variance from normal - Heritage Gas (%) [3]	**(12.7)**	(13.2)

[1] *Petajoule (PJ) is one million gigajoules (GJ).*

[2] *Service sites reflect all of the service sites of AUI, Heritage Gas, PNG and Inuvik Gas.*

[3] *Degree days relate to AUI and Heritage Gas service areas. A degree day is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not affect the results of PNG for its residential and small commercial customers due to a BCUC approved rate stabilization mechanism.*

The Utility segment is predominantly comprised of natural gas distribution rate regulated utilities, where financial results are based on a regulated allowed return on capital invested. Rate regulated cost-of-service utilities such as AUI in Alberta, Heritage Gas in Nova Scotia, and PNG in British Columbia generally collect operating and administrative costs, depreciation, interest expenses and income taxes paid in the rates charged to customers, and therefore changes in these costs do not normally impact the contribution to consolidated net income of the Corporation.

Operating income in the Utility segment is highly seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This results in stronger first and fourth quarters and weaker second and third quarters. Results for AUI and Heritage Gas can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. For AUI and Heritage Gas, increases in the number of customers or changes in customer usage are examples of other factors that might typically affect volumes and hence earned returns. PNG has a rate stabilization adjustment mechanism approved by the BCUC which allows PNG to record the after tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates.

2011 Financial Results

Operating income for 2011 was $24.4 million compared to $23.4 million in 2010. Operating income increased due to rate base growth at AUI and Heritage Gas as well as the acquisition of PNG. The increases were partially offset by transaction costs related to the PNG acquisition, higher depletion rate related to the Ikhil assets and higher corporate administrative expenses. On a combined basis, weather was not significantly different for the Utility segment in 2011 as compared to 2010.

Rate base growth of 13 percent and 23 percent at AUI and Heritage Gas, respectively, drove the 2011 results, providing an additional $4.9 million of operating income. In addition, the results for PNG during the last 11 days of the year contributed $1.3 million to 2011 operating income. These increases to operating income were partially offset by PNG's acquisition costs of $3.5 million and $2.4 million higher depletion expense at Ikhil.

Net revenue for 2011 was $86.2 million compared to $71.9 million in 2010. Net revenue increased $4.9 million from rate base growth at AUI and Heritage Gas along with $2.4 million of additional net revenue from the acquisition of PNG in late 2011. The remainder of the increased net revenue was mainly due to higher recoverable costs at the utilities.

Operating and administrative expenses for 2011 were $47.1 million compared to $36.9 million in 2010. The increases in operating costs were mainly at the regulated utilities which generally recover their costs through rates charged to their customers and the $3.5 million of acquisition costs related to the purchase of PNG. Operating costs at Ikhil were $1.0 million greater in 2011 due to repair work on one of the two gas supply wells.

Amortization expense for 2011 was $14.7 million compared to $11.6 million in 2010. The increased amortization was mainly due to $2.4 million higher depletion expense at Ikhil due to lower expected remaining reserves. The remaining increase in amortization was due to higher investment in property, plant and equipment and intangible assets.

CORPORATE

Description of Corporate Assets

The Corporate reporting segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity and return on capital without the impact of the volatility in commodity prices, interest rates and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity since risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting is reported and monitored in the Corporate segment.

2011 Financial Results

The operating loss for 2011 was $40.5 million compared to $31.9 million in 2010. The operating loss increased by $7.1 million due to lower investment gains realized and income received and $4.7 million higher unrealized mark-to-market losses on equity investments, partially offset by lower general and administrative costs of $4.1 million. Amortization expense was $4.1 million for 2011 compared to $3.1 million in 2010. The increase was due to an increase in Corporate assets.

Operating and administrative expense was $27.5 million for 2011 compared to $31.6 million in 2010. Lower expenses were a result of cost saving measures implemented and lower general and administrative costs primarily due to costs incurred in 2010 related to the International Financial Reporting Standards (IFRS) conversion project, conversion to a corporation and Harmonized Sales Tax (HST) compliance costs.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2012 in the Corporate segment is expected to be lower than the loss reported in 2011. During 2011, AltaGas incurred one-time costs related to the planned 2012 transition to US GAAP.

The effects of risk management contracts are based on estimates relating to commodity prices, interest rates and foreign exchange rates over time. The actual amounts will vary based on these drivers, and management is therefore unable to predict the impact of financial instruments on 2012 results. AltaGas does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2011, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $748.2 million compared to $227.0 million in 2010.

Invested Capital - Investment Type

Years ended December 31, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**280.9**	**167.0**	**211.5**	**8.5**	**667.9**
Intangible assets	**5.3**	**91.3**	**0.4**	**1.4**	**98.4**
Long-term investments and other assets	**(0.3)**	**(0.5)**	**0.3**	**(17.6)**	**(18.1)**
	285.9	**257.8**	**212.2**	**(7.7)**	**748.2**
Disposals:					
Property, plant and equipment	**(28.2)**	**(0.3)**	**-**	**-**	**(28.5)**
Long-term investments and other assets	**-**	**-**	**-**	**(0.1)**	**(0.1)**
Net Invested capital	**257.7**	**257.5**	**212.2**	**(7.8)**	**719.6**

Invested Capital - Investment Type

Years ended December 31, 2010

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	116.1	48.3	53.1	1.0	218.5
Intangible assets	(7.8)	4.9	3.5	5.1	5.7
Long-term investments and other assets	-	(0.1)	0.5	2.4	2.8
	108.3	53.1	57.1	8.5	227.0
Disposals:					
Property, plant and equipment	-	-	(1.9)	(0.3)	(2.2)
Long-term investments and other assets	-	-	(2.4)	-	(2.4)
Net Invested capital	108.3	53.1	52.8	8.2	222.4

AltaGas categorizes its invested capital into maintenance, growth and administration.

Growth capital expenditures of $736.3 million were reported in 2011 (2010 - $214.8 million). In the Gas segment, growth capital comprised $120.5 million for construction of the Co-stream Project, $93.9 million for construction of Gordondale, $8.8 million for the Henderson Pipeline, $7.9 million for the Septimus Pipeline, $5.3 million for the Ante Creek expansion, $5.1 million for the Bantry pipeline and compressor additions, $5.1 million for the Blair Creek expansion, $2.6 million for the Enchant to Turin Processing Partnership, $2.3 million for the Pouce Coupe Sour Gas facility, $1.9 million for the Younger A&B Train Demethanizer and $27.4 million for various Gas related projects. Within the Power segment, growth capital projects included $116.0 million for the Forrest Kerr Project, $16.3 million for the Harmattan Cogeneration projects, $15.6 million for the PNG McNair project, $6.1 million for the Crowsnest Pass project, $2.3 million for Gordondale gas-fired peakers and $8.4 for various renewable power development projects. Intangible assets in the Power segment increased by $91.3 million, of which $90.0 million related to AltaGas' obligation to BC Hydro in support of the construction and operation of the Northwest Transmission Line. Within the Utility segment, growth capital included $180.7 million PNG, $19.3 million for AUI and $11.9 million for various Utilities related assets. Corporate segment capital declined by $12.4 million, of which a decrease of $17.6 million related to Alterra offset by an increase of $5.2 million of various Corporate assets.

Maintenance and administrative capital expenditures in 2011 were $5.5 million and $6.4 million, respectively (2010 - $5.5 million and $6.7 million, respectively).

Invested Capital - Use

Years ended December 31, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	**3.7**	**1.8**	**-**	**-**	**5.5**
Growth	**280.8**	**256.0**	**211.9**	**(12.4)**	**736.3**
Administrative	**1.4**	**-**	**0.3**	**4.7**	**6.4**
Invested capital	**285.9**	**257.8**	**212.2**	**(7.7)**	**748.2**

Invested Capital - Use

Years ended December 31, 2010

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	2.5	2.5	0.5	-	5.5
Growth	104.7	50.7	56.6	2.8	214.8
Administrative	1.0	-	-	5.7	6.7
Invested capital	108.2	53.2	57.1	8.5	227.0

FINANCIAL INSTRUMENTS

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During 2011, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 15:

- Commodity forward contracts: The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock-in margins from back-to-back purchase and sarrrle agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The energy services business transacts primarily on this basis. PNG has historically hedged exposures to fluctuations in natural gas prices through the use of derivative financial instruments. These risk management facilities allow PNG to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price risk management plan. PNG has not entered into any new hedging arrangements since February 2011 and the existing hedges will expire by October 2012. These estimated fair market values have no impact on earnings due to the regulated nature of PNG's operations. Based on the current regulatory process, unrealized gains or losses arising from PNG related financial instruments are treated as part of the cost of gas.
- Commodity swap contracts:

  Power hedges: AltaGas executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power business results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0.00/MWh to $999.99/MWh in 2011 and 2010. The average Alberta spot price was $76.22/MWh in 2011 (2010 - $50.76/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average price realized for power by AltaGas was $75.94/MWh in 2011 (2010 - $66.79/MWh). In 2012, approximately 60 percent of Alberta-based power is hedged at an average price of $70/MWh.

  NGL frac spread hedges: The Corporation executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During 2011, the Corporation had NGL frac spread hedges for an average of 3,877 Bbls/d at an average price of $27.78/Bbl. The average indicative spot NGL frac spread for 2011 was $42.88/Bbl (2010 - $31.95/Bbl). The average NGL frac spread realized by AltaGas in 2011 was $33.67/Bbl (2010 - $27.27/Bbl). For 2012, AltaGas has hedged approximately three-quarters of volumes that are exposed to frac spread at an average price of $35/Bbl.

- Interest rate forward contracts: The Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2011, the Corporation had interest rate swaps for $40 million with varying terms to maturity until March 31, 2012. At December 31, 2011, the Corporation had fixed the interest rate on 96 percent of its debt including MTNs and capital leases (December 2010 - 96 percent).
- Foreign exchange forward contracts: Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold.

The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of the interest rate derivatives used quoted market rates.

AltaGas does not speculate on commodity prices and therefore does not engage in commodity transactions that create incremental exposure or are based solely on expectations of future energy market price movements. Commodity transactions are used to lock in margins, optimize underlying physical assets or reduce exposure to energy price movements. AltaGas' risk management group reviews commodity and credit risk on a daily basis and has created and adheres to a conservative risk policy and hedging program.

LIQUIDITY

AltaGas does not expect any currently known trend or uncertainty to affect its ability to access its historical sources of funding.

On March 2, 2012, AltaGas amended and extended its $600 million unsecured revolving credit facility with a syndicate of Canadian chartered banks. The credit facility contains a $200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of $800 million. The credit facility's term was extended with a new maturity date of May 30, 2016.

On March 2, 2012, AltaGas amended and extended its $75 million extendible revolving term credit facility with two Canadian chartered banks. The credit facility's term was extended with a new maturity date of May 30, 2016.

On March 2, 2012, AltaGas closed a new US$300 million unsecured credit facility maturing on March 2, 2013.

On December 20, 2011, in connection with the PNG acquisition, AltaGas assumed a $25 million bank operating facility which is available for working capital purposes and expires on May 28, 2012.

On October 17, 2011, AltaGas issued $200 million of senior unsecured medium term notes. The notes carry a coupon rate of 4.55 percent and mature on January 17, 2019.

On September 19, 2011, AltaGas amended and extended the Utility Group's $200 million unsecured, extendible revolving credit facility with a syndicate of Canadian chartered banks. The credit facility's term was extended to four years with a new maturity date of November 17, 2015.

On April 26, 2011, AltaGas entered into an agreement for a new $125 million bilateral letter of credit facility. AltaGas may borrow by way of letter of credit only under this facility.

On March 24, 2011, AltaGas issued $200 million of senior unsecured medium term notes with a coupon rate of 4.10 percent maturing on March 24, 2016.

Cash Flows

Years ended December 31 ($ millions)	**2011**	2010
Cash from operations	**209.9**	193.3
Investing activities	**(584.6)**	(161.5)
Financing activities	**376.8**	(33.3)
Change in cash	**2.1**	(1.5)

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $209.9 million in 2011 compared to $193.3 million in 2010. The increase in cash from operations was primarily a result of higher income before taxes slightly offset by lower non-cash working capital.

Working Capital

Years ended December 31 ($ millions except current ratio)	2011	2010
Current assets	**368.4**	304.9
Current liabilities	**570.6**	324.1
Working capital	**(202.2)**	(19.2)
Current ratio	**0.65**	0.94

Working capital was in a deficit position of $202.2 million at December 31, 2011, compared to a deficit position of $19.2 million at December 31, 2010. The working capital ratio was 0.65 at December 31, 2011 compared to 0.94 at December 31, 2010. The working capital ratio decreased due to an increase in current portion of long-term debt[1], risk management-current liabilities and accounts payable offset by an increase in accounts receivable and increase in risk management-current assets.

[1]Due to the maturity of $100 million medium term note in January 2012.

Investing Activities

Cash used for investing activities in 2011 was $584.6 million compared to $161.5 million in 2010. Investing activities in the quarter were mainly comprised of property, plant and equipment expenditures of $399.7 million, PNG acquisition of $138 million, acquisition of intangible assets of $31.7 million, increase of regulatory assets of $27.2 million, partially offset by disposal of assets for $13.4 million.

Financing Activities

Cash received from financing activities was $376.8 million in 2011 compared to cash used for financing activities of $33.3 million in 2010. The change in financing activities, compared to 2010, was due to lower repayments of short- and long-term debts of $308.4 million, lower dividends of $27.1 million, higher net proceeds from issuance of common shares of $144.0 million, offset by lower proceeds from issuance of preferred shares of $194.1 million.

CAPITAL RESOURCES

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. As at December 31, 2011, AltaGas had total debt outstanding of $1,320.0 million, up from $902.4 million at December 31, 2010. As at December 31, 2011, AltaGas had $1,175 million in MTNs outstanding and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances and letters of credit through bank lines amounting to $1,096 million. As at December 31, 2011, AltaGas had drawn bank debt of $50 million and letters of credit outstanding of $198 million against the syndicated credit facilities, the extendible revolving letter of credit facility, the bilateral letter of credit facility and the demand operating facilities. As at December 31, 2011, the Corporation had $848.3 million in available credit facilities and $4.2 million in cash and cash equivalents.

On December 7, 2011, a new base shelf prospectus was filed with a limit of $2 billion and valid for 25 months. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance.

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities.

The US$1.135 billion acquisition of SEMCO expected to close in third quarter 2012 includes approximately US$355 million in assumed debt. The transaction will be funded through the net proceeds of the subscription receipts offering, together with funds to be advanced pursuant to some combination of the existing credit facilities and the new credit facility and the proceeds of future debt and preferred share financings, as determined by AltaGas.

On February 22, 2012, AltaGas closed approximately $403 million in gross proceeds held in trust in connection with a subscription receipts offering for total consideration of 13,915,000 common shares. The subscription receipts offering represents the holders' right to receive one common share of the issuer contingent upon acquisition close. The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of SEMCO and fulfillment or waiver of all other outstanding conditions precedent to closing the acquisition.

At December 31, 2011, AltaGas' current portion of long-term debt was $105.9 million. The Corporation has a $100 million MTN maturing in January of 2012.

AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2011 was 2.62 times.

Credit facilities ($ millions)	Borrowing capacity	**Drawn at December 31 2011**	Drawn at December 31 2010
Demand operating facilities	71.0	**3.4**	7.9
Extendible revolving letter of credit facility	75.0	**67.7**	50.5
PNG operating facility	25.0	**13.9**	-
Bilateral letter of credit facility	125.0	**124.3**	-
AltaGas Ltd. revolving credit facility (1)	600.0	**8.0**	-
Utility Group revolving credit facility (2)	200.0	**30.4**	114.5
	1,096.0	**247.7**	172.9

(1) Revolving credit facility maturing May 30, 2016.

(2) Revolving credit facility maturing November 17, 2015.

As at December 31, 2011, AltaGas held in aggregate $71 million (December 31, 2010 - $71 million) in demand operating and demand letter of credit facilities. As at December 31, 2011, AltaGas had draws and letters of credit of $3.4 million (December 31, 2010 - $7.9 million) outstanding against these demand facilities.

As at December 31, 2011, AltaGas held a $75 million (December 31, 2010 - $75.0 million) unsecured four-year extendible revolving letter of credit facility with two Canadian chartered banks maturing on May 30, 2016. AltaGas may also borrow by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2011, AltaGas had letters of credit of $67.7 million (December 31, 2010 - $50.5 million) outstanding against the extendible revolving letter of credit facility.

As at December 31, 2011, AltaGas held a $25.0 million bank operating facility which is available for PNG's working capital purposes and expires on May 28, 2012. The operating facility was acquired through the acquisition of PNG (note 3). Draws and letters of credit outstanding at December 31, 2011 were $13.9 million.

As at December 31, 2011, AltaGas held a $125.0 million unsecured bilateral letter of credit facility. Borrowings on the facility bear fees and interest rates relevant to the nature of the draws made. At December 31, 2011, AltaGas had $124.3 million (December 31, 2010 - nil) letters of credit outstanding under the bilateral facility.

AltaGas has a $600 million, four-year revolving credit facility maturing on May 30, 2016. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At December 31, 2011, AltaGas had $8.0 million (December 31, 2010 - nil) of debt outstanding under the syndicated facility.

The Utility Group has a $200 million, four-year revolving credit facility maturing on November 17, 2015. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At December 31, 2011, AltaGas had $30.4 million (December 31, 2010 - $114.5 million) of debt outstanding under the Utility Group facility.

CONTRACTUAL OBLIGATIONS

December 31, 2011		Payments Due by Period			
($ millions)		Less than			
	Total	1 year	1 - 3 years	4 - 5 years	After 5 years
Long-term debt	1,324.3	121.2	274.3	304.1	624.7
Capital leases	5.0	1.9	3.1	-	-
Operating leases	9.3	4.7	4.6	-	-
Purchase obligations	76.1	4.1	8.2	9.8	54.0
Capital project commitments(1)	241.0	152.7	88.3	-	-
Total contractual obligations	1,655.7	284.6	378.5	313.9	678.7

(1) Capital project commitments are related to the construction costs of the Forrest Kerr Project and Gas projects. Amounts are estimates and are subject to variability depending on actual construction costs.

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2011 was $5.0 million (December 31, 2010 - $6.1 million) with the balance due in monthly payments comprising principal and interest of $0.2 million.

AltaGas has long-term operating lease agreements for gas storage, office space, office equipment and automotive equipment.

RELATED PARTIES

AltaGas pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is partially owned by an employee of AltaGas. Payments of $0.1 million were made in 2011 (2010 - $0.1 million) which is the exchange value of the property agreed to by both parties. The lease expires on April 30, 2012.

RATING AGENCIES

On February 7, 2012, Standard & Poor's (S&P) reaffirmed the BBB and Pfd-3 ratings for AltaGas in light of the SEMCO acquisition announcement.

On February 1, 2012, Dominion Bond Rating Service Limited (DBRS) reaffirmed the BBB and P-3 ratings for AltaGas in light of the SEMCO acquisition announcement.

On October 31, 2011, DBRS reaffirmed the BBB and Pfd-3 ratings for AltaGas in light of the PNG acquisition.

On August 10, 2010, S&P and DBRS commenced rating of the Series A Preferred Shares with an S&P rating of P-3H and DBRS rating of Pfd-3.

A Pfd-3 rating by DBRS is the third highest of six categories granted by DBRS. According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adversities present which detract from debt protection. Pfd-3 ratings normally correspond with companies whose bonds are rated in the higher end of the BBB category. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category.

A P-3 rating by S&P is the third highest of eight categories granted by S&P. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Except as set forth above, neither DBRS nor S&P has announced that it is reviewing or intends to revise or withdraw the ratings on AltaGas.

SHARE INFORMATION

At March 7, 2012, AltaGas had 89.5 million common shares and 8.0 million series A preferred shares outstanding with a combined market capitalization of $3.0 billion based on a closing trading price on March 7, 2012, of $31.14 per common share and $26.10 per series A preferred share. At February 29, 2012, there were 5.1 million options outstanding and 2.2 million options exercisable under the terms of the share option plan.

DIVIDENDS AND DISTRIBUTIONS

Since the corporate conversion effective July 1, 2010, AltaGas Ltd. declares and pays a monthly dividend to its shareholders. Dividends are determined by giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements.

On October 27, 2011, the Board of Directors approved an increase in the monthly dividend to $0.115 per common share from $0.11 per common share.

In 2011, AltaGas declared dividends on common shares of $112.2 million. In 2010, AltaGas declared dividends of $54.1 million and distributions of $87.0 million.

For 2011, AltaGas declared dividends on preferred shares of $11 million (net of tax).

The following table summarizes AltaGas' dividend and distribution declaration history since 2009:

Distributions/Dividends

Years ended December 31 ($ per common share or trust unit)	**2011**	2010	2009
First quarter	**0.33**	0.54	0.54
Second quarter	**0.33**	0.54	0.54
Third quarter [1]	**0.33**	0.33	0.54
Fourth quarter	**0.34**	0.33	0.54
Total	**1.33**	1.74	2.16

[1] As of July 1, 2010, after Altagas' conversion to a corporation, monthly dividends are declared to its common shareholders

Preferred Share Dividends

Years ended December 31 ($ per preferred share)	**2011**	2010	2009
First quarter	**0.3125**	-	-
Second quarter	**0.3125**	-	-
Third quarter	**0.3125**	-	-
Fourth quarter	**0.3125**	0.4589	-
Total	**1.2500**	0.4589	-

NON-MONETARY TRANSACTION

AltaGas has entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs were created through the generation of power at Bear Mountain between 2009 and 2010. The verified emission offsets received by AltaGas were used to offset the costs to comply with Specified Gas Emitters Regulation (SGER) in 2010. The contract was completed in second quarter 2010.

SUBSEQUENT EVENT

On March 2, 2012, AltaGas amended and extended its $600 million unsecured revolving credit facility with a syndicate of Canadian chartered banks. The credit facility contains a $200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of $800 million. The credit facility's term was extended with a new maturity date of May 30, 2016.

On March 2, 2012, AltaGas amended and extended its $75 million extendible revolving term credit facility with two Canadian chartered banks. The credit facility's term was extended with a new maturity date of May 30, 2016.

On February 29, 2012, AltaGas acquired the 25 MW gas-fired peaking generation in southern Alberta from Maxim Power Corp. AltaGas has had the rights to this capacity through a capital lease arrangement since 2004 and has operated the facilities since 2007. The transaction is accounted for as a purchase of equipment cancelling the previously applied capital lease accounting.

On February 1, 2012, AltaGas Ltd. and a wholly-owned subsidiary of AltaGas entered into a definitive agreement with Continental to acquire SEMCO for US$1.135 billion, including approximately US$355 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy, Inc. a privately held regulated public utility company headquartered in Port Huron, Michigan. SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through ENSTAR and an interest in a regulated natural gas storage utility in Alaska under construction called CINGSA. SEMCO also indirectly holds a regulated natural gas distribution utility and an interest in an unregulated natural gas storage facility in Michigan. The transaction is subject to customary approvals including regulatory approvals from the Michigan Public Service

Commission, the Regulatory Commission of Alaska and expiration of the waiting period under the HSR. On March 2, 2012, the Federal Trade Commission granted the application for early termination of the waiting period under HSR. The closing of the acquisition is subject to receipt of required regulatory approvals and the satisfaction or waiver of certain closing conditions. The regulatory approval process is expected to take approximately six months and AltaGas expects the acquisition to close in third quarter, 2012. The transaction is expected to be accounted for as a business acquisition using the purchase method of accounting.

In connection with the SEMCO acquisition, on February 22, 2012, AltaGas issued an aggregate of 13,915,000 subscription receipts at a price of $29 per subscription receipt for aggregate gross proceeds of approximately $403 million. On March 2, 2012, AltaGas closed a new US$300 million unsecured credit facility which expires on March 2, 2013.

On January 26, 2012, AltaGas announced the acquisition of DEI. DEI is an independent power company whose primary assets are a 30 percent working interest in the 37 MW Grayling Generating Station in Michigan – a wood biomass power facility, and a 50 percent working interest in the 48 MW Craven County wood biomass power facility in North Carolina. The transaction is accounted for as business acquisitions using the purchase method of accounting.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Accounting Standards Board (AcSB) confirmed in February 2008 that International Financial Reporting Standards (IFRS) was to replace Canadian Generally Accepted Accounting Principles (CGAAP) for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

On September 10, 2010, the AcSB amended the introduction to Part I of the CICA Handbook Accounting to permit, but not to require qualifying entities with Rate Regulated Activities (RRA) to adopt IFRS for the first time no later than interim and annual financial statements relating to annual periods beginning on or after January 1, 2012, thereby providing a one year deferral. The Canadian Securities Administrators provide for a similar one-year deferral pursuant to National Instrument 52-107 - Acceptable Accounting Principles and Auditing Standards (NI 52-107).

AltaGas is a qualified entity for the deferral period permitted by AcSB and NI 52-107. AltaGas has elected to use the deferral offered by the AcSB and NI 52-107, given the uncertainty with respect to the application of IFRS to the RRA in 2011. AltaGas reassessed the accounting policy choices available and determined that the most appropriate decision for AltaGas' business activities is the use of U.S. GAAP effective January 1, 2012.

Pursuant to NI 52-107, U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained on July 4, 2011, exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

AltaGas commenced a process to transition from Canadian GAAP to US GAAP establishing a project team to plan for and achieve a smooth transition to U.S. GAAP. Management provides regular progress reports to the Audit Committee of the Board of Directors on the status of the U.S. GAAP implementation project.

DETAILED ASSESSMENT AND DEVELOPMENT ACTIVITIES

The assessment comparing the most significant differences between US GAAP and CGAAP determined the impact on the accounting policies, financial statements, information systems, internal controls and other business activities for AltaGas. Based on the work completed, the differences identified are limited to:

1. Accounting for business combinations;
2. Pension and other post-employment benefits;

3. Accounting for joint ventures;
4. Cash flow hedges;
5. Inventory of natural gas held in storage;
6. Normal purchases / normal sales non-financial derivatives;
7. Rate-regulated operations; and
8. Presentation of deferred financing costs.

Accounting for business combinations

Effective January 1, 2009, the rules around accounting for business combinations and non-controlling interests changed under U.S. GAAP. Prior to the change, business combination rules in Canadian and U.S. GAAP were largely convergent. The U.S. rules were to be applied prospectively.

During 2009 and 2010, AltaGas entered into three transactions which were re-evaluated under U.S. rules. Those transactions are:

- October 8, 2009 acquisition of remaining 81.7 percent interest in Utility Group;
- November 18, 2009 acquisition of remaining 75.1 percent interest in Heritage Gas; and
- March 22, 2010 acquisition of all of the outstanding shares of Landis Energy Corporation.

Financial impact

All transaction costs associated with the business combinations will be charged to opening retained earnings. For the acquisition of Utility Group and Heritage Gas, a capital gain for the shares previously owned by AltaGas (business combination achieved in stages) will be recognized in retained earnings. The acquisition of Landis Energy Corporation meets the definition of business combination under U.S. GAAP.

Pension and other post-employment benefits

AltaGas has a number of employee defined benefit pension plans (DBPP) and supplemental executive retirement plans. The most significant differences between U.S. and CGAAP are:

- The over-funded or under-funded status of a DBPP must be recognized as an asset or liability on the balance sheet;
- Changes in the funded status are recognized through other comprehensive income in the year in which the changes occur;
- Specific transition rules exist for unamortized gains or losses, prior service costs or credits and previous transitional amounts; and
- Entities must use their fiscal year-end date as the measurement date for plan assets and benefit obligations.

Financial impact

Under CGAAP, AltaGas disclosed but did not recognize the unamortized gains and losses, the past service costs and the unamortized transitional obligation associated with pension and other post-employment benefits, which will be recognized under U.S. GAAP as a liability. Gains and losses that are not recognized immediately as a component of net periodic pension cost through the income statement will represent increases or decreases in other comprehensive income. Consequently, the pension costs periodically charged to the income statement under U.S. GAAP is expected to be different compared to the pension costs recognized under CGAAP.

Accounting for joint ventures

AltaGas owns varying interests in a number of different legal entities. CGAAP allows proportionate accounting of joint ventures and equity accounting for investments where significant influence exists over the entity. U.S. GAAP rules differ, in some circumstances, from CGAAP with respect to accounting for joint ventures and partnerships.

Financial impact

The change from proportionate consolidation to equity accounting method does not modify the net profit attributable to AltaGas but modifies the presentation of the financial positions for the incorporated joint ventures. The proportionate consolidation method results in the proportionate share of assets, liabilities, revenues and expenses being reported in consolidated financial results. Under the equity method, the interest in the joint venture is accounted for as a long-term investment, increased (or decreased) by the net profit (or loss) attributable to AltaGas and decreased by the amount of distributions paid from the joint venture or partnership to AltaGas.

Cash flow hedges

U.S. GAAP rules state specifically that "equity method investments do not qualify for hedge accounting". Accordingly, in the restated financial results under U.S. GAAP, cash flow hedges for Sundance PPA are derecognized.

<u>Financial impact</u>

The financial instruments previously designated as cash flow hedges for the Sundance PPAs will continue to be marked-to-market. The changes in fair value will be recognized through the income statement instead of other comprehensive income.

Inventory of natural gas held in storage

AltaGas accounts for natural gas inventory held in storage using the fair value method. U.S. GAAP requires inventory to be carried at the lower of cost and market.

<u>Financial impact</u>

The unrealized fair value gains and losses previously recognized under CGAAP will be reversed through retained earnings. Natural gas inventory shall be reported at the lower of cost and market.

Normal purchases and normal sales non-financial derivatives

Under U.S. GAAP, AltaGas will recognize the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that meet the normal purchases and normal sales ("NPNS") exemption. A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to the Corporation's business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, the Corporation intends to receive physical delivery of the commodity, and the Corporation deems the counterparty credit worthy.

<u>Financial impact</u>

Non-financial derivatives that meet the criteria for NPNS exception will not be subject to the mark-to-market accounting.

Rate-regulated operations

Other post-employment benefit (OPEB) costs are recovered from customers to reimburse amounts paid to fund the benefit plans, as established through a general tariff application and approved by the utility regulator. The actual expense incurred by AltaGas will differ from the amounts paid to fund the benefit plans depending on the performance of plan assets and the actuarial valuations of plan obligations. AltaGas currently recognize OPEB expenses equal to funded costs and a regulatory asset equal to the difference between the accrued costs and funded costs. Under U.S. GAAP the OPEB costs incurred by AltaGas do not meet the criteria for the recognition as rate-regulated assets.

<u>Financial impact</u>

OPEB costs shall be derecognized from the rate-regulated assets upon transition to U.S. GAAP with a corresponding adjustment to retained earnings.

Presentation of deferred financing costs

Under CGAAP, debt financing costs, premiums and discounts are netted against long-term debt. Under U.S. GAAP, debit financing costs are included in "Other current assets".

<u>Financial impact</u>

The change in presentation of deferred financing costs will increase the total assets and long-term debt, with a negligible impact to the debt-to-total capitalization ratio.

Significant changes to existing systems and processes are not required to implement US GAAP.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of AltaGas' Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. AltaGas' significant accounting policies are contained in the notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to relate to financial instruments, amortization expense, asset retirement obligations, asset impairment assessment, income taxes, pension and rate-regulated assets and liabilities. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Financial instruments and hedge accounting

All financial instruments on the balance sheet are initially measured at fair value. The financial assets are classified as held-for-trading, held-to-maturity, loans and receivables, or available-for-sale. Financial liabilities are classified as held-for-trading or other financial liabilities. Subsequent measurement of a financial instrument depends on its classification. AltaGas does not have any held to maturity financial instruments.

Held for trading financial assets and liabilities consist of swaps, options, forwards and equity investments. These financial instruments are initially accounted for at their fair value, and changes to fair value are recorded in income. Loans and receivables are accounted for at their amortized cost using the effective interest method. 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. Available for sale instruments are initially accounted for at their fair value, and changes to fair value are recorded through other comprehensive income. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in other revenue. Other financial liabilities not classified as held for trading are accounted for at their amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are not the same as those of a stand-alone derivative, and the total contract is not held for trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the expected purchase, sale or usage requirements exception, are carried on the Consolidated Balance Sheets at fair value.

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by management. Where bid or ask prices in an active market are not available, management's judgment on valuation inputs is necessary to determine fair value. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity, interest rate and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, currency exchange and interest rate yield curves. The forward curves used to mark these derivative instruments to market are vetted against public sources. Where observable market data is not available, AltaGas uses valuation techniques which require significant judgment by management.

AltaGas applies hedge accounting to its arrangements that qualify for hedge accounting treatment for cash flow hedges. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while any ineffective portion is recognized in income. Gains and losses on derivatives are reclassified to net income from accumulated other comprehensive income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

AltaGas designates certain derivatives as hedges at the inception of the hedging contract. The effectiveness of hedges is assessed on a regular basis and any changes in the fair value resulting from hedge ineffectiveness, is immediately recognized as income.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in assumptions could result in material adjustments to the amount of amortization that AltaGas recognizes from period to period.

Asset retirement obligations and other environmental costs

AltaGas records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs are critical accounting estimates because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2045 and 2060), requiring AltaGas to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on AltaGas' Consolidated Financial Statements.

Asset impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing impairment may be material to the AltaGas' Consolidated Financial Statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

Income taxes

The Corporation and, prior to July 1, 2010, the Trust, is subject to the provisions of the Income Tax Act (Canada) for purposes of determining the amount of income that will be subject to tax in Canada. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

Substantial future income tax assets and liabilities are recognized in the Consolidated Financial Statements. The recognition of future tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the future tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of tax authorities or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See note 13 to the Consolidated Financial Statements.

Pension plans and post-retirement benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate-of-return on plan assets and the discount rate applied to pension plan obligations. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates. Notes 2 and 20 to the Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

Rate regulation

AltaGas acquired AUI and Heritage Gas in the acquisition of Utility Group, which also owns one third of Inuvik Gas and acquired 100 percent of PNG on December 20, 2011 (note 4 of the 2011 Consolidated Financial Statements). AUI, Heritage Gas, PNG and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the AUC, NSUARB, BCUC and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC, NSUARB and BCUC exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC, NSUARB and BCUC, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive commodity market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that will be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are to be refunded to customers through the rate-setting process.

OFF-BALANCE SHEET ARRANGEMENTS

AltaGas is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. AltaGas has no obligation under derivative instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services.

DISCLOSURE CONTROLS AND PROCEDURES (DCP) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

AltaGas' management is responsible for establishing and maintaining DCP and ICFR, as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of AltaGas employees:
a) DCP to provide reasonable assurance that material information relating to AltaGas' business is made known to them particularly during the period in which AltaGas' annual filings are being prepared and information required to be

disclosed by AltaGas in its annual filings, interim filings or other reports filed or submitted under securities legislation is processed, summarized and reported within the time periods specified in securities legislation; and
b) ICFR to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The ICFR have been designed based on the framework established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR and concluded that AltaGas' DCP and ICFR were effective at December 31, 2011. All internal control systems, regardless of how well designed, have inherent limitations. As a result, even those systems determined to be effective can provide only reasonable assurance.

During 2011, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

FOURTH QUARTER HIGHLIGHTS

Operating Income	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2011**	2010	**2011**	2010
Gas	**31.0**	23.7	**104.9**	86.9
Power	**22.4**	20.4	**86.0**	74.7
Utility	**4.8**	9.6	**24.4**	23.4
Sub-total: Operating Businesses	**58.2**	53.7	**215.3**	185.0
Corporate	**(9.6)**	(6.1)	**(40.5)**	(31.9)
	48.6	47.6	**174.8**	153.1

In fourth quarter 2011, normalized operating income from the operating businesses was $63.9 million or 19 percent higher than $53.7 million in same quarter 2010. Gas and Power delivered stronger earnings than fourth quarter 2010 while Utilities realized lower results. These results were driven by higher volumes at extraction facilities, strong frac spreads, higher power generated at the gas-fired and wind facilities and the addition of PNG. The increases were partially offset by the impact of a scheduled turnaround and lower throughput at some field facilities, transaction costs related to acquisitions and the impact on Utilities of warmer than normal weather.

In fourth quarter 2011, normalized net income was $29.7 million ($0.34 per share) compared to $25.9 million ($0.31 per share) in the same quarter 2010. In fourth quarter 2011, AltaGas reported after-tax unrealized mark-to-market gains on risk management contracts and held-for-trading assets of $4.4 million, compared to mark-to-market gains of $0.6 million in fourth quarter 2010.

The fourth quarter was impacted by the planned turnaround at Harmattan, which reduced operating income by approximately $6 million. During the turnaround at Harmattan, AltaGas completed tie-in work required for the Co-stream and Cogeneration II Projects, expected to be in service in second quarter 2012.

Net income applicable to common shares for fourth quarter 2011 was $29.9 million ($0.35 per share), compared to $26.5 million ($0.32 per share) for same period 2010.

The Gas segment reported higher operating income during the fourth quarter 2011 compared to same period in 2010 primarily due to higher realized frac spreads, higher extraction fees from increased volumes, higher fees earned from the addition and expansion of gas processing facilities and lower operating expenses offset by the Harmattan turnaround, lower daily contract quantity at the Suffield system, higher variable operating costs with higher extraction volumes and increased administration costs associated with the Gas division's growth. During fourth quarter 2011, available volumes at certain gas processing facilities grew by approximately 69 Mmcf/d, which more than offset declines of approximately 63 Mmcf/d from other facilities, when compared to the reported volumes in fourth quarter 2010. This resulted in 101 percent of the current quarter's declines being offset by the addition of new volumes, also known as the replacement factor (fourth quarter 2010 – 52 percent).

The Power segment reported higher operating income in fourth quarter 2011 compared to same quarter 2010 due to higher realized power prices, the addition of the Harmattan cogeneration facility, higher generation from gas-fired peaking plants and stronger results from Bear Mountain, partially offset by higher PPA costs, higher variable operating costs, higher general and administration costs associated with the recent growth activities, transaction costs and higher amortization with the addition of the Harmattan cogeneration facility.

The Utility segment reported lower operating income in fourth quarter 2011 compared to same quarter 2010, mainly due to transaction costs related to the acquisition of PNG, higher depletion at Ikhil and warmer weather at the Alberta and Nova Scotia utilities. These differences were partially offset by rate base growth at AUI and Heritage Gas and the operating results for PNG. During the last 11 days of 2011, PNG contributed $1.3 million to AltaGas' operating income.

The Corporate segment reported a higher loss in fourth quarter 2011 compared to the same quarter last year due to higher interest expense, partially offset by mark-to-market gains.

On a cash flow basis, normalized funds from operations in fourth quarter 2011 were $69.4 million ($0.80 per share) compared to $57.6 million ($0.70 per share) in fourth quarter 2010. Normalized EBITDA in fourth quarter 2011 was $80.3 million compared to $70.1 million in fourth quarter 2010. In fourth quarter 2011, AltaGas declared dividends to common shareholders of approximately 43 percent of normalized funds from operations.

On October 27, 2011, the Board of Directors approved an increase in the monthly dividend to $0.115 per common share from $0.11 per common share. The first monthly dividend of $0.115 per common share was paid on December 15, 2011 to common shareholders of record at close of business on November 25, 2011.

On a consolidated basis, net revenue for fourth quarter 2011 was $157.4 million compared to $130.8 million in same period 2010. The Gas reporting segment's net revenue increased largely due to higher frac exposed volumes and higher frac spreads, higher fee-for-service revenues earned by extraction facilities, higher recoveries of operating costs and contributions from new and expanded gas processing facilities. These increases were partially offset by the impact of the Harmattan turnaround and lower daily contract quantity on the Suffield system. Net revenue in the Power segment increased due to higher Alberta spot power prices and higher generation from gas-fired peaking plants and Bear Mountain. Increases were partially offset by higher hedging losses, higher PPA costs due to an unfavourable 30-day RAPP, higher environmental compliance costs and higher transmission costs. The Utility segment reported higher net revenue due to the addition of PNG, higher recoverable costs and rate base growth at AUI and Heritage Gas. The Corporate segment recorded higher net revenue due to unrealized gains on risk management contracts partially offset by mark-to-market losses on an equity investment compared to mark-to-market gains in same period 2010.

Operating and administrative expense for fourth quarter 2011 was $76.5 million, up from $60.1 million in fourth quarter 2010. The increase was primarily due to higher operating costs at extraction facilities due to the Harmattan turnaround and higher volumes processed partially offset by lower operating costs related to the field gas processing facilities due to lower volumes processed and lower general and administrative costs. In the Power segment, the operating costs increased as a result of the addition of the Harmattan gas-fired cogeneration facility, higher variable costs at the peaking facilities and Bear Mountain, higher administrative costs and acquisition costs. The Utility segment incurred higher recoverable operating and administrative costs at both AUI and Heritage Gas along with the addition of PNG, including related acquisition costs. Operating expenses in Corporate segment were similar in the fourth quarter 2011 compared to the same period in 2010.

Amortization expense for fourth quarter 2011 was $24.3 million compared to $22.4 million in same period 2010. The increase was due to the addition of new and expanded facilities. Accretion expense for fourth quarter 2011 was $0.6 million compared to $0.7 million for same period 2010.

Interest expense in fourth quarter 2011 was $13.3 million compared to $12.1 million for same period 2010. The increase was due to a higher average debt balance of $1,180.1 million (2010 - $900.8 million) partially offset by a lower average borrowing rate of 6.0 percent (2010 - 6.1 percent).

Capitalized interest in fourth quarter 2011 was $4.4 million compared to $1.9 million in same period 2010.

In fourth quarter 2011, an income tax expense of $9.6 million was reported compared to an income tax expense of $6.2 million in fourth quarter 2010.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2012 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per share
Gathering and Processing volumes	5 Mmcf/d	0.009
Gathering and Processing operating margin per Mcf	1 cent/Mcf	0.019
Alberta electricity prices(1)	$1/Mwh	0.012
Natural gas liquids fractionation spread(2)	$1 per Bbl	0.005
Interest rates	25bps	0.009
Degree days(3)	5 percent	0.017

(1) *Based on approximately 60 percent of Sundance PPA volumes being hedged.*

(2) *Based on approximately 75 percent of frac spread exposed NGL volumes being hedged.*

(3) *Degree days relate to AUI and Heritage Gas service areas. A degree day is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. PNG has a rate stabilization adjustment mechanism approved by the BCUC which allows the PNG to record the after-tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates.*

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

($ millions)	**Q4-11**	**Q3-11**	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10	Q1-10
Total revenue	**422.7**	**369.6**	368.1	403.4	362.2	297.4	334.0	360.5
Net revenue(1)	**157.4**	**117.9**	113.7	137.7	130.8	102.6	124.8	127.2
Operating income(1)	**48.6**	**33.4**	34.3	58.5	47.6	32.6	35.6	37.4
Net income before taxes	**42.2**	**17.1**	16.0	38.1	35.4	10.3	26.3	31.0
Net income applicable to common shares(2)	**29.9**	**10.6**	16.6	26.6	26.5	6.0	28.4	36.4

($ per share)	**Q4-11**	**Q3-11**	Q2-11	Q1-11	Q4-10	Q3-10	Q2-10	Q1-10
Net income applicable to common shares								
Basic(2)	**0.35**	**0.13**	0.20	0.32	0.32	0.07	0.35	0.45
Diluted(2)	**0.34**	**0.12**	0.20	0.31	0.32	0.07	0.35	0.45
Distributions / dividends declared	**0.34**	**0.33**	0.33	0.33	0.33	0.33	0.54	0.54

(1) *Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of this MD&A.*

(2) *Amounts may not add due to rounding*

Significant items that impacted individual quarterly earnings were as follows:

- During first quarter 2010, AltaGas acquired all the outstanding common shares of Landis Energy Corporation for $25.6 million;
- On July 1, 2010, AltaGas converted from an income trust to a corporation resulting in AltaGas being taxable as a corporation;
- In third quarter 2010, AltaGas reported $21.1 million lower revenue as a result of mark-to-market accounting;
- In fourth quarter 2010, AltaGas completed the construction of a 15-MW gas-fired cogeneration facility at Harmattan;
- In first quarter 2011, AltaGas accepted an offer from a producer to sell the Groundbirch facility, resulting in a pre-tax gain of approximately $6 million;
- Results in first quarter 2011 were impacted by a settlement of a take-or-pay arrangement resulting in early recognition of pre-tax earnings of $2 million;
- In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflected the substantively enacted tax rates anticipated to be in effect in the periods in which the differences between tax and book values are expected to reverse. This resulted in a decrease of future tax liabilities of $6.8 million;
- In the third and fourth quarters 2011, turnarounds at Harmattan and Younger reduced revenue and increased operating expenses resulting in lower operating income of approximately $12 million before taxes. These turnarounds have occurred every three years; and
- In fourth quarter 2011, AltaGas acquired all the outstanding common shares of PNG for $224 million including assumed debt of approximately $86 million. In the quarter, AltaGas recorded $5.7 million in pre-tax transaction costs primarily related to the acquisition of PNG and other business development related activities.