AltaGas

NEWS RELEASE
ALTAGAS REPORTS SECOND QUARTER RESULTS; 195 MW FORREST KERR FACILITY GENERATING POWER

Calgary, Alberta (July 31, 2014)

Highlights

- Normalized net income of $26.8 million and normalized EBITDA of $107.3 million;
- 27 percent increase in normalized funds from operations to $105.8 million;
- Forrest Kerr generating power on time and budget;
- Received regulatory approval on Harmattan Cogeneration III project; and
- Acquired the Blythe II Energy Project, advancing the opportunity to double the 507 MW Blythe facility.

AltaGas Ltd. ("AltaGas") (TSX:ALA) today reported second quarter normalized net income of $26.8 million ($0.22 per share), compared to $35.5 million ($0.30 per share) in the same period 2013. Normalized EBITDA was $107.3 million for the second quarter 2014, compared to $106.2 million for the same period 2013. Normalized funds from operations were $105.8 million ($0.86 per share) for the second quarter 2014, compared to $83.1 million ($0.71 per share) for the same period 2013.

"We continue to deliver solid earnings and cash flow and have hit record financial results on a trailing twelve month basis," said David Cornhill, Chairman and CEO of AltaGas. "We expect growth in earnings and cash flow to continue with Forrest Kerr now in service and Volcano expected to come online soon. Bringing these facilities on with 60-year contracts demonstrates the successful execution of our strategy to grow our business with high quality assets that deliver long-term stable cash flows."

In the second quarter, earnings were driven primarily by the partial ownership of Petrogas, higher natural gas volumes processed, higher frac spreads, contributions from the Blythe facility and higher rate base at the Utilities. Earnings in the quarter were negatively impacted by significantly weaker power prices in Alberta and warmer weather affecting the US utilities, compared to the second quarter 2013. In the second quarter, funds from operations were strong as a result of receiving approximately $28 million in dividends from AltaGas' investment in Petrogas.

On a GAAP basis, net income applicable to common shares was $28.9 million ($0.23 per share) for the three months ended June 30, 2014, compared to $35.9 million ($0.31 per share) for the same period 2013.

In the second quarter, AltaGas acquired the Blythe Energy II project for US$8.5 million. The project, renamed the Sonoran Energy Project, is a fully permitted, shovel ready project located adjacent to the existing 507 MW Blythe facility in California. AltaGas expects to respond to anticipated upcoming Request for Proposals by the end of 2014, with the potential to double the size of the existing Blythe facility.

For the six months ended June 30, 2014, normalized net income increased 10 percent to $100.5 million compared to $91.1 million for the same period in 2013. In both periods, normalized earnings per share were $0.82. Normalized funds from operations increased to $235.7 million ($1.92 per share), compared to $199.2 million ($1.78 per share) for the same period in 2013.

On a GAAP basis, net income applicable to common shares was $68.8 million ($0.56 per share) for the six months ended June 30, 2014, compared to $85.0 million ($0.76 per share) for the same period 2013. Net income applicable to common shares for the six months ended June 30, 2014 includes an after-tax gain of $8.9 million from the sale of assets, offset by a non-cash after-tax provision of $28.7 million related to assets from the acquisition of Taylor NGL Limited Partnership in 2008, a non-cash after-tax provision of $8.1 million related to a number of small hydro power assets under development, mark-to-market accounting and the cost of early redemption of medium-term notes.

Northwest Run-of-River Projects

On July 30, 2014, AltaGas announced that it has brought into service its 195 MW Forrest Kerr run-of-river hydro project. Commissioning of the powerhouse systems and high voltage switchyard were completed in July and the facility is tied-in and delivering power to the Northwest Transmission Line. Over the next four to six weeks a number of online electrical and system functional checks will be performed during which time generation is expected to fluctuate. AltaGas expects final project commercial operations to be achieved by the end of third quarter 2014.

At the 16 MW Volcano Creek project, construction continues to pace ahead of schedule. The penstock excavation and switchyard work continues. Installation of the turbine generators is complete and assembly of the powerhouse is well underway. The project is on track to be in service shortly.

At the 66 MW McLymont Creek project, construction of the powerhouse foundation is advancing. Excavation of the 2,800 meter power tunnel is approximately 80 percent complete. The project is expected to be in service in mid-2015.

Energy Exports

AltaGas continues to advance its Liquefied Petroleum Gas (LPG) export initiative. AltaGas is now operating Petrogas' Ferndale facility in the State of Washington. Capacity at the Ferndale facility is expected to ramp up to 30,000 Bbls/d over the next several years.

AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) continues to make progress on building an LPG export business off Canada's west coast for an additional 30,000 Bbls/d. AIJVLP has been in active negotiations for potential site locations and a site feasibility study is underway.

In addition to LPG, AIJVLP continues to work with various parties to support the Companies' Creditors Arrangement Act (CCAA) Plan of Arrangement proceedings for the Douglas Channel LNG project. AIJVLP continues to develop definitive agreements and stakeholders are expected to vote on the CCAA plan of arrangement following filing of the plan with the court. The CCAA court deadline to reach definitive agreements is August 1, 2014.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- The Board of Directors approved the August 2014 dividend of $0.1475 per common share. The dividend will be paid on September 15, 2014, to common shareholders of record on August 25, 2014. The exdividend date is August 21, 2014. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing July 1, 2014 and ending September 30, 2014, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on September 30, 2014 to shareholders of record on September 17, 2014. The exdividend date is September 15, 2014;
- The Board of Directors approved a dividend of US$0.275 per share for the period commencing July 1, 2014 and ending September 30, 2014, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on September 30, 2014 to shareholders of record on September 17, 2014. The exdividend date is September 15, 2014;
- The Board of Directors also approved a dividend of $0.3125 per share for the period commencing July 1, 2014, and ending September 30, 2014, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on September 30, 2014 to shareholders of record on September 17, 2014. The exdividend date is September 15, 2014; and
- The Board of Directors also approved a dividend of $0.2896 per share for the period commencing July 3, 2014, and ending September 30, 2014, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on September 30, 2014 to shareholders of record on September 17, 2014. The exdividend date is September 15, 2014.

CONFERENCE CALL AND WEBCAST DETAILS:

AltaGas will hold a conference call today at 9:00 a.m. MT (11:00 a.m. ET) to discuss second quarter financial results, progress on construction projects and other corporate developments.

Members of the media, investment communities and other interested parties may dial (416) 3408527 or call toll free at 18668522121. There is no passcode. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_events. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing (905) 6949451 or 18004083053. The passcode is 8670145. The replay expires at midnight (Eastern) on August 7, 2014.

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. AltaGas creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and unaudited condensed interim 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 three and six months ended June 30, 2014, compared to the three and six months ended June 30, 2013. This MD&A dated July 30, 2014, should be read in conjunction with the accompanying unaudited interim condensed Consolidated Financial Statements and notes thereto of AltaGas as at, and for the three and six months ended June 30, 2014, and the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2013.

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 any 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, opportunities and financial results. Specifically, such forward-looking statements are set forth under: "2014 Outlook" and "Growth Capital".

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 segments' 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, including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Management Information Circular, material change reports and press releases, are also available through AltaGas' website or through the SEDAR system at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., and AltaGas Services (U.S.) Inc..

SECOND QUARTER HIGHLIGHTS (1)

- Normalized funds from operations was $105.8 million, compared to $83.1 million in second quarter 2013;
- Dividends per share declared increased by 16 percent to $1.77 on an annualized basis, compared to $1.53;
- Normalized EBITDA increased to $107.3 million, compared to $106.2 million in second quarter 2013;
- Debt-to-total capitalization ratio was 53.0 percent as at June 30, 2014, compared to 54.2 percent as at June 30, 2013, and 53.1 percent as at December 31, 2013;
- Start of water flow at 195 MW Forrest Kerr run-of-river hydroelectric facility (Forrest Kerr) on April 28, 2014;
- PetroGas' acquisition of Ferndale closed;
- On April 16, 2014, Triton LNG Limited Partnership (Triton LNG), a wholly-owned subsidiary of AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), received National Energy Board (NEB) approval to export up to 2.3 million tonnes per year of Liquefied Natural Gas (LNG);
- Acquired on April 29, 2014, Blythe II, a shovel ready gas-fired generation development site, located adjacent to the Blythe facility already owned by AltaGas, for approximately US$8.5 million. The site and development assets relate to a proposed combined-cycle 575 MW gas-fired facility. An additional 76 acres of land was also purchased, for approximately US$1.5 million adjacent to the Blythe II development site; and
- AltaGas commenced construction on the Alton Natural Gas Storage project located near Truro, Nova Scotia, with initial capacity of 4.5 Bcf and potential to expand up to 10 Bcf of natural gas storage.

(1) *Includes non-GAAP financial measures; see discussion in Non-GAAP Financial Measures section of this MD&A.*

CONSOLIDATED FINANCIAL REVIEW

(unaudited) *($ millions)*	Three months ended June 30 **2014**	2013	Six months ended June 30 **2014**	2013
Revenue	**471.2**	458.6	**1,295.0**	1,072.1
Net revenue[(1)]	**219.9**	211.8	**516.5**	449.1
Normalized operating income[(1)]	**64.5**	68.0	**201.6**	177.2
Normalized EBITDA[(1)]	**107.3**	106.2	**286.7**	252.1
Net income applicable to common shares	**28.9**	35.9	**68.8**	85.0
Normalized net income[(1)]	**26.8**	35.5	**100.5**	91.1
Total assets	**7,197.4**	6,704.3	**7,197.4**	6,704.3
Total long-term liabilities	**3,799.8**	3,598.9	**3,799.8**	3,598.9
Net additions to property, plant and equipment	**68.0**	715.8	**221.7**	835.5
Dividends declared[(2)]	**52.1**	43.8	**99.1**	81.8
Cash flows				
Normalized funds from operations[(1)]	**105.8**	83.1	**235.7**	199.2

($ per share, except shares outstanding)	Three months ended June 30 **2014**	2013	Six months ended June 30 **2014**	2013
Normalized EBITDA[(1)]	**0.87**	0.90	**2.33**	2.26
Net income - basic	**0.23**	0.31	**0.56**	0.76
Net income - diluted	**0.23**	0.30	**0.55**	0.74
Normalized net income[(1)]	**0.22**	0.30	**0.82**	0.82
Dividends declared[(2)]	**0.42**	0.37	**0.81**	0.73
Cash flows				
Normalized funds from operations[(1)]	**0.86**	0.71	**1.92**	1.78
Shares outstanding - basic (millions)				
During the period[(3)]	**123.3**	117.7	**122.9**	111.7
End of period	**123.6**	118.4	**123.6**	118.4

(1) Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of this MD&A.

(2) Dividends declared per common share per month of $0.12 beginning September 10, 2012, $0.125 beginning April 24, 2013, $0.1275 beginning July 31, 2013 and $0.1475 beginning on May 26, 2014.

(3) Weighted average.

Three Months Ended June 30

Normalized net income was $26.8 million ($0.22 per share) for second quarter 2014, compared to $35.5 million ($0.30 per share) reported for same quarter 2013. AltaGas had higher volumes processed at the Harmattan, Gordondale and Blair Creek facilities, higher realized frac spread prices, earnings contribution from Petrogas, the addition of Blythe Energy Inc. (Blythe) in May 2013, and continued customer and rate base growth at the utilities. These increases were offset by the impact of significantly lower Alberta Power Pool spot prices, lower generation in Alberta power assets, warmer weather experienced at the U.S. utilities, higher compensation costs and an income tax recovery booked in the second quarter 2013 relating to an adjustment to the deferred tax liability.

Net income applicable to common shares for second quarter 2014 was $28.9 million ($0.23 per share), compared to $35.9 million ($0.31 per share) for same quarter 2013. Results were due to the items described above, as well as a one-time tax recovery recorded in the second quarter 2013 resulting from the enactment of a Canadian tax amendment that related to tax on dividends paid on preferred shares, partially offset by unrealized gains (losses) on risk management contracts. Net income applicable to common shares for second quarter 2014 was normalized for after-tax amounts related to the unrealized gains on risk management contracts and long-term investments, development costs incurred for the energy export projects, and loss on asset disposition.

Normalized funds from operations for second quarter 2014 increased by 27 percent to $105.8 million ($0.86 per share), compared to $83.1 million ($0.71 per share) for same quarter 2013. Normalized EBITDA for second quarter 2014 was $107.3 million, compared to $106.2 million for same quarter 2013. The increase in funds from operations compared to EBITDA is primarily a result of the timing of receipt of cash distributions from AltaGas' non-consolidated interest in equity-accounted investments. In the second quarter 2014, AltaGas received a dividend from its investment in Petrogas of approximately $28 million.

Normalized operating income for second quarter 2014 was $64.5 million, compared to $68.0 million for same quarter 2013. Normalized operating results were driven by the same factors as described above, except for the income tax recovery.

Operating and administrative expense for second quarter 2014 was $109.9 million, compared to $107.9 million for same quarter 2013. The increase was primarily due to growth in assets and the energy export development initiatives. Amortization expense for second quarter 2014 was $41.8 million, compared to $37.2 million for same quarter 2013 mainly due to the asset growth of the Corporation.

Interest expense for second quarter 2014 was $23.0 million, compared to $25.2 million for same quarter 2013. A higher average debt balance of $3,210.9 million for second quarter 2014, compared to $2,808.7 million for same quarter 2013, resulted in high interest expense however this was offset by higher capitalized interest of $10.8 million in second quarter 2014, compared to $6.9 million in same quarter 2013. The higher average debt balance was the result of the Corporation's growth in the past year. The increase in interest expense was also offset by a lower average borrowing rate of 4.2 percent in second quarter 2014, versus 4.6 percent in second quarter 2013.

AltaGas recorded income tax expense of $5.7 million for second quarter 2014, compared to a tax recovery of $2.9 million in same quarter 2013. Income tax expense increased due to recoveries booked in the second quarter 2013 relating to an adjustment to the deferred tax liability and an income tax recovery resulting from the enactment of a Canadian tax amendment related to dividends paid on preferred shares. These increases were offset by decreased tax expense attributable to lower taxable earnings in Canada and in the U.S. in second quarter 2014, compared to the same quarter 2013.

Six Months Ended June 30

Normalized net income for first half 2014 was $100.5 million, an increase of 10 percent compared to $91.1 million reported for the same period 2013. For both of the periods ending June 30 2014 and 2013, normalized net income on a per share basis, was $0.82. The increase in net income of $9.4 million was due to higher volumes processed at the Harmattan, Gordondale and Blair Creek facilities, earnings contribution from Petrogas, higher frac exposed volumes, the addition of Blythe in May 2013, favorable foreign exchange on U.S. business results, colder weather experienced at the utilities, continued rate base and customer growth for the utilities, and higher realized frac spread. The increase was partially offset by lower Alberta Power Pool spot prices and lower generation from Alberta power assets, higher Sundance PPA costs, higher costs to fulfill firm delivery commitments from operational curtailments resulting from the combination of extremely cold weather in Eastern North America and low storage levels in the first quarter 2014, higher compensation costs and an income tax recovery booked in the second quarter 2013 relating to an adjustment to the deferred tax liability.

Net income applicable to common shares for first half 2014 was $68.8 million ($0.56 per share) compared to $85.0 million ($0.76 per share) for the same period 2013. Net income applicable to common shares for first half 2014 was normalized for provisions taken on certain assets, impact from the sale of non-core assets, unrealized losses on risk management contracts, costs associated with the early redemption of medium term notes (MTNs) and development costs incurred for the energy export projects.

Stronger earnings on a normalized basis resulted in stronger cash flow. Normalized funds from operations for first half 2014 increased by 18 percent to $235.7 million ($1.92 per share), compared to $199.2 million ($1.78 per share) for the same period 2013. In second quarter, AltaGas received a dividend from its investment in Petrogas of approximately $28 million. Normalized EBITDA for first half 2014 was $286.7 million, a 14 percent increase, compared to $252.1 million for the same period 2013.

Normalized operating income for first half 2014 was 14 percent higher at $201.6 million, compared to $177.2 million for the same period 2013. Normalized operating results were driven by the same factors as described above related to normalized net income except for the impact of interest and income taxes.

Operating and administrative expense for first half 2014 was $223.8 million, compared to $207.8 million for the same period 2013. The increase was primarily due to asset growth of the Corporation. Amortization expense for first half 2014 was $83.0 million, compared to $72.9 million for the same period 2013, due to asset growth of the Corporation.

Interest expense for first half 2014 was $48.3 million, compared to $49.8 million for the same period 2013. Interest expense increased due to a higher average debt balance of $3,246.8 million in first half 2014, compared to $2,746.9 million in the same period 2013. The higher debt was a result of the growth of the Corporation. The increase in interest expense was more than offset by higher capitalized interest of $20.5 million (first half 2013 - $13.2 million) and by a lower average borrowing rate of 4.3 percent in first half 2014 (first half 2013 - 4.6 percent).

AltaGas recorded income tax expense of $22.5 million for first half 2014, compared to $18.1 million for the same period 2013. Income tax expense increased due to an increase in U.S. earnings and as a result of recoveries booked in the second quarter 2013 relating to an adjustment to the deferred tax liability, and an income tax recovery resulting from the enactment of a Canadian tax amendment related to tax on dividends paid on preferred shares. These increases partially were offset by decreased tax expense attributable to lower taxable earnings in Canada, as well as an income tax recovery of $12.0 million relating to provisions on long-lived assets and gain on asset dispositions recorded in the first quarter 2014.

2014 OUTLOOK

In 2014, AltaGas is expected to deliver another strong year of earnings and cash flow growth, with the continued execution of the Corporation's growth strategy. These earnings are underpinned by the 195 MW Forrest Kerr and the 16 MW Volcano Creek project (Volcano Creek), new assets added in the last year, higher utilization of key gas processing assets, favorable weather in the first half of the year, and higher earnings from the Corporation's U.S. assets as a result of favorable exchange rates. These growth expectations are partially offset by the impact of asset sales completed in late 2013 and early 2014, lower contribution from Alberta power assets, higher interest expense, and taxes.

Activity in AltaGas' Gas business will continue to be driven by continued strong natural gas demand in North America due to historically low storage rates, increased gas consumption for power generation and industrial loads such as oil sands projects. In addition, it is expected that producers will continue to look to liquids-rich areas for their natural gas development which increases opportunities for AltaGas to add and expand processing facilities.

In 2014, the Gas segment will benefit from the contribution from Petrogas, including the contribution from the Ferndale terminal acquired by Petrogas in May 2014, increases in volumes processed at plants in liquids-rich areas, including at the Gordondale facility, where volumes reached the original licensed capacity at approximately 120 Mmcf/d in the second quarter, and the Co-stream facility at Harmattan. AltaGas has expanded its natural gas transmission system to deliver natural gas to two heavy oil projects near Cold Lake, Alberta. The expansions are underpinned by long-term take-or-pay transportation agreements and estimated to cost approximately $30 million. The first expansion project was completed ahead of schedule in fourth quarter 2013. Construction on the second expansion project commenced in June and is expected to be completed in late 2014, having a full year impact in 2015.

Management estimates an average of approximately 7,300 Bbls/d will be exposed to frac spread for the remainder of 2014. For 2014, 71 percent of the estimated volumes exposed to frac spread have been hedged at an average price of approximately $26/Bbl after deducting extraction premiums.

In the Power segment, earnings growth is expected to be driven by the full year contribution from Blythe, and the start of commercial operations of Forrest Kerr and Volcano Creek, partially offset by lower contribution from Alberta power assets. Operating results could be impacted if power prices weaken due to the timing of new generation expected to come into service in Alberta.

For the third and fourth quarters of 2014, AltaGas has hedged approximately 45 percent of volumes exposed to Alberta power prices at an average price of $65/MWh. The forward curve for Alberta power prices has shown volatility in recent months.

The Utilities segment benefited from the normal seasonally strong first quarter, and AltaGas expects to benefit from the seasonally strong fourth quarter due to the winter heating season. The Utilities are expected to report increased earnings in 2014 driven by continued rate base growth and customer growth, and colder weather year-to-date. In addition, continued favorable exchange rates are expected to result in higher Canadian dollar earnings from the U.S. utilities in 2014.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $450 million to $500 million for 2014. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' committed capital program is fully funded through internally-generated cash flow, the dividend reinvestment plan (DRIP), and available bank lines. As at June 30, 2014, the Corporation had approximately $1.4 billion available on its credit facilities.

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwestern British Columbia: 195 MW Forrest Kerr, 16 MW Volcano Creek and the 66 MW McLymont Creek project (McLymont Creek). The 277 MW Northwest Projects are contracted with 60-year Electricity Purchase Agreement (EPA) with BC Hydro fully indexed to the Consumer Price Index (CPI), as well as Impact Benefit Agreements with the Tahltan First Nation.

Forrest Kerr

The facility captures the energy produced by the natural flow and elevation drop of the Iskut River to produce and deliver clean, renewable power to the grid. Construction of the $725 million Forrest Kerr facility, which commenced in 2010, was completed on time and on budget and is supported by a 60-year, fully indexed EPA with BC Hydro. AltaGas completed final commissioning of the powerhouse systems and high voltage switchyard in July 2014 and the Forrest Kerr facility is now tied-in to the Northwest Transmission Line (NTL) at Bob Quinn, British Columbia. Over the next four to six weeks, a number of online electrical and system functional checks will be performed, during which time, generation is expected to fluctuate. AltaGas expects final project commercial operations being achieved by the end of third quarter 2014.

Volcano Creek

At the 16 MW Volcano Creek project, construction continues to pace two years ahead of schedule. The penstock excavation and switchyard work are underway. Assembly of the powerhouse and installation of the turbine generators are advancing. The project remains on track to be in service shortly.

McLymont Creek

At the 66 MW McLymont Creek project, construction of the powerhouse foundation is advancing ahead of schedule and excavation of the 2,800 meter power tunnel is approximately 80 percent complete. The project is expected to be in service in mid-2015.

Blythe II/Sonoran Energy Project

In the second quarter, AltaGas paid US$8.5 million to acquire the shovel ready Blythe II project to be called the Sonoran Energy Project, next to the existing AltaGas Blythe facility close to the California-Arizona border. AltaGas anticipates to respond to expected upcoming Request for Proposals (RFPs) by the end of 2014, with the potential to double the size of the existing Blythe facility. AltaGas also acquired 76 acres north of the current Blythe facility that provides further opportunities to expand generating capacity at Blythe over the longer term.

AIJVLP

On January 29, 2013, AltaGas signed an agreement with Idemitsu Kosan Co., Ltd. (Idemitsu) to form AIJVLP. AltaGas and Idemitsu each own, through subsidiaries, a 50 percent interest in AIJVLP. AIJVLP is pursuing opportunities to develop liquefaction infrastructure to meet the growing demand for natural gas in Asia. AIJVLP is also pursuing opportunities to develop a Liquefied Petroleum Gas (LPG) export business, including logistics, plant refrigeration and storage facilities. On March 1, 2014, AIJVLP completed the acquisition of two-thirds of Petrogas. Petrogas is a privately-held leading North American integrated midstream company. Petrogas' extensive logistics network provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities.

LPG Export Business

On May 1, 2014 Petrogas acquired the Ferndale export terminal located in the State of Washington. The facility is already shipping LPG for third parties and is expected to increase the number of LPG shipments resulting in a ramp up over the next several years to 30,000 Bbls/d to the Petrogas account.

Through AIJVLP, AltaGas is also developing a greenfield LPG terminal on the west coast of Canada and is currently conducting site evaluation studies which are expected to be completed in 2014. Terminal sites and refrigeration technology are being evaluated. AIJVLP is currently in discussions with key stakeholders to determine project timing and with market participants to develop sales and logistics agreements.

LNG Export Business

In addition to LPG, AIJVLP continues to work with various parties to support the Companies' Creditors Arrangement Act (CCAA) Plan of Arrangement proceedings for the Douglas Channel LNG project. AIJVLP continues to develop definitive agreements and stakeholders are expected to vote on the CCAA plan of arrangement following filing of the plan with the court. The CCAA court deadline to reach definitive agreements is August 1, 2014.

Separately, AltaGas continues to make progress on the development of a second LNG export facility. On April 16, 2014, Triton LNG, a wholly-owned subsidiary of AIJVLP received NEB approval to export up to 2.3 million tonnes per year of LNG. LNG exports are subject to consultations with First Nations, and the completion of the feasibility study, siting, permitting, regulatory approvals and facility construction.

AltaGas and its partners are continuing to pursue the Triton LNG project, and have signed a Transportation Reservation Agreement (TRA) with PNG for 325 Mmcf/day of natural gas transportation capacity related to the PNG expansion providing a vital pipeline link to the west coast region of British Columbia. The TRA commits Triton LNG to backstop development costs related to the expansion of the pipeline.

Pacific Northern Gas Ltd. Pipeline Looping Project (PLP)

PNG continues to proceed with the development of the potential expansion of approximately 600 Mmcf/d on its natural gas transmission line. PNG has signed TRAs with two parties to support the PNG expansion project. Douglas Channel Gas Services Ltd., one of the parties, is currently in a CCAA proceeding, of which the outcome is not known at this time. The TRAs provide for cost recovery of development costs related to the PLP and are backstopped by letters of credit provided by the counterparties. On July 24, 2013, the British Columbia Environmental Assessment Office (BCEAO) issued an order accepting PNG's PLP into the environmental assessment process following PNG's filing of its project description.

On March 31, 2014, the BCEAO issued the approved Application Information Requirements (AIR), which specifies the required information in an application for environmental assessment certificate. Under the approved environmental assessment process, PNG has up to three years to provide the required information. PNG is continuing its consultation activities while undertaking the field studies necessary to address the AIR. PNG expects to continue environmental and consultation processes with a final investment decision (FID) on PLP expected in late 2015.

Cogeneration III

AltaGas is expanding its cogeneration fleet at Harmattan to 45 MW. In first quarter, AltaGas began engineering and procured the combustion turbine for the new 15 MW Cogeneration III to meet the increased power demand at Harmattan and increase sales to the Alberta power market. Final regulatory approvals for the project were received in July 2014 and construction will begin shortly. Cogeneration III is on schedule and budget as planned and expected to be in service in first half 2015 with a total project cost estimated at $40 million.

Cold Lake

In 2013 AltaGas announced the Cold Lake expansion project which will supply gas to steam assisted gravity drainage heavy oil projects near Cold Lake in Alberta. These projects are underpinned by long-term take-or-pay agreements and will double the utilization of the system. The system has the potential for future expansion opportunities. With the first project completed ahead of schedule in fourth quarter 2013, construction on the second project has commenced and is expected to be completed in late 2014.

Alton Natural Gas Storage Project

AltaGas has commenced construction on the Alton Natural Gas Storage project, with up to 10 Bcf of natural gas storage located near Truro, Nova Scotia. The first phase of the project is 4.5 Bcf of storage and is expected to be in service in 2017 at a construction cost of approximately $100 million. AltaGas expects to complete a 20-year firm storage agreement with Heritage Gas Limited (Heritage Gas) for approximately 4 Bcf for the first phase, which will be subject to regulatory approval.

Regional LNG

AltaGas is developing a small scale LNG production facility in Dawson Creek, British Columbia. FID is predicated on securing base load off-take agreements. Capital cost of the Regional LNG project is expected to be approximately $30 million and first sales are expected in early 2015. This LNG production facility is expected to serve both commercial and residential markets in displacing diesel fuel. As market demand for LNG to displace diesel fuel further develops, expansion of the business may occur in British Columbia and other regions.

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 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.

References to net revenue, normalized operating income, normalized EBITDA, normalized net income and normalized funds from operations throughout this document have the meanings as set out in this section.

Net Revenue	Three months ended June 30		Six months ended June 30	
($ millions)	**2014**	2013	**2014**	2013
Net revenue [(1)]	**$ 219.9**	$ 211.8	**$ 516.5**	$ 449.1
Add (deduct):				
Other income (expenses)	**(1.6)**	(0.9)	**(11.4)**	(0.3)
Income from equity investments	**(7.3)**	(49.5)	**(24.6)**	(66.2)
Cost of sales	**260.2**	297.2	**814.5**	689.5
Revenue (GAAP financial measure)	**$ 471.2**	$ 458.6	**$ 1,295.0**	$ 1,072.1

(1) *Amounts may not add due to rounding.*

Management believes that net revenue, which is revenue plus other income (expenses) plus income from equity investments not held-for-trading, 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 commodities affect both revenue and cost of sales, and equity investments are part of operating activities for the Corporation.

Normalized Operating Income	Three months ended June 30		Six months ended June 30	
($ millions)	**2014**	2013	**2014**	2013
Normalized operating income	**$ 64.5**	$ 68.0	**$ 201.6**	$ 177.2
Add (deduct):				
Transaction costs related to acquisitions	**-**	(0.8)	**-**	(1.3)
Unrealized gain (loss) on long-term investments	**0.4**	0.1	**0.4**	(0.9)
Provision for long-lived assets	**-**	(0.5)	**(49.2)**	(0.5)
Costs associated with early redemption of MTNs	**-**	-	**(2.3)**	-
Gain (loss) on asset dispositions	**(0.2)**	-	**11.1**	-
Joint venture development costs	**(0.3)**	-	**(0.4)**	-
Operating income	**64.4**	66.8	**161.2**	174.5
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**2.8**	(1.6)	**(2.8)**	(8.7)
Interest expense	**(23.0)**	(25.2)	**(48.3)**	(49.8)
Foreign exchange gain (loss)	**(0.2)**	(0.4)	**0.2**	-
Income tax expense (recovery)	**(5.7)**	2.9	**(22.5)**	(18.1)
Net income applicable to non-controlling interests	**(2.0)**	(1.8)	**(4.2)**	(3.4)
Preferred share dividends	**(7.4)**	(4.8)	**(14.8)**	(9.5)
Net income applicable to common shares (GAAP financial measure)	**$ 28.9**	$ 35.9	**$ 68.8**	$ 85.0

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 to assess operating performance since management believes that 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 gain or loss on risk management contracts, interest expense, foreign exchange gain or loss, income tax expense (recovery), net income applicable to non-controlling interests and preferred share dividends.

Normalized operating income represents operating income adjusted for non-operating related expenses such as transaction costs related to acquisitions, unrealized gain (loss) on long-term investments, provision taken for long-lived assets, costs associated with early redemption of MTNs, and gain (loss) on asset dispositions. Normalized operating income also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs from AltaGas.

Normalized EBITDA	Three months ended June 30		Six months ended June 30	
($ millions)	**2014**	2013	**2014**	2013
Normalized EBITDA	**$ 107.3**	$ 106.2	**$ 286.7**	$ 252.1
Add (deduct):				
Transaction costs related to acquisitions	**-**	(0.8)	**-**	(1.3)
Unrealized gain (loss) on long-term investments	**0.4**	0.1	**0.4**	(0.9)
Gain (loss) on asset dispositions	**(0.2)**	-	**11.1**	-
Joint venture development costs	**(0.3)**	-	**(0.4)**	-
Costs associated with early redemption of MTNs	**-**	-	**(2.3)**	-
EBITDA	**107.2**	105.5	**295.5**	249.9
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**2.8**	(1.6)	**(2.8)**	(8.7)
Depreciation, depletion and amortization	**(41.8)**	(37.3)	**(83.0)**	(73.0)
Provision for long-lived assets	**-**	(0.5)	**(49.2)**	(0.5)
Accretion expenses	**(1.0)**	(0.9)	**(2.1)**	(1.9)
Interest expense	**(23.0)**	(25.2)	**(48.3)**	(49.8)
Foreign exchange gain (loss)	**(0.2)**	(0.4)	**0.2**	-
Income tax expense (recovery)	**(5.7)**	2.9	**(22.5)**	(18.1)
Net income applicable to non-controlling interests	**(2.0)**	(1.8)	**(4.2)**	(3.4)
Preferred share dividends	**(7.4)**	(4.8)	**(14.8)**	(9.5)
Net income applicable to common shares (GAAP financial measure)	**$ 28.9**	$ 35.9	**$ 68.8**	$ 85.0

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 earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk on a significant portion of the volumes subject to commodity price fluctuations, 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, depreciation, depletion and amortization, provision taken for long-lived assets, accretion of long-term obligations, interest expense, foreign exchange gain or loss, income tax expense (recovery), net income applicable to non-controlling interests, and preferred share dividends.

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as transaction costs related to acquisitions, unrealized gain (loss) on long-term investments, costs associated with early redemption of MTNs and gain (loss) on asset dispositions. Normalized EBITDA also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs from AltaGas.

Normalized Net Income		Three months ended June 30		Six months ended June 30
($ millions)	**2014**	2013	**2014**	2013
Normalized net income	**$ 26.8**	$ 35.5	**$ 100.5**	$ 91.1
Add (deduct) after-tax:				
Unrealized gain (loss) on risk management contracts	**2.1**	(1.2)	**(2.1)**	(6.5)
Unrealized gain (loss) on long-term investments	**0.3**	0.1	**0.3**	(0.8)
Transaction costs related to acquisitions	**-**	(0.5)	**-**	(0.8)
Gain (loss) on asset dispositions	**(0.1)**	-	**8.9**	-
Provision for long-lived assets	**-**	(0.4)	**(36.8)**	(0.4)
Joint venture development costs	**(0.2)**	-	**(0.3)**	-
Costs associated with early redemption of MTNs	**-**	-	**(1.7)**	-
Statutory tax rate change	**-**	2.4	**-**	2.4
Net income applicable to common shares (GAAP financial measure)	**$ 28.9**	$ 35.9	**$ 68.8**	$ 85.0

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as transaction costs related to acquisitions, gain (loss) on asset dispositions, provision taken on long-lived assets and costs associated with early redemption of MTNs. Normalized net income also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs by AltaGas.

Normalized Funds from Operations		Three months ended June 30		Six months ended June 30
($ millions)	**2014**	2013	**2014**	2013
Normalized funds from operations	**$ 105.8**	$ 83.1	**$ 235.7**	$ 199.2
Add (deduct):				
Transaction costs related to acquisitions	**-**	(0.8)	**-**	(1.3)
Funds from operations	**105.8**	82.3	**235.7**	197.9
Add (deduct):				
Net change in operating assets and liabilities	**6.1**	57.5	**48.4**	38.7
Asset retirement obligations settled	**(0.3)**	(0.2)	**(0.7)**	(0.7)
Cash from operations (GAAP financial measure)	**$ 111.6**	$ 139.6	**$ 283.4**	$ 235.9

Normalized funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in operating assets and liabilities in the period and non-operating related one-time expenses 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 operating assets and liabilities, expenditures incurred to settle asset retirement obligations and non-operating related expenses.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized Operating Income (1)		Three months ended	June 30		Six months ended	June 30
($ millions)		**2014**	2013		**2014**	2013
Gas	**$**	**40.0**	$ 20.3	**$**	**87.5**	$ 48.0
Power		**13.2**	33.0		**29.1**	55.4
Utilities		**19.9**	21.4		**101.1**	86.9
Sub-total: Operating Segments		**73.1**	74.7		**217.7**	190.3
Corporate		**(8.6)**	(6.7)		**(16.1)**	(13.1)
	$	**64.5**	$ 68.0	**$**	**201.6**	$ 177.2

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

GAS

OPERATING STATISTICS	Three months ended	June 30	Six months ended	June 30
	2014	2013	**2014**	2013
Total inlet gas processed (Mmcf/d)(1)	**1,476**	1,366	**1,525**	1,373
Extraction ethane volumes (Bbls/d)(1) (2)	**32,488**	33,380	**33,368**	33,515
Extraction NGL volumes (Bbls/d)(1) (2)	**37,379**	31,202	**37,567**	28,120
Total extraction volumes (Bbls/d)(1) (2)	**69,867**	64,582	**70,935**	61,635
Frac spread - realized ($/Bbl)(1) (3)	**22.12**	20.80	**26.37**	25.13
Frac spread - average spot price ($/Bbl)(1) (4)	**22.95**	17.85	**31.88**	22.48

(1) *Average for the period.*

(2) *Includes Harmattan NGL processed on behalf of customers.*

(3) *Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.*

(4) *Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.*

During second quarter 2014, total inlet gas processed increased by 110 Mmcf/d. The increase was primarily driven by higher volumes processed at the Harmattan, Gordondale, Blair Creek, and Younger facilities, partially offset by the sale of Ante Creek.

During second quarter 2014, average ethane volumes produced decreased by 892 Bbls/d and NGL volumes produced increased by 6,177 Bbls/d, compared to same quarter 2013. Lower ethane volumes were due to downstream operational constraints at Younger and JEEP extraction facilities, partially offset by increased volumes at Harmattan Co-stream. Higher NGL volumes in the second quarter 2014 were due to increased inlet volumes at Younger and Gordondale.

During first half of 2014, total inlet gas processed increased by 152 Mmcf/d, compared to same period 2013. The increase was driven by the same reasons as described above.

During first half of 2014, average ethane volumes produced decreased by 147 Bbls/d and NGL volumes produced increased by 9,447 Bbls/d, compared to same period of 2013. The lower ethane volumes and the higher NGL volumes were driven by the same reasons described above.

Three Months Ended June 30

The Gas segment almost doubled normalized operating income to $40.0 million in second quarter 2014, compared to $20.3 million in same quarter 2013. The increase was a result of the higher volumes processed at the Harmattan, Gordondale and Blair Creek facilities, higher frac exposed volumes and higher realized frac prices, and by the contribution to earnings from Petrogas.

The Gas segment reported operating income of $39.5 million in second quarter 2014, compared to $20.3 million in same quarter 2013.

During second quarter 2014, AltaGas hedged approximately 70 percent of frac exposed production at an average price of $25/Bbl. During second quarter 2013, AltaGas hedged 57 percent of frac exposed production at an average price of $34/Bbl. The average indicative spot NGL frac spread for second quarter 2014 was approximately $23/Bbl, compared to approximately $18/Bbl in same quarter 2013.

Six Months Ended June 30

The Gas segment reported normalized operating income of $87.5 million in first half 2014, compared to $48.0 million in same period 2013. The increase was a result of the contribution from Petrogas, higher frac exposed volumes and higher realized frac spread, and higher volumes processed at Harmattan, Gordondale and Blair Creek facilities. These increases were partially offset by higher costs to fulfill firm delivery commitments from operational curtailments resulting from the combination of extremely cold weather in eastern North America and low storage levels in the first quarter 2014.

The Gas segment reported operating income of $59.7 million in first half 2014, compared to $48.1 million in same period 2013, and includes the impact of the provision taken on Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and partially offset by the gain from the sale of the Ante Creek facility, both recorded in first quarter 2014.

During first half 2014, AltaGas hedged approximately 70 percent of frac exposed production at an average price of $26/Bbl. During first half 2013, AltaGas hedged approximately 60 percent of frac exposed production at an average price of $34/Bbl. The average indicative spot NGL frac spread for first half 2014 was approximately $32/Bbl compared to approximately $22/Bbl in same period 2013.

POWER

OPERATING STATISTICS	Three months ended June 30		Six months ended June 30	
	2014	2013	**2014**	2013
Volume of power sold (GWh)	**1,067**	1,035	**2,248**	1,902
Average price realized on the sale of power ($/MWh) (1)	**55.92**	87.01	**62.70**	80.17
Alberta Power Pool average spot price ($/MWh)	**42.43**	123.41	**51.46**	94.51

(1) *Price received excludes Blythe as it earns fixed capacity payments under its power purchase tolling agreement with Southern California Edison Company (SCE).*

During second quarter 2014, volume of power sold increased by 32 GWh compared to same quarter 2013. Volumes sold during second quarter 2014 comprised of 953 GWh conventional power generation and 114 GWh of renewable power generation, compared to 912 GWh conventional power generation and 123 GWh renewable power generation in same quarter 2013.

During first half 2014, volume of power sold increased by 346 GWh compared to same period of 2013. Volumes sold during first half 2014 comprised of 2,012 GWh of conventional power generation and 236 GWh renewable power generation, compared to 1,650 GWh conventional power generation and 252 GWh renewable power generation in same period 2013. The increase in power generated was primarily due to the Blythe acquisition in May 2013. For the first half of 2014, Blythe generated 566 GWh of power. The facility conducted a major turnaround from March 1 to April 15, 2014. Generation volumes in Alberta were lower as a result of lower spot prices.

Three Months Ended June 30

The Power segment reported normalized operating income of $13.2 million for second quarter 2014, compared to $33.0 million for same quarter 2013. Normalized operating income decreased as a result of a 66 percent decrease in Alberta Power Pool spot prices, lower generation from Alberta assets, and lower volumes at Bear Mountain. Power segment decreases were partially offset by the addition of Blythe, which was acquired on May 16, 2013.

Operating income in the Power segment was $13.0 million in second quarter 2014, compared to $31.6 million in same quarter 2013 and includes the impact of a pre-tax loss of $0.2 million related to the disposal of a non-core biomass development asset.

In second quarter 2014, AltaGas was 50 percent hedged in Alberta at an average price of $60/MWh. In second quarter 2013, AltaGas was 67 percent hedged at an average price of $62/MWh.

Six Months Ended June 30

The Power segment reported normalized operating income of $29.1 million for first half 2014, compared to $55.4 million for same period 2013. Normalized operating income decreased as a result of lower Alberta Power Pool spot prices in the first half of 2014 compared to exceptionally higher prices in the first half of 2013, higher Sundance PPA costs, lower generation from Alberta assets, and lower volumes at Bear Mountain. Power segment decreases were partially offset by the addition of Blythe, which was acquired on May 16, 2013.

Operating income in the Power segment was $18.0 million in first half 2014, compared to $53.6 million in same period 2013 and includes the impact of a provision taken on a number of small hydro power development projects in British Columbia, and a loss on disposal of a non-core biomass development asset.

In first half 2014, AltaGas was 54 percent hedged in Alberta at an average price of $63/MWh. In first half 2013, AltaGas was 64 percent hedged at an average price of $65/MWh.

UTILITIES

OPERATING STATISTICS	Three months ended June 30 2014	2013	Six months ended June 30 2014	2013
Canadian utilities				
Natural gas deliveries - end-use (PJ)[1]	**6.2**	5.3	**19.0**	17.0
Natural gas deliveries - transportation (PJ)[1]	**1.2**	1.4	**3.1**	3.0
US utilities				
Natural gas deliveries - end-use (Bcf)[1]	**10.6**	11.6	**43.1**	40.5
Natural gas deliveries - transportation (Bcf)[1]	**8.4**	9.8	**20.8**	22.6
Service sites [2]	**553,320**	546,906	**553,320**	546,906
Degree day variance from normal - AUI (%) [3]	**10.8**	3.0	**6.6**	(3.3)
Degree day variance from normal - Heritage Gas (%) [3]	**3.7**	(2.1)	**3.8**	(2.1)
Degree day variance from normal - SEMCO Gas (%) [4]	**9.9**	16.4	**21.1**	7.0
Degree day variance from normal - ENSTAR (%) [4]	**(7.7)**	12.8	**(8.1)**	0.1

(1) *Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.*

(2) *Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non-regulated business lines.*

(3) *A degree day for AUI and Heritage Gas 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 materially affect the results of PNG as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.*

(4) *A degree day for U.S. utilities is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 10 years for ENSTAR.*

Three Months Ended June 30

The Utilities segment reported operating income of $19.9 million in second quarter 2014, compared to $21.4 million in same quarter 2013. The utilities benefited from customer growth and increased rate base however this was offset by higher expenses as a result of the growth and warmer weather at the U.S. utilities, compared to the second quarter of 2013.

Six Months Ended June 30

The Utilities segment reported operating income of $101.1 million in first half 2014, compared to $86.9 million in same period 2013. The increase was mainly due to growth of customers and rate base, colder weather, and favorable foreign exchange on the U.S. business results.

CORPORATE

Three Months Ended June 30

In the Corporate segment, normalized operating loss for second quarter 2014 was $8.6 million, compared to $6.7 million in same quarter 2013. The higher normalized loss was due to increased administrative expenses to support business growth and for energy export development initiatives. Operating loss in the Corporate segment was $8.0 million for second quarter 2014, which includes costs associated with unrealized losses on risk management contracts, compared to $6.5 million for same quarter 2013.

Six Months Ended June 30

Normalized operating loss for the first six months 2014 was $16.1 million, compared to $13.1 million in same quarter 2013. The operating loss in the Corporate segment for first half 2014 was $17.7 million compared to $14.0 million for same period 2013. The increase in loss was driven by the same factors as described above.

INVESTED CAPITAL

During second quarter 2014, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $137.8 million, compared to $668.3 million in same quarter 2013. The net invested capital was $137.2 million for the three months ended June 30, 2014, compared to $667.7 million in same quarter 2013.

Invested Capital - Investment Type — **Three months ended June 30, 2014**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 8.4**	**$ 87.0**	**$ 36.7**	**$ 0.6**	**$ 132.7**
Intangible assets	**-**	**-**	**0.5**	**3.9**	**4.4**
Long-term investments	**0.7**	**-**	**-**	**-**	**0.7**
Invested capital	**9.1**	**87.0**	**37.2**	**4.5**	**137.8**
Disposals:					
Property, plant and equipment	**(0.5)**	**(0.1)**	**-**	**-**	**(0.6)**
Net Invested capital	**$ 8.6**	**$ 86.9**	**$ 37.2**	**$ 4.5**	**$ 137.2**

Invested Capital - Investment Type — Three months ended June 30, 2013

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 6.6	$ 626.2	$ 30.6	$ 0.5	$ 663.9
Intangible assets	0.1	-	1.4	2.9	4.4
	6.7	626.2	32.0	3.4	668.3
Disposals:					
Property, plant and equipment	(0.6)	-	-	-	(0.6)
Net Invested capital	$ 6.1	$ 626.2	$ 32.0	$ 3.4	$ 667.7

In the Gas segment, invested capital included $3.4 million for Alton, $1.8 million for Harmattan Co-stream, $0.8 million for the Cold Lake System expansion, $0.7 million invested in AIJVLP and $2.4 million for various small Gas related projects. During the quarter, the Gas segment received $0.5 million in proceeds from sale of assets. The invested capital for Gas included $0.9 million of maintenance capital.

In the Power segment, invested capital included $43.1 million for Forrest Kerr, $15.9 million for McLymont Creek, $9.3 million related to Blythe II, $7.0 million for Parkland peaking plant, $4.4 million for Cogeneration III, $4.1 million for Volcano Creek, and $1.7 million for the Blythe land acquisition. During the quarter, the Power segment received $0.1 million in proceeds from sale of long-lived assets. The invested capital for Power also included $1.5 million related to the turnaround at Blythe which is amortized over four to eight years, to align with the timing of major turnarounds at the facility.

The Utilities segment invested $16.1 million of capital at the Canadian utilities, $21.0 million at the U.S. utilities and $0.1 million related to the Compressed Natural Gas (CNG) business at Heritage Gas.

The Corporate segment reported an increase in expenditure of $4.5 million, primarily due to information technology infrastructure investments.

During first half 2014, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $259.3 million, compared to $774.2 million in same period 2013. The net invested capital was $231.9 million for the six months ended June 30, 2014, compared to $773.6 million in same period 2013.

Invested Capital - Investment Type — **Six months ended June 30, 2014**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 21.3**	**$ 167.4**	**$ 56.3**	**$ 2.7**	**$ 247.7**
Intangible assets	**0.2**	**-**	**0.8**	**7.3**	**8.3**
Long-term investments	**3.3**	**-**	**-**	**-**	**3.3**
Invested capital	**24.8**	**167.4**	**57.1**	**10.0**	**259.3**
Disposals:					
Property, plant and equipment	**(27.2)**	**(0.2)**	**-**	**-**	**(27.4)**
Net Invested capital	**$ (2.4)**	**$ 167.2**	**$ 57.1**	**$ 10.0**	**$ 231.9**

Invested Capital - Investment Type — Six months ended June 30, 2013

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 13.6	$ 697.1	$ 53.7	$ 1.3	$ 765.7
Intangible assets	3.1	-	2.0	3.4	8.5
	16.7	697.1	55.7	4.7	774.2
Disposals:					
Property, plant and equipment	(0.6)	-	-	-	(0.6)
Net Invested capital	$ 16.1	$ 697.1	$ 55.7	$ 4.7	$ 773.6

In the Gas segment, invested capital included $12.4 million for Alton, $3.3 million invested in AIJVLP, $2.2 million for Harmattan Co-stream, $1.4 million for the Cold Lake System expansion, and $5.5 million for various small Gas related projects. During the six months ended June 30, 2014, the Gas segment received $27.2 million in proceeds from sale of long-lived assets. The invested capital for Gas included $3.3 million of maintenance capital.

In the Power segment, invested capital included $94.1 million for Forrest Kerr, $29.0 million for McLymont Creek, $9.3 million related to Blythe II, $7.4 million for Parkland peaking plant, $7.1 million for Volcano Creek, $5.7 million for Cogeneration III, and $1.7 million for Blythe land acquisition. During the six months ended June 30, 2014, the Power segment received $0.2 million in proceeds from sale of long-lived assets. The invested capital for Power also included $13.1 million related to the turnaround at Blythe which is amortized over four to eight years, to align with the timing of major turnarounds at the facility.

The Utilities segment invested $26.9 million of capital at the Canadian utilities, $29.7 million at the U.S. utilities and $0.5 million related to the CNG business at Heritage Gas.

The Corporate segment reported expenditures of $10.0 million, primarily due to information technology infrastructure investments.

RISK MANAGEMENT

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 second quarter 2014, the Corporation had positions in the following types of derivatives, which are also disclosed in the unaudited Consolidated Financial Statements:

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 sale 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 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 interest rate and foreign exchange 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.

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 segment 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 $7.88/MWh to $897.21/MWh in second quarter 2014 and $9.02/MWh to $999.99/MWh in second quarter 2013. The average Alberta spot price was $42.43/MWh in second quarter 2014 (second quarter 2013 - $123.41/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 $55.92/MWh in second quarter 2014 (second quarter 2013 - $87.01/MWh). For the third and fourth quarters of 2014, AltaGas has hedged approximately 45 percent of volumes exposed to Alberta power prices at an average price of $65/MWh. For 2015, AltaGas has hedged approximately 10 percent of volumes exposed to Alberta power prices at an average price of approximately $66/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 second quarter 2014, the Corporation had NGL frac spread hedges for an average of 5,000 Bbls/d at an average price of approximately $25/Bbl. The average indicative spot NGL frac spread for second quarter 2014 was an estimated $23/Bbl (second quarter 2013 – $18/Bbl). The average NGL frac spread realized by AltaGas in second quarter 2014 was $22/Bbl (second quarter 2013 - $21/Bbl). Management estimates an average of approximately 7,300 Bbls/d will be exposed to frac spread in 2014. For 2014, 71 percent of the estimated volumes exposed to frac spread have been hedged at an average price of approximately $26/Bbl after deducting extraction premiums. For 2015, approximately 27 percent of estimated volumes exposed to frac spread have been hedged at an average price of approximately $26/Bbl after deducting extraction premiums.

Interest Rate Forward Contracts

From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. As at June 30, 2014, the Corporation had no interest rate swaps outstanding. At June 30, 2014, the Corporation had fixed the interest rate on 77 percent of its debt including MTNs (June 30, 2013 - 76 percent).

Foreign Exchange

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.

Foreign exchange gains and losses on long-term debts denominated in US dollars are unrealized and can only be realized when a long-term debt matures or is settled. As at June 30, 2014, management designated US$557.0 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2013 - US$570.0 million). US dollar denominated long-term debts have been designated as a hedge of the net investment in foreign subsidiaries. This designation has the effect of mitigating volatility on net income by offsetting foreign exchange gains and losses on US dollar denominated long-term debt and foreign net investment.

LIQUIDITY

Cash Flows	Three months ended June 30		Six months ended June 30	
($ millions)	**2014**	2013	**2014**	2013
Cash from operations	**$ 111.6**	$ 139.6	**$ 283.4**	$ 235.9
Investing activities	**(127.5)**	(658.5)	**(217.8)**	(762.2)
Financing activities	**(32.9)**	589.6	**(82.7)**	609.6
Effect of exchange rate	**(1.5)**	0.3	**0.2**	0.5
Change in cash	**$ (50.3)**	$ 71.0	**$ (16.9)**	$ 83.8

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $283.4 million in first half 2014, compared to $235.9 million in same period 2013. The increase in cash from operations was primarily a result of higher gas business growth, increased utilities earnings, and Petrogas dividends, partially offset by lower power distributions.

Working Capital		
As at June 30	**2014**	2013
($ millions except current ratio)		
Current assets	**$ 443.8**	$ 571.0
Current liabilities	**543.2**	623.8
Working capital	**(99.4)**	(52.8)
Current ratio	**0.82**	0.92

Working capital was in a deficit position of $99.4 million as at June 30, 2014, compared to working capital deficit of $52.8 million as at June 30, 2013. The working capital ratio was 0.82 at the end of second quarter 2014, compared to 0.92 at the end of same quarter 2013. The working capital ratio decreased due to a lower cash balance as at June 30, 2014, compared to the balances as at June 30, 2013.

Investing Activities

Cash used for investing activities in first half 2014 was $217.8 million compared to $762.2 million in same period 2013. Investing activities in first half 2014 comprised expenditures of $236.7 million for property, plant and equipment, and $9.4 million for intangible assets, partially offset by proceeds of $27.4 million received on disposition of assets. Investing activities in first half 2013 primarily comprised of the Blythe acquisition for $536.8 million, $223.1 million for property, plant and equipment and $5.1 million for intangible assets.

Financing Activities

Cash used on financing activities in first half was $82.7 million, compared to cash received of $609.6 million in same period 2013. Financing activities in first half 2014 were primarily comprised of net proceeds from issuance of common shares of $45.1 million, issuance of long-term debt of $746.2 million, partially offset by repayments of long-term and short-term debts, $695.6 million and $59.9 million respectively. Financing activities in first half 2013 were primarily comprised of net proceeds from issuance of common shares of $430.1 million and issuance of $1,033.0 million of long-term debt, partially offset by $701.6 million repayment of long-term debt, and $61.9 million repayment of short-term debt. Total dividends paid in first half 2014 were $111.7 million, compared to $89.2 million in same period 2013. The increase was due to higher shares outstanding and dividend increases.

CAPITAL RESOURCES

AltaGas' objective for managing capital is to maintain its investment grade credit ratings, ensure adequate liquidity and to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas considers shareholders' equity (including non-controlling interests), short-term and long-term debt (including current portion) less cash and cash equivalents to comprise its capital structure.

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 June 30, 2014, AltaGas had $2,425.3 million in MTNs outstanding, PNG debenture notes of $60.1 million, SEMCO Energy, Inc. (SEMCO) long-term debt of $407.8 million and $481.0 million drawn from bank credit facilities. As at June 30, 2014, AltaGas' current portion of long-term debt was $194.8 million.

AltaGas' earnings coverage for the rolling twelve months ended June 30, 2014 was 2.5 times.

AltaGas' debt-to-total capitalization ratio as at June 30, 2014 was 53.0 percent (December 31, 2013 - 53.1 percent).

($ thousands)		**June 30, 2014**		December 31, 2013
Debt				
Short-term debt	**$**	**24,667**	$	84,350
Current portion of long-term debt		**194,843**		209,069
Long-term debt		**3,022,584**		2,952,673
Less: cash and cash equivalent		**(27,883)**		(44,812)
Net debt		**3,214,211**		3,201,280
Shareholders' equity		**2,818,790**		2,791,707
Non-controlling interests		**35,682**		37,763
Total capitalization	**$**	**6,068,683**	$	6,030,750
Debt-to-total capitalization ratio (%)		**53.0**		53.1

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 following table summarizes the Corporation's debt covenants for all credit facilities as at June 30, 2014:

Ratios	Debt covenant requirements
Debt-to-capitalization	not greater than 65 percent
EBITDA-to-interest expense	not less than 2.5x
EBITDA-to-interest expense (SEMCO)	not less than 2.25x
Debt-to-capitalization (SEMCO)	not greater than 60 percent
Debt-to-capitalization (PNG)	not greater than 65 percent

As at June 30, 2014, the Corporation had approximately $1.4 billion of available credit facilities and $27.9 million in cash and cash equivalents.

On April 4, 2013, AltaGas closed a public offering of 11,615,000 common shares at a price of $34.90 per common share for aggregate gross proceeds of approximately $405 million.

On April 12, 2013, AltaGas issued US$175 million of senior unsecured MTNs. The notes carry a floating rate coupon of three-month LIBOR plus 0.79 percent and mature on April 13, 2015.

On May 17, 2013, the CINGSA construction credit facility for US$90 million was converted to a term loan of US$82.1 million with maturity of November 14, 2015. The loan was repaid on June 10, 2014.

On June 7, 2013, PNG repaid and cancelled its $35 million term revolver. The majority of the funds used to repay the term revolver were sourced from PNG's new five-year $70 million revolving term facility provided by AltaGas.

On June 11, 2013, AltaGas issued $300 million of senior unsecured MTNs. The notes carry a coupon rate of 3.57 percent and mature on June 12, 2023.

On August 23, 2013, a new $4 billion base shelf prospectus valid for 25 months was filed. 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. As at June 30, 2014, $3.1 billion remains available on the base shelf prospectus.

On December 13, 2013, AltaGas issued 8,000,000 five-year rate-reset Series E Preferred Shares, at a price of $25 per Series E Preferred Share for aggregate gross proceeds of $200 million.

On December 20, 2013, SEMCO amended its US$100 million unsecured credit facility dated August 30, 2012 by increasing the size of the facility to US$150 million and extending the maturity date to December 20, 2018.

On December 20, 2013 AltaGas entered into an agreement for a $1.4 billion unsecured credit facility which expires on December 15, 2017. This facility replaces the $200 million Utility Group revolving credit facility, the US$300 million unsecured credit facility and the $600 million AltaGas Ltd. revolving credit facility.

On January 13, 2014, AltaGas issued $200 million of senior unsecured MTNs with a coupon rate of 4.40 percent and maturity of March 15, 2024 and $100 million senior unsecured MTNs with a coupon rate of 5.16 percent and maturity of January 13, 2044.

On February 14, 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014.

On March 24, 2014 AltaGas issued US$200 million of senior unsecured MTNs with a floating rate coupon of three month LIBOR plus 0.72 percent and maturity of March 24, 2016.

On June 10, 2014, CINGSA issued US$82 million of senior secured notes in a private placement transaction. The notes carry a coupon rate of 4.48 percent and mature on March 2, 2032.

Credit Facilities *($ millions)*		Borrowing capacity		**Drawn at June 30 2014**		Drawn at December 31 2013
Demand operating facilities	$	70.0	**$**	**18.2**	$	10.8
Extendible revolving letter of credit facility		150.0		**100.6**		67.5
PNG operating facility		25.0		**7.6**		15.3
Bilateral letter of credit facility		125.0		**35.7**		67.6
AltaGas Ltd. revolving credit facility (1)		1,400.0		**318.3**		597.6
SEMCO Energy US$ unsecured credit facility (1) (2)		150.0		**0.6**		63.7
	$	1,920.0	**$**	**481.0**	$	822.5

(1) *Amount drawn at June 30, 2014 converted at June 2014 month-end rate of 1 US dollar = 1.0676 Canadian dollar (Amount drawn at December 31, 2013 converted at December 2013 month-end rate of 1 US dollar = 1.0636 Canadian dollar).*

(2) *Borrowing capacity assumed at par.*

SHARE INFORMATION

As at June 30, 2014, AltaGas had 123.6 million common shares, 8.0 million series A Preferred Shares, 8.0 million series C US$ Preferred Shares and 8.0 million series E Preferred Shares outstanding with a combined market capitalization of approximately $6.7 billion based on a closing trading price on June 30, 2014 of $49.08 per common share, $25.30 per series A Preferred Share, $25.45 per series C US$ Preferred Share and $25.80 per series E Preferred Share, respectively.

As at June 30, 2014, there were 5.1 million options outstanding and 2.6 million options exercisable under the terms of the share option plan.

DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends on preferred shares are paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, capital expenditures, and debt repayment requirements of AltaGas.

On September 10, 2012, the Board of Directors approved an increase in the monthly dividend to $0.12 per common share from $0.115 per common share effective with the September dividend.

On April 24, 2013, the Board of Directors approved an increase in the monthly dividend to $0.125 per common share from $0.12 per common share effective with the May dividend.

On July 31, 2013, the Board of Directors approved an increase in the monthly dividend to $0.1275 per common share from $0.125 per common share effective with the August dividend.

On April 30, 2014, the Board of Directors approved an increase in the monthly dividend to $0.1475 per common share from $0.1275 per common share effective with the May dividend.

The following table summarizes AltaGas' dividend declaration history:

Dividends

Years ended December 31 ($ per common share)		2014		2013
First quarter	$	**0.3825**	$	0.36
Second quarter		**0.4025**		0.37
Third quarter		**-**		0.38
Fourth quarter		**-**		0.3825
Total	$	**0.785**	$	1.4925

Series A Preferred Share Dividends

Years ended December 31 ($ per preferred share)		2014		2013
First quarter	$	**0.3125**	$	0.3125
Second quarter		**0.3125**		0.3125
Third quarter		**-**		0.3125
Fourth quarter		**-**		0.3125
Total	$	**0.625**	$	1.25

Series C Preferred Share Dividends

Years ended December 31 (US$ per preferred share)		2014		2013
First quarter	$	**0.275**		0.275
Second quarter		**0.275**		0.275
Third quarter		**-**		0.275
Fourth quarter		**-**		0.275
Total	$	**0.55**	$	1.10

Series E Preferred Share Dividends

Years ended December 31 (US$ per preferred share)		2014		2013
First quarter	$	**0.3699**		-
Second quarter		**0.3125**		-
Third quarter		**-**		-
Fourth quarter		**-**		-
Total	$	**0.6824**		-

SUBSEQUENT EVENTS

On July 3, 2014, AltaGas issued 8,000,000 five-year rate-reset Series G Preferred Shares, at a price of $25 per Series G Preferred Share for aggregate gross proceeds of $200 million, including 2,000,000 Series G Preferred Shares pursuant to the exercise in full of an underwriters' option.

On July 15, 2014, the NTL for the run-of-river projects in British Columbia came into service. Under the agreement with BC Hydro, which was disclosed in the commitments note of AltaGas' condensed unaudited financial statements for the first and second quarters 2014 and in the audited financial statements for the year ending 2013, AltaGas paid $5.3 million to BC Hydro on July 29, 2014. This is the first of the 20 annual payments (annual considerations) in support of the construction and operation of the NTL. AltaGas will pay to BC Hydro approximately $9.8 million annually, adjusted for inflation, over the next 19 years.

SIGNIFICANT ACCOUNTING POLICIES

Reference should be made to the audited Consolidated Financial Statements as at and for the year ended December 31, 2013 for information on accounting policies and practices.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the 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 be financial instruments, depreciation, depletion and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessment, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities. For a full discussion of these accounting estimates, refer to the MD&A in AltaGas' 2013 Financial Report and the notes to the unaudited interim Consolidated Financial Statements for the three and six months ended June 30, 2014.

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, DCP and ICFR to provide reasonable assurance that material information relating to AltaGas' business is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with United States Generally Accepted Accounting Principles (US GAAP).

During second quarter 2014, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS [(1)]

($ millions)	**Q2-14**	**Q1-14**	Q4-13	Q3-13	Q2-13	Q1-13	Q4-12	Q3-12
Total revenue	**471.2**	823.8	581.2	389.7	458.6	613.5	525.8	290.0
Net revenue[(2)]	**219.9**	296.5	264.6	246.6	211.8	237.1	207.6	146.2
Normalized operating income[(2)]	**64.5**	137.0	111.9	63.5	68.0	109.2	96.4	38.5
Net income before taxes	**44.0**	66.3	75.1	57.4	39.6	76.4	51.8	18.8
Net income applicable to common shares	**28.9**	39.9	53.2	43.3	35.9	49.0	26.7	8.0
($ per share)	**Q2-14**	Q1-14	Q4-13	Q3-13	Q2-13	Q1-13	Q4-12	Q3-12
Net income applicable to common shares								
Basic	**0.23**	0.33	0.44	0.36	0.31	0.46	0.25	0.08
Diluted	**0.23**	0.32	0.43	0.35	0.30	0.45	0.25	0.08
Dividends declared	**0.42**	0.38	0.38	0.38	0.37	0.36	0.36	0.35

(1) *Amounts may not add due to rounding.*

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

Significant items that impacted individual quarterly earnings were as follows:

- In third quarter 2012, AltaGas completed the acquisition of SEMCO for total consideration of US$1.156 billion including US$371 million in assumed debt, adding approximately US$725 million in regulated rate base. In the quarter, AltaGas recorded $12.5 million in pre-tax transaction costs and foreign exchange losses primarily related to the acquisition of SEMCO and other business development related activities;
- In fourth quarter 2012, AltaGas wrote down $2.9 million related to three wind projects under development;
- In fourth quarter 2012, AltaGas received an independent arbitration panel ruling regarding a claim of force majeure on Sundance Unit 3. As a result, AltaGas recorded a $11.0 million charge in cost of sales which was previously accrued in accounts receivable;
- In second quarter 2013, AltaGas completed the acquisition of Blythe for total consideration of US$515 million; AltaGas recorded $1.6 million in pre-tax transaction costs;
- In second quarter 2013, AltaGas recorded an adjustment to its deferred tax liability and an income tax recovery resulting from the enactment of a Canadian tax amendment that increased the deduction arising from the tax on dividends paid on preferred shares;
- In third quarter 2013, AltaGas reported a $37.5 million pre-tax gain on the sale of PTP by PNG;
- In third quarter 2013, AltaGas recorded provisions of $18.9 million related to the planned sale of certain non-core gas and utility assets;
- In fourth quarter 2013, AltaGas sold ECNG Energy L.P. (ECNG). AltaGas recorded a pre-tax gain of $3.9 million and transaction costs of $0.5 million related to this transaction;
- In fourth quarter 2013, AltaGas acquired a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. AltaGas paid for the initial 25 percent interest with 2.8 million shares priced at $35.69 per share and $230.5 million of cash;
- In fourth quarter 2013, AltaGas reclassified an other-than-temporary pre-tax loss of $4.3 million on its investment in Alterra from OCI to income for the period;
- In fourth quarter 2013, AltaGas recorded pre-tax provisions of $3.1 million related to six wind projects under development;
- In first quarter 2014, AltaGas completed sale of Ante Creek, a gas processing facility located near Sturgeon Lake, northwestern Alberta. The transaction closed on February 12, 2014, with a realized pre-tax gain from the sale of the asset of $12.0 million;
- In first quarter 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014. The early redemption resulted in total pre-tax cost of $2.3 million;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $38.3 million for EDS and JFP transmission pipeline assets that will be sold to NOVA Chemicals in March 2017; and
- In first quarter 2014, AltaGas recorded a pre-tax provision of $10.9 million for certain hydro power development projects in British Columbia currently in a sale process.

Consolidated Balance Sheets
(condensed and unaudited)

As at *($ thousands)*	**June 30 2014**	December 31 2013
ASSETS		
Current assets		
Cash and cash equivalents	**$ 27,883**	$ 44,812
Accounts receivable, net of allowances	**221,642**	371,235
Inventory *(note 7)*	**104,697**	123,408
Restricted cash holdings from customers	**2,906**	2,662
Regulatory assets	**40,043**	6,046
Risk management assets *(note 10)*	**23,872**	34,988
Prepaid expenses and other current assets	**22,170**	33,224
Deferred income taxes	**602**	4,975
	443,815	621,350
Property, plant and equipment	**5,082,784**	4,952,526
Intangible assets	**179,973**	195,259
Goodwill *(note 8)*	**744,841**	743,101
Regulatory assets	**232,186**	241,210
Risk management assets *(note 10)*	**9,460**	12,250
Deferred income taxes	**1,010**	836
Restricted cash holdings from customers	**11,210**	12,763
Long-term investments and other assets	**33,370**	25,864
Investments accounted for by equity method *(note 6)*	**458,770**	479,083
	$ 7,197,419	$ 7,284,242
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 251,082**	$ 321,921
Dividends payable	**18,233**	15,594
Short-term debt	**24,667**	84,350
Current portion of long-term debt *(note* 9)	**194,843**	209,069
Customer deposits	**20,218**	34,955
Regulatory liabilities	**514**	1,838
Risk management liabilities *(note 10)*	**26,213**	44,675
Deferred income taxes	**356**	508
Other current liabilities	**7,028**	14,478
	543,154	727,388
Long-term debt *(note 9)*	**3,022,584**	2,952,673
Asset retirement obligations	**78,232**	76,125
Deferred income taxes	**447,950**	442,844
Regulatory liabilities	**125,020**	124,262
Risk management liabilities *(note 10)*	**6,785**	7,071
Other long-term liabilities	**48,298**	52,584
Future employee obligations	**70,924**	71,825
	4,342,947	4,454,772

As at ($ thousands)	**June 30 2014**	December 31 2013
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 123.6 million issued and outstanding *(note 11)*	**2,257,710**	2,211,400
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 11)*	**194,126**	194,126
Preferred shares Series C cumulative redeemable five-year; par value US$25; authorized 8 million; 8 million issued and outstanding *(note 11)*	**200,626**	200,626
Preferred shares Series E cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 11)*	**194,405**	194,873
Contributed surplus	**14,062**	13,350
Accumulated deficit	**(92,431)**	(62,148)
Accumulated other comprehensive income	**50,292**	39,480
Total shareholders' equity	**2,818,790**	2,791,707
Non-controlling interests	**35,682**	37,763
	$ 7,197,419	$ 7,284,242

See accompanying notes to the condensed and unaudited Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

($ thousands except per share amounts)	Three months ended June 30 **2014**	Three months ended June 30 2013	Six months ended June 30 **2014**	Six months ended June 30 2013
REVENUE				
Sales	**$ 167,532**	$ 187,570	**$ 435,708**	$ 395,085
Services	**129,834**	101,380	**249,533**	191,018
Regulated operations	**172,756**	169,178	**613,493**	492,065
Other revenue (loss)	**(1,690)**	2,108	**(920)**	2,591
Unrealized gain (loss) on risk management contracts *(note 10)*	**2,779**	(1,625)	**(2,820)**	(8,679)
	471,211	458,611	**1,294,994**	1,072,080
EXPENSES				
Cost of sales, exclusive of items shown separately	**260,242**	297,168	**814,537**	689,547
Operating and administrative	**109,877**	107,921	**223,832**	207,772
Accretion expenses	**1,038**	926	**2,076**	1,892
Depreciation, depletion and amortization	**41,791**	37,237	**82,971**	72,924
Provision for long-lived assets *(note 4)*	**-**	549	**49,197**	549
	412,948	443,801	**1,172,613**	972,684
Income from equity investments	**7,289**	49,546	**24,625**	66,164
Other income (expenses) *(note 5)*	**1,644**	888	**11,372**	305
Foreign exchange gain (loss)	**(225)**	(396)	**235**	4
Interest expense				
Short-term debt	**333**	824	**706**	1,145
Long-term debt	**22,667**	24,395	**47,622**	48,689
Income before income taxes	**43,971**	39,629	**110,285**	116,035
Income tax expense (recovery)				
Current	**4,913**	2,301	**14,006**	8,831
Deferred	**744**	(5,181)	**8,536**	9,295
Net income after taxes	**38,314**	42,509	**87,743**	97,909
Net income applicable to non-controlling interests	**2,031**	1,752	**4,166**	3,394
Net income applicable to controlling interests	**36,283**	40,757	**83,577**	94,515
Preferred share dividends	**7,359**	4,813	**14,797**	9,547
Net income applicable to common shares	**$ 28,924**	$ 35,944	**$ 68,780**	$ 84,968
Net income per common share *(note 12)*				
Basic	**$ 0.23**	$ 0.31	**$ 0.56**	$ 0.76
Diluted	**$ 0.23**	$ 0.30	**$ 0.55**	$ 0.74
Weighted average number of common shares outstanding *(note 11)* *(thousands)*				
Basic	**123,306**	117,676	**122,947**	111,734
Diluted	**125,362**	120,946	**124,887**	115,222

See accompanying notes to the condensed and unaudited Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

(condensed and unaudited)

($ thousands)	Three months ended June 30 **2014**	Three months ended June 30 2013	Six months ended June 30 **2014**	Six months ended June 30 2013
Net income after taxes	**$ 38,314**	$ 42,509	**$ 87,743**	$ 97,909
Total other comprehensive income (loss) (net of taxes)	**(40,544)**	33,039	**10,812**	44,122
Comprehensive income (loss) attributable to common shareholders and non-controlling interests (net of tax)	**$ (2,230)**	$ 75,548	**$ 98,555**	$ 142,031
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$ 2,031**	$ 1,752	**$ 4,166**	$ 3,394
Common shareholders	**(4,261)**	73,796	**94,389**	138,637
	$ (2,230)	$ 75,548	**$ 98,555**	$ 142,031

Consolidated Accumulated Other Comprehensive Income (Loss) (1)

($ thousands)	**Available-for-sale**	**Cash flow hedges**	**Defined benefit pension plans**	**Hedge net investments**	**Translation foreign operations**	**Total**
Opening balance, January 1, 2014	$ (2,945)	$ (10,407)	$ (5,719)	$ (35,926)	$ 94,477	$ 39,480
Other comprehensive income (loss) before reclassification	342	5,436	130	(2,054)	6,047	9,901
Amounts reclassified from other comprehensive income (loss) *(note 3)*	-	961	(50)	-	-	911
Net current period other comprehensive income (loss)	$ 342	$ 6,397	$ 80	$ (2,054)	$ 6,047	$ 10,812
Ending balance, June 30, 2014[(2) (3) (4) (5)]	**$ (2,603)**	**$ (4,010)**	**$ (5,639)**	**$ (37,980)**	**$ 100,524**	**$ 50,292**
Opening balance, January 1, 2013	$ (5,787)	$ (994)	$ (10,246)	(2,263)	3,843	$ (15,447)
Other comprehensive income (loss) before reclassification	(751)	(232)	-	(28,056)	72,334	43,295
Amounts reclassified from other comprehensive income *(note 3)*	-	360	467	-	-	827
Net current period other comprehensive income (loss)	$ (751)	$ 128	$ 467	(28,056)	72,334	$ 44,122
Ending balance, June 30, 2013[(2) (3) (4) (5)]	$ (6,538)	$ (866)	$ (9,779)	(30,319)	76,177	$ 28,675

(1) All amounts are net of tax where applicable. Amounts in parenthesis indicate debits.

(2) Available-for-sale - net of tax recovery $ 382 (June 30, 2013 - tax recovery $948).

(3) Cash flow hedges - net of tax recovery $1,350 (June 30, 2013 - tax recovery $78).

(4) Defined benefit pension plans - net of tax recovery $1,857 (June 30, 2013 - tax recovery $3,394).

(5) Hedge net investment - net of tax recovery $5,470 (June 30, 2013 - tax recovery $4,359).

See accompanying notes to the condensed unaudited Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

($ thousands)	Six months ended June 30 **2014**	2013
Common shares *(note 11)*		
Balance, beginning of year	**$ 2,211,400**	$ 1,639,895
Shares issued for cash on exercise of options	**14,587**	13,473
Shares issued under DRIP [1]	**31,723**	28,715
Shares issued on public offering	**-**	388,892
Balance, end of period	**2,257,710**	2,070,975
Preferred shares *(note 11)*		
Balance, beginning of year	**589,625**	394,752
Series E issued	**(468)**	-
Balance, end of period	**589,157**	394,752
Contributed surplus		
Balance, beginning of year	**13,350**	10,570
Share options expense	**2,045**	2,538
Exercise of share options	**(1,247)**	(977)
Forfeiture of share options	**(86)**	(529)
Balance, end of period	**14,062**	11,602
Accumulated deficit		
Balance, beginning of year	**(62,148)**	(69,979)
Net income applicable to controlling interests	**83,577**	94,515
Common share dividends	**(99,063)**	(81,814)
Preferred share dividends	**(14,797)**	(9,547)
Balance, end of period	**(92,431)**	(66,825)
Accumulated other comprehensive income (loss)		
Balance, beginning of year	**39,480**	(15,447)
Other comprehensive income	**10,812**	44,122
Balance, end of period	**50,292**	28,675
Total shareholders' equity	**2,818,790**	2,439,179
Non-controlling interests		
Balance, beginning of year	**37,763**	40,006
Net income applicable to non-controlling interests	**4,166**	3,394
Distribution by subsidiaries to non-controlling interests	**(6,247)**	(884)
Balance, end of period	**35,682**	42,516
Total equity	**$ 2,854,472**	$ 2,481,695

[1] Dividend Reinvestment and Optional Share Purchase Plan.

See accompanying notes to the condensed unaudited Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(condensed and unaudited)

($ thousands)	Three months ended June 30 2014	Three months ended June 30 2013	Six months ended June 30 2014	Six months ended June 30 2013
Cash from operations				
Net income after taxes	**$ 38,314**	$ 42,509	**$ 87,743**	$ 97,909
Items not involving cash:				
Depreciation, depletion and amortization	**41,791**	37,237	**82,971**	72,924
Provision on long-lived assets	**-**	549	**49,197**	549
Accretion expenses	**1,038**	926	**2,076**	1,892
Share-based compensation	**968**	1,070	**1,959**	2,009
Deferred income tax expense	**744**	(5,181)	**8,536**	9,295
(Gain) Loss on sale of assets	**248**	-	**(11,140)**	(12)
Income from equity investments	**(7,289)**	(49,546)	**(24,625)**	(66,164)
Unrealized (gain) loss on risk management contracts	**(2,779)**	1,625	**2,820**	8,679
Unrealized (gain) loss on long-term investments	**(432)**	(87)	**(432)**	949
Other	**1,593**	1,670	**(705)**	2,230
Asset retirement obligations settled	**(256)**	(157)	**(681)**	(650)
Distributions from equity investments	**31,575**	51,530	**37,244**	67,560
Changes in operating assets and liabilities:				
Accounts receivable	**156,988**	106,493	**152,944**	119,504
Inventory	**(43,635)**	(36,495)	**19,420**	(12,093)
Other current assets	**(1,192)**	1,409	**10,879**	1,378
Regulatory assets (current)	**(563)**	1,859	**(33,945)**	1,199
Accounts payable and accrued liabilities	**(102,557)**	(19,553)	**(74,691)**	(71,996)
Customer deposits	**1,243**	(5,546)	**(14,831)**	(14,655)
Regulatory liabilities (current)	**(420)**	(444)	**(1,331)**	2,855
Other current liabilities	**(754)**	3,265	**(6,913)**	(1,850)
Other operating assets and liabilities	**(3,027)**	6,481	**(3,095)**	14,367
	111,598	139,614	**283,400**	235,879
Investing activities				
Change in restricted cash holdings from customers	**(139)**	316	**(232)**	2,681
Acquisition of property, plant and equipment	**(119,473)**	(120,501)	**(236,673)**	(223,064)
Acquisition of intangible assets	**(5,492)**	(1,403)	**(9,443)**	(5,057)
Proceeds from dispositions of assets	**606**	146	**27,411**	368
Contributions to equity investments	**(2,846)**	(223)	**(3,924)**	(343)
Business acquisitions, net of cash acquired	**(177)**	(536,802)	**(177)**	(536,802)
Acquisition of equity investment	**-**	-	**5,208**	-
	(127,521)	(658,467)	**(217,830)**	(762,217)

($ thousands)	Three months ended June 30 **2014**	2013	Six months ended June 30 **2014**	2013
Financing activities				
Net issuance (repayment) of short-term debt	**18,099**	(236,620)	**(59,919)**	(61,917)
Issuance of long-term debt, net of debt issuance costs	**105,302**	932,959	**746,236**	1,033,028
Repayment of long-term debt	**(119,768)**	(469,049)	**(695,632)**	(701,576)
Dividends - common shares	**(49,552)**	(41,651)	**(96,424)**	(79,656)
Dividends - preferred shares	**(7,359)**	(4,813)	**(15,269)**	(9,547)
Distributions to non-controlling interest	**(4,196)**	-	**(6,247)**	(884)
Net proceeds from shares issued on exercise of options	**8,267**	6,269	**13,340**	13,475
Net proceeds from issuance of common shares	**16,299**	402,488	**31,723**	416,631
Costs of issuance of preferred shares Series E	**(3)**	-	**(468)**	-
	(32,911)	589,583	**(82,660)**	609,554
Effect of exchange rate changes on cash and cash equivalents	**(1,518)**	308	**161**	487
Change in cash and cash equivalents	**(48,834)**	70,730	**(17,090)**	83,216
Cash and cash equivalents, beginning of year	**78,235**	24,492	**44,812**	11,827
Cash and cash equivalents, end of year	**$ 27,883**	$ 95,530	**$ 27,883**	$ 95,530

The following cash payments have been included in the determination of earnings:

($ thousands)	Three months ended June 30 **2014**	2013	Six months ended June 30 **2014**	2013
Interest paid (net of capitalized interest)	**$ 19,924**	$ 22,193	**$ 43,658**	$ 47,377
Income taxes paid	**$ 2,909**	$ 2,772	**$ 11,900**	$ 5,872

See accompanying notes to the condensed unaudited Consolidated Financial Statements.

Notes to the Condensed Unaudited Interim Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in thousands of Canadian dollars unless otherwise indicated.)

1. ORGANIZATION AND OVERVIEW OF BUSINESS

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by the Corporation, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., and AltaGas Services (U.S.) Inc.

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities. AltaGas has three business segments, Gas, Power and Utilities.

AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing, the liquefied natural gas (LNG) export development project, the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas). AIJVLP also manages the liquefied petroleum gas (LPG or propane) development project.

The Power segment includes 1,096 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets in Canada and United States, along with the Northwest Projects additional 277 MW of run-of-river assets under construction in British Columbia.

The Utilities segment is predominantly comprised of natural gas distribution rate-regulated utilities. AltaGas owns and operates regulated natural gas utilities in Canada and United States. The utilities are generally allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of capital from the regulator-approved capital investment base.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These condensed unaudited interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (US GAAP) for interim financial statements. As a result, these condensed unaudited interim Consolidated Financial Statements do not include all of the information and disclosures required in the annual Consolidated Financial Statements and should be read in conjunction with the Corporation's 2013 annual audited Consolidated Financial Statements prepared in accordance with US GAAP. In management's opinion, the condensed unaudited interim Consolidated Financial Statements include all adjustments that are all of a recurring nature and necessary to present fairly the financial position of the Corporation.

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), US 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 exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2019, the date on which AltaGas ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standard for rate-regulated accounting.

These condensed unaudited interim Consolidated Financial Statements of AltaGas include the accounts of the Corporation and all of its wholly-owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership. Investments in unconsolidated companies where AltaGas has significant influence over, but not control, are accounted for by the equity method.

Transactions between and amongst, AltaGas and its wholly-owned subsidiaries, and the proportionate interests in joint ventures or partnerships are eliminated on consolidation as required by US GAAP. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “Non-controlling interests” in the Consolidated Financial Statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries is shown as an allocation of the consolidated net income and is presented separately in "Net income applicable to non-controlling interests".

SIGNIFICANT ACCOUNTING POLICIES

These condensed unaudited Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2013 US GAAP annual audited Consolidated Financial Statements, except, as described below, for the exchange rates used.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency for domestic entities are converted at the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statement of Income. Non-monetary assets and liabilities are converted at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

For foreign entities with a functional currency other than Canadian dollars, AltaGas’ reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. The exchange rate used to convert a US dollar to a Canadian dollar for the period ended June 30, 2014 was 1.0676 (as at December 31, 2013 - 1.0636).

Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in accumulated other comprehensive income (AOCI). The average exchange rate used to convert a US dollar to a Canadian dollar for the six months period ended June 30, 2014 was 1.0970 (six months ended June 30, 2013 - 1.0161).

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain include but are not limited to depreciation, depletion and amortization expense, asset retirement obligations, long-lived and intangible assets impairment assessment, financial instruments, income taxes, employee future benefits, litigation, share-based compensation and regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate which often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

FUTURE CHANGES IN ACCOUNTING POLICIES

In January 2014, FASB issued ASU No. 2014-05, “Service Concession Arrangements”. The amendments in this Update provide guidance for accounting for service concession arrangements, previously not covered by US GAAP. A service concession arrangement is an arrangement between a public-sector entity grantor and an operating entity under which the operating entity operates the grantor’s infrastructure. The amendments in this Update should be applied on a modified retrospective basis to service concession arrangements that exist at the beginning of an entity’s fiscal year of adoption with a cumulative effect recognized as an adjustment to the opening retained earnings balance for the annual period of adoption. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2014. AltaGas will adopt the Update for the financial periods beginning on January 1, 2015. The adoption of this Update does not have any impact for the preparation and presentation of AltaGas’ consolidated financial statements.

In April 2014, FASB issued ASU No. 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity". The amendments in this Update change the definition of discontinued operations by limiting the discontinued operations to the disposals of components of an entity that represent a strategic shift that have (or will have) a major effect on an entity’s operations and financial results. The amendments are effective for all disposals (or classification as held for sale) of components of an entity that occur within annual periods beginning on or after December 15, 2014 and interim periods within those periods. Early adoption is permitted for disposals (or classification as held for sale) that have not been reported in financial statements previously issued or available for issuance. AltaGas will adopt the Update for the financial periods beginning on January 1, 2015. AltaGas does not expect any impact in the preparation and presentation of its consolidated financial statements.

In May 2014, FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers". The principle of the amendments in this Update is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. Early adoption is not permitted. AltaGas commenced a process for the adoption of the Update. The impacts in the recognition, measurement and presentation of revenue from contracts with customers in accordance with the Update are under assessment for AltaGas' consolidated financial statements.

In June 2014, FASB issued ASU No. 2014-12, "Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period". The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2015. Early adoption is permitted. AltaGas will adopt the Update for the financial periods beginning on January 1, 2016. AltaGas does not expect any impact in the preparation and presentation of its consolidated financial statements.

3. RECLASSIFICATION FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

AOCI components reclassified	Income Statement line item	Three months ended June 30, 2014	Six months ended June 30, 2014
Cash flow hedges			
NGL (ineffective hedge)	Unrealized gains on risk management contracts	**$ 105**	**$ 938**
Bond forward	Interest expense – Long-term debt	**-**	**64**
	Other income (expenses)	**-**	**196**
Defined benefit pension plans	Operating and administrative expense	**142**	**152**
	Total before income taxes	**247**	**1,350**
Deferred income taxes	Income tax expenses – Deferred	**(193)**	**(439)**
		$ 54	**$ 911**

AOCI components reclassified	Income Statement line item	Three months ended June 30, 2013	Six months ended June 30, 2013
Cash flow hedges			
Bond forward	Interest expense – Long-term debt	$ 181	$ 360
Defined benefit pension plans	Operating and administrative expense	342	647
	Total before income taxes	523	1,007
Deferred income taxes	Income tax expenses – Deferred	(70)	(180)
		$ 453	$ 827

4. PROVISION FOR LONG-LIVED ASSETS

	Three months ended June 30 **2014**	Three months ended June 30 2013	Six months ended June 30 **2014**	Six months ended June 30 2013
Gas (a)	-	-	**$ (38,337)**	$ -
Power (b)	-	(549)	**(10,860)**	(549)
	-	$ (549)	**$ (49,197)**	$ (549)

(a) Includes a provision of $19.6 million for Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and $18.7 million provision for related Transmission contracts, all of which will be sold to NOVA Chemicals Corporation in March 2017, in accordance with contractual requirements.

(b) The total provision in 2014 of $10.9 million relates to certain hydro power assets under development in British Columbia. AltaGas is in discussions with a third party to sell these smaller hydro projects currently under development, and indicative values resulted in the write down of the assets to the current estimated fair value. The total provision in 2013 of $0.5 million relates to a write-off of a gas peaking plant.

5. OTHER INCOME (EXPENSES)

On February 12, 2014, AltaGas Processing Partnership, a wholly-owned subsidiary of AltaGas, sold Ante Creek, a 58.5 Mmcf/d (licensed capacity) gas processing facility located near Sturgeon Lake, northwestern Alberta, for cash proceeds of $28.2 million and a realized pre-tax gain of $12.0 million.

On February 14, 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014. The early redemption resulted in total pre-tax cost of $2.3 million.

6. BUSINESS ACQUISITION

Petrogas

On October 1, 2013, AltaGas completed the acquisition of a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. Petrogas is engaged in the marketing, storage, and distribution of natural gas liquids, drilling fluids, fracing fluids, crude oil and condensate diluents. Petrogas and its subsidiaries own underground storage facilities, own and lease surface storage, and own and operate processing plants, truck and transportation equipment, loading and terminaling facilities and crude oil blending facilities. AltaGas paid for the acquisition with approximately 2.8 million common shares priced at $35.69 per share and $230.5 million of cash. The investment was accounted for using the equity method.

On October 24, 2013, AltaGas announced it planned to increase its effective ownership of Petrogas to 33 1/3 percent, exercising a call option included in the share purchase agreement with the vendor.

On March 1, 2014, AltaGas transferred its 25 percent ownership interest to AIJVLP. On March 1, 2014, AIJVLP acquired an additional 41 2/3 percent interest in Petrogas for $300.8 million cash consideration and a $250.0 million note payable to the vendor. As a result of the transaction, Petrogas is effectively owned one-third by each of AltaGas, Idemitsu Kosan Co., Ltd. (Idemitsu), and its former majority shareholder.

Blythe

On May 16, 2013, AltaGas, through a wholly owned subsidiary, AltaGas Power Holdings (U.S.) Inc., completed the acquisition of Blythe Energy Inc. (Blythe) for US$515 million before adjustments for working capital. Blythe owns a 507 MW natural gas fired power plant, associated major spare parts, and a related 230 kV 67-mile electric transmission line in southern California. Blythe Energy Center is contracted under a power purchase agreement (PPA) through to July 2020 with Southern California Edison (SCE). Contract provisions match PPA revenues to all major plant costs.

AltaGas paid an aggregate purchase price of $537.0 million. AltaGas financed the acquisition through a combination of $405 million gross proceeds from 11,615,000 common share public offering and the remainder from a US$300 million senior unsecured revolving credit facility with three Canadian chartered banks. Transaction costs such as legal, accounting, valuation and other professional fees related specifically to the acquisition were $1.6 million pre-tax and have been expensed in the 2013 Consolidated Statement of Income, within "Operating and administrative expenses".

In the finalization of the purchase price allocation, AltaGas remeasured the enacted tax rates in computing deferred taxes, considering state and local income taxes and federal tax benefits. As result of the remeasurement, the deferred income tax liabilities assumed were lower then those previously calculated with a lower fair value adjustment to the acquired property, plant and equipment.

The final purchase price allocation, based on the statement of financial position as at May 16, 2013 and using an exchange rate of 1.0163 to convert a US dollar to a Canadian dollar, is provided below:

Cash consideration		536,977
Total consideration	**$**	**536,977**
Purchase price allocation		
Assets acquired:		
Current assets	$	21,296
Property, plant and equipment		540,187
Non-current assets		4,924
		566,407
Less liabilities assumed:		
Current liabilities		10,274
Deferred income taxes		16,914
Asset retirement obligations		2,242
		29,430
	$	**536,977**

7. INVENTORY

As at		**June 30 2014**		December 31 2013
Natural gas held in storage	**$**	**87,688**	$	106,715
Other inventory		**17,009**		16,693
	$	**104,697**	$	123,408

8. GOODWILL

As at		**June 30 2014**		December 31 2013
Balance, beginning of period	**$**	**743,101**	$	714,902
Foreign exchange translation		**1,740**		29,878
Other changes		**-**		(1,679)
	$	**744,841**	$	743,101

9. LONG-TERM DEBT

	Maturity date	June 30 2014	December 31 2013
Credit facilities			
$1,400 million Unsecured extendible revolving (a)	15-Dec-2017	**318,296**	578,566
Medium-term notes			
$200 million Senior unsecured - 7.42 percent	29-Apr-2014	**-**	200,000
$200 million Senior unsecured - 4.10 percent	24-Mar-2016	**200,000**	200,000
$100 million Senior unsecured - 6.94 percent	29-Jun-2016	**100,000**	100,000
$200 million Senior unsecured - 5.49 percent	27-Mar-2017	**200,000**	200,000
$175 million Senior unsecured - 4.60 percent	15-Jan-2018	**175,000**	175,000
$200 million Senior unsecured - 4.55 percent	17-Jan-2019	**200,000**	200,000
$200 million Senior unsecured - 4.07 percent	01-Jun-2020	**200,000**	200,000
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**350,000**	350,000
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**300,000**	300,000
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200,000**	-
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100,000**	-
US$175 million Senior unsecured - floating (b)	13-Apr-2015	**186,830**	186,130
US$200 million Senior unsecured - floating (c)	24-Mar-2016	**213,520**	-
SEMCO long-term debt			
US$90 million CINGSA Secured construction and term loan (d)	14-Nov-2015	**-**	86,258
US$82 million CINGSA Senior secured - 4.48 percent (e)	2-Mar-2032	**87,543**	-
US$300 million SEMCO Senior secured - 5.15 percent (f)	21-Apr-2020	**320,280**	319,080
Debenture notes			
PNG RoyNat Debenture - 3.74 percent (g)	15-Sep-2017	**10,400**	11,000
PNG 2018 Series Debenture - 8.75 percent (g)	15-Nov-2018	**11,000**	11,000
PNG 2024 CFI Debenture - 7.39 percent (h)	01-Nov-2024	**7,659**	7,899
PNG 2025 Series Debenture - 9.30 percent (g)	18-Jul-2025	**15,000**	15,000
PNG 2027 Series Debenture - 6.90 percent (g)	02-Dec-2027	**16,000**	16,000
Loan from Province of Nova Scotia (i)	31-Jul-2017	**3,600**	3,060
SEMCO capital lease obligation - 3.50 percent	01-May-2040	**621**	471
Promissory notes	25-Oct-2015	**1,460**	1,946
Other long-term debt		**218**	332
		3,217,427	3,161,742
Less current portion		**194,843**	209,069
		$ 3,022,584	$ 2,952,673

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. Letters of credit outstanding as at June 30, 2014 were NIL (December 31, 2013 - $19.0 million)

(b) The notes carry a floating rate coupon of three months LIBOR plus 0.79 percent.

(c) The notes carry a floating rate coupon of three months LIBOR plus 0.72 percent.

(d) The loan was repaid on June 10, 2014.

(e) Collateral for the US$82 million CINGSA senior secured loan is certain CINGSA assets. Alaska Storage Holding Company, LLC, a subsidiary in which AltaGas has a controlling interest, is the non-recourse guarantor of this loan.

(f) Collateral for the US$300 million MTNs is certain SEMCO Energy, Inc. (SEMCO) assets.

(g) Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of PNG's property, plant and equipment, and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

(h) Collateral for the Corpfinance International Ltd. (CFI) Debenture consists of first fixed specific and floating charges and a security interest over all the assets and undertakings of McNair Creek, a first security interest over all the interests of PNG in partnership interests and shares in McNair Creek.

(i) The loan is non-interest bearing and, if certain prescribed revenue targets are achieved, interest will immediately begin to accumulate on a prospective basis at a rate of 6 percent per annum. In July 2011, Heritage Gas elected to repay the loan in five equal installments beginning July 31, 2012. Heritage Gas may also elect to fully repay the loan at any time with no penalty.

10. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation purchases and sells natural gas, NGL and power. The Corporation uses derivative instruments to reduce exposure to fluctuations in commodity prices and foreign currency exchange rates that arise from these activities. The Corporation does not make use of derivative instruments for speculative purposes.

Fair Values of Financial Instruments

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

The following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Cash, Cash Equivalents, Accounts Receivable, Accounts Payable, Short-term debt and *Dividends Payable* - the carrying amount approximates fair value because of the short maturity of these instruments.

Current portion of long-term debt and *Long-term debt* - the fair value of current portion of long-term debt and long-term debt have been estimated based on discounted future interest and principal payments using estimated interest rates.

Summary of Fair Values	**June 30 2014**	December 31 2013
Current portion of long-term debt		
Carrying amount	**$ 194,843**	$ 209,069
Fair value of current portion of long-term debt	**$ 194,944**	$ 212,354

Summary of Fair Values	**June 30 2014**	December 31 2013
Long-term debt		
Carrying amount	**$ 3,022,584**	$ 2,952,673
Fair value of long-term debt	**$ 3,161,550**	$ 3,062,636

Fair Value Hierarchy

AltaGas categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 - fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly traded shares valued at the closing price as at the balance sheet date.

Level 2 - fair values are determined based on inputs other than quoted prices that are observable for the asset or liability. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity prices, interest rates 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-to-market these derivative instruments are vetted against public sources.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. AltaGas uses valuation techniques when observable market data is not available.

June 30, 2014	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	**$ 27,883**	**-**	**-**	**$ 27,883**
Risk management assets - current	**-**	**$ 23,872**	**-**	**$ 23,872**
Risk management assets - non-current	**-**	**$ 9,460**	**-**	**$ 9,460**
Long-term investments and other assets [(1)]	**$ 6,077**	**-**	**-**	**$ 6,077**
Financial liabilities				
Risk management liabilities - current	**-**	**$ 26,213**	**-**	**$ 26,213**
Risk management liabilities - non-current	**-**	**$ 6,785**	**-**	**$ 6,785**
Current portion of long-term debt	**-**	**$ 194,944**	**-**	**$ 194,944**
Long-term debt	**-**	**$ 3,161,550**	**-**	**$ 3,161,550**

December 31, 2013	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	$ 44,812	-	-	$ 44,812
Risk management assets - current	-	$ 34,988	-	$ 34,988
Risk management assets - non-current	-	$ 12,250	-	$ 12,250
Long-term investments and other assets	$ 5,365	-	-	$ 5,365
Financial Liabilities				
Risk management liabilities - current	-	$ 44,675	-	$ 44,675
Risk management liabilities - non-current	-	$ 7,071	-	$ 7,071
Current portion of long-term debt	-	$ 212,354	-	$ 212,354
Long-term debt	-	$ 3,062,636	-	$ 3,062,636

[(1)] *Excludes non-financial assets and financial assets carried at cost.*

Summary of Unrealized Gains (Losses) on Risk Management Contracts Recognized in Net Income

	Three months ended June 30 **2014**	Three months ended June 30 2013	Six months ended June 30 **2014**	Six months ended June 30 2013
Natural Gas	**$ 3,968**	$ (955)	**$ (1,020)**	$ (1,833)
Storage Optimization	**(1,071)**	1,752	**790**	82
NGL Frac Spread	**(104)**	342	**(937)**	(254)
Power	**140**	(2,514)	**(1,474)**	(5,397)
Heat Rate	**(120)**	(53)	**(299)**	(267)
Foreign Exchange	**(5)**	(197)	**107**	(545)
Embedded Derivative	**(29)**	-	**13**	(465)
	$ 2,779	$ (1,625)	**$ (2,820)**	$ (8,679)

Summary of Unrealized Gains (Losses) and Tax Recovery (Expense) on Financial Instruments Recognized in Accumulated Other Comprehensive Income

	Unrealized losses	Tax recovery	**Six months ended June 30 2014**	Unrealized losses	Tax recovery	Six months ended June 30 2013
Available-for-sale	**$ (2,985)**	**$ 382**	**$ (2,603)**	$ (7,486)	$ 948	$ (6,538)
Bond Forward	**-**	**-**	**-**	(634)	-	(634)
NGL Frac Spread	**(5,360)**	**1,350**	**(4,010)**	(310)	78	(232)
AOCI	**$ (8,345)**	**$ 1,732**	**$ (6,613)**	$ (8,430)	$ 1,026	$ (7,404)

Offsetting of Derivative Assets and Derivative Liabilities

As at June 30, 2014

Risk management assets (1)	**Gross amounts of recognized assets/liabilities**	**Gross amounts offset in Balance Sheet**	**Net amounts presented in Balance Sheet**
Natural Gas	**$ 56,629**	**$ 40,059**	**$ 16,570**
Storage Optimization	**858**	**335**	**523**
	$ 57,487	**$ 40,394**	**$ 17,093**
Risk management liabilities (2)			
Natural Gas	**$ 53,532**	**$ 40,059**	**$ 13,473**
Storage Optimization	**1,284**	**335**	**949**
Total	**$ 54,816**	**$ 40,394**	**$ 14,422**

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $12,976 and risk management assets (non-current) balance of $4,117.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $11,724 and risk management liabilities (non-current) balance of $2,698.*

As at June 30, 2013

Risk management assets (1)	Gross amounts of recognized assets/liabilities	Gross amounts offset in Balance Sheet	Net amounts presented in Balance Sheet
Natural gas	$ 66,621	$ 47,377	$ 19,244
Storage optimization	352	20	332
	$ 66,973	$ 47,397	$ 19,576
Risk management liabilities (2)			
Natural gas	$ 63,585	$ 47,377	$ 16,208
Storage optimization	37	20	17
	$ 63,622	$ 47,397	$ 16,225

(1) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $15,049 and risk management assets (non-current) balance of $4,527.*

(2) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $12,989 and risk management liabilities (non-current) balance of $3,236.*

Offsetting of fair value amounts is generally not applied except where a right of set-off exists. A right of set-off exists only when AltaGas and its counterparty in the financial instrument owe a determinable amount, the two parties agree to set-off the amounts due, AltaGas intends to set-off, and the right of set-off is enforceable by law.

Long-term Investments and Other Assets

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (Alterra), through a private equity offering. These shares were classified as available-for-sale. The investments classified as available-for-sale also include funds under trust, acquired with SEMCO. The after-tax accumulated changes in fair value of these financial assets are being reported in AOCI.

In July 2009, AltaGas purchased additional shares of Alterra as part of its initial public offering. These shares were classified as held-for-trading. In July 2010, AltaGas purchased a second tranche of common shares in Alterra, which were classified as held-for-trading. Unrealized gains (losses) on held-for-trading are recognized in the Consolidated Statement of Income under "Other income (expense)".

AltaGas' available-for-sale and held-for-trading investments are reported under "Long-term investment and other assets" in the Consolidated Balance Sheet.

11. SHAREHOLDERS' EQUITY

Authorization

AltaGas is authorized to issue an unlimited number of voting common shares. AltaGas is also authorized to issue preferred shares not to exceed 50 percent of the voting rights attached to the issued and outstanding common shares.

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2013	105,336,884	$	1,639,895
Shares issued for cash on exercise of options	806,093		18,916
Shares issued under DRIP	1,745,411		60,305
Shares issued on private issuance	2,801,905		100,000
Shares issued on public offering	11,615,000		392,284
December 31, 2013	122,305,293	$	2,211,400
Shares issued for cash on exercise of options	**571,760**		**14,587**
Shares issued under DRIP	**745,562**		**31,723**
Issued and outstanding at June 30, 2014	**123,622,615**	**$**	**2,257,710**

Preferred Shares Series A Issued and Outstanding	Number of shares		Amount
January 1, 2013	8,000,000		194,126
December 31, 2013	8,000,000		194,126
Issued and outstanding at June 30, 2014	**8,000,000**	**$**	**194,126**

Preferred Shares Series C Issued and Outstanding	Number of shares		Amount
January 1, 2013	8,000,000		200,626
December 31, 2013	8,000,000		200,626
Issued and outstanding at June 30, 2014	**8,000,000**	**$**	**200,626**

Preferred Shares Series E Issued and Outstanding	Number of shares		Amount
January 1, 2013	-		-
Shares issued on public offering	8,000,000		194,873
December 31, 2013	8,000,000		194,873
Share issuance costs	-		**(468)**
Issued and outstanding at June 30, 2014	**8,000,000**	**$**	**194,405**

	Three months ended June 30		Six months ended June 30	
Weighted Average Shares Outstanding	**2014**	2013	**2014**	2013
Number of shares - basic	**123,305,947**	117,676,420	**122,946,893**	111,734,089
Dilutive equity instruments [(1)]	**2,055,955**	3,269,861	**1,940,202**	3,488,384
Number of shares - diluted	**125,361,902**	120,946,281	**124,887,095**	115,222,473

[(1)] *Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at June 30, 2014 and 2013, respectively.*

For six months ended June 30, 2014, 114,000 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (December 31, 2013 - 805,500 options).

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at June 30, 2014, 7,302,454 shares were reserved for issuance under the plan. As at June 30, 2014, options granted under the plan have a term between 6 and 10 years until expiry and vest no longer than over a four-year period.

As at June 30, 2014, unexpensed fair value of share option compensation cost associated with future periods was $4.7 million (December 31, 2013 - $6.2 million).

The following table summarizes information about the Corporation's share options:

	Options outstanding	
	Number of options	Exercise price[1]
Share options outstanding, December 31, 2013	5,561,505	$ 27.25
Granted	122,000	45.70
Exercised	(571,760)	23.33
Forfeited	(51,938)	32.94
Share options outstanding, June 30, 2014	**5,059,807**	**$ 28.08**
Share options exercisable, June 30, 2014	**2,606,132**	**$ 23.75**

[1] *Weighted average.*

The following table summarizes the employee share option plan as at June 30, 2014:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Exercise price
$13.65 to $18.00	448,595	$ 15.80	4.99	448,595	$ 15.80
$18.01 to $25.08	1,296,050	20.86	5.68	1,053,188	20.76
$25.09 to $49.20	3,315,162	32.56	7.02	1,104,349	29.82
	5,059,807	**$ 28.08**	**6.69**	**2,606,132**	**$ 23.75**

Equity-based Compensation Plan

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. The phantom shares are valued based on dividends declared and the trading price of the Corporation's common shares. The shares vest on a graded vesting schedule over a term between 36 and 44 months. For the six months ended June 30, 2014, the compensation expense recorded was $2.8 million (six months ended June 30, 2013 - $1.4 million).

As at June 30, 2014, the unexpensed fair value of equity-based compensation cost associated with future periods was $17.2 million (December 31, 2013 - $9.2 million).

12. NET INCOME APPLICABLE TO COMMON SHARES

The following table summarizes the computation of net income applicable to common shares:

	Three months ended		Six months ended	
	June 30 2014	June 30 2013	**June 30 2014**	June 30 2013
Numerator ($ thousands):				
Net income applicable to controlling interests	**$ 36,283**	$ 40,757	**$ 83,577**	$ 94,515
Less: Preferred share dividends	**7,359**	4,813	**14,797**	9,547
Net income applicable to common shares	**$ 28,924**	$ 35,944	**$ 68,780**	$ 84,968
Denominator (thousands):				
Weighted average number of common shares outstanding	**123,306**	117,676	**122,947**	111,734
Dilutive equity instruments[1]	**2,056**	3,270	**1,940**	3,488
Weighted average number of common shares outstanding - diluted	**125,362**	120,946	**124,887**	115,222
Basic net income applicable per common share	**$ 0.23**	$ 0.31	**$ 0.56**	$ 0.76
Diluted net income applicable per common share	**$ 0.23**	$ 0.30	**$ 0.55**	$ 0.74

(1) *Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at June 30, 2014 and 2013.*

13. COMMITMENTS

AltaGas has long-term natural gas purchase arrangements, service agreements, power purchase agreements, and operating leases for office space, office equipment and automobile equipment, all of which are transacted at market prices and in the normal course of business.

AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2014 to 2019, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $12.3 million over the next 8 years, of which $7.4 million is payable in the next five years.

In 2009, AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. AltaGas is obligated to pay approximately $3.4 million per annum over the term of the contract for storage services.

In 2010, AltaGas entered into a 60-year Consumer Price Index indexed Electricity Purchase Agreement with BC Hydro for the Northwest run-of-river projects. AltaGas paid $90 million, recognized as "Intangible assets", to BC Hydro in support of the construction and operation of the Northwest Transmission Line (NTL). After commercial operation date, AltaGas shall make a series of 20 annual payments (annual considerations), the first of which in the amount of $5.3 million, and annually thereafter in the amount of approximately $9.8 million, adjusted for inflation. Annual considerations have not been recognized in the statement of financial position as at June 30, 2014.

14. PENSION PLANS AND RETIREE BENEFITS

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality and other factors affecting the payment of future benefits.

The net pension expense by plan for the period was as follows:

Three months ended June 30, 2014	**Canada Defined Benefit**	**Canada Post-retirement Benefits**	**United States Defined Benefit**	**United States Post-retirement Benefits**	**Total Defined Benefit**	**Total Post-retirement Benefits**
Current service cost	**$ 1,429**	**$ 124**	**$ 1,352**	**$ 339**	**$ 2,781**	**$ 463**
Interest cost	**1,293**	**143**	**2,279**	**768**	**3,572**	**911**
Expected return on plan assets	**(1,157)**	**(31)**	**(3,012)**	**(955)**	**(4,169)**	**(986)**
Amortization of past service cost	**19**	**-**	**13**	**(62)**	**32**	**(62)**
Amortization of net actuarial loss	**136**	**5**	**198**	**64**	**334**	**69**
Amortization of regulatory asset	**209**	**6**	**455**	**113**	**664**	**119**
Net benefit cost recognized	**$ 1,929**	**$ 247**	**$ 1,285**	**$ 267**	**$ 3,214**	**$ 514**

Six months ended June 30, 2014	**Canada Defined Benefit**	**Canada Post-retirement Benefits**	**United States Defined Benefit**	**United States Post-retirement Benefits**	**Total Defined Benefit**	**Total Post-retirement Benefits**
Current service cost	**$ 2,857**	**$ 248**	**$ 2,720**	**$ 681**	**$ 5,577**	**$ 929**
Interest cost	**2,585**	**287**	**4,586**	**1,545**	**7,171**	**1,832**
Expected return on plan assets	**(2,313)**	**(62)**	**(6,060)**	**(1,921)**	**(8,373)**	**(1,983)**
Amortization of past service cost	**38**	**-**	**26**	**(125)**	**64**	**(125)**
Amortization of net actuarial loss	**273**	**10**	**398**	**130**	**671**	**140**
Amortization of regulatory asset	**417**	**13**	**915**	**226**	**1,332**	**239**
Net benefit cost recognized	**$ 3,857**	**$ 496**	**$ 2,585**	**$ 536**	**$ 6,442**	**$ 1,032**

Three months ended June 30, 2013	Canada Defined Benefit	Canada Post-retirement Benefits	United States Defined Benefit	United States Post-retirement Benefits	Total Defined Benefit	Total Post-retirement Benefits
Current service cost	$ 1,573	$ 156	$ 1,535	$ 309	$ 3,108	$ 465
Interest cost	1,139	145	1,856	552	2,995	697
Expected return on plan assets	(946)	(19)	(2,482)	(817)	(3,428)	(836)
Cost of special events	-	-	60	-	60	-
Amortization of past service cost	19	-	13	(58)	32	(58)
Amortization of net actuarial loss	272	12	985	133	1,257	145
Amortization of regulatory asset	322	54	426	106	748	160
Net benefit cost recognized	$ 2,379	$ 348	$ 2,393	$ 225	$ 4,772	$ 573

Six months ended June 30, 2013	Canada				United States				Total			
		Defined Benefit		Post-retirement Benefits		Defined Benefit		Post-retirement Benefits		Defined Benefit		Post-retirement Benefits
Current service cost	$	3,146	$	311	$	3,048	$	615	$	6,194	$	926
Interest cost		2,277		290		3,686		1,097		5,963		1,387
Expected return on plan assets		(1,891)		(38)		(4,930)		(1,628)		(6,821)		(1,666)
Cost of special events		-		-		120		-		120		-
Amortization of past service cost		38		-		25		(116)		63		(116)
Amortization of net actuarial loss		544		24		1,955		265		2,499		289
Amortization of regulatory asset		644		108		847		210		1,491		318
Net benefit cost recognized	$	4,758	$	695	$	4,751	$	443	$	9,509	$	1,138

15. COMPARATIVE FIGURES

Certain comparative figures related to income tax liabilities for the three and six months period ended June 30, 2013 and for the year ended December 31, 2013 have been reclassified for presentation purposes.

16. SEASONALITY

The utility business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales increase during the winter resulting in strong first and fourth quarter results and weaker second and third quarters.

17. SUBSEQUENT EVENTS

Subsequent events have been reviewed through July 30, 2014, the issuance date of these condensed unaudited interim financial statements.

On July 3, 2014, AltaGas issued 8,000,000 five-year rate-reset Series G Preferred Shares, at a price of $25 per Series G Preferred Share for aggregate gross proceeds of $200 million.

On July 15, 2014, the NTL for the run-of-river projects in British Columbia came into service. Under the agreement with BC Hydro, which was disclosed in the commitments note of AltaGas' condensed unaudited financial statements for the first and second quarters 2014 and in the audited financial statements for the year ending 2013, AltaGas paid $5.3 million to BC Hydro on July 29, 2014. This is the first of the 20 annual payments (annual considerations) in support of the construction and operation of the NTL. AltaGas will pay BC Hydro approximately $9.8 million annually, adjusted for inflation, over the next 19 years.

18. SEGMENTED INFORMATION

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The following describes the Corporation's four reporting segments:

Gas	– NGL processing and extraction plants; – transmission pipelines to transport natural gas and NGL; – natural gas gathering lines and field processing facilities; – purchase and sale of natural gas and electricity; – natural gas storage facilities; – LNG and LPG development projects; and – Equity investment in a North-American entity engaged in the marketing, storage, and distribution of NGL, drilling fluids, crude oil and condensate diluents.
Power	– coal-fired, gas-fired, wind, biomass and run-of-river power output under power purchase agreements and a power purchase arrangement, both operational and under construction; – gas-fired power plants in Alberta; and – sale of power to commercial and industrial users in Alberta.
Utilities	– rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and – rate-regulated natural gas storage in Michigan and Alaska.
Corporate	– the cost of providing corporate services, financing and general corporate overhead, investments in public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts.

The following tables show the composition by segment:

Three months ended June 30, 2014 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 259,852	$ 77,656	$ 172,852	-	$ (41,928)	$ 468,432
Unrealized gain on risk management	-	-	-	2,779	-	2,779
Cost of sales	(161,955)	(48,029)	(90,605)	-	40,347	(260,242)
Operating and administrative	(45,579)	(10,988)	(47,330)	(7,561)	1,581	(109,877)
Accretion expenses	(932)	(85)	(21)	-	-	(1,038)
Depreciation, depletion and amortization	(16,661)	(8,487)	(15,908)	(735)	-	(41,791)
Provision on long-lived assets	-	-	-	-	-	-
Income from equity investments	4,112	3,126	51	-	-	7,289
Other income (expenses)	621	(174)	869	328	-	1,644
Foreign exchange gain (loss)	-	-	-	(225)	-	(225)
Interest expense	-	-	-	(23,000)	-	(23,000)
Income (loss) before income taxes	$ 39,458	$ 13,019	$ 19,908	$ (28,414)	-	$ 43,971
Net additions (reductions) to:						
Property, plant and equipment[1]	$ 6,539	$ 58,716	$ 936	$ 1,780	-	$ 67,971
Intangible assets	-	-	-	$ 2,847	-	$ 2,847

Six months ended June 30, 2014 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 651,489	$ 181,289	$ 616,675	$ -	$ (151,639)	$ 1,297,814
Unrealized loss on risk management	-	-	-	(2,820)	-	(2,820)
Cost of sales	(452,265)	(122,977)	(386,698)	-	147,403	(814,537)
Operating and administrative	(91,051)	(23,589)	(99,099)	(14,329)	4,236	(223,832)
Accretion expenses	(1,867)	(167)	(42)	-	-	(2,076)
Depreciation, depletion and amortization	(33,602)	(16,076)	(31,842)	(1,451)	-	(82,971)
Provision on long-lived assets	(38,337)	(10,860)	-	-	-	(49,197)
Income from equity investments	13,353	10,540	732	-	-	24,625
Other income (expense)	12,024	(116)	1,353	(1,889)	-	11,372
Foreign exchange gain	-	-	-	235	-	235
Interest expense	-	-	-	(48,328)	-	(48,328)
Income (loss) before income taxes	$ 59,744	$ 18,044	$ 101,079	$ (68,582)	-	$ 110,285
Net additions (reductions) to:						
Property, plant and equipment[1]	$ (1,382)	$ 162,892	$ 56,472	$ 3,688	-	$ 221,670
Intangible assets	-	$ 661	-	$ 6,178	-	$ 6,839
Investments accounted for by equity method	$ 5	-	-	-	-	$ 5
As at June 30, 2014						
Goodwill	$ 161,401	-	$ 583,440	-	-	$ 744,841
Segmented assets	$ 2,329,886	$ 2,062,859	$ 2,682,527	$ 122,147	-	$ 7,197,419

[1] *Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

Three months ended June 30, 2013 (unaudited)		Gas		Power		Utilities		Corporate		Intersegment Elimination		Total
Revenue	$	254,887	$	65,427	$	169,415		-	$	(29,493)	$	460,236
Unrealized loss on risk management		-		-		-		(1,625)		-		(1,625)
Cost of sales		(167,335)		(69,710)		(87,962)		-		27,839		(297,168)
Operating and administrative		(49,131)		(7,207)		(47,454)		(5,783)		1,654		(107,921)
Accretion expenses		(881)		(32)		(13)		-		-		(926)
Depreciation, depletion and amortization		(17,421)		(5,200)		(13,587)		(1,029)		-		(37,237)
Provision on long-lived assets		-		(549)		-		-		-		(549)
Income from equity investments		130		48,910		506		-		-		49,546
Other income		70		-		544		274		-		888
Foreign exchange gain (loss)		-		-		-		(396)		-		(396)
Interest expense		-		-		-		(25,219)		-		(25,219)
Income (loss) before income taxes	$	20,319	$	31,639	$	21,449	$	(33,778)		-	$	39,629
Net additions (reductions) to:												
Property, plant and equipment[(1)]	$	5,914	$	646,838	$	59,702	$	3,380		-	$	715,834
Intangible assets	$	1,106	$	(24)	$	3,004	$	(491)		-	$	3,595

Six months ended June 30, 2013 (unaudited)		Gas		Power		Utilities		Corporate		Intersegment Elimination		Total
Revenue	$	541,731	$	132,194	$	492,313		-	$	(85,479)	$	1,080,759
Unrealized loss on risk management		-		-		-		(8,679)		-		(8,679)
Cost of sales		(362,950)		(121,665)		(287,012)		-		82,080		(689,547)
Operating and administrative		(94,496)		(12,843)		(92,615)		(11,217)		3,399		(207,772)
Accretion expenses		(1,816)		(63)		(13)		-		-		(1,892)
Depreciation, depletion and amortization		(34,817)		(8,210)		(27,859)		(2,038)		-		(72,924)
Provision on long-lived assets		-		(549)		-		-		-		(549)
Income from equity investments		296		64,724		1,144		-		-		66,164
Other income (expenses)		144		-		916		(755)		-		305
Foreign exchange gain		-		-		-		4		-		4
Interest expense		-		-		-		(49,834)		-		(49,834)
Income (loss) before income taxes	$	48,092	$	53,588	$	86,874	$	(72,519)		-	$	116,035
Net additions (reductions) to:												
Property, plant and equipment[(1)]	$	14,556	$	718,540	$	99,572	$	2,859		-	$	835,527
Intangible assets	$	3,357	$	(98)	$	2,887	$	(983)		-	$	5,163
As at June 30, 2013												
Goodwill	$	161,401		-	$	578,081		-		-	$	739,482
Segmented assets	$	2,035,809	$	1,913,535	$	2,569,297	$	185,701		-	$	6,704,342

[(1)] *Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

Supplementary Quarterly Financial Information
(unaudited)

FINANCIAL HIGHLIGHTS[1] *($ millions unless otherwise indicated)*	**Q2-14**	Q1-14	Q4-13	Q3-13	Q2-13
Net Revenue[2]					
Gas	**$ 102.6**	$ 122.0	$ 100.6	$ 89.0	$ 87.8
Power	**32.6**	36.2	47.9	53.9	44.6
Utilities	**83.2**	148.9	123.1	104.2	82.5
Corporate	**3.1**	(7.8)	(4.8)	0.2	(1.4)
Intersegment Elimination	**(1.6)**	(2.7)	(2.2)	(0.7)	(1.7)
	$ 219.9	$ 296.5	$ 264.6	$ 246.6	$ 211.8
EBITDA[2]					
Gas	**$ 57.1**	$ 76.5	$ 55.4	$ 44.1	$ 38.7
Power	**21.6**	23.6	36.8	44.8	37.4
Utilities	**35.8**	97.1	70.8	59.0	35.0
Corporate	**(7.3)**	(9.0)	(13.8)	(8.1)	(5.6)
	$ 107.2	$ 188.2	$ 149.2	$ 139.8	$ 105.5
Operating Income (Loss)[2]					
Gas	**$ 39.5**	$ 20.3	$ 37.7	$ 10.4	$ 20.3
Power	**13.0**	5.0	26.2	37.6	31.6
Utilities	**19.9**	81.2	55.4	42.0	21.4
Corporate	**(8.0)**	(9.7)	(14.6)	(9.1)	(6.5)
	$ 64.4	$ 96.8	$ 104.7	$ 80.9	$ 66.8
Normalized Operating Income (Loss)[2]					
Gas	**$ 40.0**	$ 47.5	$ 38.8	$ 26.3	$ 20.3
Power	**13.2**	15.9	29.6	37.6	33.0
Utilities	**19.9**	81.2	55.4	7.5	21.4
Corporate	**(8.6)**	(7.6)	(11.9)	(7.9)	(6.7)
	$ 64.5	$ 137.0	$ 111.9	$ 63.5	$ 68.0

(1) *Columns may not add due to rounding.*

(2) *Non-GAAP financial measure.*

Supplementary Quarterly Operating Information

(unaudited)

	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)(1)	**1,476**	1,573	1,454	1,244	1,366
Extraction volumes (Bbls/d)(1) (2)	**69,867**	72,015	68,765	63,592	64,582
Frac spread - realized ($/Bbl)(1) (3)	**22.12**	30.38	25.04	24.63	20.80
Frac spread - average spot price ($/Bbl)(1)(4)	**22.95**	40.30	32.38	28.64	17.85
POWER					
Volume of power sold (GWh)(1)	**1,067**	1,181	1,327	1,256	1,035
Average price realized on sale of power ($/MWh)(1) (5)	**55.92**	69.36	65.22	79.42	87.01
Alberta Power Pool average spot price ($/MWh)(1)	**42.43**	60.60	48.59	83.61	123.41
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(6)	**6.2**	12.8	10.8	2.7	5.3
Natural gas deliveries - transportation (PJ)(6)	**1.2**	1.9	1.5	1.2	1.4
U.S. utilities					
Natural gas deliveries end use (Bcf) (6)	**10.6**	32.5	23.9	5.8	11.6
Natural gas deliveries transportation (Bcf) (6)	**8.4**	12.4	10.9	8.0	9.8
Service sites(7)	**553,320**	557,062	555,198	548,013	546,906
Degree day variance from normal - AUI (%)(8)	**10.8**	5.5	11.2	(39.1)	3.0
Degree day variance from normal - Heritage Gas (%)(8)	**3.7**	3.9	9.4	(8.0)	(2.1)
Degree day variance from normal - SEMCO Gas (%)(9)	**9.9**	24.1	11.3	26.4	16.4
Degree day variance from normal - ENSTAR (%)(9)	**(7.7)**	(8.3)	(1.3)	(6.4)	12.8

(1) Average for the period.

(2) Includes Harmattan NGL processed on behalf of customers.

(3) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.

(4) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.

(5) Price received excludes Blythe as it earns fixed capacity payments under its PPA with SCE.

(6) Petajoule (PJ) is one million gigajoules (GJ). Bcf is one billion cubic feet.

(7) Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non-regulated business lines.

(8) A degree day for AUI and Heritage Gas 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 materially affect the results of PNG as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.

(9) A degree day for U.S. utilities is a measure of coldness, determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Energy Gas Company and during the prior 10 years for ENSTAR.

Other Information

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
GJ	gigajoule
GWh	gigawatt-hour
kV	kilovolt
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
mtpa	metric tonnes per annum
MW	megawatt
MWh	megawatt-hour
PJ	petajoule
MMBTU	million British thermal unit

ABOUT ALTAGAS

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

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