AltaGas

NEWS RELEASE
ALTAGAS REPORTS SECOND QUARTER EARNINGS AND ON TRACK TO ADD $1.8 BILLION OF NEW ASSETS IN 2012

Calgary, Alberta (July 26, 2012) – AltaGas Ltd. (AltaGas) (TSX:ALA) (TSX:ALA.PR.A) (TSX:ALA.PR.U) (TSX:ALA.R) today reported net income applicable to common shares of $25.8 million ($0.29 per share) for the three months ended June 30, 2012, compared to $13.3 million ($0.16 per share) for the same period 2011. Normalized net income applicable to common shares was $10.4 million ($0.12 per share) for the three months ended June 30, 2012, compared to $16.3 million ($0.20 per share) for the same period 2011.

Normalized net income for the six months ended June 30, 2012 was $50.6 million, a 12 percent increase compared to $45.3 million for the same period 2011. Normalized earnings per share for the six months ended June 30, 2012 was $0.56, up from $0.55 in the same period 2011. Given the power and frac spread hedges in place for the remainder of 2012, approximately five percent of AltaGas' expected EBITDA is exposed to commodity prices. The addition of new assets underpinned by long-term contracts and regulated returns adds stable cash flows and more predictability to earnings.

"We continue to deliver solid earnings so far in 2012, despite weaker gas and power markets. We continue to execute our significant capital investment plan and are on track to add approximately $1.8 billion in new assets in 2012 that will add over $200 million in EBITDA on an annualized basis", said David Cornhill, Chairman and CEO of AltaGas. "With our recent announcements to acquire an interest in a gas plant and construct a pipeline to connect to our Joffre extraction facility as well as a feasibility study related to the transportation of natural gas in BC for LNG export, we continue to be well positioned for long-term earnings, cash flow and sustainable dividend growth into the future."

The acquisition of SEMCO Holding Corporation (SEMCO) is expected to close on August 30, 2012, subject to the approval of the Regulatory Commission of Alaska. Approval of the transaction was received from the Michigan Public Service Commission on May 24, 2012. On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.135 billion including the assumption of US$355 million debt. The addition of SEMCO will add approximately US$725 million in rate base, is expected to be accretive to earnings and cash flow per share by more than 10 percent and is expected to add approximately $130 million in incremental earnings before interest, taxes, depreciation and amortization (EBITDA), in 2013, the first full year of ownership.

The 15 megawatt (MW) gas-fired Cogeneration II facility at the Harmattan Complex was commissioned and in commercial operation on June 7, 2012 with the project completed on time and on budget. During the recent seasonally high temperatures experienced in Alberta, all natural gas fired facilities were operating at or near full capacity.

The expansion at the Blair Creek facility is in the commissioning phase and adds approximately 50 Mmcf/d of processing capacity. The expansion is underpinned by long-term contracts with three producers.

The 195 MW Forrest Kerr run-of-river project (Forrest Kerr Project) is progressing well and is ahead of schedule and on budget. Forrest Kerr Project construction is expected to be completed by March 2014, with commission to follow based on the availability of the Northwest Transmission Line. AltaGas has a 60-year Electricity Purchase Agreement (EPA) with BC Hydro which is fully indexed to the Canadian Consumer Price Index (CPI) as well as an Impact Benefit Agreement (IBA) with the Tahltan First Nation.

The Harmattan Co-stream project (Co-stream Project), which will use 250 Mmcf/d of existing spare capacity is expected to be in service third quarter 2012. The Co-stream Project will recover ethane and other NGLs from natural gas sourced in the NOVA Gas Transmission Ltd. (NGTL) Western System. The project is underpinned by a 20-year cost-of-service contract with NOVA Chemicals Corporation. On July 19, 2012, the Alberta Court of Appeal dismissed the third party appeal of the decision of the Energy Resources Conservation Board (ERCB) which approved the Co-stream Project.

AltaGas' 120 Mmcf/d Gordondale deep-cut, natural gas processing facility is currently on track to be in service in late 2012. The plant is located in the Montney resource area, one of the largest, low cost, liquid-rich resource plays in the Western Canadian Sedimentary Basin. This plant will allow AltaGas to provide a midstream solution to a number of producers in the area and is underpinned by a long-term natural gas supply contract with Encana Corporation.

AltaGas announced the acquisition of Quatro Resources Inc.'s (Quatro) midstream assets and the construction of a 70-kilometre pipeline to connect the Gilby Gas Plant and AltaGas' 30 Mmcf/d Sylvan Lake Gas Plant to AltaGas' deep-cut, turbo expander facility at the Joffre Ethane Extraction Plant (JEEP). Increased volumes processed at the plant are expected to fully utilize JEEP's excess capacity. This project is another example of AltaGas' ability to integrate key assets and leverage existing capacity.

AltaGas' wholly owned subsidiary, Pacific Northern Gas Ltd. (PNG), and LNG Partners, LLC (LNG Partners) amended their agreement to extend it by six months for 80 MMcf/d of firm gas transportation service on PNG's Western B.C. system. PNG and LNG Partners also executed an agreement under which LNG Partners will fund the cost of a feasibility study for expansion of PNG's western transmission system to provide an additional 170 to 195 MMcf/d of firm capacity for LNG Partners.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- AltaGas announced that the August dividend will be paid on September 17, 2012, to holders of record on August 27, 2012, of common shares. The ex-dividend date is August 23, 2012. The amount of the dividend will be $0.115 for each common share. This dividend is an eligible dividend for Canadian income tax purposes.
- The Board approved a dividend of $0.3125 per share for the period commencing July 1, 2012, and ending September 30, 2012, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on September 28, 2012, to shareholders of record on September 14, 2012. The ex-dividend date is September 12, 2012.
- The Board also approved a dividend of US$0.3473 per share for the period commencing June 6, 2012, and ending September 30, 2012, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on October 1, 2012, to shareholders of record on September 17, 2012. The ex-dividend date is September 13, 2012.

Financial Highlights(1)

Effective January 1, 2012, AltaGas follows United States Generally Accepted Accounting Principles (US GAAP). All prior comparative information has been restated to US GAAP.

- EBITDA were $51.6 million for second quarter 2012, compared to $54.8 million for same quarter 2011.
- Funds from operations were $39.9 million ($0.44 per share) for second quarter 2012, compared to $46.5 million ($0.56 per share) for same quarter 2011.
- Net debt as at June 30, 2012 was $1,496.6 million, compared to $1,003.3 million as at June 30, 2011 and $1,337.1 million as at December 31, 2011. AltaGas' debt-to-total capitalization ratio as at June 30, 2012 was 48.5 percent, versus 45.1 percent as at June 30, 2011 and 49.6 percent as at December 31, 2011.
- AltaGas closed a preferred share offering of 8,000,000 Cumulative Redeemable Five-Year Fixed Rate Reset Preferred Shares, Series C, at a price of US$25.00 for aggregate gross proceeds of US$200 million. Holders of the Series C Preferred Shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding September 30, 2017 at an annual rate of 4.40%, payable on the last day of March, June, September and December as and when declared by the Board of Directors of AltaGas.
- On April 13, 2012 AltaGas issued $200 million of senior unsecured medium-term notes. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020.

(1) Includes Non-GAAP financial measures. See public disclosures available at www.altagas.ca or www.sedar.com for definitions.

IN THE SECOND QUARTER, ALTAGAS:

- Entered into an agreement with Quatro to acquire 50 percent interest of Quatro's midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas Plant for approximately $20 million. The acquisition is expected to close in third quarter 2012. In addition, AltaGas will construct a 70-kilometre pipeline to connect the Gilby Gas Plant and AltaGas' 30 Mmcf/d Sylvan Lake Gas Plant to AltaGas' deep-cut, turbo expander facility at JEEP. Increased volumes processed at the plant are expected to fully utilize JEEP's excess capacity.
- On May 24, AltaGas received final approval from the Michigan Public Service Commission for the SEMCO Acquisition. Closing of the transaction is expected on August 30, 2012.
- On June 12, 2012 AltaGas received an environmental assessment certificate for its 66 MW McLymont Creek run-of-river facility. Construction of the McLymont Creek Project is scheduled to start in the third quarter subject to receipt of detailed provincial and federal authorizations and permits required for construction.
- AltaGas commissioned the 15 MW gas-fired Cogeneration II facility at the Harmattan Complex. The commercial operation date of the 15 MW gas-fired Cogeneration II facility at the Harmattan Complex was June 7, 2012. The project was completed on time and on budget.

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 2012 financial and operating results and other general issues and developments concerning AltaGas.

Members of the media, investment communities and other interested parties may dial (416)-340-2216 or call toll free at 1-866-226-1792. No pass code is required. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_webcasts. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing (905)-694-9451 or 1-800-408-3053. The passcode is 6935447. The replay expires at midnight (Eastern) on May 3, 2012.

The complete second quarter report for 2012, including Management's Discussion and Analysis and unaudited financial statements, is available on www.altagas.ca in the Investors/Financial Reporting section of its website.

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 renewable 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 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, 2012, compared to the three and six months ended June 30, 2011. This MD&A dated July 26, 2012, should be read in conjunction with the accompanying unaudited interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three and six months ended June 30, 2012, and with the audited Consolidated Financial Statements and MD&A contained in AltaGas' annual report for the year ended December 31, 2011. Effective January 1, 2012, AltaGas follows United States Generally Accepted Accounting Principles (US GAAP). Information derived from the Consolidated Statements of Income and Consolidated Balance Sheets for the three months and six months ended and as at June 30, 2011, along with other selected financial information for 2011 has been restated to comply with US GAAP. All prior comparative information that have been restated to US GAAP are labeled "restated".

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: "Consolidated Outlook"; "Growth Capital"; "Gas Outlook"; "Power Outlook"; "Utility Outlook" and "Corporate Outlook".

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

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

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

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

ALTAGAS ORGANIZATION

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

CONSOLIDATED FINANCIAL REVIEW

Effective January 1, 2012, the Corporation follows United States Generally Accepted Accounting Principles (US GAAP). Information derived from the Consolidated Statements of Income and Consolidated Balance Sheets for the three and six months ended and as at June 30, 2011, along with other selected financial information for 2011 have been restated to comply with US GAAP. All prior comparative information that has been restated to US GAAP is labeled "restated".

(unaudited) *($ millions)*	Three Months Ended June 30 **2012**	 2011 (restated)	Six Months Ended June 30 **2012**	 2011 (restated)
Revenue	**271.7**	322.8	**648.2**	707.3
Net revenue[1]	**144.9**	107.2	**312.4**	243.4
Normalized operating income[1]	**30.4**	38.0	**99.7**	92.9
Normalized EBITDA[1]	**52.6**	58.6	**144.9**	134.2
Net income applicable to common shares	**25.8**	13.3	**67.1**	40.0
Normalized net income[1]	**10.4**	16.3	**50.6**	45.3
Total assets	**3,844.8**	2,878.0	**3,844.8**	2,878.0
Total long-term liabilities	**1,897.3**	1,290.5	**1,897.3**	1,290.5
Net additions to property, plant and equipment	**175.7**	76.6	**323.8**	129.2
Dividends declared[2]	**31.1**	27.5	**62.0**	54.8
Cash flows				
Normalized funds from operations[1]	**41.3**	46.5	**116.8**	108.1

($ per share)	Three Months Ended June 30 **2012**	 2011 (restated)	Six Months Ended June 30 **2012**	 2011 (restated)
Normalized EBITDA[1]	**0.58**	0.70	**1.61**	1.62
Net income - basic	**0.29**	0.16	**0.75**	0.48
Net income - diluted	**0.28**	0.16	**0.74**	0.48
Normalized net income[1]	**0.12**	0.20	**0.56**	0.55
Dividends declared[2]	**0.345**	0.33	**0.69**	0.66
Cash flows				
Normalized funds from operations[1]	**0.46**	0.56	**1.30**	1.30
Shares outstanding - basic (millions)				
During the period[3]	**90.0**	83.2	**89.8**	83.0
End of period	**90.3**	83.4	**90.3**	83.4

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

(2) *Dividends declared of $0.115 per common share per month commencing October 27, 2011.*

(3) *Weighted average.*

Three Months Ended June 30

Results in second quarter 2012 reflect the seasonality inherent in AltaGas' operations. Second quarter is typically lower than first quarter as a result of lower earnings in the natural gas distribution utilities, lower power prices in Alberta and lower volumes in the Gas business due to normal maintenance cycles for gas processing infrastructure.

Net income applicable to common shares in second quarter 2012 was $25.8 million ($0.29 per share) compared to $13.3 million ($0.16 per share) in same quarter last year. AltaGas reported an after-tax mark-to-market gain of $16.5 million in second quarter 2012 compared to an after-tax mark-to-market loss of $9.8 million in second quarter 2011. Also reported in second quarter 2011 was approximately $6.8 million of income tax recovery related to changes in the future tax rate assumption.

Normalized net income applicable to common shares is calculated to reflect the financial performance of the underlying assets. Net income applicable to common shares is normalized for mark-to-market accounting, transaction costs and foreign exchange loss related to acquisitions. Net income applicable to common shares for second quarter 2011 has been normalized for mark-to-market accounting and a one-time adjustment to deferred tax liabilities.

Normalized net income in second quarter 2012 was $10.4 million ($0.12 per share) compared to $16.3 million ($0.20 per share) in same quarter last year. In second quarter, earnings increased due to higher volumes at some gas processing facilities, the addition of power plants, higher generation at Bear Mountain Wind Park (Bear Mountain) and natural gas-fired plants, higher hedged power volumes at higher prices and growth in rate base at the natural gas distribution utilities. These increases were offset by lower gas volumes processed at some facilities, primarily due to outages downstream from several of AltaGas' plants, lower frac margins and lower spot power prices in Alberta.

On a cash flow basis, normalized funds from operations for the three months ended June 30, 2012, was $41.3 million ($0.46 per share) compared to $46.5 million ($0.56 per share) in second quarter 2011. Normalized EBITDA in second quarter 2012 was $52.6 million compared to $58.6 million in same quarter 2011.

On a consolidated basis, normalized operating income for second quarter 2012 was $30.4 million compared to $38.0 million in same quarter 2011. Operating income was driven by higher gas volumes processed and processing fees charged at some plants, specifically at facilities that were expanded during 2011, and lower operating costs experienced by certain gas facilities. Operating income was also positively affected by higher hedged power volumes, higher generation from Bear Mountain, addition of new power assets, lower natural gas costs at gas-fired power generating facilities and rate base growth in the natural gas distribution utilities. However, these increases were offset by the impact of lower natural gas volumes processed due to the impact of low gas prices on producer activity and maintenance outages downstream from several of AltaGas' plants. Increases in earnings were also offset by lower Alberta spot power prices, lower spot frac margins and lower approved returns at AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas).

On a consolidated basis, net revenue for second quarter 2012 was $144.9 million compared to $107.2 million in same quarter 2011. The increase was driven by higher natural gas volumes processed at some gas plants, higher power volumes hedged, higher power generated at Bear Mountain, addition of new power assets, lower natural gas costs at the gas-fired power facilities, the addition of Pacific Northern Gas Ltd. (PNG), and rate base growth at the Nova Scotia and Alberta utilities. The increase in net revenue was partially offset by lower realized frac spreads, lower natural gas processed at some facilities, lower Alberta spot power prices and lower approved returns at AUI and Heritage Gas.

Operating and administrative expense for second quarter 2012 was $69.8 million, up from $61.0 million in second quarter 2011. The increase was primarily due to the addition of PNG and higher maintenance costs at the peaking facilities, offset by lower operating costs experienced at certain gas facilities as a result of lower power prices and lower volumes processed.

Amortization expense for second quarter 2012 was $21.4 million compared to $20.0 million in same quarter 2011. The increase was due to the addition of new and expanded gas and power facilities, amortization at PNG and higher depletion expense at Ikhil. Accretion expense for second quarter 2012 was $0.8 million compared to $0.6 million for same quarter 2011.

Interest expense in second quarter 2012 was $13.1 million compared to $13.7 million for same quarter 2011. Interest expense decreased due to higher capitalized interest of $8.3 million (second quarter 2011 - $2.0 million) and a lower average borrowing rate of 5.4 percent (second quarter 2011 - 6.4 percent). The decrease was partially offset by a higher average debt balance of $1,578.9 million (second quarter 2011 - $995.4 million).

In second quarter 2012, AltaGas recorded current and deferred income tax expense of $8.7 million compared to a recovery of $3.9 million in second quarter 2011. In second quarter 2012, deferred income taxes were higher compared to same quarter 2011 due to higher unrealized gains on risk management contracts and an adjustment in second quarter 2011 to deferred tax liabilities of approximately $6.8 million related to changes in the future tax rate assumption.

Six Months Ended June 30

On a year-to-date basis, AltaGas continues to deliver strong results. Normalized net income for the six months ended June 30, 2012 was $50.6 million ($0.56 per share) compared to $45.3 million ($0.55 per share) in the same period 2011.

Net income applicable to common shares for the six months ended June 30, 2012 was $67.1 million ($0.75 per share) compared to $40.0 million ($0.48 per share) in the same period last year. For the six months ended June 30, 2012, AltaGas reported after-tax mark-to-market gains of $18.8 million and after-tax transaction costs of $2.3 million including foreign exchange loss related to acquisitions. For the same period 2011, AltaGas reported after-tax mark-to-market losses of $17.6 million, $6.8 million of income tax recovery related to changes in the future tax rate assumption and after-tax gain on the sale of a gas plant of $5.4 million.

On a cash flow basis, normalized funds from operations for the six months ended June 30, 2012, was $116.8 million ($1.30 per share) compared to $108.1 million ($1.30 per share) in the same period 2011. Normalized EBITDA for the six months ended June 30, 2012 was $144.9 million, an 8 percent increase, compared to $134.2 million in the same period 2011.

On a consolidated basis, normalized operating income for the six months ended June 30, 2012 was 7 percent higher at $99.7 million compared to $92.9 million for the same period 2011. Earnings from the operating assets continue to reflect the successful execution of AltaGas' strategy. On a year-to-date basis, the results were driven by higher frac exposed volumes and higher processing fees earned from increased volumes and rates earned at several facilities, lower operating costs at some gas facilities due to lower power prices and volumes processed, higher power volumes hedged at higher prices, the addition of new power assets, higher power generated at Bear Mountain and lower natural gas costs at gas-fired power generating facilities, the acquisition of PNG and rate base growth at the Nova Scotia and Alberta utilities. These increases were partially offset by lower gas volumes processed at some natural gas processing facilities, lower natural gas liquids (NGL) volumes extracted as a result of maintenance outages downstream from several of AltaGas' extraction plants, warmer weather in Nova Scotia and Alberta, the effect of AUI's General Rate Application (GRA) decision and lower approved return on equity (ROE) and debt return at both AUI and Heritage Gas and lower realized frac margins and Alberta spot power prices.

On a consolidated basis, net revenue for the six months ended June 30, 2012 was $312.4 million compared to $243.4 million in the same period 2011. The increase in net revenue was driven by higher frac exposed volumes, higher fees earned from increased gas volumes processed, higher power volumes hedged at higher prices, higher power generated at Bear Mountain, low natural gas costs at gas-fired power facilities, addition of new power assets, the acquisition of PNG and rate base growth at the Nova Scotia and Alberta utilities. These increases were partially offset by a gain of

$6.2 million recorded in first quarter 2011 for the sale of a gas plant. In addition, lower realized frac margins, lower transmission revenues which was largely driven by lower daily contract quantity on the Suffield system, lower Alberta power prices, lower approved revenue requirement at AUI and warmer weather in Alberta and Nova Scotia reduced net revenue for the six months ended June 30, 2012.

Operating and administrative expense for the six months ended June 30, 2012 was $143.5 million, up from $125.1 million in the same period 2011. The increase was primarily due to costs associated with the addition of PNG, transaction costs related to acquisitions during the period and higher maintenance costs at the peaking facilities, partially offset by lower operating costs at some gas facilities due to lower power prices and volumes processed.

Amortization expense for the six months ended June 30, 2012 was $43.6 million compared to $40.1 million in the same period 2011. The increase was due to the addition of new and expanded facilities, including the acquisition of PNG in fourth quarter 2011 and higher depletion expense at Ikhil. Accretion expense for the six months ended June 30, 2012 was $1.6 million compared to $1.2 million for the same period 2011.

Interest expense for the six months ended June 30, 2012 was $25.8 million compared to $26.6 million for the same period 2011. Interest expense decreased due to higher capitalized interest of $14.9 million (six months ended June 30, 2011 - $3.5 million) and a lower average borrowing rate of 5.5 percent (six months ended June 30, 2011 - 6.3 percent). The decrease was partially offset by a higher average debt balance of $1,491.1 million (six months ended June 30, 2011 - $957.8 million).

For the six months ended June 30, 2012, AltaGas recorded current and deferred income tax expense of $22.4 million compared to an expense of $5.4 million for the same period 2011. For the six months ended June 30, 2012, deferred income taxes were higher compared to the same period 2011 due to higher unrealized gains on risk management contracts and an adjustment for the same period in 2011 to deferred tax liabilities of approximately $6.8 million related to changes in the future tax rate assumption.

CONSOLIDATED OUTLOOK

On a consolidated basis, AltaGas is expected to report stronger earnings in 2012 compared to 2011. Stronger earnings are expected in the Gas, Power and Utility businesses as a result of significant projects being commissioned in the second half of 2012, no major turnarounds in Gas, the acquisition of PNG in fourth quarter 2011, continued rate base growth at the Nova Scotia and Alberta utilities, the acquisition of SEMCO Holding Corporation (SEMCO) on August 30, 2012, as well as the impact of lower natural gas costs at the gas-fired power facilities. These are expected to be partially offset by lower spot power prices in Alberta and lower spot frac spreads. Further offset is expected to include lower volumes processed at some of the natural gas processing plants in areas where producers are reducing drilling activity in response to low natural gas prices.

In 2012, AltaGas is expected to add approximately $1.8 billion in new and expanded assets across all business segments; $550 million in Gas and $90 million in Power, with the remainder at the Utilities. The acquisition of SEMCO for total consideration of US$1.135 billion is expected to close on August 30, 2012, adding approximately US$725 million in regulated rate base. Rate base growth at the Canadian utilities is expected to be approximately 10 percent in 2012. These new and expanded assets are expected to add over $200 million in annualized EBITDA.

AltaGas is expected to see significant seasonality in its financial results due to the inherent seasonality in its Utility business. The seasonality of the Utility business results in lower second and third quarters and stronger first and fourth quarters.

In 2012, throughput at AltaGas' processing facilities is expected to be higher than 2011. Volumes are expected to grow from the addition of new and expanded assets. Specifically, the acquisition of 50 percent of the Quatro Gilby Gas Plant, the Harmattan Co-stream project (Co-stream Project) and Blair Creek expansion are expected to be in service in third quarter 2012 and the Gordondale Gas Processing Plant (Gordondale) is expected to be in service in late 2012. AltaGas expects these volume increases to offset the impact of lower volumes expected in areas with low producer activity as a result of continued depressed natural gas prices.

In 2012, more than half of the throughput volumes for the field processing business are anticipated to be captured through facilities near or inside Montney, Wilrich, Notikewin and other liquids-rich gas formations, and associated gas from oil or solution gas production. Management expects volume from field processing to be higher than 2011 even if natural gas prices remain at prices similar to the first half of 2012. AltaGas has been able to offset volume declines in the dry gas areas with growth in volumes processed from liquids-rich areas. Long-term take-or-pay commitments by AltaGas' customers are the primary revenue sources associated with these new volumes.

Based on management's analysis of historical NGL prices, NGL published commodity prices and the current forward curve, management expects spot NGL frac spread prices for AltaGas to range between $20/Bbl and $30/Bbl before deducting extraction premiums for the remainder of 2012. Management estimates that 13 percent of total extraction volumes in 2012 will be exposed to frac spread. For 2012, approximately 80 percent of the exposure has been hedged at an average price of approximately $35/Bbl. For 2013, approximately 35 percent of volumes exposed to frac spreads have been hedged at approximately $35/Bbl.

AltaGas expects earnings from conventional power assets to be slightly lower in 2012 compared to 2011 as a result of lower spot power prices in Alberta, which are expected to be lower than in 2011. This is expected to be partially offset by the addition of the cogeneration facility (Cogeneration II), the Crowsnest Pass waste-heat facility, the Gordondale peaking plant, Busch Ranch wind farm and the recently acquired biomass facilities. The gas-fired power facilities are expected to benefit from low natural gas costs. For third and fourth quarter 2012, AltaGas has hedged approximately 60 percent of volumes exposed to Alberta power prices at an average price of $68/MWh. For 2013, AltaGas has hedged approximately 31 percent of power exposed to spot prices at an average price of $65/MWh.

AltaGas expects a stronger year from its Utility business in 2012 compared to 2011. Higher earnings are expected as a result of the acquisition of PNG in fourth quarter 2011, rate base growth at AUI and Heritage Gas, the potential for an incremental $20 million payment related to PNG's sale of its interest in the Pacific Trail Pipelines (PTP), and the SEMCO acquisition expected to close on August 30, 2012. AltaGas expects to add US$725 million of rate base through the SEMCO acquisition and grow rate base by approximately 10 percent at its Canadian utilities. The acquisition of SEMCO is expected to be 10 percent accretive to earnings and cash flow in the first full year of operation.

GROWTH CAPITAL

Based on projects currently under review, development or construction, and the cash to close the pending acquisition of SEMCO, AltaGas expects capital expenditure for 2012 to be approximately $1.6 billion. The allocation will be approximately 20 percent for Gas, 25 percent for Power and 55 percent for Utilities.

AltaGas' committed capital program is fully funded through its growing internally generated cash flow, its dividend reinvestment plan, its available bank lines, and its continued strong access to capital markets. On closing of the SEMCO acquisition and upon satisfaction of certain escrow release conditions, the 13,915,000 subscription receipts issued on February 22, 2012, will be converted to 13,915,000 common shares of AltaGas for gross proceeds of approximately $403.0 million. As at June 30, 2012, the Corporation had $1,121.4 million of available credit facilities.

AltaGas mitigates project cost escalation and schedule risk on its projects under construction through its procurement and contracting strategies. The following is a summary of progress made during second quarter 2012 on projects currently under construction and advanced development, as well as the pending SEMCO acquisition:

SEMCO Acquisition

On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.135 billion including US$355 million in assumed debt.

During second quarter 2012, AltaGas received final approval from the Michigan Public Service Commission and completed a hearing with the Regulatory Commission of Alaska (RCA) for the SEMCO acquisition. The RCA approval process is progressing as expected and the acquisition of SEMCO is expected to close on August 30, 2012.

Forrest Kerr Hydroelectric Project

Construction of the 195 MW Forrest Kerr run-of-river project (Forrest Kerr Project) is progressing well and is ahead of schedule and on budget. The project includes approximately 440,000 cubic meters of rock to be excavated to support the tunneling and the powerhouse construction. Excavation is 62 percent complete with all tunnels, except for the power tunnel, and the powerhouse being complete. The power tunnel is one-third completed and is expected to be completed by first quarter 2013. Excavation has been advancing at a rate better than planned due to stable and consistent rock formations. The construction of the intake structure is complete. The major equipment foundations at the intake structure are 81 percent complete and are expected to be completed by third quarter 2012. Construction of the powerhouse will start in third quarter 2012.

Forrest Kerr Project construction is expected to be completed by March 2014, with commission to follow based on the availability of the Northwest Transmission Line. AltaGas has a 60-year Electricity Purchase Agreement (EPA) with BC Hydro which is fully indexed to the Canadian Consumer Price Index (CPI) as well as an Impact Benefit Agreement (IBA) with the Tahltan First Nation.

McLymont Creek and Volcano Creek Hydroelectric Projects

During second quarter 2012, the Environmental Assessment Certificate and Special Use Permit were issued for the 66 MW McLymont Creek project. Construction of the access road and bridge work also commenced this quarter and is expected to continue until end of 2012. The environment application process is ongoing for the 16 MW Volcano Creek project. Detailed engineering for McLymont Creek and Volcano Creek is on track to be completed prior to commencement of the facility construction planned to start in first quarter 2013. Combined, the two projects are estimated to cost approximately $300 million and are scheduled to be in service in late 2015. AltaGas has 60-year EPAs with BC Hydro which are fully indexed to the Canadian CPI as well as IBAs with the Tahltan First Nation for these two projects.

Harmattan Co-stream Project

The Co-stream Project will use 250 Mmcf/d of existing spare capacity to recover ethane and other NGL from natural gas sources in the NOVA Gas Transmission Ltd. (NGTL) Western System. The project is underpinned by a 20-year cost-of-service contract with NOVA Chemicals Corporation.

Management expects the project to cost approximately $180 million, including changes in scope and escalations for materials and labour. The project pipelines were ready for service at the end of second quarter 2012. Plant construction continues, with operations expected to commence in third quarter 2012. As at June 30, 2012, 95 percent of expected costs have been incurred. Based on underlying commercial terms, the project’s return on investment continues to meet management’s expectations. The project is expected to add approximately $30 million in annualized EBITDA.

In early January 2011, two of the initial interveners in AltaGas’ Energy Resources Conservation Board (ERCB) application filed notices of motion for leave to appeal the ERCB decision to approve the Co stream Project at the Court of Appeal of Alberta. In late January, one of those parties filed an application with the ERCB for a Review and Variance of the ERCB Decision. The application was dismissed by the ERCB on May 27, 2011. The leave to appeal applications were heard on June 8, 2011 and the appealing parties were granted leave to appeal on August 8, 2011. The appealing parties filed their notices of appeal with the Alberta Court of Appeal on September 7, 2011, and the hearing was held on April 5, 2012. The Alberta Court of Appeal dismissed the appeal on July 19, 2012.

Gordondale Gas Plant

In second quarter 2012, construction progressed on AltaGas' 120 Mmcf/d Gordondale deep-cut, natural gas processing facility in the Montney resource play near the town of Gordondale, approximately 100 kilometres northwest of Grande Prairie, Alberta. The project is underpinned by a long-term contract with Encana.

AltaGas had approximately $244 million of committed capital costs at the end of second quarter 2012. In total, the project is expected to cost approximately $260 million. The remaining costs to be incurred will be subject to cost and labour productivity risk. During the quarter, management directed several initiatives to mitigate cost escalation and maintain schedule. The project's estimated return on investment continues to be within management's expectations. The facility is expected to be in service in late 2012.

At the end of second quarter 2012, 70 percent of major mechanical and electrical work was complete, and essentially all major equipment had been shipped to site.

Busch Ranch Project

AltaGas has acquired a 50 percent interest in the Busch Ranch Wind Project (Busch Ranch) under construction for a total cost of US$25 million. Busch Ranch is a 29 MW wind farm in Colorado with Black Hills/Colorado Electric Utility Company, LP (Black Hills). The project has a 25-year Power Purchase Arrangement (PPA). The project is on budget and ahead of schedule with completion expected in second half 2012.

Blair Creek

Upon the execution of long-term contracts with three producers, AltaGas began construction of the estimated $50 million expansion of Blair Creek in late 2011. In second quarter 2012, construction progressed on the expansion which is expected to increase production capacity by 50 Mmcf/d and raise the licensed capacity to 82 Mmcf/d. The expansion is expected to commence commercial operation in third quarter 2012.

JEEP Pipeline

AltaGas is currently in the process of acquiring a 50 percent interest of Quatro Resources Inc.'s (Quatro) midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas Plant for approximately $20 million. The acquisition is expected to close in third quarter 2012. In addition, AltaGas plans to construct a 70-kilometre pipeline (West Central Gas Pipeline) to connect the Gilby Gas Plant and AltaGas' 30 Mmcf/d Sylvan Lake Gas Plant to AltaGas' deep-cut, turbo expander facility at the Joffre Ethane Extraction Plant (JEEP). Increased volumes processed at the plant are expected to fully utilize JEEP's excess capacity.

The construction of the pipeline will provide producers in the Hoadley Glauconite and Duvernay resource plays with increased recovery of NGL, improve their recoverable barrels of oil equivalent (BOEs) and increase the value received for their ethane and other NGL products. The pipeline project is subject to customary conditions. The project is expected to cost approximately $100 million and be completed by late 2013. The volumes committed to the pipeline and JEEP are underpinned by a long-term fee-for-service contract.

Farmington Pipeline

In early 2012, management entered into a letter of intent with a major producer to construct, own and operate two pipelines, a C3+ (propane plus) and a C5+ (condensate), both approximately 45 kilometres in length to connect the producer's processing facilities to the Plateau system within northeast B.C. This project along with expansions of other transmission assets is expected to cost approximately $40 million and commence operations in late 2012.

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)	**2012**	2011 (restated)	**2012**	2011 (restated)
Net revenue	**144.9**	107.2	**312.4**	243.4
Add: Cost of sales	**126.8**	215.6	**335.8**	463.9
Revenue (GAAP financial measure)	**271.7**	322.8	**648.2**	707.3

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

Normalized Operating Income	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized operating income	**30.4**	38.0	**99.7**	92.9
Add (deduct):				
Unrealized gain (loss) on held-for-trading	**(1.4)**	(3.8)	**0.3**	(6.6)
Transaction (costs) recovery	**0.4**	-	**(1.2)**	-
Gain on sale of Groundbirch facility	**-**	-	**-**	6.2
Operating income	**29.4**	34.2	**98.8**	92.5
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**23.6**	(8.6)	**24.8**	(15.5)
Interest expense	**(13.1)**	(13.7)	**(25.8)**	(26.6)
Foreign exchange loss	**(2.0)**	-	**(2.1)**	-
Income tax recovery (expense)	**(8.7)**	3.9	**(22.4)**	(5.4)
Net income applicable to non-controlling interests	**(0.3)**	-	**(0.6)**	-
Preferred share dividends	**(3.1)**	(2.5)	**(5.6)**	(5.0)
Net income applicable to common shares (GAAP financial measure)	**25.8**	13.3	**67.1**	40.0

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 by management to assess operating performance since it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, interest expense, foreign exchange loss, income tax expense or 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 and mark-to-market gains and losses related to equity investments. Normalized operating income for six months ended June 30, 2011 has been adjusted for one-time gain on sale of Groundbirch facility.

Normalized Net Income	Three Months Ended		Six Months Ended	
		June 30		June 30
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized net income	**10.4**	16.3	**50.6**	45.3
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**17.7**	(6.5)	**18.5**	(11.8)
Unrealized gain (loss) on held-for-trading assets	**(1.2)**	(3.3)	**0.3**	(5.7)
Transaction costs and foreign exchange loss related to acquisitions	**(1.1)**	-	**(2.3)**	-
Gain on sale of Groundbirch facility	**-**	-	**-**	5.4
Deferred income tax rate adjustment	**-**	6.8	**-**	6.8
Net Income applicable to common shares (GAAP financial measure)	**25.8**	13.3	**67.1**	40.0

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) recovery related to acquisitions including foreign exchange. Normalized net income for six months ended June 30, 2011 has been adjusted for one-time after-tax gain on sale of Groundbirch facility and one-time adjustment to deferred income tax rate.

Normalized EBITDA	Three Months Ended		Six Months Ended	
		June 30		June 30
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized EBITDA	**52.6**	58.6	**144.9**	134.2
Add (deduct):				
Unrealized gain (loss) on held-for-trading	**(1.4)**	(3.8)	**0.3**	(6.6)
Transaction (costs) recovery	**0.4**	-	**(1.2)**	-
Gain on sale of Groundbirch facility	**-**	-	**-**	6.2
EBITDA	**51.6**	54.8	**144.0**	133.8
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**23.6**	(8.6)	**24.8**	(15.5)
Depreciation, depletion and amortization	**(21.4)**	(20.0)	**(43.6)**	(40.1)
Accretion of asset retirement obligations	**(0.8)**	(0.6)	**(1.6)**	(1.2)
Interest expense	**(13.1)**	(13.7)	**(25.8)**	(26.6)
Foreign exchange gain loss	**(2.0)**	-	**(2.1)**	-
Income tax (expense)	**(8.7)**	3.9	**(22.4)**	(5.4)
Net income applicable to non-controlling interests	**(0.3)**	-	**(0.6)**	-
Preferred share dividends	**(3.1)**	(2.5)	**(5.6)**	(5.0)
Net income applicable to common shares (GAAP financial measure)	**25.8**	13.3	**67.1**	40.0

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, and therefore evaluates company performance excluding unrealized gains or losses from risk management contracts. EBITDA is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, amortization, accretion of asset retirement obligations, interest expense, income tax (expense) recovery, 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 and mark-to-market gains and losses related to equity investments. Normalized EBITDA for six months ended June 30, 2011 has been adjusted for one-time gain on sale of Groundbirch facility.

Normalized Funds from Operations		Three Months Ended June 30		Six Months Ended June 30
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized Funds from Operations	**41.3**	46.5	**116.8**	108.1
Add (deduct):				
Transaction costs and foreign exchange loss related to acquisitions	**(1.4)**	-	**(3.0)**	-
Funds from operations	**39.9**	46.5	**113.8**	108.1
Add (deduct):				
Net change in non-cash working capital	**1.9**	4.1	**24.0**	(21.4)
Asset retirement obligations settled	**(0.1)**	(0.1)	**(0.5)**	(0.2)
Cash from operations (GAAP financial measure)	**41.7**	50.5	**137.3**	86.5

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

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income		Three Months Ended June 30		Six Months Ended June 30
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Gas	**19.5**	25.2	**49.6**	55.4
Power	**14.0**	15.5	**40.9**	42.1
Utilities	**5.2**	4.9	**24.7**	16.6
Sub-total: Operating Businesses	**38.7**	45.6	**115.2**	114.1
Corporate[(1)]	**(9.3)**	(11.4)	**(16.4)**	(21.6)
	29.4	34.2	**98.8**	92.5

[(1)] *Includes mark-to-market gain/loss on equity investments, excludes mark-to-market gains/losses on risk management contracts.*

GAS

OPERATING STATISTICS	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	**2012**	2011
Extraction and Transmission (E&T)				
Extraction inlet gas processed (Mmcf/d)(1)	**829**	828	**896**	868
Extraction ethane volumes (Bbls/d)(1)	**20,844**	25,284	**25,104**	26,581
Extraction NGL volumes (Bbls/d)(1)	**13,703**	13,559	**14,980**	13,908
Total extraction volumes (Bbls/d)(1)	**34,547**	38,843	**40,084**	40,489
Frac spread - realized ($/Bbl)(1) (2)	**27.64**	36.65	**31.17**	34.50
Frac spread - average spot price ($/Bbl)(1) (3)	**26.85**	41.27	**34.26**	41.09
Field Gathering and Processing (FG&P)				
Processing throughput (gross Mmcf/d)(1)	**351**	391	**375**	383
Energy Services				
Average volumes transacted (GJ/d)(1)(4)	**318,738**	377,967	**347,450**	390,801

(1) *Average for the period.*

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

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

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

In second quarter 2012, average ethane volumes decreased by 4,440 Bbls/d and NGL volumes increased by 144 Bbls/d, compared to same quarter 2011. During first half 2012, average ethane volumes decreased by 1,477 Bbls/d and NGL volumes increased by 1,072 Bbls/d, compared to same period 2011. Ethane volumes were lower during the current quarter largely due to outages downstream from several of AltaGas' extraction plants which accounted for approximately 4,300 Bbls/d of the decrease. NGL volumes were higher in the six months ended June 30, 2012 compared to the same period in 2011 as a result of the commencement of the Septimus Pipeline in December 2011, higher throughput processed at Harmattan and increased recoveries at JEEP.

FG&P throughput in second quarter 2012 averaged 351 Mmcf/d compared to 391 Mmcf/d in second quarter 2011. FG&P throughput in first half 2012 averaged 375 Mmcf/d compared to 383 Mmcf/d in same period 2011. Volumes processed were down due to declines and shut-ins led by producers in response to low natural gas prices and outages. These decreases were partially offset by the addition of the Marlboro Gas Plant last year, 2011 facility expansions and facilities with liquids-rich resource plays. For the three months ended June 30, 2012, management has estimated that an average of approximately 40 Mmcf/d of flowing natural gas wells had been shut-in or diverted that were previously processed at AltaGas' facilities.

During second quarter 2012, available volumes at certain gas processing facilities grew by approximately 24 Mmcf/d, which more than offset declines, excluding shut-ins, of approximately 12 Mmcf/d.

Three Months Ended June 30

The Gas segment recorded operating income of $19.5 million in second quarter 2012 compared to $25.2 million for same quarter 2011. The decrease was due to lower realized frac exposed margins, lower volumes processed, lower ethane volumes processed as a result of outages experienced downstream from several of AltaGas' extraction facilities, a one-time positive liability adjustment recorded in second quarter 2011, planned maintenance at two extraction plants and lower transmission revenue. These decreases were partially offset by a settlement of a customer dispute, lower operating costs and higher rates charged to process gas at some FG&P facilities.

During second quarter 2012, AltaGas had NGL frac spread hedges that covered approximately 80 percent of frac exposed production at an average price of approximately $35/Bbl before deducting extraction premiums. During second quarter 2011, NGL frac spread hedges covered approximately 70 percent of frac exposed production at an average price of $27/Bbl before deducting extraction premiums. The average indicative spot NGL frac spread, before deducting extraction premiums, for the second quarter 2012 was approximately $33/Bbl compared to approximately $47/Bbl in same quarter 2011.

Net revenue in the Gas business for second quarter 2012 was $75.9 million, compared to $80.6 million for same quarter 2011. Net revenues were lower in the quarter due to declines in realized frac exposed margins offset by higher frac exposed volumes. Additional net revenue declines were due to lower gas processing volumes, lower fee-for-service revenues as a result of outages downstream from several of AltaGas' extraction plants and lower transmission revenues which was driven largely by lower daily contract quantity on the Suffield system. These declines in net revenue were offset by the settlement of a customer dispute and higher volumes and rates charged for gas processed at some FG&P facilities.

Operating and administrative expense in second quarter 2012 was $41.5 million compared to $41.3 million in second quarter 2011. Operating costs were slightly higher due to a one-time liability adjustment recorded in second quarter 2011 offset by lower operating costs due to lower power prices, lower volumes at certain gas processing facilities and the efforts to control costs to address lower volumes at some facilities.

Amortization expense in second quarter 2012 was $14.1 million compared to $13.5 million in second quarter 2011. Accretion expense in second quarter 2012 was $0.7 million compared to $0.6 million in second quarter 2011. Increase in amortization and accretion expenses was as a result of expansions in second half 2011.

Six Months Ended June 30

The Gas segment recorded operating income of $49.6 million in first half 2012 compared to $55.4 million for same period 2011. Excluding approximately $8 million of one-time gains recorded from the sale of the Groundbirch facility and liability adjustment in first half 2011, the Gas segment reported a 5 percent increase in operating income over first half 2011. The increase was due to higher frac exposed volumes, lower operating costs, higher extraction fees earned from higher throughput and NGL volumes, and higher rates charged for gas processed at some FG&P facilities. These increases were partially offset by lower realized frac exposed margins, lower fee-for-service revenues earned as a result of outages downstream from several of AltaGas' extraction plants, lower transmission revenue, planned maintenance at two extraction plants and higher administration costs.

During first half 2012, AltaGas had NGL frac spread hedges that covered approximately 80 percent of frac exposed production at an average price of approximately $35/Bbl before deducting extraction premiums. During first half 2011, NGL frac spread hedges covered approximately 70 percent of frac exposed production at an average price of $27/Bbl before deducting extraction premiums. The average indicative spot NGL frac spread, before deducting extraction premiums, for first half 2012 was approximately $40/Bbl compared to approximately $47/Bbl in same period 2011.

Net revenue in the Gas business for the six months ended June 30, 2012 was $163.4 million, compared to $168.2 million for same period 2011. Excluding one-time gains recorded in first half 2011, net revenue was impacted by lower transmission revenues which was driven largely by lower daily contract quantity on the Suffield system and lower operating cost recoveries. These decreases were partially offset by higher fees earned at extraction and gas processing facilities. Net revenue was also positively impacted by higher frac exposed volumes processed offset by lower realized frac margins.

Operating and administrative expense for the six months ended June 30, 2012 was $84.4 million compared to $84.5 million for same period 2011. Operating costs were slightly lower due to lower power prices and lower volumes processed at certain gas processing facilities, offset by a one-time liability adjustment recorded in second quarter 2011 and higher administration costs associated with employee benefits.

Amortization expense for the six months ended June 30, 2012 was $27.9 million compared to $27.1 million for same period 2011. Accretion expense in first half 2012 was $1.5 million compared to $1.2 million in first half 2011. Increase in amortization and accretion expenses was as a result of expansions in second half 2011.

Gas Outlook

The Gas business is expected to deliver stronger results for full year 2012 compared to full year 2011. Third quarter 2012 results are expected to be higher than second quarter 2012 due to expected commencement of operations of the Blair Creek expansion and Co-stream Project, acquisition of 50 percent of the Quatro Gilby Gas Plant and return to normal operations for facilities downstream from several of AltaGas' extraction plants. Results in third quarter 2012 will be offset by lower anticipated local market prices for propane when compared to 2011 and first quarter 2012 levels. This is expected to result in lower realized frac spreads in second half of the year

For full year 2012, stronger results are expected due to the completion of the Gordondale, Co-stream and Blair Creek projects, acquisition of 50 percent of the Quatro Gilby Gas Plant, as well as expansions at other field processing and extraction assets that were completed in the latter part of 2011, as producers look to increase netbacks from liquids-rich gas. Furthermore, the addition and expansion of transmission assets during 2012 are expected to provide incremental operating income during the year. Stronger results are also expected as a result of no major turnarounds in 2012, compared to two major turnarounds in 2011.

Throughput at the extraction assets is expected to increase in 2012 over 2011 as a result of a full year operation of the Septimus Pipeline, the addition of the Co-stream Project in third quarter 2012 and success in contracting new gas supply for Harmattan. Drilling activity in northeast B.C. and west central Alberta has increased as producers continue the development of tight and shale gas plays within the area. In 2012, more than half of the throughput volumes for the field processing business are anticipated to be captured through facilities near or inside Montney, Wilrich, Notikewin and other liquids-rich gas formations, and associated gas from oil or solution gas production. Management expects volume from field processing to be higher than 2011 even if natural gas prices remain at prices similar to the first half of 2012. AltaGas has been able to offset volume declines in the dry gas areas with growth in volumes processed from liquids-rich areas. Long-term take-or-pay commitments by AltaGas' customers are the primary revenue source associated with these new volumes.

The above increases are expected to be partially offset by lower volumes in areas where there are fewer opportunities for producers to benefit from liquids-rich gas and lower daily contract quantity commitment on the Suffield natural gas transmission system. Other reductions for 2012 include one-time items from 2011 of approximately $8 million, comprised of the gains recorded from the sale of the Groundbirch facility and liability adjustment.

Based on management's analysis of historical NGL prices, NGL published commodity prices and the current forward curve, management expects spot NGL frac spread prices for AltaGas to range between $20/Bbl and $30/Bbl before deducting extraction premiums, for the remainder of 2012. Management estimates that 13 percent of total extraction volumes in 2012 will be exposed to frac spread. For 2012, approximately 80 percent of the exposure has been hedged at an average price of approximately $35/Bbl before deducting extraction premiums compared to 70 percent hedged at approximately $28/Bbl before deducting extraction premiums in 2011. For 2013, approximately 35 percent of volumes exposed to frac spreads have been hedged at approximately $35/Bbl.

POWER

OPERATING STATISTICS	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	**2012**	2011
Volume of power sold (GWh)(1)	**802**	729	**1,618**	1,468
Average price realized on the sale of power ($/MWh)(1)	**58.54**	64.26	**65.69**	71.10
Alberta Power Pool average spot price ($/MWh)(1)	**40.03**	52.12	**50.08**	67.73

(1) *Average for the period.*

Three Months Ended June 30

The Power segment reported operating income of $14.0 million for second quarter 2012 compared to $15.5 million for same quarter 2011. Operating income decreased as a result of lower Alberta power pool prices, partially offset by higher hedged volumes, favorable results from the gas-fired peaking plants, higher power generated at Bear Mountain and new power assets.

In the three months ended June 30, 2012, AltaGas was 74 percent hedged in Alberta at an average price of $65/MWh. In the same period in 2011, AltaGas was 66 percent hedged at an average price of $70/MWh.

Net revenue for the three months ended June 30, 2012 was $21.3 million compared to $21.4 million for same period 2011. Net revenue decreased due to lower Alberta power pool prices and higher PPA costs. These decreases were almost completely offset by higher hedged volumes, increased prices received at the gas-fired peaking plants, lower natural gas prices at all gas-fired generating facilities, higher power generated at Bear Mountain and the addition of new biomass and hydro power generation facilities.

Operating and administrative expense was $4.6 million for second quarter 2012 compared to $3.2 million for same quarter 2011. The increase was primarily due to increased business development costs, higher maintenance costs at peaker facilities and operating and administrative costs related to new power assets.

Amortization expense was $2.7 million for second quarter 2012 compared to $2.6 million for same quarter 2011.

Six Months Ended June 30

The Power segment reported operating income of $40.9 million for first half 2012 compared to $42.1 million for same period 2011. Operating income decreased as a result of lower Alberta power pool prices, higher PPA costs and higher general and administrative costs. These decreases were partially offset by hedging a higher percentage of volumes exposed to Alberta power pool price, higher hedged prices, increased generation and prices received at the gas-fired peaking plants, lower natural gas prices at all gas-fired generating facilities, higher power generated at Bear Mountain, and the addition of new biomass and hydro power generation facilities.

In first half 2012, AltaGas was 74 percent hedged in Alberta at an average price of $72/MWh. In same period 2011, AltaGas was 61 percent hedged at an average price of $67/MWh.

Net revenue for the six months ended June 30, 2012 was $55.8 million compared to $53.5 million for same period 2011. Net revenue increased due to higher hedged volumes, higher hedged prices, increased generation and prices received at the gas-fired peaking plants, lower natural gas prices at all gas-fired generating facilities, higher power generated at Bear Mountain and the addition of new biomass and hydro power generation facilities. These increases were partially offset by lower Alberta power pool prices and higher PPA costs.

Operating and administrative expense was $9.6 million for first half 2012 compared to $6.2 million for same period 2011. The increase was primarily due to higher maintenance costs at peaker facilities, operating and administrative costs related to new power assets and increased business development activities.

Amortization expense was $5.2 million for first half 2012 compared to $5.1 million for same period 2011.

Power Outlook

Overall the Power business is expected to report slightly lower earnings in 2012 compared to 2011. Earnings are expected to increase as a result of the addition of approximately 70 MWs of new power generation assets in 2012. In Canada, the addition of the second cogeneration facility at Harmattan, the gas-fired peaker at the Gordondale Gas Plant site, and the waste heat recovery plant are all expected to add to earnings in 2012. The addition of approximately 35 MW of biomass power generation assets and the acquisition of a 50 percent interest in a wind farm in the United States with long-term PPAs are also expected to increase earnings.

The increased earnings from new assets and the effective hedging strategy is expected to partially offset the impact of lower power prices in Alberta in 2012 compared to 2011 based on the current forward spot prices. A major maintenance outage at the Sundance 3 facility has been scheduled by its operator for later this year due to the mechanical failure of critical generator components experienced in 2010. During the outage, AltaGas receives revenue from the operator based on the 30-day rolling average power price (RAPP).

For third and fourth quarter 2012, AltaGas has hedged approximately 60 percent of volumes exposed to Alberta power price at an average price of $68/MWh. For 2013, AltaGas has hedged approximately 31 percent of power at an average price of $65//MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to long-term averages.

UTILITIES

OPERATING STATISTICS	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	**2012**	2011
Natural gas deliveries - end-use (PJ)[1]	**4.6**	3.7	**15.4**	12.9
Natural gas deliveries - transportation (PJ)[1]	**1.7**	1.2	**3.7**	2.4
Service sites [2]	**115,437**	73,881	**115,437**	73,881
Degree day variance from normal - AUI (%) [3]	**(2.9)**	4.6	**(9.3)**	9.5
Degree day variance from normal - Heritage Gas (%) [3]	**(9.7)**	2.4	**(8.9)**	(1.8)

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

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

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

REGULATORY METRICS

	Six Months Ended June 30	
	2012	2011
Approved return on equity (%)		
AUI[(1)]	**8.75**	8.75
PNG	**10.09**	-
Heritage Gas	**11.00**	13.00
Approved return on debt (%)		
AUI[(2)]	**5.17**	5.28
PNG	**6.83**	-
Heritage Gas	**7.25**	8.75
Rate base		
AUI[(3)]	**179.6**	153.0
PNG[(3)]	**178.7**	-
Heritage Gas[(4)]	**186.6**	169.2

[(1)] *GRA decision received in third quarter 2011 adjusted approved ROE to 8.75 percent*.

[(2)] *2011 approved return on debt has been restated to reflect the 2010 - 2012 GRA decision issued by the Alberta Utilities Commission (AUC) on April 9, 2012.*

[(3)] *Mid-year rate base*.

[(4)] *Weighted average rate base over the year.*

Three Months Ended June 30

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

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

The Utility business reported operating income of $5.2 million for second quarter 2012, a 7 percent increase compared to $4.9 million for same quarter 2011. Operating income increased mainly due to reversal of transaction costs accrual of $1.1 million in 2011 and the acquisition of PNG, which contributed $0.3 million to operating income in the quarter and rate base growth at AUI and Heritage Gas. The increases were partially offset by the effect of AUI's GRA decision, higher depletion and depreciation related to Ikhil assets and lower approved ROE and debt recovery rates at the Alberta and Nova Scotia utilities.

Net revenue for the three months ended June 30, 2012 was $26.6 million compared to $18.9 million for the same period 2011. Net revenue was higher mainly due the addition of PNG in December 2011 and rate base growth at both AUI and Heritage Gas. These increases were partially offset by lower recoverable costs at AUI and lower ROE and debt recovery rates at AUI and Heritage Gas in second quarter 2012 compared to second quarter 2011.

Operating and administrative expense was $17.5 million for second quarter 2012 compared to $10.9 million for same quarter 2011. The increase in operating costs was mainly due to the addition of PNG. Primarily all operating and administrative costs incurred at the utilities are recoverable through the rate setting mechanism to customers.

Amortization expense was $3.9 million in second quarter 2012 compared to $3.0 million in second quarter 2011. The increase in amortization expense was mainly due to the addition of PNG and higher depletion expense at Ikhil due to lower expected remaining reserves. These increases were partially offset by lower amortization at AUI as a result of the Alberta Utilities Commission (AUC) decision on its 2011/2012 GRA.

Six Months Ended June 30

The Utility business reported operating income of $24.7 million for first half 2012, a 49 percent increase compared to $16.6 million for same period 2011. Operating income increased mainly due to the acquisition of PNG, which contributed $11.5 million to operating income in the period and rate base growth of 17 percent and 11 percent at AUI and Heritage Gas, respectively. These increases were partially offset by warmer than normal weather experienced in Alberta and Nova Scotia and lower approved ROE, debt recovery rates at the Alberta and Nova Scotia utilities in first half 2012 compared to first half 2011 and the effect of AUI's GRA decision.

Net revenue for the six months ended June 30, 2012 was $69.9 million compared to $45.0 million for the same period in 2011. Net revenue increased $27.8 million due to the acquisition of PNG in late 2011 and rate base growth at AUI and Heritage Gas. These increases were partially offset by warmer weather experienced in Alberta and Nova Scotia, lower recoverable costs at AUI and lower ROE and debt recovery rates at Heritage Gas in the first half 2012 compared to second half 2011.

Operating and administrative expense was $36.4 million for the six months ended June 30, 2012 compared to $22.3 million for the same period in 2011. The increase in operating costs was mainly due to the addition of PNG. Primarily all operating and administrative costs incurred at the utilities are recoverable from customers through the customer rate setting mechanism.

Amortization expense was $8.8 million for the six months ended June 30, 2012 compared to $6.1 million for the same period in 2011. The increase in amortization expense was mainly due to the addition of PNG and higher depletion expense at Ikhil due to lower expected remaining reserves. These increases were partially offset by lower amortization at AUI as a result of the AUC decision on its 2011/2012 GRA.

Utilities Outlook

Results in 2012 are expected to be stronger than 2011, driven by rate base growth of 17 percent and 12 percent at AUI and Heritage Gas, respectively. The addition of PNG and SEMCO are also expected to result in a significant increase in earnings and cash flow from the Utility business. The first full year of PNG is expected to add approximately $25 million in EBITDA and SEMCO, upon close on August 30, 2012, is expected to add approximately $40 million in EBITDA in fourth quarter 2012. AltaGas expects regulated rate base at the utilities to increase from approximately $505 million in 2011 to $1.3 billion in 2012. This growth will come from the addition of US$725 million of rate base through the SEMCO acquisition and rate base growth at the Canadian utilities. In addition, Heritage Gas is expected to have approximately $11 million of work-in-progress by year end for CNG infrastructure which is expected to be included in rate base in early 2013. AltaGas expects total utility customers to increase to approximately 536,000 in 2012 from approximately 115,000 in 2011. In 2012, AltaGas expects to receive $20 million in relation to PNG’s 2011 sale of its interest in PTP. Receipt of the payment is contingent on the purchasers of PTP making a decision to proceed with construction of the Kitimat LNG facility.

AUI

Throughout 2010 and 2011 AUI operated in regulatory lag for a number of items, including all of AUI's debt recovery rates and its full 2010 to 2012 GRA including costs of service and capital programs. On April 9, 2012 the Alberta Utilities Commission (AUC) issued a decision on AUI's 2010-2012 GRA. The decision approved AUI's applied for capital programs for 2010, 2011 and 2012, along with revenue requirements for 2010 and 2011 which were lower by $3.0 million and $3.8 million respectively than recognized by AUI. The main reason for the lower revenue requirements was lower than applied for depreciation and negative salvage value, neither of which affect earnings in the period, along with lower than applied for inter-affiliate costs and interest rates on AUI's debt.

AUI filed its Incentive Regulation (IR) application in July 2011 which will change the basis of AUI's regulation from a cost-of-service recovery model to an incentive based model. The hearing for AUI's IR application commenced on April 16, 2012 with a decision expected in the fourth quarter of 2012. IR will be effective January 1, 2013, and the initial term is expected to be five years.

PNG

On November 30, 2011, PNG filed its 2012 GRA and on December 7, 2011, the BCUC approved interim rates as requested in the application. PNG filed an update to the GRA on March 15, 2012, to reflect its new forecast of 2012 costs based on its acquisition by AltaGas. A decision on the application is expected in third quarter 2012.

PNG and LNG Partners, LLC (LNG Partners) amended their agreement for 80 MMcf/d of firm gas transportation service on PNG's Western B.C. System. The amendments include a six month extension to LNG Partners' exclusive option on the 80 MMcf/d of firm capacity available on PNG's western transmission system and the lengthening of the term of the Transportation Service Agreement to 30 years. The start date for the service is to be on or before March 31, 2015 if the option is exercised. PNG and LNG Partners also executed an agreement under which LNG Partners will fund the cost of a feasibility study for expansion of PNG's western transmission system to provide an additional 170 to 195 MMcf/d of firm capacity for LNG Partners.

Heritage Gas

Heritage Gas is currently in the first year of a Nova Scotia Utility and Review Board (NSUARB) approved three-year test period. In second quarter 2012, the NSUARB approved Heritage Gas' phase 2 GRA for 2013 and 2014.

In 2012, Heritage Gas is forecasting to spend approximately $30 million to continue the expansion of service to the regions of the Halifax Regional Municipality along with the Amherst/Airport region. The 2012 capital expenditures is also expected to include approximately $11 million, with an additional $3 million in 2013, for Heritage Gas to develop and construct a compressed natural gas (CNG) trucking network in Nova Scotia. The Nova Scotia Government has adopted a hybrid approach to regulation of CNG distribution in the Province which allows non-rate regulated entities to participate in a portion of the market. To date, Heritage Gas has signed Memorandum of Agreements (MOA) with two major customers and expects to begin service to these customers in early 2013. On April 2, 2012 Heritage Gas filed a franchise extension application with the NSUARB related to CNG. CNG trucking will enable Heritage Gas to expand its gas distribution business and access customers which would otherwise be uneconomical.

Inuvik Gas & Ikhil

The Ikhil Joint Venture operator, along with the other joint venture partners, continues to work with the town of Inuvik, the Northwest Territories Government and other parties to evaluate alternative energy supply options for meeting future energy requirements.

CORPORATE

Three Months Ended June 30

The operating loss excluding the impact of mark-to-market accounting on risk management contracts for second quarter 2012 was $9.3 million compared to $11.4 million for second quarter 2011. The decrease in loss was primarily due to $1.4 million of unrealized pre-tax loss on equity investments in second quarter 2012 compared to an unrealized pre-tax loss of $3.8 million in same quarter 2011.

Net revenue was $22.3 million in second quarter 2012 compared to net revenue in a deficit position of $12.2 million in same quarter 2011. The increase was primarily due to changes in unrealized pre-tax gain versus loss on risk management contracts of $32.2 million, as well as an unrealized pre-tax loss of $1.4 million on an equity investment in second quarter 2012 compared to an unrealized pre-tax loss of $3.8 million in same quarter last year.

Operating and administrative expense was $7.3 million in second quarter 2012 compared to $7.0 million in second quarter 2011. The increase in general and administrative expense is primarily due to professional fees of $0.5 million related to the acquisition of SEMCO.

Amortization expense was $0.8 million in second quarter 2012, same as second quarter 2011.

Six Months Ended June 30

The operating loss excluding the impact of mark-to-market accounting on risk management contracts for the six months ended June 30, 2012 was $16.4 million compared to $21.6 million for the same period in 2011. The decrease in loss was due to $0.3 million of unrealized pre-tax gain on equity investments in first half 2012 compared to an unrealized pre-tax loss of $6.6 million in same period 2011. This was partially offset by higher general and administrative costs primarily due to transaction costs.

Net revenue was $25.3 million for the six months ended June 30, 2012 compared to net revenue in a deficit position of $22.1 million for the same period in 2011. The increase was primarily due to changes in unrealized pre-tax gains versus losses on risk management contracts of $40.3 million, as well as an unrealized pre-tax gain of $0.3 million on an equity investment compared to an unrealized pre-tax loss of $6.6 million in same period last year.

Operating and administrative expense was $15.1 million for the six months ended June 30, 2012 compared to $13.2 million for the same period 2011. The increase in general and administrative expense is primarily due to professional fees of $1.8 million related to acquisitions.

Amortization expense was $1.7 million for the six months ended June 30, 2012 and 2011.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2012 in the Corporate segment is expected to be higher than the loss reported in 2011 primarily due to $7.5 million of transaction costs related to the acquisition of SEMCO and higher general and administrative costs related to the Corporation’s growth, partially offset by lower costs in 2012 compared to 2011 related to the transition to US GAAP.

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

INVESTED CAPITAL

During second quarter 2012, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $198.2 million compared to $154.5 million in second quarter 2011. The net invested capital was $198.2 million in second quarter 2012 compared to $154.4 million in same quarter 2011.

Invested Capital - Investment Type — **Three Months Ended June 30, 2012**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**110.1**	**77.6**	**11.5**	**0.6**	**199.8**
Intangible assets	**0.2**	**-**	**0.8**	**0.1**	**1.1**
Long-term investments and other assets	**-**	**-**	**-**	**(2.7)**	**(2.7)**
	110.3	**77.6**	**12.3**	**(2.0)**	**198.2**
Disposals:					
Property, plant and equipment	**-**	**-**	**-**	**-**	**-**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**110.3**	**77.6**	**12.3**	**(2.0)**	**198.2**

Invested Capital - Investment Type — Three Months Ended June 30, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	40.7	21.4	3.5	3.4	69.0
Intangible assets	4.3	87.3	0.6	0.1	92.3
Long-term investments and other assets	-	(0.1)	-	(6.7)	(6.8)
	45.0	108.6	4.1	(3.2)	154.5
Disposals:					
Property, plant and equipment	-	-	-	(0.1)	(0.1)
Long-term investments and other assets	-	-	-	-	-
Net Invested capital	45.0	108.6	4.1	(3.3)	154.4

During first half 2012, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $399.8 million compared to $209.8 million in same period 2011. During first half 2012, AltaGas terminated a capital lease reducing property, plant and equipment balance by $13.8 million. The net invested capital was $386.0 million in first half 2012 compared to $181.4 million in same period 2011.

Invested Capital - Investment Type — **Six Months Ended June 30, 2012**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**194.4**	**149.5**	**16.4**	**0.7**	**361.0**
Intangible assets	**1.1**	**-**	**1.0**	**0.1**	**2.2**
Long-term investments and other assets	**-**	**35.9**	**0.1**	**0.6**	**36.6**
	195.5	**185.4**	**17.5**	**1.4**	**399.8**
Disposals:					
Property, plant and equipment	**-**	**(13.8)**	**-**	**-**	**(13.8)**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**195.5**	**171.6**	**17.5**	**1.4**	**386.0**

Invested Capital - Investment Type

Six Months Ended June 30, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	65.7	50.6	7.1	5.2	128.6
Intangible assets	5.0	87.3	1.7	0.1	94.1
Long-term investments and other assets	0.6	(0.3)	-	(13.2)	(12.9)
	71.3	137.6	8.8	(7.9)	209.8
Disposals:					
Property, plant and equipment	(28.0)	-	-	(0.1)	(28.1)
Long-term investments and other assets	-	-	-	(0.3)	(0.3)
Net Invested capital	43.3	137.6	8.8	(8.3)	181.4

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

Growth capital expenditures of $194.7 million was reported in second quarter 2012 (second quarter 2011 - $149.8 million). In the Gas business, growth capital comprised $48.6 million for construction of Gordondale, $29.9 million for the Blair Creek expansion, $23.4 million for construction of the Co-stream Project and $6.7 million for various Gas related projects. Within the Power business, growth capital included $65.5 million for the Forrest Kerr Project, $4.5 million for the Harmattan Cogeneration project and $6.4 million for various renewable power development projects. The Utility business reported growth capital of $12.3 million. The Corporate segment reported a decrease in capital of $2.6 million related to the change in fair value of AltaGas' investment in Alterra.

Maintenance and administrative capital expenditures in second quarter 2012 were $2.1 million and $1.4 million, respectively (second quarter 2011 - $0.9 million and $3.8 million, respectively).

Invested Capital - Use

Three Months Ended June 30, 2012

($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Maintenance	**0.9**	**1.2**	**-**	**-**	**2.1**
Growth	**108.6**	**76.4**	**12.3**	**(2.6)**	**194.7**
Administrative	**0.8**	**-**	**-**	**0.6**	**1.4**
Invested capital	**110.3**	**77.6**	**12.3**	**(2.0)**	**198.2**

Invested Capital - Use

Three Months Ended June 30, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	0.8	0.1	-	-	0.9
Growth	43.9	108.5	4.1	(6.7)	149.8
Administrative	0.3	-	-	3.5	3.8
Invested capital	45.0	108.6	4.1	(3.2)	154.5

Growth capital expenditures of $394.6 million was reported in first half 2012 (first half 2011 - $203.3 million). In the Gas business, growth capital comprised $84.7 million for construction of Gordondale, $41.2 million for the Blair Creek expansion, $51.5 million for construction of the Co-stream Project and $14.8 million for various Gas related projects. Within the Power business, growth capital included $114.6 million for the Forrest Kerr Project, $34.7 million for the acquisition of Decker Energy International Inc. (DEI), $12.1 million for the buyout of a capital lease, $7.9 million for the

Harmattan Cogeneration project, $3.3 million for the Crowsnest Pass project and $11.6 million for various renewable power development projects. The Utility business reported growth capital of $17.5 million. The Corporate segment reported an increase in capital of $0.7 million related to the change in fair value of AltaGas' investment in Alterra.

Maintenance and administrative capital expenditures in first half 2012 were $3.3 million and $1.9 million, respectively (first half 2011 - $1.8 million and $4.7 million, respectively).

Invested Capital - Use — **Six Months Ended June 30, 2012**

($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Maintenance	**2.1**	**1.2**	**-**	**-**	**3.3**
Growth	**192.2**	**184.2**	**17.5**	**0.7**	**394.6**
Administrative	**1.2**	**-**	**-**	**0.7**	**1.9**
Invested capital	**195.5**	**185.4**	**17.5**	**1.4**	**399.8**

Invested Capital - Use — Six Months Ended June 30, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	1.7	0.1	-	-	1.8
Growth	69.0	137.5	8.8	(12.0)	203.3
Administrative	0.6	-	-	4.1	4.7
Invested capital	71.3	137.6	8.8	(7.9)	209.8

FINANCIAL INSTRUMENTS

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During second quarter 2012, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 8:

- 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 energy services division transacts primarily on this basis. PNG has historically hedged exposures to fluctuations in natural gas prices through the use of derivative financial instruments, in accordance with its annual gas contracting and gas supply price risk management plan. PNG has not entered into any new hedging arrangements since February 2011 and the existing hedges will expire by October 2012. These estimated fair market values have no impact on earnings due to the regulated nature of PNG’s operations. Based on the current regulatory process, unrealized gains or losses arising from PNG related financial instruments are treated as part of the cost of gas and are recovered from its customers.
- Commodity swap contracts:

  Power hedges: AltaGas executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power business results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0.00/MWh to $902.99/MWh in second quarter 2012 and $0.00/MWh to $999.99/MWh in second quarter 2011. The average Alberta spot price was $40.03/MWh in second quarter 2012 (second quarter 2011 - $52.12/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 $58.54/MWh in second quarter 2012 (second quarter 2011 - $64.26/MWh). For the third and fourth quarter 2012, AltaGas has hedged approximately 60 percent of volumes exposed to Alberta power price at an average price of $68/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 2012, the Corporation had NGL frac spread hedges for an average of 4,475 Bbls/d at an average price of approximately $35/Bbl before deducting extraction premiums. The average indicative spot NGL frac spread before deducting extraction premiums for second quarter 2012 was approximately $34/Bbl (second quarter 2011 – $48/Bbl). The average NGL frac spread realized by AltaGas in second quarter 2012 was $27.64/Bbl after deducting extraction premiums (second quarter 2011 - $36.65/Bbl). The Corporation has hedged an average of 4,475 Bbls/d, or approximately 80 percent of volumes that are exposed to spot prices for the remainder of 2012, at an average price of $35/Bbl before deducting extraction premiums. For 2013, AltaGas has hedged approximately one-third of its volumes that are exposed to frac spread at an average price of $35/Bbl.

- 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. At June 30, 2012, the Corporation had no interest rate swaps outstanding. At June 30, 2012, the Corporation had fixed the interest rate on 90 percent of its debt including medium-term notes (MTNs) (December 2011 - 96 percent).
- Foreign exchange forward contracts: Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold. In second quarter 2012, AltaGas entered in a back-to-back swap transaction for a notional amount of $192.5 million maturing between August 15 and August 30, 2012.

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.

LIQUIDITY

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

On June 6, 2012, AltaGas issued 8,000,000 five-year rate reset preferred shares, Series C (the Series C Preferred Shares), at a price of US$25 per Series C Preferred Share, for aggregate gross proceeds of US$200 million.

On May 25, 2012, PNG’s $25 million bank operating facility was amended and extended with a new maturity date of November 22, 2013.

On April 13, 2012, AltaGas issued $200 million of senior unsecured medium-term notes. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020.

Cash Flows	Three Months Ended		Six Months Ended	
		June 30		June 30
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Cash from operations	**41.7**	50.5	**137.3**	86.5
Investing activities	**(185.5)**	(76.2)	**(429.5)**	(124.6)
Financing activities	**145.1**	(74.2)	**291.7**	47.0
Change in cash	**1.3**	(99.9)	**(0.5)**	8.9

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $41.7 million in second quarter 2012 compared to $50.5 million in second quarter 2011. The decrease in cash from operations was primarily as a result of lower funds from operations and lower net change in non-cash working capital in the quarter as compared to second quarter 2011.

Working Capital		As at June 30
($ millions except current ratio)	**2012**	2011 (restated)
Current assets	**290.5**	275.9
Current liabilities	**351.9**	378.0
Working capital	**(61.4)**	(102.1)
Current ratio	**0.83**	0.73

Working capital was in a deficit position of $61.4 million as at June 30, 2012, compared to a deficit position of $102.1 million as at June 30, 2011. The working capital ratio was 0.83 at the end of second quarter 2012 compared to 0.73 at the end of same quarter 2011. The working capital ratio increased due to an increase in inventory and risk management assets and a decrease in current portion of long-term debt. This was partially offset by a decrease in regulatory assets and accounts receivable and an increase in accounts payable.

Investing Activities

Cash used for investing activities in second quarter 2012 was $185.5 million compared to $76.2 million in second quarter 2011. Investing activities in second quarter 2012 primarily comprised of $181.3 million property, plant and equipment expenditures, $2.0 million of investment in regulatory assets and $1.0 million of long-term investment acquisitions, compared to $85.5 million of property, plant and equipment expenditures and $13.4 million of proceeds received from disposition of property, plant and equipment in second quarter 2011.

Financing Activities

Cash received from financing activities was $145.1 million in second quarter 2012 compared to $74.2 million of cash used in financing activities in second quarter 2011. Financing activities in second quarter 2012 primarily comprised the issuance of $199.4 million and repayment of $200.0 million MTNs compared to the repayments of $0.1 million in second quarter 2011. Dividends paid in second quarter 2012 were $34.1 million, net proceeds from issuance of common shares and preferred shares were, $11.2 million and $199.3 million respectively, compared to $29.9 million of dividends paid and $7.8 million of net proceeds from issuance of common shares in second quarter 2011.

CAPITAL RESOURCES

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. As at June 30, 2012, AltaGas had total debt outstanding of $1,496.6 million, up from $1,337.1 million at December 31, 2011. As at June 30, 2012, AltaGas had $1,275 million in MTNs outstanding and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances, and letters of credit through bank credit facilities of $1,431 million. As at June 30, 2012, AltaGas had drawn bank debt of $132.0

million and letters of credit outstanding of $177.6 million against the syndicated credit facilities, the extendible revolving letter of credit facility, the bilateral letter of credit facility, the term revolver, and the demand from operating facilities. As at June 30, 2012, the Corporation had $1,121.4 million in available credit facilities and $2.4 million in cash and cash equivalents. On June 6, 2012, AltaGas issued US$200 million of preferred shares. On April 13, 2012, AltaGas issued $200 million of senior unsecured MTNs. The net proceeds from these offerings were used to repay outstanding indebtedness under its credit facilities.

On December 7, 2011, a new $2 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.

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

The US$1.135 billion acquisition of SEMCO expected to close on August 30, 2012 includes approximately US$355 million in assumed debt. The transaction will be funded through the net proceeds of the subscription receipts offering, together with funds to be advanced pursuant to some combination of the existing credit facilities, the new credit facility, and the proceeds of future debt financings, as determined by AltaGas.

On February 22, 2012, AltaGas closed approximately $403.0 million in gross proceeds held in trust in connection with a subscription receipts offering for total consideration of 13,915,000 common shares. The subscription receipts offering represents the holder's right to receive one common share of the issuer contingent upon acquisition close. The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of SEMCO and fulfillment or waiver of all other outstanding conditions precedent to closing the acquisition.

As at June 30, 2012, AltaGas' current portion of long-term debt was $11.2 million (June 30, 2011 - $106.0 million).

AltaGas' earnings interest coverage for the rolling 12 months ended June 30, 2012 was 2.87 times.

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 accumulated other comprehensive income), 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. AltaGas' debt-to-total capitalization ratio as at June 30, 2012, was 48.5 percent (December 31, 2011 - 49.6 percent).

		June 30 2012		December 31 2011 (restated)
Debt				
Short-term debt	$	**13,421**	$	16,824
Current portion of long-term debt		**11,163**		105,962
Long-term debt		**1,472,023**		1,214,298
Less cash and cash equivalent		**(2,380)**		(2,875)
		1,494,227		1,334,209
Shareholders' equity		**1,587,421**		1,355,362
Total capitalization	$	**3,081,648**	$	2,689,571
Debt-to-total capitalization ratio (%)		**48.5**		49.6

The following table summarizes the Corporation's debt covenants for all credit facilities as at June 30, 2012:

Ratios	Debt covenant requirements
Debt-to-capitalization	not greater than 60 percent
EBITDA-to-interest expense	not less than 2.5x
Debt-to-capitalization (Utility Group)	not greater than 67.5 percent
Debt-to-capitalization (PNG)	not greater than 65 percent

Credit facilities ($ millions)	Borrowing capacity	**Drawn at June 30 2012**	Drawn at December 31 2011
Demand operating facilities	71.0	**10.2**	3.4
Extendible revolving letter of credit facility	75.0	**51.9**	67.7
PNG operating facility	25.0	**7.2**	13.9
PNG term revolver	35.0	**20.0**	20.0
Bilateral letter of credit facility	125.0	**119.3**	124.3
AltaGas Ltd. revolving credit facility (1)	600.0	**39.5**	8.0
Utility Group revolving credit facility (2)	200.0	**61.4**	30.4
USD credit facility (3)	300.0	**-**	-
	1,431.0	**309.5**	267.7

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

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

(3) USD unsecured credit facility maturing March 2, 2013 (assumed at par).

As at June 30, 2012, AltaGas held in aggregate $71.0 million (December 31, 2011 - $71.0 million) in demand operating and demand letter of credit facilities. As at June 30, 2012, AltaGas had draws and letters of credit of $10.2 million (December 31, 2011 - $3.4 million) outstanding against these demand facilities.

As at June 30, 2012, AltaGas held a $75.0 million (December 31, 2011 - $75.0 million) unsecured four-year extendible revolving letter of credit facility with two Canadian chartered banks maturing on May 30, 2016. AltaGas may also borrow by way of prime loans, US base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. As at June 30, 2012, AltaGas had letters of credit of $51.9 million (December 31, 2011 - $67.7 million) outstanding against the extendible revolving letter of credit facility.

As at June 30, 2012, AltaGas held a $25.0 million bank operating facility which is available for PNG's working capital purposes and expires on November 22, 2013. The operating facility was acquired through the acquisition of PNG. Draws and letters of credit outstanding as at June 30, 2012 were $7.2 million (December 31, 2011 - $13.9 million).

As at June 30, 2012, AltaGas held a $35.0 million term revolver which was acquired through the acquisition of PNG. Draws outstanding as at June 30, 2012 were $20.0 million (December 31, 2011 - $20.0 million).

As at June 30, 2012, AltaGas held a $125.0 million unsecured bilateral letter of credit facility. Borrowings on the facility bear fees and interest rates relevant to the nature of the draws made. As at June 30, 2012, AltaGas had $119.3 million (December 31, 2011 - $124.3 million) letters of credit outstanding under the bilateral facility.

AltaGas has a $600 million, four-year revolving credit facility maturing on May 30, 2016. Borrowings on the facility can be by way of prime loans, US base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. As at June 30, 2012, AltaGas had $39.5 million (December 31, 2011 - $8.0 million) of debt outstanding under the syndicated facility.

The Utility Group has a $200 million, four-year revolving credit facility maturing on November 17, 2015. Borrowings on the facility can be by way of prime loans, US base rate loans, letters of credit, LIBOR loans or bankers' acceptance equivalent loans. At June 30, 2012, AltaGas had $61.4 million (December 31, 2011 - $30.4 million) of debt outstanding under the facility.

AltaGas has a US$300 million, unsecured credit facility maturing on March 2, 2013. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptance equivalent loans. At June 30, 2012, AltaGas had $Nil outstanding under the facility.

RELATED PARTIES

AltaGas and one of its managers agreed on a loan in the principal amount of $750 thousand, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2015 (second quarter 2011 - $750 thousand).

SHARE INFORMATION

As at June 30, 2012, AltaGas had 89.8 million common shares, 8.0 million series A preferred shares and 8.0 million series C USD preferred shares outstanding with a combined market capitalization of $3.0 billion based on a closing trading price on June 30, 2012, of $28.95 per common share, $25.56 per series A preferred share and $24.39 per series C USD preferred share. As at June 30, 2012, there were 5.4 million options outstanding and 2.0 million options exercisable under the terms of the share option plan.

DIVIDENDS

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

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

The following table summarizes AltaGas' dividend declaration history:

Dividends Years ended December 31 ($ per common share)	**2012**	2011
First quarter	**0.345**	0.33
Second quarter	**0.345**	0.33
Third quarter	**-**	0.33
Fourth quarter	**-**	0.34
Total	**0.690**	1.330

Preferred Share Dividends Years ended December 31 ($ per preferred share)	**2012**	2011
First quarter	**0.3125**	0.3125
Second quarter	**0.3125**	0.3125
Third quarter	**-**	0.3125
Fourth quarter	**-**	0.3125
Total	**0.6250**	1.2500

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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

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

In light of discussions of the IASB's future agenda, in May 2012 the AcSB amended the introduction to Part 1 of the Handbook extending the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by one year to January 1, 2013.

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

Pursuant to 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 on July 4, 2011, exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

SIGNIFICANT ACCOUNTING POLICIES

Except as otherwise disclosed, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP financial statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP 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 amortization expense, asset retirement obligations, asset impairment assessment, income taxes, pension and rate-regulated assets and liabilities. For a full discussion of these accounting estimates, refer to the MD&A in AltaGas' 2011 Financial Report and the notes to the interim Consolidated Financial Statements for the six months ended June 30, 2012.

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 DC&P 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, DC&P 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 US GAAP.

During second quarter 2012, 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)	**Q2-12**	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10
Total revenue	**271.7**	376.5	399.8	339.2	322.8	384.5	362.2	297.4
Net revenue(2)	**144.9**	167.4	156.9	116.5	107.2	136.1	130.8	102.6
Operating income(2)	**29.4**	69.6	49.2	33.5	34.2	58.3	47.6	32.6
Net income before taxes	**37.9**	57.8	44.6	18.0	11.8	38.5	35.4	10.3
Net income applicable to common shares(3)	**25.8**	41.3	31.7	11.1	13.3	26.7	26.5	6.0

($ per share)	**Q2-12**	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11	Q4-10	Q3-10
Net income applicable to common shares								
Basic(3)	**0.29**	0.46	0.38	0.13	0.16	0.32	0.32	0.07
Diluted(3)	**0.28**	0.46	0.37	0.13	0.16	0.32	0.32	0.07
Distributions / dividends declared	**0.345**	0.345	0.34	0.33	0.33	0.33	0.33	0.33

(1) *Restated to comply with US GAAP from Q1-11.*

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

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

Significant items that impacted individual quarterly earnings were as follows:

- On July 1, 2010, AltaGas converted from an income trust to a corporation resulting in AltaGas being taxable as a corporation;
- In third quarter 2010, AltaGas reported $21.1 million lower revenue as a result of mark-to-market accounting;
- In fourth quarter 2010, AltaGas completed the construction of a 15 MW gas-fired cogeneration facility at Harmattan;
- In first quarter 2011, AltaGas accepted an offer from a producer to sell the Groundbirch facility, resulting in a pre-tax gain of approximately $6.2 million;
- Results in first quarter 2011 were impacted by a settlement of a take-or-pay arrangement resulting in early recognition of pre-tax earnings of $2 million;
- In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflected the substantively enacted tax rates anticipated to be in effect in the periods in which the differences between tax and book values are expected to reverse. This resulted in a decrease of future tax liabilities of $6.8 million;
- In the third and fourth quarters 2011, turnarounds at Harmattan and Younger reduced revenue and increased operating expenses resulting in lower operating income of approximately $12 million before taxes. These turnarounds have occurred every three years;
- In fourth quarter 2011, AltaGas acquired all the outstanding common shares of PNG for $224 million including assumed debt of approximately $86 million. In the quarter, AltaGas recorded $5.7 million in pre-tax transaction costs primarily related to the acquisition of PNG and other business development related activities; and
- In second quarter 2012, AltaGas reported $22.3 million of revenue as a result of mark-to-market accounting.

Consolidated Balance Sheets

(unaudited)

($ thousands)	June 30 2012	December 31 2011 (restated)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 2,380**	$ 2,875
Accounts receivable	**181,248**	234,534
Inventory *(note 4)*	**13,633**	12,467
Restricted cash holdings from customers	**26,530**	19,672
Regulatory assets	**949**	5,141
Risk management assets *(note 8)*	**58,416**	68,404
Prepaid expense and other current assets	**7,346**	8,642
	290,502	351,735
Property, plant and equipment	**2,784,147**	2,486,050
Intangible assets	**195,811**	177,516
Goodwill *(note 5)*	**281,123**	281,123
Regulatory assets	**123,411**	125,271
Risk management assets *(note 8)*	**20,797**	21,642
Long-term investments and other assets *(note 8)*	**29,119**	25,406
Investments accounted for by equity method	**119,915**	87,483
	$ 3,844,825	$ 3,556,226
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 7)*	**$ 230,883**	$ 314,422
Dividends payable	**10,379**	10,264
Short-term debt	**13,421**	16,824
Current portion of long-term debt *(note 6)*	**11,163**	105,962
Customer deposits	**32,007**	25,570
Regulatory liabilities	**1,472**	503
Risk management liabilities *(note 8)*	**44,649**	72,973
Other current liabilities	**7,934**	11,352
	351,908	557,870
Long-term debt *(note 6)*	**1,472,023**	1,214,298
Asset retirement obligations	**45,477**	44,318
Deferred income taxes	**278,452**	265,834
Regulatory liabilities	**23,861**	26,686
Risk management liabilities *(note 8)*	**13,266**	20,608
Other long-term liabilities *(note 7)*	**28,800**	28,810
Future employee obligations	**35,407**	37,014
	2,249,194	2,195,438

($ thousands)	**June 30 2012**	December 31 2011 (restated)
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 90.25 million issued and outstanding *(note 9)*	**1,229,647**	1,204,269
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 9)*	**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 9)*	**199,334**	-
Contributed surplus	**8,753**	7,441
Accumulated deficit	**(33,560)**	(38,635)
Accumulated other comprehensive loss	**(10,879)**	(11,839)
Total shareholders' equity	**1,587,421**	1,355,362
Non-controlling interests	**8,210**	5,426
	$ 3,844,825	$ 3,556,226

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(unaudited)

($ thousands except per share amounts)	Three Months Ended **June 30 2012**	Three Months Ended June 30 2011 (restated)	Six Months Ended **June 30 2012**	Six Months Ended June 30 2011 (restated)
REVENUE				
Operating	**$ 249,447**	$ 340,741	**$ 610,848**	$ 709,112
Unrealized gain (loss) on risk management contracts *(note 8)*	**23,643**	(8,621)	**24,800**	(15,524)
Other (expenses) revenue	**(1,298)**	(3,430)	**515**	(6,531)
Income (loss) from equity investments	**(80)**	(5,884)	**12,065**	20,235
	271,712	322,806	**648,228**	707,292
EXPENSES				
Cost of sales	**126,752**	215,625	**335,808**	463,881
Operating and administrative	**69,772**	60,955	**143,500**	125,124
Accretion of asset retirement obligations	**768**	608	**1,583**	1,216
Depreciation, depletion and amortization	**21,436**	20,006	**43,626**	40,059
	218,728	297,194	**524,517**	630,280
Foreign exchange loss	**2,015**	49	**2,149**	12
Interest expense				
Short-term debt	**448**	1,484	**905**	2,912
Long-term debt	**12,617**	12,230	**24,922**	23,706
Income before income taxes	**37,904**	11,849	**95,735**	50,382
Income tax expense (recovery)				
Current	**806**	1,094	**3,970**	3,213
Deferred	**7,881**	(5,043)	**18,477**	2,161
Net income after taxes	**29,217**	15,798	**73,288**	45,008
Net income applicable to non-controlling interests	**337**	-	**637**	-
Net income applicable to the controlling interests	**28,880**	15,798	**72,651**	45,008
Preferred share dividends	**3,090**	2,500	**5,590**	5,000
Net income applicable to common shares	**$ 25,790**	$ 13,298	**$ 67,061**	$ 40,008
Net income per common share (note 10)				
Basic	**$ 0.29**	$ 0.16	**$ 0.75**	$ 0.48
Diluted	**$ 0.28**	$ 0.16	**$ 0.74**	$ 0.48
Weighted average number of common shares outstanding (notes 9 and 10) *($ thousands)*				
Basic	**90,049**	83,171	**89,770**	82,963
Diluted	**91,225**	84,239	**91,060**	83,925

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive (Loss) Income

(unaudited)

($ thousands)	Three Months Ended **June 30 2012**	Three Months Ended June 30 2011 (restated)	Six Months Ended **June 30 2012**	Six Months Ended June 30 2011 (restated)
Net income after taxes	**$ 29,217**	$ 15,798	**$ 73,288**	$ 45,008
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	**39**	(2)	**79**	(2)
Defined benefit plans - Unamortized transition amount, (net of tax)	**15**	-	**28**	-
Effective portion of gains on derivative instruments that qualifies as cash flow hedge (net of tax)	**964**	421	**573**	831
Unrealized income (loss) on available-for-sale financial assets (net of tax)	**(1,120)**	(3,063)	**280**	(5,229)
	(102)	(2,644)	**960**	(4,400)
Comprehensive income	**$ 29,115**	$ 13,154	**$ 74,248**	$ 40,608
Accumulated other comprehensive loss, beginning of period	**$ (10,777)**	$ (5,486)	**$ (11,839)**	$ (3,730)
Other comprehensive income (loss), net of tax	**(102)**	(2,644)	**960**	(4,400)
Accumulated other comprehensive loss, end of period	**$ (10,879)**	$ (8,130)	**$ (10,879)**	$ (8,130)

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(unaudited)

($ thousands)		June 30 2012	Six Months Ended June 30 2011 (restated)
Common shares *(note 9)*			
Balance, beginning of period	$	**1,204,269**	1,023,033
Shares issued for cash on exercise of options		**8,166**	2,497
Shares issued under DRIP [1]		**17,212**	16,813
Balance, end of period		**1,229,647**	1,042,343
Preferred shares *(note 9)*			
Balance, beginning of period		**194,126**	194,126
Series C issued		**199,334**	-
Balance, end of period		**393,460**	194,126
Contributed surplus			
Balance, beginning of period		**7,441**	5,672
Amortization of share options		**1,775**	869
Exercise of share options		**(316)**	(1,202)
Forfeitures of share options		**(147)**	(147)
Balance, end of period		**8,753**	5,192
Accumulated deficit			
Balance, beginning of period		**(38,635)**	(9,210)
Net income applicable to the controlling interests		**72,651**	45,008
Common share dividends		**(61,986)**	(54,797)
Preferred share dividends - Series A		**(5,000)**	(5,000)
Preferred share dividends - Series C		**(590)**	-
Balance, end of period		**(33,560)**	(23,999)
Accumulated other comprehensive loss			
Balance, beginning of period		**(11,839)**	(3,730)
Other comprehensive income (loss)		**960**	(4,400)
Balance, end of period		**(10,879)**	(8,130)
Total shareholders' equity		**1,587,421**	1,209,532
Non-controlling interests			
Balance, beginning of period		**5,426**	-
Net income applicable to non-controlling interests		**637**	-
Business acquisition *(note 3)*		**7,939**	-
Redemption of non-controlling interests		**(5,205)**	-
Distribution by subsidiaries to non-controlling interests		**(587)**	-
Balance, end of period		**8,210**	-
Total equity		**1,595,631**	1,209,532

[1] *Dividend Reinvestment and Optional Share Purchase Plan.*

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(unaudited)

($ thousands)	Three Months Ended June 30 2012	Three Months Ended June 30 2011 (restated)	Six Months Ended June 30 2012	Six Months Ended June 30 2011 (restated)
Cash from operations				
Net income after taxes	**$ 29,217**	$ 15,798	**73,288**	45,008
Items not involving cash:				
Depreciation, depletion and amortization	**21,436**	20,006	**43,626**	40,059
Accretion of asset retirement obligations	**768**	608	**1,583**	1,216
Share-based compensation	**748**	(350)	**1,313**	(481)
Deferred income tax expense	**7,881**	(5,043)	**18,477**	2,161
Gain on sale of assets	**-**	-	**-**	(6,172)
(Income) loss from equity investments	**80**	5,884	**(12,065)**	(20,235)
Unrealized (gains) losses on risk management contracts	**(23,643)**	8,621	**(24,800)**	15,524
Unrealized (gains) losses on held-for-trading investments	**1,381**	3,798	**(345)**	6,560
Other	**(919)**	636	**1,760**	1,615
Asset retirement obligations settled	**(67)**	(61)	**(516)**	(195)
Distributions from equity investments	**3,181**	1,721	**11,402**	29,219
Contributions to equity investments	**(266)**	(5,142)	**(433)**	(6,342)
Changes in components of working capitals				
Accounts receivable	**33,219**	(2,286)	**53,286**	9,936
Inventory	**(2,460)**	8,345	**(1,165)**	11,585
Other current assets	**(177)**	(2,472)	**1,297**	(1,893)
Regulatory assets (current)	**1,819**	1,122	**4,192**	(296)
Accounts payable and accrued liabilities	**(26,839)**	22,866	**(83,541)**	(31,170)
Dividends payable	**54**	48	**115**	95
Customer deposits	**256**	3,487	**6,437**	1,572
Regulatory liabilities (current)	**(1,295)**	698	**970**	726
Other current liabilities	**1,841**	(488)	**(3,418)**	(5,605)
Changes in accounts payable and accrued liabilities related to property, plant and equipment and intangible assets	**(14,383)**	(21,446)	**37,423**	(3,922)
Increase / decrease in other non-cash working capital	**9,823**	(5,824)	**8,413**	(2,476)
	41,655	50,526	**137,299**	86,489
Investing activities				
Change in restricted cash holdings from customers	**(522)**	(3,541)	**(6,859)**	(1,792)
Acquisition of property, plant, and equipment	**(181,366)**	(85,485)	**(384,258)**	(131,669)
Acquisition of intangible assets	**(15)**	(38)	**(15)**	(5,148)
Investment in regulatory assets	**(2,044)**	(572)	**960**	578
Disposition of property, plant, and equipment	**-**	13,400	**-**	13,400
Acquisition of long-term investments	**(1,000)**	-	**(4,000)**	-
Business acquisitions, net of cash acquired	**-**	-	**(34,705)**	-
Distribution to non-controlling interest	**(587)**	-	**(587)**	-
	(185,534)	(76,236)	**(429,464)**	(124,631)

($ thousands)	Three Months Ended June 30 2012	June 30 2011 (restated)	Six Months Ended June 30 2012	June 30 2011 (restated)
Financing activities				
Net repayment of short-term debt	**(2,688)**	(51,252)	**(1,973)**	(110,745)
Issuance of long-term debt	**199,410**	-	**467,296**	198,038
Repayment of long-term debt	**(228,074)**	(850)	**(330,852)**	-
Dividends - common shares	**(31,025)**	(27,373)	**(61,925)**	(54,702)
Dividends - preferred shares	**(3,090)**	(2,500)	**(5,590)**	(5,000)
Net proceeds from issuance of common shares	**11,204**	7,784	**25,380**	19,425
Net proceeds from issuance of preferred shares	**199,334**	-	**199,334**	-
	145,071	(74,191)	**291,670**	47,016
Change in cash and cash equivalents	**1,192**	(99,901)	**(495)**	8,874
Cash and cash equivalents, beginning of period	**1,188**	109,798	**2,875**	1,023
Cash and cash equivalents, end of period	**$ 2,380**	$ 9,897	**2,380**	9,897

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

	Three Months Ended June 30 2012	2011	Six Months Ended June 30 2012	2011
Interest paid	**$ 9,674**	$ 13,027	**$ 24,730**	$ 21,200
Income taxes paid	**$ 1,694**	$ 106	**$ 6,764**	$ 2,750

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

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

1. ORGANIZATION AND OVERVIEW OF BUSINESS

On July 1, 2010 AltaGas Ltd. (AltaGas or the Corporation) completed its conversion from an income trust to a corporation pursuant to a plan of arrangement (the Arrangement) under the Canadian Business Corporations Act. The material businesses of AltaGas Ltd. are operated by the Corporation, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc., and AltaGas Utility Holdings (Pacific) Inc. (collectively the operating subsidiaries).

AltaGas is a diversified energy infrastructure business with focus on natural gas, power and regulated utilities. AltaGas has three operating businesses, Gas, Power and Utilities. AltaGas' Gas business serves producers in the Western Canada Sedimentary Basic (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing. The Gas business includes expansions at several gas processing facilities within liquids-rich development areas as well as construction of the Harmattan Co-stream (Co-stream Project) and the Gordondale Gas Processing Facility (Gordondale).

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

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

On February 1, 2012, AltaGas and AltaGas Utility Holdings (U.S.) LLC (AUH(US)) entered into an agreement with Continental Energy Systems LLC (Continental) and SEMCO Holding Corporation (SEMCO) pursuant to which AUH(US) agreed to acquire all of the issued and outstanding shares of SEMCO for aggregate consideration of US$1.135 billion, subject to adjustment, including approximately US$355 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy Inc. (SEMCO Energy), a privately held regulated public utility company headquartered in Port Huron, Michigan, with natural gas distribution operations in Alaska and Michigan. The closing of the acquisition is subject to receipt of required regulatory approvals and the satisfaction or waiver of certain closing conditions. During second quarter 2012, AltaGas received final approval from the Michigan Public Service Commission and completed a hearing with the Regulatory Commission of Alaska (RCA) for the SEMCO acquisition. The RCA approval process is progressing as expected and the acquisition of SEMCO is expected to close on August 30, 2012.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These unaudited interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (US GAAP). These unaudited interim Consolidated Financial Statements have been restated to give effect to the results of operations financial position and cash flows as if US GAAP had always been applied.

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 on July 4, 2011, exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AltaGas ceases to have activities subject to rate regulation.

These unaudited interim Consolidated Financial Statements of AltaGas Ltd. 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 including Younger, Sarnia Airport Storage Pool Limited (Sarnia Storage), Alton Natural Gas Storage (Alton), ASTC Power Partnership (ASTC), McNair Creek Hydro Limited Partnership, Inuvik Gas Ltd. (Inuvik Gas), Ikhil Joint Venture, Craven LP, LLC and Grayling Generating Station Limited Partnership. Transactions between AltaGas Ltd. and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation. 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 the "net income applicable to non-controlling interests".

These unaudited interim Consolidated Financial Statements do not contain all disclosures required by US GAAP for annual Consolidated Financial Statements. Note 18 to these unaudited interim Consolidated Financial Statements detail the Canadian GAAP to US GAAP transition and reconciliation information.

SIGNIFICANT ACCOUNTING POLICIES

Business Acquisitions

Business acquisitions are accounted for using the acquisition method. Under the acquisition method assets and liabilities of the acquired entity are recorded at fair value. Acquisition-related costs are expensed immediately. The excess of the consideration transferred over the fair value of the assets and liabilities acquired is recognized as goodwill.

Rate-Regulated Operations

AltaGas Utilities Inc. (AUI), Heritage Gas, Pacific Northern Gas Ltd. (PNG) and Inuvik Gas (collectively "Utilities") engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC), Nova Scotia Utility and Review Board (NSUARB), British Columbia Utilities Commission (BCUC) and the Northwest Territories Public Utilities Board (NWTPUB), respectively.

The AUC, NSUARB and BCUC exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the AUC, NSUARB and BCUC, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive commodity market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

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

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, balances with banks and investments in money market instruments with original maturities of less than three months.

Accounts Receivable

Accounts receivable does not bear interest. Receivables are recorded net of the allowance for doubtful accounts in the accompanying consolidated balance sheets. AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies, NGL and proprietary natural gas held in storage, which are valued at the lower of cost or net realizable value. Cost of inventory is assigned using a weighted average cost formula.

Restricted Cash Holdings from Customers

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by AltaGas and therefore they are separately presented as restricted cash holdings from customers in the consolidated balance sheet. Any corresponding liability is classified as customer deposits within current liabilities.

Cash deposited by customers under the terms of natural gas utility service rules is unrestricted and is available for general use by respective rate-regulated subsidiaries of AltaGas. As such these funds are included in cash and cash equivalents in the consolidated balance sheet. Any corresponding liability is classified as customer deposits within current liabilities.

Property, Plant and Equipment (PPE) and Depreciation

Property, plant and equipment are carried at cost. The Corporation continues to amortize the cost of capital assets, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of regulated utilities assets, where depreciation is calculated on a straight-line basis or over the contract term of a specific agreement at rates approved by the regulatory authorities.

The range of useful lives for AltaGas' property, plant and equipment is as follows:

Gas	
Extraction and transmission (E&T)	15 - 40 years
Field gathering and processing (FG&P)	15 - 36 years
Energy services	19 years
Natural Gas Storage	20 - 50 years
Other	1- 32 years
Power	
Power generation assets	20 - 30 years
Utilities	
Utilities assets	1 - 33 percent
Corporate	
Other assets	1 - 5 years

Leases are classified as either capital or operating. Leases that transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases.

Interest costs are capitalized on major additions (qualifying assets) to property, plant and equipment until the asset is ready for its intended use. A qualifying asset is an asset with a cost over a certain internally predetermined amount and requiring at least six months for its construction and the completion of all required activities for the asset to be ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on AltaGas' prior quarter actual borrowing interest rate, unless AltaGas borrowed funds specifically for the purpose of obtaining an asset. In this case, the interest costs to be capitalized are calculated using the actual interest rate applicable to the funds obtained for that asset.

Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction (AFUDC). AFUDC is the amount that a rate-regulated enterprise is allowed to recover for its cost of financing assets under construction. It is calculated as the mid-year cost of construction work-in-progress multiplied by the regulated percentage cost-of-capital. Capitalized overhead, administrative expenses and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers in future periods through depreciation charges.

As required by the respective regulatory authorities, net additions to utility assets at Heritage Gas are not depreciated until the year after they are brought into active service and net additions to utility assets at AUI are depreciated commencing in the year in which the assets are brought into active service. Currently by NSUARB order, depreciation has been suspended at Heritage Gas.

Intangible Assets

Energy arrangements, contracts and relationships are recorded at cost, and are amortized on a straight-line basis over their term or estimated useful life:

Energy services relationships	15-19 years
E&T contracts	10 - 20 years
Electricity service agreement	60 years
Software	28 - 120 months
Land rights	25 - 60 years
Franchises and consents	9 - 25 years

AltaGas owns 50 percent of two Sundance B Power Purchase Arrangements (PPAs) through its interest in the ASTC. ASTC is committed to purchasing all of the power from the two 353 MW capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses hereunder are accounted for using the equity method. Acquisition of the Sundance B PPAs required a capital outlay. AltaGas is obligated to make payments to the owners of the underlying generating units over the remaining term of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the power is recorded based on target generator availability. The capital outlay is included in the energy services relationships.

Energy services relationships are amortized on a straight-line basis over the 15-year expected useful life of the relationships.

The E&T contracts are amortized on a straight-line basis over the average expected life of the contracts.

The electricity service agreement relates to the 60-year CPI indexed electricity purchase agreement (EPA) for the Forrest Kerr Project which is expected to be operational in July 2014. Until commercial operation, the asset is not subject to amortization.

Goodwill

Goodwill represents that portion of the consideration transferred on acquisitions which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but tested at least annually for impairment, or more often when impairment indicators exist.

Impairment of Long-Lived Assets

If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset is not recoverable, as determined by the projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value less cost to sell.

Financial Instruments

AltaGas uses the settlement date for transactions to account for financial instruments. Any difference in value between the trade and settlement date for third-party transactions are recognized on the balance sheet and in net income or in OCI as appropriate.

All financial instruments, including derivatives, are recorded on the Consolidated Balance Sheet initially at fair value. The financial assets are classified as held-for-trading, held-to-maturity, loans and receivables, or available-for-sale. Financial liabilities are classified as held-for-trading or other financial liabilities. Subsequent measurement is determined by classification.

Held-for-trading financial assets and liabilities consist of swaps, options, forwards and equity investments. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value are recorded in net income. AltaGas does not have any held-to-maturity financial instruments. Loans and receivables are recognized at amortized cost using the effective interest method. The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially recorded at fair value and changes to fair value are recorded through other comprehensive income (OCI). Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in other revenue.

Other financial liabilities not classified as held-for-trading are recognized at amortized cost, using the effective interest method.

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

Hedges

As part of its risk management strategy, AltaGas uses derivatives to reduce its exposure to commodity price, interest rate and foreign exchange risk. AltaGas designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. AltaGas performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item.

The effective portion of changes in the fair value of cash flow hedges is recognized in OCI. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income. Gains or losses from cash flow hedges that have been included in accumulated other comprehensive income are included in net income when the underlying transaction has occurred or is likely not to occur.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for using the equity method. Other long-term investments are recorded at cost or designated as available-for-sale or held-for-trading. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost.

Investments Accounted for by Equity Method

AltaGas accounts for its investments in less than majority owned corporate joint ventures and affiliates (equity investments) under the equity method. AltaGas applies the equity method to the equity investments when it has the ability to exercise significant influence over the operating and financial policies of the joint venture and affiliate. Under this method, the assets and liabilities of the joint ventures and affiliates are not consolidated. The investments in net assets of the equity investments are recorded in the balance sheets under the caption “Investments accounted for by equity method”. The gain/(loss) from operations of the joint ventures and affiliates is reported on a net basis as equity in the income statement under the caption “Income (loss) from equity investments”.

Development Costs

AltaGas expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

AltaGas recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations. Certain utility assets will have future legal obligations on retirement but an asset retirement obligation has not been recorded due to their indeterminate life, and corresponding indeterminable timing and scope of these asset retirement obligations.

Revenue Recognition

In the Gas reporting segment, the extraction and transmission, field gathering and processing and energy services operations recognize revenue at the time the product or service is delivered.

The Power reporting segment recognizes revenue at the time the product or service is delivered.

The Utility reporting segment recognizes revenue when the product or service is delivered on the basis of regular meter readings or estimates of usage and is consistent with the underlying rate-setting mechanism mandated by the applicable regulatory authority.

Realized gains and losses from risk management activities related to commodity prices are recognized when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheet. Unrealized gains and losses in respect of fair value changes to AltaGas' risk management activities which do not meet the criteria as effective hedges are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate reporting segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred. For financial instruments classified as other than held-for-trading transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate, a shorter period, to the net carrying amount of the financial asset or liability.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the average exchange rate applicable to the period.

Share-Based Compensation Plans

AltaGas follows the fair value method of accounting for share options granted to certain employees, including officers. Share options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by AltaGas on exercise of the option rights is credited to shareholders' capital.

AltaGas uses the Black-Scholes model to determine the fair value of the options on their grant date and recognizes the share-based compensation cost over the vesting period.

AltaGas has a share-based compensation plan in which participants receive phantom shares requiring settlement in cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom shares is recognized in the period the change occurs.

Pension Plans and Post-Retirement Benefits

AltaGas recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheets.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost is the sum of the individual current service costs, and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 15.3 years and 13.2 years, respectively.

Unamortized actuarial gains (losses) and transitional obligations are initially recognized in the other comprehensive income (losses) and amortized on a straight-line basis over the average remaining service life of active employees for the respective plan through the income statement.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of tax accounting. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax bases of assets and liabilities and are measured using the enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.
The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future rates and recovered from or paid to customers in the future.

Net Income per Share

Basic and diluted net income applicable to common shares are computed respectively using the weighted average number of common shares and the weighted number of common shares that could potentially dilute during a reporting period (share-based compensation awards).

The potentially dilutive impact of the share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation.

The computation of the diluted net income applicable to common shares excludes the anti-dilutive shares. These anti-dilutive shares were due to certain share-based compensation awards calculated under the treasury stock method. This anti-dilution occurs where the exercise prices are higher than the average market value of AltaGas' stock-price during the applicable period.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. Cost is deemed to be the fair value as no active market currently exists for emission credits.

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, asset impairment, litigation, environmental and asset retirement obligations, financial instruments, pension plans and other post-retirement benefits, share-based compensation, income taxes 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.

CHANGE IN ACCOUNTING POLICIES

Balance Sheet Disclosures (Topic 210) about Offsetting Assets and Liabilities
In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. Accounting Standards Update (ASU) Number (No.) 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. AltaGas does not expect the implementation of this disclosure guidance to have a material impact on its financial statements.

Asset impairment - Intangibles Assets and Goodwill

Effective January 1, 2012, AltaGas has adopted ASU No. 2011-08, “Intangibles – Goodwill and Other”. This new approach is used when events or circumstances indicate that goodwill may be impaired. In line with this standard, AltaGas’ reporting segments will first assess qualitative factors to determine whether it is more likely than not that the assets’ fair value is less than the carrying amount, in which case it is necessary to perform the quantitative goodwill impairment test. The carrying amount of the reporting segment’s goodwill may not be recoverable if the carrying amount of the reporting segment as a whole exceeds the reporting segment’s fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value.

Comprehensive Income and Equity

In June 2011, FASB issued ASU No. 2011-05, "Other Comprehensive Income". This standard amends Accounting Standards Codification (ASC) 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The adoption of this update changes the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the financial statements. In December 2011, FASB issued ASU No. 2011-12 “Deferral of the Effective Date for Amendments to the Presentation of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05”. The amendments of this Update are effective January 1, 2012 as the amendments in ASU No. 2011-05, except for the presentation requirements for the reclassification adjustments out of accumulated other comprehensive income, which have been deferred by ASU No. 2011-12.

3. BUSINESS ACQUISITION

Decker Energy International Inc.

On November 23, 2011, AltaGas DEI Acquisition Inc. entered into an Agreement and Plan of Merger with Decker Energy International Inc. (DEI). Pursuant to this, AltaGas DEI Acquisition Inc. merged with DEI on January 26, 2012 to form DEI. At this time, DEI became an indirect wholly owned subsidiary of AltaGas. DEI is an independent power company whose primary assets are comprised of a 30 percent working interest in the 37 MW Grayling Generating Station in Michigan – a wood biomass power facility, and a 50 percent working interest in the 48 MW Craven County wood biomass power facility in North Carolina. Fuel supply for the biomass facilities include wood chips, mill residuals and other wood waste products from several suppliers. These assets are fully contracted with long-term Power Purchase Arrangements (PPAs).

AltaGas paid cash for an aggregate purchase price of $34.7 million. Transaction costs related to the acquisition cost amounted to $1.4 million and were expensed in the Consolidated Statement of Income.

4. INVENTORY

		June 30 2012		December 31 2011 (restated)
Natural gas held in storage		**11,313**		10,081
Inventory utilities		**1,533**		1,663
Inventory gas plants		**787**		723
	$	**13,633**	$	12,467

5. GOODWILL

		June 30 2012		December 31 2011 (restated)
Balance, beginning of period	**$**	**281,123**	$	222,602
Acquisition		**-**		58,595
US GAAP transitional adjustment *(note 18)*		**-**		(74)
Balance, as at June 30, 2012	**$**	**281,123**	$	281,123

6. LONG-TERM DEBT

	Maturity date	**June 30 2012**	December 31 2011 (restated)
Credit facilities			
$600 million Unsecured extendible revolving 4 years[(1) (2)]	30-May-2016	**39,467**	8,000
$200 million Utility Group[(2)]	17-Nov-2015	**61,390**	30,962
Medium-term notes			
$100 million Senior unsecured - 5.07 percent	19-Jan-2012	**-**	100,000
$200 million Senior unsecured - 7.42 percent	29-Apr-2014	**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 - 4.10 percent	24-Mar-2016	**200,000**	200,000
$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**	-
Debentures notes			
PNG 5 years revolver - 4.38 percent[(3)]	30-Jan-2015	**20,000**	20,000
PNG RoyNat Debenture - 3.72 percent[(3)]	15-Sep-2017	**12,800**	13,400
PNG 2018 Series Debenture - 8.75 percent[(3)]	15-Nov-2018	**12,200**	12,200
PNG 2025 Series Debenture - 9.30 percent[(3)]	18-Jul-2025	**16,000**	16,000
PNG 2027 Series Debenture - 6.90 percent[(3)]	02-Dec-2027	**17,000**	17,000
PNG 2024 CFI Debenture - 7.39 percent[(4)]	01-Nov-2024	**8,633**	8,775
Loan from Province of Nova Scotia[(5)]	31-Jul-2017	**4,949**	4,815
Capital lease obligations - 6.85 percent[(6)]	31-Aug-2014	**-**	4,567
Promissory notes	25-Oct-2015	**3,352**	3,839
Other long-term debt		**12,395**	5,702
		1,483,186	1,320,260
Less current portion		**11,163**	105,962
		$ 1,472,023	$1,214,298

(1) The credit facility contains a $200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of $800 million.

(2) 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.

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

(4) Collateral for the CFI Debenture consists of first fixed specific and floating charges and a security interest over all the assets and undertakings of McNair Creek and a first security interest over all the interests of PNG and its partner in partnership interests and shares in McNair Creek.

(5) 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.

(6) The lease was terminated during first quarter 2012 and the leased assets were acquired by AltaGas.

7. NORTHWEST TRANSMISSION LINE

In 2010, AltaGas entered into a 60-year Indexed EPA and other related agreements with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric project. As at June 30, 2012, AltaGas is obligated to pay approximately $69.3 million over the next twenty-seven months to BC Hydro in support of the construction and operation of the Northwest Transmission Line. $40.5 million of this amount is recorded in accounts payable and accrued liabilities and $28.8 million in other long-term liabilities.

8. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation purchases and sells natural gas, NGL and power and issues short and long-term debt. The Corporation uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates 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 interest rate and foreign exchange derivatives was calculated using quoted market rates.

The fair value of long-term debt has been estimated based on discounted future interest and principal payments using estimated interest rates.

The carrying amount and fair values of AltaGas' financial assets and liabilities were as follows:

Summary of Fair Values June 30, 2012	Held-for-trading	Cash flow hedges	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents[1]	$ 2,380	$ -	$ -	$ -	$ -	$ -	$ 2,380
Accounts receivable[1]	-	-	148,707	-	-	32,541	181,248
Restricted cash holdings from customers[1]	-	-	26,530	-	-	-	26,530
Risk management assets (current)	56,045	2,371	-	-	-	-	58,416
Prepaid expense and other current assets[1]	-	-	2,216	-	-	5,130	7,346
Risk management assets (non-current)	20,797	-	-	-	-	-	20,797
Long-term investments and other assets	3,884	-	-	3,610	-	21,625	29,119
	$ 83,106	$ 2,371	$ 177,453	$ 3,610	$ -	$ 59,296	$ 325,836
Financial liabilities							
Accounts payable and accrued liabilities[1]	$ -	$ -	$ -	$ -	$ 50,372	$ 180,511	$ 230,883
Dividends payable	-	-	-	-	10,379	-	10,379
Short-term debt[1]	-	-	-	-	13,421	-	13,421
Current portion of long-term debt[2]	-	-	-	-	11,163	-	11,163
Customer deposits[1]	-	-	-	-	32,007	-	32,007
Risk management liabilities (current)	43,463	1,186	-	-	-	-	44,649
Other current liabilities[1]	-	-	-	-	2,571	5,363	7,934
Long-term debt[3]	-	-	-	-	1,472,023	-	1,472,023
Risk management liabilities (non-current)	13,266	-	-	-	-	-	13,266
Other long-term liabilities	-	-	-	-	-	28,800	28,800
	$ 56,729	$ 1,186	$ -	$ -	$ 1,591,936	$ 214,674	$ 1,864,525

[1] Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.

[2] Fair value of current portion of long-term debt is approximately $11.2 million.

[3] Fair value of long-term debt excluding non-financial instruments is approximately $1,472.1 million.

Summary of Fair Values December 31, 2011 (restated)	Held-for-trading	Cash flow hedges	Loans and receivables	Available for sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents[1]	$ 2,875	$ -	$ -	$ -	$ -	$ -	$ 2,875
Accounts receivable[1]	-	-	226,527	-	-	8,007	234,534
Restricted cash holdings from customers[1]	-	-	19,672	-	-	-	19,672
Risk management assets (current)	48,073	20,331	-	-	-	-	68,404
Prepaid expense and other assets[1]	-	-	2,594	-	-	6,048	8,642
Risk management assets (non-current)	21,586	56	-	-	-	-	21,642
Long-term Investments and other assets (note 8)	3,539	-	-	3,290	-	18,577	25,406
	$ 76,073	$ 20,387	$ 248,793	$ 3,290	$ -	$ 32,632	$ 381,175
Financial liabilities							
Accounts payable and accrued liabilities[1]	$ -	$ -	$ -	$ -	$ 79,316	$ 235,106	$ 314,422
Dividends payable[1]	-	-	-	-	10,264	-	10,264
Short-term debt[1]	-	-	-	-	16,824	-	16,824
Current portion of long-term debt[2]	-	-	-	-	105,962	-	105,962
Customer deposits[1]	-	-	-	-	25,570	-	25,570
Risk management liabilities (current)	54,010	18,963	-	-	-	-	72,973
Other current liabilities[1]	-	-	-	-	1,716	9,636	11,352
Long-term debt[3]	-	-	-	-	1,214,298	-	1,214,298
Risk management liabilities (non-current)	20,250	358	-	-	-	-	20,608
Other long-term liabilities	-	-	-	-	10	28,800	28,810
	$ 74,260	$ 19,321	$ -	$ -	$ 1,453,960	$ 273,542	$ 1,821,083

[1] *Due to the nature and/or short maturity of these financial instruments the carrying amount approximates the fair value.*

[2] *Fair value of current portion of long-term debt is approximately $103.4 million.*

[3] *Fair value of long-term debt excluding non-financial instruments is approximately $1,255.6 million.*

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

	Three Months Ended June 30 2012	2011 (restated)	Six Months Ended June 30 2012	2011 (restated)
Natural gas	**$ (7,953)**	$ (5,669)	**$ (12,086)**	$ (4,256)
Storage optimization	**(1,448)**	245	**16**	(1,250)
NGL Frac Spread	**36,634**	3,122	**32,665**	(3,591)
Power	**(3,780)**	(5,666)	**4,972**	(6,114)
Heat rate	**171**	(502)	**(360)**	195
Interest rate swaps	**(60)**	(74)	**(53)**	(178)
Foreign exchange	**79**	(77)	**(354)**	(330)
	$ 23,643	$ (8,621)	**$ 24,800**	$ (15,524)

Accumulated Other Comprehensive Income (Loss) Recognized for Financial Instruments Since Inception

	Unrealized losses	**Tax recovery**	**As at June 30 2012**	Unrealized losses	Tax recovery	As at June 30 2011 (restated)
NGL Frac Spread	**$ (1,186)**	**$ 297**	**$ (889)**	$ (898)	$ 225	$ (673)
Bond forward	**(1,340)**	**-**	**(1,340)**	(1,993)	-	(1,993)
Available-for-sale	**(6,417)**	**802**	**(5,615)**	(4,337)	564	(3,773)
OCI	**$ (8,943)**	**$ 1,099**	**$ (7,844)**	$ (7,228)	$ 789	$ (6,439)

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

	For Six Months Ended			For Six Months Ended		
	Unrealized gains	**Tax expense**	**June 30 2012**	Unrealized gains (losses)	Tax (expense) recovery	June 30 2011 (restated)
NGL Frac Spread	**$ 320**	**$ (80)**	**$ 240**	$ 731	$ (208)	$ 523
Bond forward	**333**	**-**	**333**	308	-	308
Available-for-sale	**320**	**(40)**	**280**	(6,019)	790	(5,229)
OCI	**$ 973**	**$ (120)**	**$ 853**	$ (4,980)	$ 582	$ (4,398)

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, interest rate and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, currency exchange and interest rate yield curves. The forward curves used to mark-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, 2012	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	**2,380**	**-**	**-**	**2,380**
Risk management assets - current	**-**	**58,416**	**-**	**58,416**
Risk management assets - non-current	**-**	**20,797**	**-**	**20,797**
Long-term investments and other assets	**7,494**	**-**	**-**	**7,494**
Financial Liabilities				
Risk management liabilities - current	**-**	**44,649**	**-**	**44,649**
Risk management liabilities - non-current	**-**	**13,266**	**-**	**13,266**
December 31, 2011 (restated)	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	2,875	-	-	2,875
Risk management assets - current	-	68,404	-	68,404
Risk management assets - non-current	-	21,642	-	21,642
Long-term investments and other assets	6,829	-	-	6,829
Financial Liabilities				
Risk management liabilities - current	-	72,973	-	72,973
Risk management liabilities - non-current	-	20,608	-	20,608

Long-term Investments and Other Assets

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (formerly Magma Energy Corp., "Alterra") through a private equity offering. These shares were classified as available-for-sale. The accumulated changes in fair value of these common shares are being reported in OCI, as an unrealized pre-tax loss of $6.4 million as at June 30, 2012 (June 30, 2011 - unrealized pre-tax loss of $4.3 million). 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 another tranche of common shares in Alterra, which were classified as held-for-trading. All shares of Alterra are reported in long-term investments and other assets.

Summary of Unrealized Gains (Losses) on Held-for-Trading Recognized in Net Income

	Three Months Ended		Six Months Ended	
	June 30, 2012	June 30, 2011	**June 30, 2012**	June 30, 2012
Financial assets held-for-trading	**$ (1,381)**	$ (3,798)	**$ 345**	$ (6,560)

9. 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.

Preferred Shares

On August 19, 2010, AltaGas issued 8,000,000 cumulative redeemable five-year rate-reset preferred shares, series A (the Series A Preferred Shares), at a price of $25 per Series A Preferred Share, for aggregate proceeds of $200 million.

Holders of the Series A Preferred Shares are entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding September 30, 2015 (the Initial Period) at an annual rate of 5.00 percent, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first dividend payments of $0.4589 per Series A Preferred Share were made on December 31, 2010. The dividend rate will reset on September 30, 2015, and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent. The Series A Preferred Shares are redeemable by AltaGas, at its option, on September 30, 2015, and on September 30 of every fifth year thereafter.

Holders of Series A Preferred Shares have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, Series B (the Series B Preferred Shares), subject to certain conditions, on September 30, 2015, and on September 30 of every fifth year thereafter. Holders of Series B Preferred Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.66 percent, as and when declared by the Board of Directors of AltaGas.

On June 6, 2012, AltaGas issued 8,000,000 five-year rate reset preferred shares, Series C (the Series C Preferred Shares), at a price of US$25 per Series C Preferred Share, for aggregate gross proceeds of US$200 million.

Holders of the Series C Preferred Shares are entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding September 30, 2017 (the Initial Period) at an annual rate of US$1.10 per share, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first dividend payments of $0.3473 per Series C Preferred Share will be payable on October 1, 2012. The dividend rate will reset on September 30, 2017, and every five years thereafter, equal to the sum of the United States Government Bond Yield on the applicable rate calculation date plus 3.58 percent. The Series C Preferred Shares shall not be redeemable prior to September 30, 2017. On September 30 in every fifth year thereafter, AltaGas may, at its option, redeem for cash all or any part of the outstanding Series C shares by payment of US$25 per Series C share plus accrued and unpaid dividends.

Holders of Series C Preferred Shares have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, Series D (the Series D Preferred Shares), subject to certain conditions, on September 30, 2017, and on September 30 of every fifth year thereafter. Holders of Series D Preferred Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the floating quarterly dividend rate by US$25 per share and multiplying that product by a fraction, the numerator of which is the actual of days in such quarterly floating rate period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year. The floating quarterly dividend rate will be the annual rate of interest equal to the sum of the Treasury Bill rate on the applicable rate calculation date plus 3.58 percent.

Common Shares Issued and Outstanding	Number of shares		Amount
December 31, 2011	**89,248,374**	**$**	**1,204,269**
Shares issued for cash on exercise of options	**398,274**		**8,166**
Shares issued under DRIP	**604,435**		**17,212**
Issued and outstanding at June 30, 2012	**90,251,083**	**$**	**1,229,647**

Weighted Average Shares Outstanding	Three Months Ended June 30 2012	2011	Six Months Ended June 30 2012	2011
Number of shares - basic	**90,048,663**	83,171,369	**89,770,098**	82,963,480
Dilutive equity instruments [1]	**1,176,590**	1,067,734	**1,289,820**	962,188
Number of shares - diluted	**91,225,253**	84,239,103	**91,059,918**	83,925,668

[1] *Includes in-the-money options .*

Subscription Receipts

On February 22, 2012, AltaGas closed approximately $403.0 million in gross proceeds which is held in trust in consideration of a subscription receipt offering of 13,915,000 common shares. The subscription receipts offering represents the holder's right to receive one common share of the issuer contingent upon acquisition close. Each holder of a subscription receipt will receive one common share for each subscription receipt held, without payment of additional consideration or further action, plus an amount per common share, if any, equal to the amount per common share of any cash dividends declared by AltaGas on the common shares to holders of record on a date during the period from and including the closing date up to but not including the transaction closing date, net of any applicable withholding taxes. The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of SEMCO and fulfillment or waiver of all other outstanding conditions precedent to closing the acquisition.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. At June 30, 2012, 3,640,328 shares were reserved for issuance under the plan. As at June 30, 2012, options granted under the plan generally have a term of 10 years until expiry and vest no longer than over a four-year period.

As at June 30, 2012, outstanding options were exercisable at various dates within the next ten years. As at June 30, 2012, the unexpensed fair value of share option compensation cost associated with future periods was $6.1 million (December 31, 2011 - $5.8 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, 2011	**5,337,705**	**$ 22.37**
Granted	**619,000**	**29.24**
Exercised	**(398,275)**	**19.71**
Forfeited	**(173,650)**	**(20.95)**
Share options outstanding, June 30, 2012	**5,384,780**	**$ 23.39**
Share options exercisable, June 30, 2012	**1,987,993**	**$ 21.93**

[1] *Weighted average.*

The following table summarizes the employee share option plan as at June 30, 2012:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted Average Exercise price	Weighted Average Remaining contractual life	Number exercisable	Exercise price
$7.25 to $15.25	598,155	$ 14.21	6.39	337,780	$ 14.19
$15.26 to $25.08	2,542,625	20.57	7.48	1,082,838	21.28
$25.09 to $31.82	2,244,000	29.03	8.26	567,375	27.77
	5,384,780	$ 23.39	7.68	1,987,993	$ 21.93

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. Beginning in 2008, all employees were eligible to receive phantom shares. 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 three years. The compensation expense recorded in second quarter 2012 in respect of this plan was $2.6 million (second quarter 2011 - $3.4 million). As at June 30, 2012, the unexpensed fair value of equity-based compensation costs associated with future periods was $12.6 million (December 31, 2011 - $14.4 million).

10. NET INCOME APPLICABLE TO COMMON SHARES

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

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011 (restated)	**2012**	2011 (restated)
Numerator:				
Net income applicable to common shares - basic	**$ 25,790**	$ 13,298	**$ 67,061**	$ 40,008
Net income applicable to common shares - diluted	**$ 25,790**	$ 13,298	**$ 67,061**	$ 40,008
Denominator:				
Weighted-average number of common shares outstanding	**90,049**	83,171	**89,770**	82,963
Dilutive equity instruments(1)	**1,176**	1,068	**1,290**	962
Number of shares outstanding - diluted	**91,225**	84,239	**91,060**	83,925
Basic net income applicable per common share	**$ 0.29**	$ 0.16	**$ 0.75**	$ 0.48
Diluted net income applicable per common share	**$ 0.28**	$ 0.16	**$ 0.74**	$ 0.48

(1) *Includes in-the-money options.*

11. COMMITMENTS

On February 1, 2012, AltaGas Ltd. and a wholly owned subsidiary of AltaGas entered into a definitive agreement with Continental to acquire SEMCO for US$1.135 billion, including approximately US$355 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy, Inc. a privately held regulated public utility company headquartered in Port Huron, Michigan. SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through ENSTAR and an interest in a regulated natural gas storage utility in Alaska under construction called CINGSA. SEMCO also indirectly holds a regulated natural gas distribution utility and an interest in an unregulated natural gas storage facility in Michigan. The transaction is subject to customary approvals including regulatory approvals from the Michigan Public Service Commission, the Regulatory Commission of Alaska and expiration of the waiting period under the HSR. On March 2, 2012, the Federal Trade Commission granted the application for early termination of the waiting period under HSR. During second quarter 2012, AltaGas received final approval from the Michigan Public Service Commission and completed a hearing with the RCA for the SEMCO acquisition. The RCA approval process is progressing as expected and the acquisition of SEMCO is expected to close on August 30, 2012. The transaction is expected to be accounted for as a business acquisition using the acquisition method of accounting.

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 $11.7 million over the next 11 years, of which $5.9 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 $3.3 million per annum over the term of the contract for storage services.

In 2010, AltaGas entered into a 60-year CPI indexed EPA with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric project. At June 30, 2012, AltaGas is committed to pay approximately $168.5 million for construction work related to this project which is expected to be in service in mid-2014.

12. PENSION PLANS AND RETIREE BENEFITS

The costs of the defined benefit and post-retirement 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:

	Defined Benefit Plans		Post-retirement Benefit Plans	
For the three months ended June 30	**2012**	2011 (restated)	**2012**	2011 (restated)
Current service cost	**$ 1,149**	$ 1,188	**$ 102**	$ 92
Interest cost	**1,154**	1,108	**136**	131
Expected return on plan assets	**(860)**	(944)	**(15)**	(11)
Amortization of transitional obligation	**19**	19	**-**	-
Amortization of past service cost	**-**	-	**-**	31
Amortization of net actuarial loss	**192**	106	**19**	19
Net benefit cost recognized	**$ 1,654**	$ 1,477	**$ 242**	$ 262

	Defined Benefit Plans		Post-retirement Benefit Plans	
For the six months ended June 30	**2012**	2011 (restated)	**2012**	2011 (restated)
Current service cost	**$ 2,298**	$ 2,376	**$ 204**	$ 185
Interest cost	**2,309**	2,216	**271**	262
Expected return on plan assets	**(1,720)**	(1,888)	**(30)**	(23)
Amortization of transitional obligation	**38**	38	**-**	-
Amortization of past service cost	**-**	-	**-**	63
Amortization of net actuarial loss	**385**	211	**38**	38
Net benefit cost recognized	**$ 3,310**	$ 2,953	**$ 483**	$ 525

13. RELATED PARTY TRANSACTIONS

AltaGas and one of its managers agreed on a loan in the principal amount of $750 thousand, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2015. The loan is classified within the long-term investments and other assets and the interest is recognized in other revenue.

14. CONTINGENT LIABILITY

The Sundance B Unit 3 facility experienced an outage in second quarter 2010. The facility operator has notified AltaGas that it believes this event is a force majeure due to a high impact low probability event. AltaGas' management does not consider this to be a force majeure event. Mechanical failure has historically been treated as a maintenance item, rather than a force majeure event. Accordingly, AltaGas has not recorded a charge in its Consolidated Financial Statements related to the notification from the facility operator.

15. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current financial statement presentation.

16. SEASONALITY

The utility business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales during the winter typically account for approximately two-thirds of annual revenue resulting in strong first and fourth quarter results and weaker second and third quarters.

17. SEGMENTED INFORMATION

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end user. The majority of the transactions among the reporting segments are recorded at the market price of the commodities and the remainder is at the exchange amount. 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 – energy consulting and purchase and sale of natural gas and electricity – natural gas storage facilities
Power	– coal-fired and gas-fired power output under power purchase arrangements – wind, run-of-river, gas-fired and biomass power plants – sale of power to commercial and industrial users in Alberta
Utilities	– regulated natural gas distribution assets in Alberta, British Columbia and Nova Scotia – one-third interest in gas production and distribution utility in the town of Inuvik, Northwest Territories
Corporate	– the cost of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets 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, 2012 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 187,194	$ 48,156	$ 35,878	$ (1,298)	$ (21,781)	$ 248,149
Unrealized gain on risk management	-	-	-	23,643	-	23,643
Income from equity investments	129	(186)	(23)	-	-	(80)
Cost of sales	(111,463)	(26,715)	(9,258)	-	20,684	(126,752)
Operating and administrative	(41,525)	(4,566)	(17,486)	(7,292)	1,097	(69,772)
Accretion of asset retirement obligations	(734)	(28)	(6)	-	-	(768)
Depreciation, depletion and amortization	(14,074)	(2,667)	(3,856)	(839)	-	(21,436)
Foreign exchange loss	-	-	-	(2,015)	-	(2,015)
Interest expense	-	-	(4,627)	(8,438)	-	(13,065)
Income (loss) before income taxes	$ 19,527	$ 13,994	$ 622	$ 3,761	-	$ 37,904
Net additions (reductions) to:						
Property, plant and equipment[(1)]	109,840	77,518	(12,488)	856	-	$ 175,726
Intangible assets	(655)	(308)	19,876	128	-	$ 19,041
Long-term investment and other assets	(1,074)	(3,360)	212	1,579	-	$ (2,643)
Goodwill	161,402	-	119,721	-	-	$ 281,123
Segmented assets	$ 2,028,305	$ 880,416	$ 802,933	$ 133,171	-	$ 3,844,825

Six Months Ended June 30, 2012 (unaudited)	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 448,274	$ 107,573	$ 114,565	$ 515	$ (59,564)	$ 611,363
Unrealized gain on risk management	-	-	-	24,800	-	24,800
Income from equity investments	224	11,768	73	-		12,065
Cost of sales	(285,116)	(63,521)	(44,770)	-	57,599	(335,808)
Operating and administrative	(84,354)	(9,643)	(36,364)	(15,104)	1,965	(143,500)
Accretion of asset retirement obligations	(1,516)	(56)	(11)	-	-	(1,583)
Depreciation, depletion and amortization	(27,874)	(5,210)	(8,816)	(1,726)	-	(43,626)
Foreign exchange loss	-	-	-	(2,149)	-	(2,149)
Interest expense	-	-	(8,999)	(16,828)	$ -	(25,827)
Income (loss) before income taxes	$ 49,638	$ 40,911	$ 15,678	$ (10,492)	-	$ 95,735
Net additions (reductions) to:						
Property, plant and equipment[(1)]	191,412	151,325	(19,946)	1,037	-	$ 323,828
Intangible assets	(1,893)	$ 788	19,256	144	-	$ 18,295
Long-term investment and other assets	5,886	28,301	(3,867)	$ 5,825	-	$ 36,145
Goodwill	161,402	-	119,721	-	-	$ 281,123
Segmented assets	$ 2,028,305	$ 880,416	$ 802,933	$ 133,171	-	$ 3,844,825

(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 (note 3).

Three Months Ended June 30, 2011 (unaudited and restated)		Gas		Power		Utilities		Corporate		Intersegment Elimination		Total
Revenue	$	300,385	$	35,472	$	33,290	$	(3,531)	$	(28,305)	$	337,311
Unrealized loss on risk management		-		-		-		(8,621)		-		(8,621)
Income from equity investments		(83)		(5,864)		63		-		-		(5,884)
Cost of sales		(219,670)		(8,246)		(14,499)		-		26,790		(215,625)
Operating and administrative		(41,283)		(3,240)		(10,924)		(7,023)		1,515		(60,955)
Accretion of asset retirement obligations		(596)		(12)		-		-		-		(608)
Depreciation, depletion and amortization		(13,531)		(2,572)		(3,019)		(884)		-		(20,006)
Foreign exchange gain		-		-		-		(49)		-		(49)
Interest expense		-		-		(534)		(13,180)		-		(13,714)
Income (loss) before income taxes	$	25,222	$	15,538	$	4,377	$	(33,288)		-	$	11,849
Net additions (reductions) to:												
Property, plant and equipment[(1)]		44,893		21,398		11,604		(1,263)		-	$	76,632
Intangible assets		(1,007)		89,968		-		-		-	$	88,961
Long-term investment and other assets		18,488		60,954		1,590		1,342		-	$	82,374
Goodwill		161,402		-		61,200		-		-	$	222,602
Segmented assets	$	1,677,950	$	600,615	$	484,906	$	114,528		-	$	2,877,999

Six Months Ended June 30, 2011 (unaudited and restated)		Gas		Power		Utilities		Corporate		Intersegment Elimination		Total
Revenue	$	608,376	$	78,504	$	94,568	$	(6,542)	$	(72,325)	$	702,581
Unrealized loss on risk management		-		-		-		(15,524)		-		(15,524)
Income from equity investments		198		19,777		260		-		-		20,235
Cost of sales		(440,412)		(44,778)		(49,846)		-		71,155		(463,881)
Operating and administrative		(84,510)		(6,225)		(22,328)		(13,231)		1,170		(125,124)
Accretion of asset retirement obligations		(1,192)		(24)		-		-		-		(1,216)
Depreciation, depletion and amortization		(27,061)		(5,143)		(6,087)		(1,768)		-		(40,059)
Foreign exchange gain		-		-		-		(12)		-		(12)
Interest expense		-		-		(3,359)		(23,259)		-		(26,618)
Income (loss) before income taxes	$	55,399	$	42,111	$	13,208	$	(60,336)		-	$	50,382
Net additions to:												
Property, plant and equipment[(1)]		61,209		50,628		16,313		1,080		-	$	129,230
Intangible assets		(21,108)		89,936		-		-		-	$	68,828
Long-term investment and other assets		12,695		60,954		1,379		1,123		-	$	76,151
Goodwill		161,402		-		61,200		-		-	$	222,602
Segmented assets	$	1,677,950	$	600,615	$	484,906	$	114,528		-	$	2,877,999

[(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 (note 3).

18. US GAAP TRANSITION

ADOPTION OF US GAAP

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

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

In May 2012, AcSB extended the deferral option of the mandatory changeover for entities with rate-regulated activity by one year to January 1, 2013.

AltaGas is a qualified entity for the deferral period permitted by AcSB and NI 52-107. AltaGas has elected to use the deferral offered by the AcSB and NI 52-107 given the uncertainty with respect to the application of IFRS to the RRA. In 2011, AltaGas reassessed the accounting policy choices available and decided to adopt US GAAP effective January 1, 2012.

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

For financial reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Corporation’s 2012 financial statements. Consolidated financial statements have been restated to give effects to the results of financial positions, operations and cash flows as if US GAAP has always been applied.

Measurement, classification and disclosure differences arising out of the Corporation’s election to adopt US GAAP are presented below. With respect to measurement and classification differences, Section I “US GAAP differences” presents quantitative reconciliations of balance sheets, statements of income and statements of cash flows, previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with the descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP.

Balance sheet reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. Statement of income, statement of other comprehensive income and accumulated other comprehensive loss and statement of cash flow reconciliations are presented for the three and six months ended June 30, 2011 and for the year ended December 31, 2011.

In addition, US GAAP requires certain disclosures of financial information, significant to the Corporation, that were not required under Canadian GAAP. This information, which is as at December 31, 2011, is presented in Section II “Additional disclosures required under US GAAP”.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP financial statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

Certain comparative figures for the adoption of US GAAP have been reclassified from those previously reported.

Section I – US GAAP differences

The following table summarizes the change in total assets:

($ thousands)	Notes	January 1, 2011	December 31, 2011
Total assets - Canadian GAAP		$ 2,752,538	$ 3,542,420
Business combinations	A	(2,757)	(2,757)
Accounting for joint ventures	B	(16,394)	(12,843)
Pension and other post-retirement benefits	C	1,187	15,353
Natural gas held in storage	D	(903)	1,228
Debt issuance costs	F	9,470	12,825
Total assets - US GAAP		$ 2,743,141	$ 3,556,226

The following table summarizes the change in total liabilities:

$ thousands)	Notes	January 1, 2011	December 31, 2011
Total liabilities - Canadian GAAP		$ 1,541,507	$ 2,180,280
Business combinations	A	(5,971)	(5,971)
Accounting for joint ventures	B	(16,394)	(12,843)
Pension and other post-retirement benefits	C	4,618	19,844
Natural gas held in storage	D	(255)	278
Debt issuance costs	F	9,470	12,825
Income tax on preferred share dividends	G	275	1,025
Total liabilities - US GAAP		$ 1,533,250	$ 2,195,438

The following table summarizes the increases (decreases) to net income:

($ thousands)	3 months ended June 30 2011	6 months ended June 30 2011	Year ended December 31 2011
Net income applicable to common shares - Canadian GAAP	$ 16,569	$ 43,120	$ 83,602
C. Pension and other post-retirement benefits	(32)	(66)	392
D. Natural gas held in storage	29	-	1,598
E. De-designation of cash flow hedges	(3,080)	(2,671)	(2,114)
G. Income tax on preferred share dividends	(188)	(375)	(750)
Total transition adjustments	(3,271)	(3,112)	(874)
Net income applicable to common shares - US GAAP	$ 13,298	$ 40,008	$ 82,728
Net income applicable to common shares - basic per share - Canadian GAAP	$ 0.20	$ 0.52	$ 0.99
Effect of US GAAP transition	(0.04)	(0.04)	(0.01)
Net income applicable to common shares - basic per share - US GAAP	$ 0.16	$ 0.48	$ 0.98

The reconciliations of Balance Sheets from Canadian GAAP to US GAAP are as follows:

As at January 1, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
ASSETS				
Current assets				
Cash and cash equivalents	B	$ 2,109	(1,086)	$ 1,023
Accounts receivable	B	225,217	(17,635)	207,582
Inventory	D	13,106	(903)	12,203
Restricted cash holdings from customers		17,624	-	17,624
Regulatory assets		2	-	2
Risk management assets		41,226	-	41,226
Prepaid expense and other current assets	B, C & F	5,587	107	5,694
		304,871	(19,517)	285,354
Property, plant and equipment	A, B	1,976,538	(53,006)	1,923,532
Intangible assets	B	139,942	(59,919)	80,023
Goodwill	A & B	199,497	23,105	222,602
Regulatory assets	C	76,515	2,908	79,423
Risk management assets		22,587	-	22,587
Long-term investments and other assets	C & F	32,588	5,812	38,400
Investments accounted for by equity method	B	-	91,220	91,220
		$ 2,752,538	(9,397)	$ 2,743,141
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	B	$ 229,618	(16,245)	$ 213,373
Dividends payable		9,078	-	9,078
Short-term debt		9,478	-	9,478
Current portion of long-term debt		1,508	-	1,508
Customer deposits		21,432	-	21,432
Regulatory liabilities		1,494	-	1,494
Risk management liabilities		39,209	-	39,209
Other current liabilities	B & C	12,302	(52)	12,250
		324,119	(16,297)	307,822
Long-term debt	F	893,498	9,470	902,968
Asset retirement obligations		39,516	-	39,516
Deferred income taxes	A, B, C, D & G	233,763	(7,192)	226,571
Regulatory liabilities		18,518	-	18,518
Risk management liabilities		20,598	-	20,598
Other long-term liabilities		15	-	15
Future employee obligations	C	11,480	5,762	17,242
		1,541,507	(8,257)	1,533,250
Common shares		1,023,033	-	1,023,033
Preferred shares		194,126	-	194,126
Contributed surplus		5,672	-	5,672
Accumulated other comprehensive (loss) income	C & E	(2,752)	(978)	(3,730)
Accumulated deficit	A, C, D, E & G	(9,048)	(162)	(9,210)
		$ 2,752,538	(9,397)	$ 2,743,141

As at June 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
ASSETS				
Current assets				
Cash and cash equivalents	B	$ 10,550	(653)	$ 9,897
Accounts receivable	B	215,039	(17,393)	197,646
Inventory	B & E	1,523	(905)	618
Restricted cash holdings from customers		19,416	-	19,416
Regulatory assets		40,441	-	40,441
Risk management assets		298	-	298
Prepaid expense and other current assets	B, C & F	7,548	39	7,587
		294,815	(18,912)	275,903
Property, plant and equipment	A & B	2,065,216	(52,845)	2,012,371
Intangible assets	B	207,024	(58,173)	148,851
Goodwill	A, B & C	199,497	23,105	222,602
Regulatory assets	C	81,042	2,716	83,758
Risk management assets		19,963	-	19,963
Long-term investments and other assets	B, C & F	18,238	7,732	25,970
Investments accounted for by equity method	B	-	88,581	88,581
		$ 2,885,795	(7,796)	$ 2,877,999
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	B	198,948	(16,745)	182,203
Dividends payable		9,173	-	9,173
Short-term debt		4,287	-	4,287
Current portion of long-term debt		105,886	-	105,886
Customer deposits		23,004	-	23,004
Regulatory liabilities		2,220	-	2,220
Risk management liabilities		44,585	-	44,585
Other current liabilities	B & C	6,723	(78)	6,645
		394,826	(16,823)	378,003
Long-term debt	G	881,602	11,524	893,126
Asset retirement obligations		40,536	-	40,536
Deferred income taxes	A, B, C, D & G	236,852	(6,840)	230,012
Regulatory liabilities		19,608	-	19,608
Risk management		19,654	-	19,654
Other long-term liabilities		69,320	-	69,320
Future employee obligations	C	12,282	5,926	18,208
		1,674,680	(6,213)	1,668,467
Common shares		1,042,343	-	1,042,343
Preferred shares		194,126	-	194,126
Contributed surplus		5,192	-	5,192
Accumulated other comprehensive loss	C & E	(9,821)	1,691	(8,130)
Accumulated deficit	A, C, D, E & G	(20,725)	(3,274)	(23,999)
		$ 2,885,795	(7,796)	$ 2,877,999

As at December 31, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
ASSETS				
Current assets				
Cash and cash equivalents	B	$ 4,220	(1,345)	$ 2,875
Accounts receivable	B	251,215	(16,681)	234,534
Inventory	B & E	11,332	1,135	12,467
Restricted cash holdings from customers		19,672	-	19,672
Regulatory assets		5,141	-	5,141
Risk management assets		68,404	-	68,404
Prepaid expense and other current assets	B, C & F	8,427	215	8,642
		368,411	(16,676)	351,735
Property, plant and equipment	A & B	2,540,215	(54,165)	2,486,050
Intangible assets	B	232,685	(55,169)	177,516
Goodwill	A, B & C	258,092	23,031	281,123
Regulatory assets	C	104,786	20,485	125,271
Risk management assets		21,642	-	21,642
Long-term investments and other assets	B, C & F	16,589	8,817	25,406
Investments accounted for by equity method	B	-	87,483	87,483
		$ 3,542,420	13,806	$ 3,556,226
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	B	327,143	(12,721)	314,422
Dividends payable		10,264	-	10,264
Short-term debt		16,824	-	16,824
Current portion of long-term debt		105,962	-	105,962
Customer deposits		25,570	-	25,570
Regulatory liabilities		503	-	503
Risk management liabilities		72,973	-	72,973
Other current liabilities	B & C	11,314	38	11,352
		570,553	(12,683)	557,870
Long-term debt	G	1,201,473	12,825	1,214,298
Asset retirement obligations		44,318	-	44,318
Deferred income taxes	A, B, C, D & G	272,272	(6,438)	265,834
Regulatory liabilities		26,686	-	26,686
Risk management		20,608	-	20,608
Other long-term liabilities		28,810	-	28,810
Future employee obligations	C	15,560	21,454	37,014
		2,180,280	15,158	2,195,438
Common shares		1,204,269	-	1,204,269
Preferred shares		194,126	-	194,126
Contributed surplus		7,441	-	7,441
Accumulated other comprehensive loss	C & E	(11,522)	(317)	(11,839)
Accumulated deficit	A, C, D, E & G	(37,600)	(1,035)	(38,635)
Non-controlling interests		5,426	-	5,426
		$ 3,542,420	13,806	$ 3,556,226

The adjustments to June 30, 2011 equity are as follows:

($ thousands)	Common Shares	Preferred Shares	Contributed Surplus	Accumulated OCI	Retained Earnings	Total Equity
Canadian GAAP	**1,042,343**	**194,126**	**5,192**	**(9,821)**	**(20,725)**	**$ 1,211,115**
A. Business combinations	-	-	-	-	3,214	3,214
C. Pension and other post-retirement benefits	-	-	-	(1,691)	(1,808)	(3,499)
D. Natural gas held in storage	-	-	-	-	(648)	(648)
E. De-designation of cash flow hedges	-	-	-	3,382	(3,382)	-
G. Income tax on preferred share dividends	-	-	-	-	(650)	(650)
US GAAP	**1,042,343**	**194,126**	**5,192**	**(8,130)**	**(23,999)**	**$ 1,209,532**

The statements of income for three months ended June 30, 2011 reconciled from Canadian GAAP to US GAAP is as follows:

For the three months ended June 30, 2011 *($ thousands except per share amounts)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
REVENUE				
Operating	B	376,173	(35,432)	340,741
Unrealized (loss) on risk management contracts	D & E	(4,555)	(4,066)	(8,621)
Other (expenses) revenue	B	(3,532)	102	(3,430)
Income from equity investments	B	-	(5,884)	(5,884)
		368,086	(45,280)	322,806
EXPENSES				
Cost of sales	B	254,407	(38,782)	215,625
Operating and administrative	B & C	61,661	(706)	60,955
Accretion of asset retirement obligations		608	-	608
Depreciation, depletion and amortization	B	21,674	(1,668)	20,006
		338,350	(41,156)	297,194
Foreign exchange loss		49	-	49
Interest expense				
Short-term debt		1,484	-	1,484
Long-term debt		12,230	-	12,230
Income before income taxes		15,973	(4,124)	11,849
Income tax expense (recovery)				
Current	B & G	120	974	1,094
Future	C, D, E & G	(3,466)	(1,577)	(5,043)
Net income from operations		19,319	(3,521)	15,798
Preferred share dividends	G	2,750	(250)	2,500
Net income applicable to common shares		16,569	(3,271)	13,298
Net income per share				
Basic		0.20	(0.04)	0.16
Diluted		0.20	(0.04)	0.16
Weighted average number of shares outstanding				
Basic		83,171	-	83,171
Diluted		84,239	-	84,239

The statements of income for six months ended June 30, 2011 reconciled from Canadian GAAP to US GAAP is as follows:

For the six months ended June 30, 2011 *($ thousands except per share amounts)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
REVENUE				
Operating	B	790,044	(80,932)	709,112
Unrealized (loss) on risk management contracts	D & E	(11,983)	(3,541)	(15,524)
Other (expenses) revenue	B	(6,543)	12	(6,531)
Income from equity investments	B	-	20,235	20,235
		771,518	(64,226)	707,292
EXPENSES				
Cost of sales	B	520,104	(56,223)	463,881
Operating and administrative	B & C	126,136	(1,012)	125,124
Accretion of asset retirement obligations		1,216	-	1,216
Depreciation, depletion and amortization	B	43,340	(3,281)	40,059
		690,796	(60,516)	630,280
Foreign exchange loss		12	-	12
Interest expense				
Short-term debt		2,912	-	2,912
Long-term debt		23,706	-	23,706
Income before income taxes		54,092	(3,710)	50,382
Income tax expense (recovery)				
Current	B & G	1,316	1,897	3,213
Future	C, D, E & G	4,156	(1,995)	2,161
Net income from operations		48,620	(3,612)	45,008
Preferred share dividends	G	5,500	(500)	5,000
Net income applicable to common shares		43,120	(3,112)	40,008
Net income per share				
Basic		0.52	(0.04)	0.48
Diluted		0.51	(0.03)	0.48
Weighted average number of shares outstanding				
Basic		82,963	-	82,963
Diluted		83,925	-	83,925

The statements of comprehensive income and accumulated other comprehensive loss for the three and six months ended June 30, 2011 and for the year ended December 31, 2011 reconciled from Canadian GAAP to US GAAP are as follows:

For the three months ended June 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net Income applicable to the controlling interest		19,319	(3,521)	15,798
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	C	-	(2)	(2)
Effective portion of gains (loss) on derivative instruments that qualifies as cash flow hedge (net of tax)	E	(2,659)	3,080	421
Unrealized income (loss) gain on available-for-sale financial assets (net of tax)		(3,063)	-	(3,063)
		(5,722)	3,078	(2,644)
Comprehensive income		13,597	(443)	13,154
Accumulated other comprehensive loss, beginning of period	C & E	(4,099)	(1,387)	(5,486)
Other comprehensive loss, net of tax		(5,722)	3,078	(2,644)
Accumulated other comprehensive loss, end of period		(9,821)	1,691	(8,130)

For the six months ended June 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net Income applicable to the controlling interest		48,620	(3,612)	45,008
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	C	-	(2)	(2)
Effective portion of gains (loss) on derivative instruments that qualifies as cash flow hedge (net of tax)	E	(1,840)	2,671	831
Unrealized income (loss) gain on available-for-sale financial assets (net of tax)		(5,229)	-	(5,229)
		(7,069)	2,669	(4,400)
Comprehensive income		41,551	(943)	40,608
Accumulated other comprehensive loss, beginning of period	C & E	(2,752)	(978)	(3,730)
Other comprehensive loss, net of tax		(7,069)	2,669	(4,400)
Accumulated other comprehensive loss, end of period		(9,821)	1,691	(8,130)

For the year ended December 31, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net Income applicable to the controlling interest		94,602	(1,873)	92,729
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	C	-	(1,453)	(1,453)
Effective portion of gains (loss) on derivative instruments that qualifies as cash flow hedge (net of tax)	E	(1,420)	2,114	694
Unrealized income (loss) gain on available-for-sale financial assets (net of tax)		(7,350)	-	(7,350)
		(8,770)	661	(8,109)
Comprehensive income		85,832	(1,212)	84,620
Accumulated other comprehensive loss, beginning of year	C & E	(2,752)	(978)	(3,730)
Other comprehensive loss, net of tax		(8,770)	661	(8,109)
Accumulated other comprehensive loss, end of year		(11,522)	(317)	(11,839)

The consolidated statements of cash flows for the three and six months ended June 30, 2011 reconciled from Canadian GAAP to US GAAP are as follows:

For the three months ended June 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net cash used in operating activities	B, C, D & E	50,714	(188)	50,526
Net cash used in investing activities	B	(76,156)	(80)	(76,236)
Net cash provided by financing activities		(75,191)	1,000	(74,191)
Change in cash and cash equivalents		(100,633)	732	(99,901)
Cash and cash equivalents, beginning of period	B	111,183	(1,385)	109,798
Cash and cash equivalents, end of period	B	10,550	(653)	9,897

For the six months ended June 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net cash used in operating activities	B, C, D & E	86,533	(44)	86,489
Net cash used in investing activities	B	(123,108)	(1,523)	(124,631)
Net cash provided by financing activities		45,016	2,000	47,016
Change in cash and cash equivalents		8,441	433	8,874
Cash and cash equivalents, beginning of period	B	2,109	(1,086)	1,023
Cash and cash equivalents, end of period	B	10,550	(653)	9,897

Notes to transitional adjustments

US GAAP discloses certain assets, liabilities, revenues and expenses on different lines in the financial statements compared to Canadian GAAP.

A. Business Combinations

Definition of business combinations

The criteria for determining the nature of transactions included in the scope of the ASC 805 differs from the criteria used under Canadian GAAP. The ASC 805 definition of a business focuses on an integrated set of activities and assets that is capable of providing a return. This requires that the integrated set include inputs and processes applied to those inputs which, together are or will be used to create outputs, but does not necessarily require that it currently include outputs. For this reason, entities considered to be in the development stage could meet the definition of a business under US GAAP. In March 2010, AltaGas acquired an entity and the transaction was accounted for under Canadian GAAP as an asset acquisition on the basis that it was a development stage entity. Under US GAAP this acquisition is accounted for as a business acquisition.

The effect on the balance sheets is reflected with the following increases (decreases):

($ thousands)	January 1 2011	December 31 2011
Property, plant and equipment	(25,932)	(25,932)
Goodwill	18,635	18,635
Future income taxes	7,297	7,297

Acquisition-related transaction costs

Under Canadian GAAP, Part V Handbook 1581 and until December 31, 2010, acquisition-related transaction costs were capitalized and included in the allocation of the purchase price to the acquired assets and assumed liabilities. Under US GAAP, acquisition-related transaction costs are expensed in the period incurred, beginning with transactions completed on or after January 1, 2009. After January 1, 2011, business combinations have been accounted for in accordance with Canadian GAAP, Part V Handbook 1582, with the same accounting treatment of acquisition-related transaction costs as per US GAAP.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Accumulated deficit	(3,051)	(3,051)
Goodwill	(4,284)	(4,284)
Deferred income taxes	(1,233)	(1,233)

Business combinations achieved in stages

Until December 31, 2010 under Canadian GAAP, Part V Handbook 1581, for business combinations achieved in stages, the acquirer does not re-measure its previously held equity interest in an acquired company. Under ASC 805, the acquirer re-measures the previously held equity interest at the acquisition-date fair value and recognizes the resulting gain or loss, if any, in income, beginning with transactions completed on or after January 1, 2009. After January 1, 2011, business combinations have been accounted for in accordance with Canadian GAAP, Part V Handbook 1582, with the same accounting treatment for business combinations achieved in stages as is required under ASC 805.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Accumulated deficit	6,265	6,265
Goodwill	8,824	8,824
Deferred income taxes	2,559	2,559

The combined effect on the balance sheets of the adoption of ASC 805 is as follows:

($ thousands)	January 1 2011	December 31 2011
Total assets		
Property, plant and equipment	(25,932)	(25,932)
Goodwill	23,175	23,175
Total liabilities		
Deferred income taxes	(5,971)	(5,971)
Equity		
Accumulated deficit	3,214	3,214

B. Accounting for Joint Ventures

The Corporation exercises joint control but not control over its investments in ASTC, Inuvik Gas, Sarnia Storage and Alton. Under Canadian GAAP, these investments were proportionately consolidated. Under the proportionate consolidation method, the Corporation recognized its pro-rata share of the jointly controlled assets and liabilities and of the jointly controlled entities in the consolidated balance sheets and recognized its pro-rata share of the revenues and expenses of the jointly controlled assets and liabilities and of the jointly controlled entities in the consolidated income statement.

Under US GAAP, the Corporation accounts for its investments in jointly controlled legal entities and most limited partnerships using the equity method whereby the amount of the Corporation's investment is adjusted quarterly for the Corporation's pro-rata share of their net income or loss and reduced by the amount of any cash distribution received. The Corporation's pro-rata share of the entities' net income is recognized in the item “Income from equity investments” in the Statement of Income.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Cash and cash equivalents	(1,086)	(1,345)
Accounts receivable	(16,132)	(12,005)
Inventory	-	(93)
Prepaid expenses and other current assets	(91)	(202)
Property, plant and equipment	(27,074)	(28,232)
Intangible assets	(59,919)	(55,169)
Long-term investments and other assets	691	343
Goodwill	(70)	(70)
Total assets	(103,681)	(96,773)
Accounts payable and accrued liabilities	(16,245)	(12,721)
Other current liabilities	(52)	11
Deferred income taxes	(97)	(133)
Total liabilities	(16,394)	(12,843)
Investments accounted for by equity method	87,287	83,930

Presentation of equity method investments

Under Canadian GAAP, the Corporation accounted for its investment in Boston Bar Limited Partnership using the equity method. The investment was classified within 'Long-term investment and other non-current assets' and the income associated with this investment was classified in the income statement within 'Other revenue'.

Under US GAAP, the investment in Boston Bar Limited Partnership is classified within 'Investments accounted for by equity method' and income is classified within 'Income from equity investments'.

The effect on the balance sheets of this reclassification is as follows:

($ thousands)	January 1 2011	December 31 2011
Long-term investment and other assets	(3,933)	(3,553)
Investments accounted for by equity method	3,933	3,553

C. Pension and Other Post-retirement Plans

Under Canadian GAAP, the Corporation disclosed, but did not recognize, its amortized gains and losses, its past service costs and its unamortized transitional obligation associated with pension and other post-retirement benefits. Under US GAAP, the Corporation has recognized its unfunded pension obligation as a liability. The unamortized gains and losses and past service costs are recognized in accumulated other comprehensive losses and the unamortized transitional obligation previously determined under Canadian GAAP is recognized in retained earnings.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Accounts Receivable	(1,503)	(4,676)
Goodwill	-	(74)
Non-current assets - Regulatory assets	2,909	20,485
Long-term investments and other assets	(218)	(381)
Deferred income taxes	(1,144)	(1,637)
Other current liabilities	-	27
Future employee obligations	5,762	21,454
Accumulated other comprehensive (loss) income	(1,688)	(3,141)
Accumulated deficit	(1,742)	(1,350)

D. Risk Management: Natural Gas Held in Storage

US GAAP requires inventory to be carried at the lower of cost and net realizable value. Under Canadian GAAP, AltaGas designated its natural gas storage business as a broker/trader business that purchases and sells natural gas on a back-to-back basis. As a result, proprietary natural gas held in storage was carried at fair value based on published market prices as at the balance sheets dates less costs to sell.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Inventory	(903)	1,228
Deferred income taxes	(255)	278
Accumulated deficit	(648)	950

E. Risk Management: De-designation of Cash Flow Hedges

Under Canadian GAAP the results of the joint venture ASTC were accounted for using proportionate consolidation. AltaGas hedged the power delivered by ASTC to the Alberta Power Pool. Under Canadian GAAP, hedge accounting was applied to those cash flow hedges. Under US GAAP, a forecasted transaction is eligible for designation as a hedged transaction in a cash flow hedge if the forecasted transaction is a transaction with a party external to the reporting entity and it presents an exposure to variations in cash flows for the hedged risk that could affect reported earnings. US GAAP specifically states specifically that “equity-method investments cannot be considered analogous to a consolidated subsidiary. Under the equity method of accounting, the investor generally records its share of the earnings or loss from the investment. In addition, the equity-method investment represents the investor's share of the investee's net assets”.

The cash flow hedges for the power delivered by ASTC to the Alberta power grid have been de-designated and the after-taxes unrealized gains have been reversed from the statement of accumulated other comprehensive loss and recognized in earnings and accumulated deficit.

F. Debt Issuance Costs

Under Canadian GAAP, debt issuance costs were netted against long-term debt. Under US GAAP, debt issuance costs are included in “other current assets” and "long-term investments and other assets" depending on the underlying terms of the related debts.

The effect on the balance sheets as a result of this GAAP difference is as follows:

($ thousands)	January 1 2011	December 31 2011
Prepaid expenses and other current assets	197	417
Long-term investments and other assets	9,273	12,407
Long-term debt	9,470	12,825

G. Income Tax on Preferred Share Dividends

Measurement

Under Canadian GAAP, the substantively enacted tax rate was used to measure the future tax asset offset to the Part VI.I tax. Under US GAAP, the enacted tax rate must be used.

The effect on the balance sheets of this GAAP difference is as follows:

As at *($ thousands)*	January 1 2011	December 31 2011
Deferred income taxes	275	1,025
Accumulated deficit	(275)	(1,025)

Presentation

Under Canadian GAAP Part V, when preferred shares are classified as equity and dividends on preferred shares are charged to retained earnings, the related corporation tax is charged to retained earnings. Income tax reductions or recoveries as a result of the Part VI.I tax are also accounted for in the same manner as the Part VI.I tax that led to the reduction and receive the same accounting treatment as the dividends to the extent the income tax reductions or recovery arises in the same period as the Part VI.I tax.

Under US GAAP, Part VI.I tax income tax reductions or recoveries are included in income tax expense.

This resulted in no effect on the balance sheets as at January 1, 2011 and December 31, 2011.

Section II – Additional disclosures required under US GAAP

The following represents the effect of US GAAP adoption to the note disclosures required for annual financial statements that are not otherwise found in these interim consolidated financial statements or Canadian GAAP annual financial statements.

Financial Statement Effects of Rate Regulation

AltaGas accounts for certain transactions in accordance with applicable regulations enforced by AUC, BCUC and NSUARB, which may be different in the absence of rate regulation. This results in the creation of regulatory assets and liabilities.

As at January 1, 2011 and December 31, 2011, the effect on the note 'financial statement effects of rate regulation' is as follows:

As at January 1, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Regulatory assets - current				
Deferred cost of gas		2	-	2
		$ 2	-	$ 2
Regulatory assets - non-current				
Deferred regulatory costs		265	-	265
Future recovery of other retirement benefits	C	1,631	2,909	4,540
Deferred depreciation and amortization		5,479	-	5,479
Deferred income taxes		28,798	-	28,798
Revenue deficiency account		40,342	-	40,342
		$ 76,515	2,909	$ 79,424
Regulatory liabilities - current				
Deferred property taxes		51	-	51
Deferred cost of gas		825	-	825
Deferred regulatory costs		618	-	618
		1,494	-	1,494
Regulatory liabilities - non-current				
Future removal and site restoration costs		18,518	-	18,518
		$ 18,518	-	$ 18,518

As at December 31, 2011	Section I Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
Regulatory assets - current						
Deferred cost of gas			5,141	-		5,141
		$	5,141	-	$	5,141
Regulatory assets - non-current						
Rate stabilization adjustment mechanism			126	-		126
Deferred regulatory costs			2,190	-		2,190
Pipeline rehabilitation costs			2,704	-		2,704
Future recovery of other retirement benefits	C		4,341	20,485		24,826
Deferred depreciation and amortization			9,180	-		9,180
Deferred income taxes			41,128	-		41,128
Revenue deficiency account			45,117	-		45,117
		$	104,786	20,485	$	125,271
Regulatory liabilities - current						
Deferred property taxes			94	-		94
Deferred cost of gas			56	-		56
Deferred regulatory costs			353	-		353
		$	503	-	$	503
Regulatory liabilities - non-current						
LNG Partners option fees deferral			3,021	-		3,021
West Fraser termination payment deferral			3,454	-		3,454
Future removal and site restoration costs			20,211	-		20,211
		$	26,686	-	$	26,686

Property, Plant and Equipment

As a result of the US GAAP transition adjustments noted in Section I of the note, the net book value of property, plant and equipment decreased by $53.0 million as at January 1, 2011 and by $54.2 million as at December 31, 2011. Interest capitalized on long-term capital contribution projects for the year ended December 31, 2011 was $11.0 million (2010 - $4.4 million).

The restated continuity schedule of property, plant and equipment under US GAAP is as follows:

	January 1, 2011			December 31, 2011		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas						
E&T assets	$ 901,585	$ (124,956)	$ 776,629	$ 1,028,781	$ (148,924)	$ 879,857
FG&P assets	686,799	(222,201)	464,598	819,795	(255,136)	564,659
Energy services assets	1,344	(1,238)	106	1,453	(1,385)	68
Other assets	11,798	(8,357)	3,441	11,778	(9,174)	2,604
Power						
Capital lease	13,798	(8,760)	5,038	13,798	(10,117)	3,681
Power generation assets	370,217	(9,013)	361,204	536,914	(17,143)	519,771
Utilities	293,790	(3,033)	290,757	512,958	(16,025)	496,933
Corporate						
Other assets	26,988	(5,229)	21,759	21,478	(3,001)	18,477
	$ 2,306,319	$ (382,787)	$ 1,923,532	$ 2,946,955	$ (460,905)	$ 2,486,050

Intangible Assets

As a result of the US GAAP transition adjustments noted in Section I of the note, the net book value of intangible assets decreased by $60.0 million as at January 1, 2011 and by $55.2 million as at December 31, 2011.

The restated continuity schedule of intangible assets under US GAAP is as follows:

	January 1, 2011			December 31, 2011		
	Cost	Amortization	Net book value	Cost	Amortization	Net book value
Energy services and E&T arrangements and contracts	$ 57,798	$ (11,053)	$ 46,745	$ 57,798	$ (13,816)	$ 43,982
Electricity service agreement[1]	-	-	-	90,000	-	90,000
Energy services relationships	20,892	(6,708)	14,184	20,892	(8,101)	12,791
Computer software	38,066	(25,114)	12,952	36,750	(20,330)	16,420
Land rights	5,002	(1,412)	3,590	13,437	(1,505)	11,932
Franchises and consents	3,015	(463)	2,552	3,014	(623)	2,391
	$ 124,773	(44,750)	80,023	$ 221,891	(44,375)	$ 177,516

[1]The Electricity Service Agreement relates to a 60-year CPI Indexed EPA not yet subject to amortization.

Goodwill

As at January 1 and December 31, 2011, the effect on goodwill is reflected with the following increases (decreases):

	Section I Notes	January 1, 2011	December 31, 2011
Under Canadian GAAP		$ 199,497	$ 258,092
Business combinations	A	23,175	23,175
Accounting for joint ventures	B	(70)	(70)
Pension and other post-retirement benefits	C	-	(74)
Under US GAAP		$ 222,602	$ 281,123

Long-term Investments and Other Assets

As at January 1, 2011 and December 31, 2011, the effect on long-term investments and other assets is reflected with the following increases (decreases):

As at January 1, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Investments in publicly-traded entities		$ 24,448	691	$ 25,139
Equity accounted investments in private entities	B	3,933	(3,933)	-
Accrued pension asset		1,703	(218)	1,485
Other	F	2,504	9,273	11,777
		32,588	5,813	38,401

As at December 31, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Investments in publicly-traded entities		$ 6,819	343	$ 7,162
Equity accounted investments in private entities	B	3,553	(3,553)	-
Accrued pension asset		5,057	(381)	4,676
Other	B & F	1,160	12,408	13,568
		16,589	8,817	25,406

Income Taxes

As at January 1, 2011 and December 31, 2011, the effect on the note 'income taxes' is reflected with the following increases (decreases):

As at January 1, 2011	Section I Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
Income before income taxes - consolidated		$	102,989	27,051	$	130,040
Financial instruments - net	D & E		1,337	(28,158)		(26,821)
Income before financial instruments and income taxes			104,326	(1,107)		103,219
Income from AltaGas Income Trust distributed to unitholders			(76,146)	-		(76,146)
Income before income taxes - operating subsidiaries			28,180	(1,107)		27,073
Statutory income tax rate (%)			28.00	-		28.00
Expected taxes at statutory rates			7,890	(310)		7,580
Add (deduct) the tax effect of:						
Financial instruments			(632)	7,446		6,814
Rate reductions applied to deferred income tax liabilities	D & E		305	-		305
Permanent differences between accounting and tax basis of assets and liabilities	B		352	(106)		246
Non-taxable portion of capital gains (losses) on disposition of assets and investments			(277)	-		(277)
Rate adjustment	C		-	173		173
Taxable preferred shares	G		-	642		642
Other			225	(173)		52
Deferred income tax (recovery) on regulated assets			(5,255)	-		(5,255)
Prior year adjustment			(881)	-		(881)
			1,727	7,672		9,399
Income tax provision (recovery)						
Current			(222)	1,321		1,099
Deferred			1,949	6,351		8,300
		$	1,727	7,672	$	9,399
Effective income tax rate (%)			1.68	5.55		7.23

As at December 31, 2011	Section I Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
Income before income taxes - consolidated		$	113,391	(396)	$	112,995
Financial instruments - net	D & E		8,337	666		9,003
Income before income taxes - operating subsidiaries			121,728	270		121,998
Statutory income tax rate (%)			26.50	-		26.50
Expected taxes at statutory rates			32,258	71		32,329
Add (deduct) the tax effect of:						
Financial instruments	D & E		(2,446)	(150)		(2,596)
Rate reductions applied to deferred income tax liabilities			(1,109)	-		(1,109)
Permanent differences between accounting and tax basis of assets and liabilities	B		682	(195)		487
Non-taxable portion of capital gains (losses) on disposition of assets and investments			319	-		319
Rate adjustment			(6,861)	-		(6,861)
Taxable preferred shares	G		-	1,750		1,750
Other			660	-		660
Deferred income tax (recovery) on regulated assets			(4,725)	-		(4,725)
Prior year adjustment			11	-		11
			18,789	1,476		20,265
Income tax provision (recovery)						
Current			175	3,877		4,052
Deferred			18,614	(2,401)		16,213
		$	18,789	1,476	$	20,265
Effective income tax rate (%)			16.57	1.36		17.93

The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between the tax basis and book carrying values on the Corporation's assets at enacted tax rates.

As at January 1, 2011 and December 31, 2011, deferred income taxes under US GAAP were composed of the following:

As at		January 1, 2011		December 31, 2011
Property, plant and equipment and intangible assets	$	216,134	$	278,479
Regulatory assets		17,665		20,576
Deferred financing		(1,134)		(3,041)
Partnerships		12,994		8,448
Deferred compensation		(4,776)		(3,658)
Financial instruments		937		(2,444)
Non-capital losses		(15,249)		(33,509)
Preferred shares		275		1,025
Other		(275)		(42)
	$	226,571	$	265,834

Uncertain tax positions

Under Canadian GAAP, the Corporation recognized the benefit of an uncertain tax position when it was probable of being sustained.

Under US GAAP, the Corporation recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Management reviewed all open tax returns and determined that no provisions were required for uncertainty on income taxes.

Pension Plans and Retiree Benefits

The following restated table summarizes the details of the defined benefit plans, including the SERP and post-retirement plans under US GAAP as at January 1, 2011 and December 31, 2011:

	Defined Benefit January 1, 2011	Post-Retirement Benefits January, 2011	Defined Benefit December 31, 2011	Post -Retirement Benefits December 31,2011
Accrued benefit obligation				
Balance, beginning of year	36,610	2,571	48,017	2,946
Assumed through acquisition	-	-	29,253	6,444
Actuarial loss	6,553	131	2,745	49
Current service cost	3,105	129	4,580	370
Member contributions	-	-	22	-
Interest cost	2,538	177	4,433	524
Benefits paid	(789)	(62)	(3,418)	(269)
Balance, end of year	$ 48,017	$ 2,946	$ 85,632	$ 10,064
Plan assets				
Fair value, beginning of year	28,688	-	33,687	-
Assumed through acquisition	-	-	23,139	1,184
Actual gain (loss) on plan assets	3,551	-	(2,463)	(24)
Employer contributions	2,366	62	6,188	825
Member contributions	99	-	124	-
Benefits paid	(789)	(62)	(3,418)	(269)
Actual plan expenses	(228)	-	(334)	-
Fair value, end of year	$ 33,687	$ -	$ 56,923	$ 1,716
Funded status	$ (14,330)	$ (2,946)	$ (28,709)	$ (8,348)
Accrued benefit obligation recognized in the financial statements	$ (14,330)	$ (2,946)	$ (28,709)	$ (8,348)

The following amounts were not recognized in the net periodic benefit cost and recorded in the other comprehensive losses:

	Defined Benefit January 1, 2011	Post-Retirement Benefits January, 2011	Defined Benefit December 31, 2011	Post -Retirement Benefits December 31,2011
Amounts included in other comprehensive income (loss)				
Transitional asset (obligation)	-	-	-	-
Past service credit (cost)	-	-	(471)	-
Net actuarial gain (loss)	(2,523)	272	(3,922)	205
Total accumulated other comprehensive income (loss) on a pre-tax basis	(2,523)	272	(4,393)	205
Increase (decrease) by the amount included in deferred tax liabilities	631	(68)	1,098	(51)
Net amount in accumulated other comprehensive income (loss) after-tax adjustment	$ (1,892)	$ 204	$ (3,295)	$ 154

The assets are invested under balanced fund mandates with a broad mix of fixed income, Canadian equity and foreign equity investments. The collective investment mixes for the plans are as follows as at January 1, 2011:

	Percentage of Plan Assets
Cash and short-term equivalents	4.05
Canadian equities	33.93
Foreign equities	27.85
Fixed income instruments	34.17
	100.00%

The collective investment mixes for the plans are as follows as at December 31, 2011:

	Percentage of Plan Assets
Cash and short-term equivalents	8.91
Canadian equities	31.64
Foreign equities	27.52
Fixed income instruments	31.93
	100.00%

Joint Ventures

Financial information for AltaGas' interest in joint venture arrangements under US GAAP is summarized in the tables below. The tables represent 100 percent of the investee financial information which AltaGas accounts for using the proportionate consolidation and equity accounting methods.

As at January 1, 2011	Proportionate Consolidation Method	Equity Method	Total
Revenues	156,668	94,232	250,900
Expenses	119,504	75,746	195,250
	$ 37,164	$ 18,486	$ 55,650
Current assets	39,969	19,762	59,731
Property, plant and equipment	256,951	38,949	295,900
Intangible assets	17,619	59,919	77,538
Long-term investments and other assets	-	2	2
Current liabilities	(8,519)	(17,125)	(25,644)
Other long-term liabilities	(3,625)	(954)	(4,579)
	$ 302,395	$ 100,553	$ 402,948
Operating activities	42,323	25,554	67,877
Investing activities	918	(11,035)	(10,117)
Financing activities	(29,693)	(13,683)	(43,376)
	$ 13,548	$ 836	$ 14,384

As at December 31, 2011	Proportionate Consolidation Method	Equity Method	Total
Revenues	194,899	157,512	352,411
Expenses	131,305	120,928	252,233
	$ 63,594	$ 36,584	$ 100,178
Current assets	48,858	15,793	64,651
Property, plant and equipment	260,411	33,823	294,234
Intangible assets	16,819	55,169	71,988
Long-term investments and other assets	-	2	2
Current liabilities	(15,590)	(13,311)	(28,901)
Other long-term liabilities	(4,951)	(843)	(5,794)
	$ 305,547	$ 90,633	$ 396,180
Operating activities	60,807	43,260	104,067
Investing activities	(11,469)	(17,301)	(28,770)
Financing activities	(45,100)	(26,736)	(71,836)
	$ 4,238	$ (777)	$ 3,461

Supplementary Quarterly Financial Information
(unaudited)

($ millions unless otherwise indicated)	**Q2-12**	Q1-12	Q4-11	Q3-11	Q2-11
FINANCIAL HIGHLIGHTS[1]					
Net Revenue[2]					
Gas	**75.8**	87.5	92.6	77.2	80.6
Power	**21.3**	34.6	31.7	27.8	21.4
Utilities	**26.6**	43.3	24.7	15.9	18.9
Corporate	**22.3**	3.0	8.3	(4.0)	(12.2)
Intersegment Elimination	**(1.1)**	(0.9)	(0.4)	(0.4)	(1.5)
	144.9	167.5	156.9	116.5	107.2
EBITDA[2]					
Gas	**34.3**	44.7	45.9	32.7	39.3
Power	**16.7**	29.5	25.0	24.1	18.1
Utilities	**9.1**	24.4	10.1	5.9	7.9
Corporate	**(8.6)**	(6.0)	(8.6)	(8.0)	(10.6)
	51.5	92.6	72.4	54.7	54.7
Operating Income (Loss)[2]					
Gas	**19.5**	30.1	31.4	18.4	25.2
Power	**14.0**	26.9	22.4	21.5	15.5
Utilities	**5.2**	19.4	4.7	2.9	4.9
Corporate	**(9.3)**	(6.8)	(9.4)	(9.3)	(11.4)
	29.4	69.6	49.1	33.5	34.2

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

(2) *Non-GAAP financial measure.*

Supplementary Quarterly Operating Information

(unaudited)

	Q2-12	Q1-12	Q4-11	Q3-11	Q2-11
OPERATING HIGHLIGHTS					
GAS					
E&T					
Extraction inlet gas processed (Mmcf/d)(1)	**829**	944	923	871	828
Extraction volumes (Bbls/d)(1)	**34,547**	45,186	43,454	39,781	38,843
Frac spread - realized ($/Bbl)(1)(3)	**27.64**	34.11	42.00	22.95	36.65
Frac spread - average spot price ($/Bbl)(1)(4)	**26.85**	40.42	46.59	42.15	41.27
FG&P					
Processing Throughput (gross Mmcf/d)(1)	**351**	400	391	404	391
Energy Services					
Average volumes transacted (GJ/d)(1)	**318,738**	376,071	357,105	340,396	377,967
POWER					
Volume of power sold (GWh)(1)	**802**	816	774	760	729
Average price realized on sale of power ($/MWh)(1)	**58.54**	72.56	79.14	80.67	64.26
Alberta Power Pool average spot price ($/MWh)(1)	**40.03**	60.12	76.42	94.70	52.12
UTILITIES					
Natural gas deliveries - end-use (PJ)(5)	**4.6**	10.8	21.8	2.3	3.7
Natural gas deliveries - transportation (PJ)(5)	**1.7**	2.0	4.6	1.1	1.2
Service sites(2)	**115,437**	115,623	115,932	75,126	73,881
Degree day variance from normal - AUI (%) (6)	**(2.9)**	(11.5)	-	(33.7)	4.6
Degree day variance from normal - Heritage Gas (%) (6)	**(9.7)**	(8.6)	(12.7)	(20.9)	2.4

(1) Average for the period.

(2) As at period end.

(3) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL and derived from sales recorded by the business during the period on frac exposed volumes plus the settlement value of frac hedges settled in the period divided by the total frac exposed volumes produced during the period. Third quarter 2011 realized frac spread was affected by Younger Extraction Plant turnaround and the timing of NGL sales and NGL volumes reported.

(4) Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

(5) Petajoule (PJ) is one million gigajoules (GJ).

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

Other Information

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
PJ	petajoule

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 renewable energy sources. For more information visit: www.altagas.ca.

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