AltaGas

NEWS RELEASE
ALTAGAS REPORTS THIRD QUARTER RESULTS

Calgary, Alberta (November 1, 2012) – In third quarter, AltaGas Ltd. (AltaGas) (TSX:ALA) (TSX:ALA.PR.A) (TSX:ALA.PR.U) achieved several milestones toward adding $1.8 billion in new and expanded assets in 2012. On August 30, 2012, AltaGas closed the acquisition of SEMCO Holding Corporation (SEMCO), the largest acquisition in its eighteen-year history. The acquisition increased Utility customers from just over 100,000 to over 540,000 along with more than a two-fold increase in rate base. During the quarter, construction of the Busch Ranch wind project (Busch Ranch) in southern Colorado was completed successfully ahead of schedule and on budget. In addition, AltaGas commissioned the 50 Mmcf/d expansion of the Blair Creek facility and completed construction of the Gordondale Gas Processing Facility (Gordondale), both of which provide services to producers in the Montney area. As well, the Corporation completed construction of the Harmattan Co-stream project (Co-stream Project). The new and expanded assets in 2012 are underpinned by regulated returns or long-term contracts.

Normalized net income applicable to common shares for the three months ended September 30, 2012 was $12.3 million ($0.13 per share), compared to $14.1 million ($0.17 per share) for the same period 2011. Net income applicable to common shares was $8.0 million ($0.08 per share) for the three months ended September 30, 2012, compared to $11.1 million ($0.13 per share) for the same period 2011. Third quarter results reflect the increased seasonality of earnings from the addition of new natural gas distribution utilities in British Columbia and in the United States. Earnings per share was also impacted by 13.9 million more shares issued to fund the SEMCO acquisition.

Normalized net income for the nine months ended September 30, 2012 was $62.9 million, a six percent increase compared to $59.4 million for the same period 2011. Normalized earnings per share for the nine months ended September 30, 2012 was $0.69, compared to $0.71 for the same period 2011.

Results for the three months ended September 30, 2012 were marked by strong cash flows. Normalized EBITDA was $65.3 million, 16 percent higher compared to $56.3 million for the same quarter 2011. Normalized funds from operations was $54.1 million, 24 percent higher compared to $43.5 million reported for the same quarter 2011.

"This has been a milestone quarter for AltaGas as we added more assets than any other quarter in our history," said David Cornhill, Chairman and CEO of AltaGas. "We remain on track to add approximately $1.8 billion in new assets in 2012 which is expected to add stable earnings from long-term contracts and regulated returns. We continue to be well positioned to deliver long-term earnings, cash flow and sustainable dividend growth into the future. In September we were pleased to announce a 4.3 percent increase in our common share dividend."

The US$1.156 billion acquisition of SEMCO was successfully closed on August 30, 2012. The addition of SEMCO represents a significant step in the execution of AltaGas' strategy and increases stable, regulated cash flows to further support both its dividend and capital growth projects in Canada and the United States.

Construction of the 195 MW Forrest Kerr run-of-river project (Forrest Kerr Project) is progressing well and remains ahead of schedule and on budget. The total project is approximately 70 percent complete. Construction of the intake structure is complete, with powerhouse and in-river work well underway. Forrest Kerr Project construction is expected to be completed by the end of 2013, with commissioning to follow based on the availability of the Northwest Transmission Line. During the third quarter progress continued as expected on the additional Northwest hydroelectric projects, McLymont Creek and Volcano Creek. The two smaller projects are expected to be in service in late 2015. AltaGas has 60-year Electricity Purchase Agreements (EPAs) with BC Hydro which are fully indexed to the Consumer Price Index (CPI) as well as Impact Benefit Agreements (IBAs) with the Tahltan First Nation.

Busch Ranch in southern Colorado was commissioned ahead of schedule and on budget. AltaGas owns a 50 percent interest in the 29 MW wind project with the local utility Black Hills/Colorado Electric Utility Company LP (Black Hills Energy). The power generated is sold pursuant to a 25-year renewable energy purchase agreement with Black Hills Energy. AltaGas added 65 MW of new power assets in 2012, increasing total power generation capacity by 13 percent.

The Co-stream Project, which will use 250 Mmcf/d of existing spare capacity at the Harmattan Complex, is in the final commissioning stages and performance testing is in progress. The project is underpinned by a 20-year cost-of-service contract with NOVA Chemicals Corporation. Construction on AltaGas' 120 Mmcf/d Gordondale deep-cut, natural gas processing facility is complete and AltaGas successfully commenced processing gas on October 28, 2012. The plant is located in the Montney resource area, one of the largest, low-cost, liquids-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. The 50 Mmcf/d expansion at the Blair Creek facility was successfully commissioned and producer gas is being processed. The expansion is underpinned by long-term contracts with three producers.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- AltaGas announced that the November common share dividend will be paid on December 17, 2012, to holders of record on November 26, 2012. The ex-dividend date is November 22, 2012. The amount of the dividend will be $0.12 for each common share. This dividend is an eligible dividend for Canadian income tax purposes.
- The Board approved a preferred share dividend of $0.3125 per share for the period commencing October 1, 2012, and ending December 30, 2012, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on December 31, 2012, to preferred shareholders of record on December 13, 2012. The ex-dividend date is December 11, 2012.
- The Board approved a preferred share dividend of US$0.275 per share for the period commencing October 1, 2012, and ending December 30, 2012, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on December 31, 2012, to preferred shareholders of record on December 13, 2012. The ex-dividend date is December 11, 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.

- Net income applicable to common shares for third quarter 2012 was $8.0 million, compared to $11.1 million for same quarter 2011.
- Net income applicable to common shares for third quarter 2012 was adjusted for $5.1 million of after-tax mark-to-market gains and $9.4 million of after-tax transaction costs and foreign exchange losses related to the acquisition of SEMCO, resulting in normalized net income of $12.3 million for third quarter 2012.
- Normalized EBITDA was $65.3 million for third quarter 2012, compared to $56.3 million for same quarter 2011.
- Normalized Funds from operations was $54.1 million ($0.57 per share) for third quarter 2012, compared to $43.5 million ($0.52 per share) for same quarter 2011.
- Net debt as at September 30, 2012 was $2,527.9 million, compared to $1,063.0 million as at September 30, 2011 and $1,334.2 million as at December 31, 2011. AltaGas' debt-to-total capitalization ratio as at September 30, 2012 was 56.0 percent, versus 46.9 percent as at September 30, 2011 and 49.5 percent as at December 31, 2011.
- On August 30, 2012 AltaGas issued 13,915,000 common shares for net proceeds of $378.4 million.
- On September 28, 2012 AltaGas issued $350 million of senior unsecured medium term notes. The notes carry a coupon rate of 3.72 percent and mature on September 28, 2021.

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

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 third 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) 340-8061 or call toll free at 1 866 225 0198. There is no passcode. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/investors/presentations_and_events. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available by dialing (905) 694-9451 or 1-800-408-3053. The passcode is 8916823. The replay expires at midnight (Eastern) on November 8, 2012.

The complete third quarter 2012 report, 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 nine months ended September 30, 2012, compared to the three and nine months ended September 30, 2011. This MD&A dated November 1, 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 nine months ended September 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 nine months ended and as at September 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"; "Utilities 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 Services (U.S.) Inc., 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 nine months ended and as at September 30, 2011, along with other selected financial information for 2011 has been restated to comply with US GAAP. All prior comparative information that has been restated to US GAAP is labeled "restated".

	Three Months Ended September 30		Nine Months Ended September 30	
(unaudited)	**2012**	2011	**2012**	2011
($ millions)		(restated)		(restated)
Revenue	**311.3**	339.2	**959.5**	1,046.5
Net revenue[1]	**147.3**	116.5	**459.7**	359.9
Normalized operating income[1]	**38.5**	35.0	**138.3**	127.9
Normalized EBITDA[1]	**65.3**	56.3	**210.3**	190.5
Net income applicable to common shares	**8.0**	11.1	**75.1**	51.1
Normalized net income[1]	**12.3**	14.1	**62.9**	59.4
Total assets	**5,696.8**	2,975.8	**5,696.8**	2,975.8
Total long-term liabilities	**3,239.8**	1,323.3	**3,239.8**	1,323.3
Net additions to property, plant and equipment	**1,041.8**	112.2	**1,365.6**	241.4
Dividends declared[2]	**33.4**	27.6	**95.4**	82.4
Cash flows				
Normalized funds from operations[1]	**54.1**	43.5	**171.2**	151.7

	Three Months Ended September 30		Nine Months Ended September 30	
($ per share)	**2012**	2011	**2012**	2011
		(restated)		(restated)
Normalized EBITDA[1]	**0.69**	0.67	**2.30**	2.29
Net income - basic	**0.08**	0.13	**0.82**	0.61
Net income - diluted	**0.08**	0.13	**0.81**	0.61
Normalized net income[1]	**0.13**	0.17	**0.69**	0.71
Dividends declared[2]	**0.35**	0.33	**1.04**	0.99
Cash flows				
Normalized funds from operations[1]	**0.57**	0.52	**1.87**	1.82
Shares outstanding - basic (millions)				
During the period[3]	**95.3**	83.6	**91.6**	83.2
End of period	**104.7**	83.8	**104.7**	83.8

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

(2) *Dividends declared of $0.11 per common share per month from January 1 until October 27, 2011, $0.115 commencing October 27, 2011 and $0.12 per common share per month commencing September 10, 2012.*

(3) *Weighted average.*

Three Months Ended September 30

AltaGas' results reflect the seasonality inherent in its operations. Second and third quarters are typically lower than first and fourth quarters 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 for third quarter 2012 was $8.0 million ($0.08 per share) compared to $11.1 million ($0.13 per share) for same quarter last year.

Normalized net income is calculated to reflect the financial performance of the underlying assets. Net income applicable to common shares is normalized for mark-to-market accounting and non-recurring items. In third quarter 2012, AltaGas reported several non-recurring items related to the acquisition of Semco Holding Corporation (SEMCO) including transaction costs and foreign exchange losses of $9.4 million after-tax. AltaGas also reported an after-tax mark-to-market gain of $5.1 million in third quarter 2012 compared to an after-tax mark-to-market loss of $3.0 million in third quarter 2011.

Normalized net income for third quarter 2012 was $12.3 million ($0.13 per share) compared to $14.1 million ($0.17 per share) for same quarter last year. In third quarter, earnings increased due to higher frac exposed volumes processed as a result of no major turnarounds, the addition of power plants and growth in rate base at the natural gas distribution utilities. These increases were offset by lower gas volumes processed at some facilities, lower contributions from energy services, lower transmission revenue and lower generation at Bear Mountain Wind Park (Bear Mountain). In third quarter 2011, AltaGas reported $6.0 million lower operating income as a result of planned turnarounds at the Younger Extraction Plant (Younger) and Harmattan Complex (Harmattan). Results for third quarter 2012 were impacted by the inherent seasonality of the utilities results. Earnings per share for third quarter 2012 was also impacted by incremental outstanding shares required to fund the SEMCO acquisition.

On a cash flow basis, normalized funds from operations for the three months ended September 30, 2012 increased 24 percent to $54.1 million ($0.57 per share) from $43.5 million ($0.52 per share) in third quarter 2011. Normalized EBITDA for third quarter 2012 was $65.3 million, a 16 percent increase, compared to $56.3 million for same quarter 2011.

On a consolidated basis, normalized operating income for third quarter 2012 was $38.5 million compared to $35.0 million for same quarter 2011. Operating income was driven by higher frac exposed volumes processed as a result of no major turnarounds, the addition of power plants, the acquisition of SEMCO and rate base growth in the natural gas distribution utilities in Nova Scotia and Alberta. However, these increases were partially offset by the impact of lower gas volumes processed, lower contributions from energy services and lower transmission revenue. Increases in earnings were also offset by lower generation at Bear Mountain and lower approved returns at AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas).

On a consolidated basis, net revenue for third quarter 2012 was $147.3 million compared to $116.5 million for same quarter 2011. The increase was driven by last year's major turnarounds at the Younger and Harmattan facilities, the addition of new power plants, the addition of SEMCO and 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 gas processing volumes, lower contributions from energy services, lower transmission revenues, lower generation at Bear Mountain and lower approved returns at AUI and Heritage Gas.

Operating and administrative expense for third quarter 2012 was $81.0 million, compared to $64.3 million in third quarter 2011. The increase was primarily due to the addition of SEMCO and PNG, partially offset by last year's planned turnarounds and lower operating costs experienced at certain gas facilities as a result of lower power prices and lower volumes processed.

Amortization expense for third quarter 2012 was $26.0 million compared to $20.7 million for same quarter 2011. The increase was due to the addition of new and expanded gas and power facilities, amortization at SEMCO and PNG and higher depletion expense at the Ikhil Joint Venture (Ikhil). Accretion expense for third quarter 2012 was $0.8 million compared to $0.6 million for same quarter 2011.

Foreign exchange losses for third quarter 2012 were $6.8 million (third quarter 2011 - $0.1 million), primarily as a result of foreign currency transactions related to the SEMCO acquisition.

Interest expense for third quarter 2012 was $13.9 million compared to $12.8 million for same quarter 2011. Interest expense increased due to a higher average debt balance of $1,951.1 million (third quarter 2011 - $1,032.3 million). The increase was partially offset by a higher capitalized interest of $10.6 million (third quarter 2011 - $3.1 million) and a lower average borrowing rate of 5.0 percent (third quarter 2011 - 6.1 percent).

In third quarter 2012, AltaGas recorded income tax expense of $5.1 million compared to $4.4 million in third quarter 2011. In third quarter 2012, income taxes were higher compared to same quarter 2011 due to higher unrealized gains on risk management contracts and the addition of SEMCO and PNG.

Nine Months Ended September 30

Net income applicable to common shares for the nine months ended September 30, 2012 was $75.1 million ($0.82 per share) compared to $51.1 million ($0.61 per share) for the same period last year.

For the nine months ended September 30, 2012, AltaGas reported several non-recurring items related to the acquisition of SEMCO including after-tax transaction costs and foreign exchange losses of $11.7 million. AltaGas also reported after-tax mark-to-market gains of $23.9 million for the nine months ended September 30, 2012, compared to an after-tax mark-to-market loss of $20.5 million for the same period 2011. For the nine months ended September 30, 2011, AltaGas also reported $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.

Normalized net income for the nine months ended September 30, 2012 was $62.9 million ($0.69 per share) compared to $59.4 million ($0.71 per share) for the same period 2011. Operating income for nine months ended September 30, 2011 was negatively impacted by $6.0 million due to planned turnarounds at the Younger and Harmattan facilities. Results for nine months ended September 30, 2012 were impacted by the inherent seasonality of the utilities businesses. Earnings per share for nine months ended September 30, 2012 was also impacted by incremental outstanding shares required to fund the SEMCO acquisition.

On a cash flow basis, normalized funds from operations for the nine months ended September 30, 2012 increased 13 percent to $171.2 million ($1.87 per share), compared to $151.7 million ($1.82 per share) for the same period 2011. Normalized EBITDA for the nine months ended September 30, 2012 was $210.3 million, a 10 percent increase, compared to $190.5 million for the same period 2011.

On a consolidated basis, normalized operating income for the nine months ended September 30, 2012 was 8 percent higher at $138.3 million compared to $127.9 million for the same period 2011. Earnings from the operating assets continue to reflect the successful execution of AltaGas' strategy. Excluding the impact of planned turnarounds in 2011, on a year-to-date basis, the results were driven by the acquisitions of SEMCO and PNG, higher power volumes hedged at higher prices, higher frac exposed volumes, lower natural gas costs at gas-fired power generating facilities, the addition of new power plants, lower operating costs at some gas facilities due to lower power prices and volumes processed, higher power generated at Bear Mountain and rate base growth at the Nova Scotia and Alberta utilities. These increases were partially offset by lower power prices realized in Alberta, lower realized frac margins, lower volumes processed at some gas processing facilities, lower contributions from energy services, lower transmission revenue, lower fee-for-service revenues earned as a result of outages downstream from several of AltaGas' extraction plants, warmer weather in Nova Scotia and Alberta, lower approved returns at both AUI and Heritage Gas and higher operating and administrative expenses and amortization due to the growth from the addition of new assets.

On a consolidated basis, net revenue for the nine months ended September 30, 2012 was $459.7 million compared to $359.9 million for the same period 2011. Excluding the impact of planned turnarounds in third quarter 2011, the increase in net revenue was driven by higher realized storage margins, higher fees earned by the extraction and gas processing businesses, higher power volumes hedged at higher prices, higher power generated at Bear Mountain, low natural gas costs at gas-fired power facilities, the addition of new power plants, the acquisitions of SEMCO and PNG and rate base growth at the Nova Scotia and Alberta utilities. These increases were partially offset by a gain recorded in first quarter 2011 for the sale of a gas plant, lower transmission revenues, lower gas processing volumes, lower realized power prices in Alberta, lower approved returns at AUI and Heritage Gas, and warmer weather in Alberta and Nova Scotia.

Operating and administrative expense for the nine months ended September 30, 2012 was $224.5 million, compared to $189.4 million for the same period 2011. The increase was primarily due to the addition of SEMCO and PNG and transaction costs related to acquisitions during the period, partially offset by lower operating costs at some gas processing facilities due to lower power prices and volumes processed.

Amortization expense for the nine months ended September 30, 2012 was $69.6 million compared to $60.8 million for the same period 2011. The increase was due to the addition of new and expanded facilities, including the acquisitions of SEMCO and PNG and higher depletion expense at Ikhil. Accretion expense for the nine months ended September 30, 2012 was $2.4 million compared to $1.8 million for the same period 2011.

Foreign exchange losses for the nine months ended September 30, 2012 were $8.9 million (nine months ended September 30, 2011 - $0.1 million), primarily as a result of foreign currency transactions related to the SEMCO acquisition.

Interest expense for the nine months ended September 30, 2012 was $39.7 million compared to $39.4 million for the same period 2011. Interest expense increased due to a higher average debt balance of $1,645.5 million (nine months ended September 30, 2011 - $982.9 million). The increase was partially offset by higher capitalized interest of $25.4 million (nine months ended September 30, 2011 - $6.6 million) and lower average borrowing rate of 5.3 percent (nine months ended September 30, 2011 - 6.3 percent).

For the nine months ended September 30, 2012, AltaGas recorded income tax expense of $27.6 million compared to $9.8 million for the same period 2011. For the nine months ended September 30, 2012, income tax was higher compared to the same period 2011 due to higher unrealized gains on risk management contracts and the addition of SEMCO and PNG. For the same period in 2011, there was an adjustment to deferred tax liabilities of approximately $6.8 million related to changes in the future tax rate assumption which resulted in lower income tax expense in the period.

CONSOLIDATED OUTLOOK

On a consolidated normalized basis, AltaGas is expected to report stronger earnings for 2012 as a result of significant projects being commissioned in fourth quarter 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 and the acquisition of SEMCO on August 30, 2012. The impact of these factors 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 have reduced 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. The acquisition of SEMCO for total consideration of US$1.156 billion on August 30, 2012, added 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 completion of the Blair Creek expansion in third quarter 2012, the completion of the Harmattan Co-stream project (Co-stream Project) and the commencement of operations at the Gordondale Gas Processing Plant (Gordondale). Long-term take-or-pay commitments by AltaGas' customers are the primary revenue sources associated with these new volumes. AltaGas expects these volume increases to offset the impact of lower volumes 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, Glauconite, Duvernay and other liquids-rich gas formations, along with associated gas from oil or solution gas production. AltaGas has been able to offset a large portion of volume declines in the dry gas areas with growth in volumes processed from liquids-rich areas.

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 12 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. For 2013, approximately 35 percent of volumes exposed to frac spreads have been hedged at approximately $35/Bbl.

AltaGas expects the Power business to benefit from the addition of the second cogeneration facility (Cogeneration II) at Harmattan, the Gordondale peaking plant, the 29 MW Busch Ranch wind farm (Busch Ranch) and the recently acquired biomass facilities. The Alberta spot market price has started out strong in the fourth quarter 2012 and the forward curve is consistent with the prior year. The gas-fired power facilities are expected to benefit from low natural gas costs. For fourth quarter 2012, AltaGas has hedged approximately 74 percent of volumes exposed to Alberta power prices at an average price of $67/MWh. For 2013, AltaGas has hedged approximately one-third of power exposed to spot prices at an average price of $66/MWh.

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. A resolution to this matter is expected in the fourth quarter 2012. AltaGas recorded $15.6 million in revenue for the duration of the outage which is recorded as an account receivable from the operator of the Sundance B Unit 3.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for the remainder of 2012 and full year 2013 to be approximately $500 million. Given AltaGas' transformational growth, the Corporation is focused on enhancing productivity and streamlining businesses. This is expected to include the disposition of smaller non-core assets.

AltaGas' committed capital program is fully funded through growing internally generated cash flow, dividend reinvestment plan, available bank lines, and continued strong access to capital markets. As at September 30, 2012, the Corporation had $904.1 million 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 third quarter 2012 on projects currently under construction and in advanced development:

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. The total project is approximately 70 percent complete. The power tunnel is approximately 80 percent complete and is expected to be completed by the end of first quarter 2013. Excavation has been progressing well due to stable and consistent rock formations. Construction of the intake structure, including the major equipment foundations is complete. Construction of the powerhouse and in-river work have commenced as planned in third quarter 2012.

Forrest Kerr construction is expected to be completed by the end of 2013, with commissioning 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 Consumer Price Index (CPI) as well as an Impact Benefit Agreement (IBA) with the Tahltan First Nation.

McLymont Creek and Volcano Creek Hydroelectric Projects

The McLymont Development Plan was approved and the General Land Tenure, Occupant License to Cut and the Water License were issued for the 66 MW McLymont Creek project (McLymont Project). Construction of the access road and bridge work continued this quarter and are expected to continue to the end of 2012. The environment application process is ongoing for the 16 MW Volcano Creek project. Detailed engineering for both the McLymont Creek and Volcano Creek projects is on track to be completed prior to commencement of the facility construction, planned to start in first quarter 2013. The two projects are scheduled to be in service in late 2015. AltaGas has 60-year EPAs with BC Hydro which are fully indexed to the CPI as well as IBAs with the Tahltan First Nation for these two projects.

Harmattan Co-stream Project

The Co-stream Project is currently processing approximately 150 Mmcf/d of raw gas and 100 Mmcf/d of Co-stream gas. AltaGas expects throughput at the complex to be processing approximately 400 Mmcf/d by the end of 2012. 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 (NOVA Chemicals).

The construction schedule was delayed during the third quarter through to fourth quarter. At the end of third quarter 2012, seven of nine systems required for the start-up of the project had been commissioned including pipelines. Currently, the facilities are in performance testing phase. 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 with the Court of Appeal of Alberta to appeal the ERCB decision to approve the Co-stream Project. In late January 2011, one of those parties filed an application with the ERCB for a Review and Variance (R&V) of the ERCB Decision. The R&V 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. On September 28, 2012, one of those parties applied to the Supreme Court of Canada for leave to appeal the decision made by the Alberta Court of Appeal.

Gordondale Gas Plant

Construction on AltaGas' 120 Mmcf/d Gordondale deep-cut, natural gas processing facility is complete and commissioning of the facility is in progress. The Gordondale plant is currently processing approximately 35 Mmcf/d and AltaGas expects volumes to ramp-up over the coming quarters as Encana increases its production in the area. The project is located in the Montney resource play near the town of Gordondale, approximately 100 kilometres northwest of Grande Prairie, Alberta and is underpinned by a long-term contract with Encana.

During the quarter, management continued its efforts to maintain schedule while mitigating cost escalation, as a result the facility is on track to be in service in fourth quarter 2012. AltaGas has continued to experience cost pressure on the project. The project's estimated return on investment continues to be within management's expectations.

JEEP West Central Gas Pipeline

In third quarter 2012, AltaGas acquired a 50 percent interest in Quatro Resources Inc.'s (Quatro) midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas Plant for approximately $20 million. 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 Glauconite and Duvernay resource plays with increased NGL recovery, 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. Capital costs and schedule will continue to be refined as the project plan is finalized. The volumes committed to the pipeline and JEEP are underpinned by long-term fee-for-service contracts.

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. Capital costs and schedule will continue to be refined as the project plan is finalized.

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 September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Net revenue	**147.3**	116.5	**459.7**	359.9
Add: Cost of sales	**164.0**	222.7	**499.8**	686.6
Revenue (GAAP financial measure)	**311.3**	339.2	**959.5**	1,046.5

Management believes that 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 September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized operating income	**38.5**	35.0	**138.3**	127.9
Add (deduct):				
Unrealized gain (loss) on held-for-trading	**0.6**	(1.6)	**0.9**	(8.1)
Transaction costs related to acquisitions	**(5.7)**	-	**(6.9)**	-
Gain on sale of Groundbirch facility	**-**	-	**-**	6.2
Operating income	**33.4**	33.4	**132.3**	126.0
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**6.0**	(2.5)	**30.8**	(18.1)
Interest expense	**(13.9)**	(12.8)	**(39.7)**	(39.4)
Foreign exchange loss	**(6.8)**	(0.1)	**(8.9)**	(0.1)
Income tax expense	**(5.1)**	(4.4)	**(27.6)**	(9.8)
Net income applicable to non-controlling interests	**(1.0)**	-	**(1.6)**	-
Preferred share dividends	**(4.6)**	(2.5)	**(10.2)**	(7.5)
Net income applicable to common shares (GAAP financial measure)	**8.0**	11.1	**75.1**	51.1

Operating income is a measure of AltaGas' profitability from its principal operating activities prior to how these activities are financed, how the results are taxed, or the impact of unrealized gains or losses on risk management contracts. The measure is used to assess operating performance since management believes that it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized 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, gains or losses on sale of assets and mark-to-market gains and losses related to equity investments.

Normalized EBITDA	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized EBITDA	**65.3**	56.3	**210.3**	190.5
Add (deduct):				
Unrealized gain (loss) on held-for-trading	**0.6**	(1.6)	**0.9**	(8.1)
Transaction costs related to acquisitions	**(5.7)**	-	**(6.9)**	-
Gain on sale of Groundbirch facility	**-**	-	**-**	6.2
EBITDA	**60.2**	54.7	**204.3**	188.6
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**6.0**	(2.5)	**30.8**	(18.1)
Depreciation, depletion and amortization	**(26.0)**	(20.7)	**(69.6)**	(60.8)
Accretion of asset retirement obligations	**(0.8)**	(0.6)	**(2.4)**	(1.8)
Interest expense	**(13.9)**	(12.8)	**(39.7)**	(39.4)
Foreign exchange loss	**(6.8)**	(0.1)	**(8.9)**	(0.1)
Income tax expense	**(5.1)**	(4.4)	**(27.6)**	(9.8)
Net income applicable to non-controlling interests	**(1.0)**	-	**(1.6)**	-
Preferred share dividends	**(4.6)**	(2.5)	**(10.2)**	(7.5)
Net income applicable to common shares (GAAP financial measure)	**8.0**	11.1	**75.1**	51.1

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, gains or losses on sale of assets and mark-to-market gains and losses related to equity investments.

Normalized Net Income	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized net income	**12.3**	14.1	**62.9**	59.4
Add (deduct):				
Unrealized gain (loss) on risk management contracts	**4.6**	(1.6)	**23.1**	(13.4)
Unrealized gain (loss) on held-for-trading assets	**0.5**	(1.4)	**0.8**	(7.1)
Transaction costs and foreign exchange loss related to acquisitions	**(9.4)**	-	**(11.7)**	-
Gain on sale of Groundbirch facility	**-**	-	**-**	5.4
Deferred income tax rate adjustment	**-**	-	**-**	6.8
Net Income applicable to common shares (GAAP financial measure)	**8.0**	11.1	**75.1**	51.1

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as transaction costs related to acquisitions including foreign exchange and gains or losses on sale of assets.

Normalized Funds from Operations	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Normalized Funds from Operations	**54.1**	43.5	**171.2**	151.7
Add (deduct):				
Transaction costs and foreign exchange loss related to acquisitions	**(12.5)**	-	**(15.8)**	-
Funds from operations	**41.6**	43.5	**155.4**	151.7
Add (deduct):				
Net change in non-cash working capital	**(24.7)**	19.8	**(0.7)**	(1.7)
Asset retirement obligations settled	**0.1**	-	**(0.4)**	(0.2)
Cash from operations (GAAP financial measure)	**17.0**	63.3	**154.3**	149.8

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 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 September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Gas(1)	**17.7**	18.4	**67.3**	73.8
Power	**21.9**	21.5	**62.8**	63.6
Utilities	**5.5**	2.9	**30.2**	19.4
Sub-total: Operating Businesses	**45.1**	42.8	**160.3**	156.8
Corporate(2)	**(11.7)**	(9.4)	**(28.0)**	(30.8)
	33.4	33.4	**132.3**	126.0

(1) *Includes gains on sale of gas plant in first quarter 2011.*

(2) *Includes mark-to-market gain/loss on equity investments and transaction costs and excludes mark-to-market gains/losses on risk management contracts.*

GAS

OPERATING STATISTICS	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	**2012**	2011
Extraction and Transmission (E&T)				
Extraction inlet gas processed (Mmcf/d)(1)	**850**	871	**881**	869
Extraction ethane volumes (Bbls/d)(1)	**25,754**	25,456	**25,322**	26,202
Extraction NGL volumes (Bbls/d)(1)	**14,307**	14,325	**14,762**	14,076
Total extraction volumes (Bbls/d)(1)	**40,061**	39,781	**40,084**	40,278
Frac spread - realized ($/Bbl)(1) (2)	**28.59**	22.95	**30.35**	30.37
Frac spread - average spot price ($/Bbl)(1) (3)	**22.75**	42.15	**30.57**	41.47
Field Gathering and Processing (FG&P)				
Processing throughput (gross Mmcf/d)(1)	**362**	404	**371**	391
Energy Services				
Average volumes transacted (GJ/d)(1)(4)	**334,973**	340,396	**343,203**	373,814

(1) *Average for the period.*

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

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

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

In third quarter 2012, average ethane volumes increased by 298 Bbls/d and NGL volumes decreased by 18 Bbls/d, compared to same quarter 2011. During nine months ended September 30, 2012, average ethane volumes decreased by 880 Bbls/d and NGL volumes increased by 686 Bbls/d, compared to same period 2011. Ethane volumes were lower for the nine months ended September 30, 2012 largely due to outages downstream from several of AltaGas' extraction plants and reduced ethane recovery at Harmattan during the commissioning phase of the Co-stream Project. NGL volumes were higher in the nine months ended September 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 Younger and JEEP.

FG&P throughput in third quarter 2012 averaged 362 Mmcf/d compared to 404 Mmcf/d in third quarter 2011. FG&P throughput for the nine months ended September 30, 2012 averaged 371 Mmcf/d compared to 391 Mmcf/d in same period 2011. During third quarter 2012, volumes at certain gas processing facilities grew by approximately 47 Mmcf/d compared to third quarter 2011. Overall, 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 expansion of the Blair Creek facility, the addition of the Gilby Gas Plant effective July 1, 2012 and the Marlboro Gas Plant last year. For the three months ended September 30, 2012, management has estimated that an average of approximately 43 Mmcf/d of flowing natural gas wells had been shut-in or diverted that were previously processed at AltaGas' facilities.

Three Months Ended September 30

In third quarter 2012, the $50 million expansion of the Blair Creek facility was successfully commissioned and is now processing producer gas. The expansion has increased production capacity by 50 Mmcf/d and raised the licensed capacity to 82 Mmcf/d. The expansion was underpinned by long-term contracts with three producers. In third quarter 2012, AltaGas also acquired a 50 percent interest in the Quatro midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas Plant for approximately $20 million.

The Gas segment recorded operating income of $17.7 million in third quarter 2012 compared to $18.4 million for same quarter 2011. Excluding the impact of planned turnarounds in third quarter 2011 of approximately $6.0 million, the decrease was due to lower volumes processed, lower contributions from energy services and lower transmission revenue.

During third quarter 2012, AltaGas hedged approximately 83 percent of frac exposed production at an average price of approximately $35/Bbl before deducting extraction premiums. During third quarter 2011, AltaGas hedged approximately 65 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 third quarter 2012 was approximately $23/Bbl compared to approximately $42/Bbl in same quarter 2011.

Net revenue in the Gas business for third quarter 2012 was $74.6 million, compared to $77.2 million for same quarter 2011. Net revenue was lower in the quarter due to lower contributions from energy services, lower transmission revenues which was driven largely by lower daily contract quantity on the Suffield system and outage upstream of the Porcupine Hills Pipeline, lower gas processing volumes and lower fee-for-service revenues earned by extraction facilities.

Operating and administrative expense in third quarter 2012 was $41.6 million compared to $44.5 million in third quarter 2011. Operating costs were lower due to the Younger and Harmattan turnarounds in third quarter 2011, lower operating costs due to lower power prices and efforts to control operating and administrative costs.

Amortization expense in third quarter 2012 was $14.5 million compared to $13.7 million in third quarter 2011. Accretion expense in third quarter 2012 was $0.8 million compared to $0.6 million in third quarter 2011. Increase in amortization and accretion expenses was a result of expansions that occurred since fourth quarter 2011, the addition of the Gilby gas plant and the Blair Creek expansion in third quarter 2012.

Nine Months Ended September 30

The Gas segment recorded operating income of $67.3 million for the nine months ended September 30, 2012 compared to $73.8 million for same period 2011. During the nine months ended September 30, 2011, several one-time items were recorded that amounted to net gains of approximately $4.2 million comprised of the sale of the Groundbirch facility, settlement of a take-or-pay contract, and non-cash liability reduced by the impact of planned turnarounds. Excluding these one-time items, the Gas segment reported lower operating income of $2.3 million compared to the nine months ended September 30, 2011. The decrease was due to lower realized frac margins, lower contributions from energy services, lower transmission revenue, lower fee-for-service revenues earned as a result of outages downstream from several of AltaGas' extraction plants, lower volumes processed and planned maintenance at two extraction plants. These decreases were partially offset by higher frac exposed volumes and lower operating costs.

For the nine months ended September 30, 2012, AltaGas hedged approximately 80 percent of frac exposed production at an average price of approximately $35/Bbl before deducting extraction premiums. For the nine months ended September 30, 2011, AltaGas hedged 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 nine months ended September 30, 2012 was approximately $30/Bbl compared to approximately $41/Bbl in same period 2011.

Net revenue in the Gas business for the nine months ended September 30, 2012 was $237.9 million, compared to $245.3 million for same period 2011. Excluding the impact of planned turnarounds and one-time gains recorded in the first nine months of 2011, net revenue was impacted by lower transmission revenues which was driven largely by lower daily contract quantity on the Suffield system and an outage upstream of the Porcupine Hills Pipeline, lower contributions from energy services, lower gas processing volumes and lower operating cost recoveries. These decreases were partially offset by higher realized storage margins and higher fees earned by the extraction and gas processing businesses. Net revenue was also higher due to increased frac exposed volumes processed offset by lower realized frac margins.

Operating and administrative expense for the nine months ended September 30, 2012 was $125.9 million compared to $129.0 million for same period 2011. Operating costs were lower due to the impact of planned turnarounds in third quarter 2011, lower power prices and lower volumes processed at certain gas processing facilities, offset by a one-time liability adjustment recorded in the nine months ended September 30, 2011.

Amortization expense for the nine months ended September 30, 2012 was $42.4 million compared to $40.8 million for same period 2011. Accretion expense for the nine months ended September 30, 2012 was $2.3 million compared to $1.8 million for same period 2011. Increase in amortization and accretion expenses was as a result of expansions in the Gas business since fourth quarter 2011.

Gas Outlook

The Gas business is expected to deliver similar results for full year 2012 compared to full year 2011.

The following activities are expected to add to earnings in 2012; the completion of the Co-stream and Blair Creek projects, the 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 of operation of the Septimus Pipeline, the recent addition of the Co-stream Project and success in contracting new gas supply for Harmattan. Drilling activity in northeast B.C. and west central Alberta has increased compared to previous years 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, Glauconite, Duvernay and other liquids-rich gas formations, along with associated gas from oil or solution gas production. AltaGas has been able to offset a large portion of 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 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 $10 million, comprised of the gains recorded from the sale of the Groundbirch facility, settlement of a take-or-pay contract and liability adjustment offset by the $6 million impact of planned turnarounds at Younger and Harmattan in second and third quarter 2011.

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 12 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. For 2013, approximately 35 percent of volumes exposed to frac spreads have been hedged at approximately $35/Bbl.

POWER

OPERATING STATISTICS	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	**2012**	2011
Volume of power sold (GWh)	**843**	760	**2,461**	2,227
Average price realized on the sale of power ($/MWh)	**73.34**	80.67	**68.35**	74.83
Alberta Power Pool average spot price ($/MWh)	**78.09**	94.70	**59.48**	76.26

Three Months Ended September 30

The Busch Ranch project was completed on budget and ahead of schedule. AltaGas acquired a 50 percent interest in the 29 MW wind farm in Colorado for US$25 million. The project has a 25-year renewable energy purchase agreement with Black Hills/Colorado Electric Utility Company, LP (Black Hills). The project was fully commissioned on October 15, 2012.

The Power segment reported operating income of $21.9 million for third quarter 2012 compared to $21.5 million for same quarter 2011. Operating income increased as a result of new biomass power plants and the addition of Cogeneration II at Harmattan, partially offset by lower generation at Bear Mountain and lower realized power prices.

In the three months ended September 30, 2012, AltaGas was 59 percent hedged in Alberta at an average price of $67/MWh which effectively mitigated much of the lower Alberta power prices. In the same period in 2011, AltaGas was 68 percent hedged at an average price of $70/MWh.

Net revenue for the three months ended September 30, 2012 was $28.7 million compared to $27.8 million for same period 2011. Net revenue increased due to the addition of new biomass power plants, the addition of Cogeneration II at Harmattan, higher prices received at the gas-fired peaking plants and lower natural gas costs at all gas-fired generating facilities. These increases were partially offset by lower generation at Bear Mountain and lower realized power prices in Alberta.

Operating and administrative expense was $4.0 million for third quarter 2012 compared to $3.7 million for same quarter 2011. The increase was primarily due to operating and administrative costs related to new power plants.

Amortization expense was $2.9 million for third quarter 2012 compared to $2.6 million for same quarter 2011.

Nine Months Ended September 30

The Power segment reported operating income of $62.8 million for the nine months ended September 30, 2012 compared to $63.6 million for same period 2011. Operating income decreased as a result of lower Alberta power pool prices and higher general and administrative costs related to new power assets. These decreases were partially offset by hedging a higher percentage of volumes exposed to Alberta power pool price at higher prices, higher prices received at the gas-fired peaking plants, lower natural gas costs at all gas-fired generating facilities, the addition of new biomass power assets, the addition of Cogeneration II at Harmattan and higher power generated at Bear Mountain.

For the nine months ended September 30, 2012, AltaGas was 69 percent hedged in Alberta at an average price of $71/MWh. In same period 2011, AltaGas was 60 percent hedged at an average price of $67/MWh.

Net revenue for the nine months ended September 30, 2012 was $84.5 million compared to $81.3 million for same period 2011. Net revenue increased due to the addition of new biomass power assets, the addition of Cogeneration II at Harmattan, higher prices received at the gas-fired peaking plants, lower natural gas costs at all gas-fired generating facilities, and higher power generated at Bear Mountain. These increases were partially offset by lower Alberta power pool prices, which were mitigated by our effective hedging strategy.

Operating and administrative expense was $13.6 million for the nine months ended September 30, 2012 compared to $9.9 million for same period 2011. The increase was primarily due to operating and administrative costs related to new power assets and increased business development activities.

Amortization expense was $8.1 million for the nine months ended September 30, 2012 compared to $7.7 million for same period 2011.

Power Outlook

Overall AltaGas expects the earnings impact of new assets and AltaGas' effective hedging strategy, coupled with early strength in the Alberta spot market price, will continue to benefit the Power business in fourth quarter 2012. The second cogeneration facility at Harmattan and 35 MW of biomass power generation assets are expected to continue to increase earnings for the remainder of 2012. In the fourth quarter of 2012 the gas-fired peaker at the Gordondale Gas Plant site is also expected to add to earnings. In early October the Busch Ranch project in southern Colorado commenced commercial operations. The Alberta spot market has started out strong in the fourth quarter 2012 and the forward curve is consistent with the prior year. For fourth quarter 2012, AltaGas has hedged approximately 74 percent of volumes exposed to Alberta power price at an average price of $67/MWh. For 2013, AltaGas has hedged approximately one-third of power at an average price of $66/MWh. Management expects to be able to continue to execute short term hedges at premium prices to long term averages.

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. A resolution to this matter is expected in the fourth quarter 2012. AltaGas recorded $15.6 million in revenue for the duration of the outage which is recorded as an accounts receivable from the operator of the Sundance B Unit 3.

UTILITIES

OPERATING STATISTICS [1]	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	**2012**	2011
Utilities Canada				
Natural gas deliveries - end-use (PJ)[2]	**2.6**	2.3	**18.0**	15.3
Natural gas deliveries - transportation (PJ)[2]	**1.4**	1.1	**5.1**	3.5
Utilities USA				
Natural gas deliveries - end-use (Mmcf)	**2,624.1**	-	**2,624.1**	-
Natural gas deliveries - transportation (Mmcf)	**2,879.2**	-	**2,879.2**	-
Service sites [3]	**543,261**	75,126	**543,261**	75,126
Degree day variance from normal - AUI (%) [4]	**(53.6)**	(33.7)	**(12.9)**	6.5
Degree day variance from normal - Heritage Gas (%) [4]	**(38.8)**	(20.9)	**(10.4)**	(2.8)
Degree day variance from normal - SEMCO Michigan (%) [4]	**41.7**	-	**41.7**	-
Degree day variance from normal - SEMCO Alaska (%) [4]	**3.5**	-	**3.5**	-

[1] SEMCO results are from August 30, 2012.

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

[3] Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and SEMCO Michigan and Alaska, including transportation and non-regulated business lines.

[4] Degree days relate to AUI, Heritage Gas and SEMCO 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 materially affect the results of PNG for its residential and small commercial customers due to a BCUC approved rate stabilization mechanism. For SEMCO degree days are a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior fifteen years for Michigan and during the prior ten years for Alaska.

REGULATORY METRICS	Nine Months Ended September 30	
	2012	2011
Approved return on equity (%)		
Utilities Canada (average)	**10.0**	11.1
Utilities US (average)	**11.3**	-
Approved return on debt (%)		
Utilities Canada (average)	**6.4**	7.1
Utilities US (average)	**5.6**	-
Rate base[1]		
Utilities Canada	**546.6**	325.0
Utilities US[2][3]	**725.0**	-

[1] Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application.

[2] In U.S. dollars.

[3] Reflects AltaGas' 65 percent interest in Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA).

Three Months Ended September 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, Heritage Gas in Nova Scotia and SEMCO in Alaska and Michigan generally collect forecast operating and administrative costs, depreciation, interest expenses and income taxes 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. Earnings are however subject to variances between forecast costs and actual costs incurred.

The financial results in the Utility business are highly seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This results in stronger first and fourth quarters and weaker second and third quarters. Results for AUI, Heritage Gas and SEMCO can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. For AUI, Heritage Gas and SEMCO, 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 $5.5 million for third quarter 2012, a 90 percent increase compared to $2.9 million for same quarter 2011. Operating income increased mainly due to the acquisition of SEMCO, which contributed $3.4 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 2011/2012 GRA decision, higher depletion related to the Ikhil assets and lower approved returns at AUI and Heritage Gas.

Net revenue for the three months ended September 30, 2012 was $37.5 million compared to $15.9 million for the same period 2011. Net revenue was higher mainly due to the addition of SEMCO this quarter and 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 returns at AUI and Heritage Gas.

Operating and administrative expense was $24.2 million for third quarter 2012 compared to $10.0 million for same quarter 2011. The increase in operating costs was mainly due to the addition of SEMCO and PNG. Most operating and administrative costs incurred at the utilities are recoverable through the rate setting mechanism.

Amortization expense was $7.8 million in third quarter 2012 compared to $3.1 million in third quarter 2011. The increase in amortization expense was mainly due to the addition of SEMCO and 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.

Nine Months Ended September 30

For the nine months ended September 30, 2012, the Utility business reported operating income of $30.2 million, a 56 percent increase compared to $19.4 million for same period 2011. Operating income increased mainly due to the acquisitions of SEMCO and PNG, which contributed $15.1 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 returns at the Alberta and Nova Scotia utilities and the effect of AUI's 2011/2012 GRA decision.

Net revenue for the nine months ended September 30, 2012 was $107.4 million compared to $60.9 million for the same period 2011. Net revenue increased $43.4 million due to the acquisition of SEMCO this quarter and 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 returns at Heritage Gas.

Operating and administrative expense was $60.6 million for the nine months ended September 30, 2012 compared to $32.3 million for the same period 2011. The increase in operating costs was mainly due to the addition of SEMCO and PNG.

Amortization expense was $16.6 million for the nine months ended September 30, 2012 compared to $9.2 million for the same period 2011. The increase in amortization expense was mainly due to the addition of SEMCO and 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 the addition of PNG and SEMCO, and rate base growth of 17 percent and 12 percent at AUI and Heritage Gas, respectively. The first full year of PNG is expected to add approximately $24 million in EBITDA, from regulated operations, and SEMCO 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 by the end of 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. AltaGas increased total utility customers to more than 540,000 in 2012 from approximately 115,000 in 2011.

SEMCO

On February 1, 2012, AltaGas announced the acquisition of SEMCO for US$1.156 billion including US$371 million in assumed debt. During second quarter 2012, AltaGas received final approval from the Michigan Public Service Commission and in August 2012 received final approval from the Regulatory Commission of Alaska (RCA) for the SEMCO acquisition. On August 30, 2012, upon receipt of all approvals, AltaGas successfully completed the acquisition.

SEMCO indirectly holds a regulated natural gas distribution utility in Alaska through SEMCO Alaska (ENSTAR) and a 65 percent interest in a regulated natural gas storage utility in Alaska under construction called Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA). SEMCO also indirectly holds a regulated natural gas distribution utility and an interest in a regulated natural gas storage facility in Michigan.

SEMCO Michigan is expected to make application for updated rates in 2014 or later. ENSTAR is expected to apply for updated rates in 2014.

AUI

AUI received the Performance Based Regulatory (PBR) decision in September 2012. The decision set out the AUC's determinations about the form of PBR regulation that will be employed by Alberta electric and natural gas distribution companies beginning in 2013 in place of the existing cost-of-service regulatory system. The initial PBR term will last for five years and the AUC will make a determination at the end of the initial term as to how it will proceed for future years. Under the new PBR framework, utility rates will be set using a formula that adjusts the prior year's rates for inflation, productivity, exogenous events, extra capital invested and other factors. The PBR framework is intended to incentivize utilities to be more efficient.

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 western portion of the system was received in September 2012. A decision on the remainder of the system is expected in fourth 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 which includes an extension for this option to December 31, 2012. This provides an exclusive option for LNG Partners' for 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 have agreed that 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

In addition to growing its regulated network, during 2012 and 2013 Heritage Gas expects to spend approximately $8 million and $6 million respectively 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. Heritage Gas will initially operate its CNG business on an unregulated basis and has contracted to commence delivery to its first customer in April 2013. CNG trucking enables Heritage Gas to expand its gas distribution business and access customers who would otherwise be unable to enjoy the benefits of natural gas service.

Inuvik Gas & Ikhil

AltaGas has a one-third interest in both Inuvik Gas Ltd. (Inuvik Gas) and Ikhil natural gas reserves, which supply Inuvik Gas with natural gas to be delivered to the town of Inuvik. The Ikhil natural gas reserves have depleted more rapidly than expected. As such, alternative energy sources are being pursued. Inuvik Gas has installed a propane air mixture system to produce synthetic natural gas. Work continues with the town of Inuvik, the Northwest Territories Government and other parties to develop a long-term gas supply for the town.

CORPORATE

Three Months Ended September 30

The operating loss excluding the impact of mark-to-market accounting on risk management contracts for third quarter 2012 was $11.7 million compared to $9.4 million for same quarter 2011. The increase in loss was primarily due to transaction costs related to the SEMCO acquisition of $5.8 million partially offset by $0.6 million of unrealized pre-tax gain on equity investments in third quarter 2012 compared to an unrealized pre-tax loss of $1.6 million in same quarter 2011.

Net revenue was $6.7 million in third quarter 2012 compared to net revenue in a deficit position of $4.0 million in same quarter 2011. The increase was primarily due to changes in unrealized pre-tax gain versus loss on risk management contracts of $8.5 million, as well as an unrealized pre-tax gain of $0.6 million on an equity investment in third quarter 2012 compared to an unrealized pre-tax loss of $1.6 million in same quarter last year.

Operating and administrative expense was $11.5 million in third quarter 2012 compared to $6.5 million in same quarter 2011. The increase in general and administrative expense is primarily due to professional fees of $5.8 million related to the acquisition of SEMCO. The increase was partially offset by lower general and administrative costs.

Amortization expense was $0.8 million in third quarter 2012, compared to $1.4 million in third quarter 2011. The decrease is primarily due to reallocation of certain capital assets from other operating segments during third quarter 2011.

Nine Months Ended September 30

The operating loss excluding the impact of mark-to-market accounting on risk management contracts for the nine months ended September 30, 2012 was $28.0 million compared to $30.8 million for the same period in 2011. The decrease in loss was due to $0.9 million of unrealized pre-tax gain on equity investments for the nine months ended September 30, 2012 compared to an unrealized pre-tax loss of $8.1 million in same period 2011. This was partially offset by higher general and administrative costs primarily due to transaction costs.

Net revenue was $32.0 million for the nine months ended September 30, 2012 compared to net revenue in a deficit position of $26.1 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 $48.9 million, as well as an unrealized pre-tax gain of $0.9 million on an equity investment compared to an unrealized pre-tax loss of $8.1 million in same period last year.

Operating and administrative expense was $26.6 million for the nine months ended September 30, 2012 compared to $19.7 million for the same period 2011. The increase in general and administrative expense is primarily due to professional fees related to acquisitions.

Amortization expense was $2.6 million for the nine months ended September 30, 2012 compared to $3.1 million for same period 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 transaction costs related to acquisitions and higher general and administrative costs related to the Corporation’s growth.

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 third quarter 2012, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $1,059.7 million compared to $109.4 million in third quarter 2011. The net invested capital was $1,059.6 million in third quarter 2012 compared to $109.4 million in same quarter 2011.

Invested Capital - Investment Type

					Three Months Ended September 30, 2012
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**123.4**	**93.5**	**827.7**	**-**	**1,044.6**
Intangible assets	**0.5**	**-**	**13.1**	**0.3**	**13.9**
Long-term investments and other assets	**-**	**-**	**-**	**1.2**	**1.2**
	123.9	**93.5**	**840.8**	**1.5**	**1,059.7**
Disposals:					
Property, plant and equipment	**-**	**(0.1)**	**-**	**-**	**(0.1)**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**123.9**	**93.4**	**840.8**	**1.5**	**1,059.6**

Invested Capital - Investment Type					Three Months Ended September 30, 2011
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	62.5	33.8	13.5	0.6	110.4
Intangible assets	0.4	0.1	1.0	-	1.5
Long-term investments and other assets	-	(0.1)	-	(2.4)	(2.5)
	62.9	33.8	14.5	(1.8)	109.4
Disposals:					
Property, plant and equipment	-	-	-	-	-
Long-term investments and other assets	-	-	-	-	-
Net Invested capital	62.9	33.8	14.5	(1.8)	109.4

For the nine months ended September 30, 2012, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $1,459.5 million compared to $325.5 million in same period 2011. For the nine months ended September 30, 2012, AltaGas terminated a capital lease reducing property, plant and equipment balance by $13.9 million. Subsequent to the lease termination, AltaGas purchased the previously leased assets.

The net invested capital was $1,445.6 million for the nine months ended September 30, 2012 compared to $297.2 million in same period 2011.

Invested Capital - Investment Type					**Nine Months Ended September 30, 2012**
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Property, plant and equipment	**317.8**	**243.0**	**844.1**	**0.7**	**1,405.6**
Intangible assets	**1.6**	**-**	**14.1**	**0.4**	**16.1**
Long-term investments and other assets	**-**	**35.9**	**0.1**	**1.8**	**37.8**
	319.4	**278.9**	**858.3**	**2.9**	**1,459.5**
Disposals:					
Property, plant and equipment	**-**	**(13.9)**	**-**	**-**	**(13.9)**
Long-term investments and other assets	**-**	**-**	**-**	**-**	**-**
Net Invested capital	**319.4**	**265.0**	**858.3**	**2.9**	**1,445.6**

Invested Capital - Investment Type					Nine Months Ended September 30, 2011
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	128.2	84.5	20.6	8.5	241.8
Intangible assets	5.5	91.3	2.7	0.1	99.6
Long-term investments and other assets	-	(0.4)	-	(15.5)	(15.9)
	133.7	175.4	23.3	(6.9)	325.5
Disposals:					
Property, plant and equipment	(28.0)	-	-	-	(28.0)
Long-term investments and other assets	-	-	-	(0.3)	(0.3)
Net Invested capital	105.7	175.4	23.3	(7.2)	297.2

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

Growth capital expenditures of $1,056.4 million was reported in third quarter 2012 (third quarter 2011 - $107.4 million).

In the Gas business, growth capital comprised $67.3 million for construction of Gordondale, $24.6 million for construction of the Co-stream Project, $20.6 million for the Quatro asset purchase, $7.5 million for the Blair Creek expansion and $1.3 million for various Gas related projects.

In the Power business, growth capital projects included $68.3 million for the Forrest Kerr Project, $25.2 million for Busch Ranch offset by the expected U.S. government grant of $7.4 million, $3.1 million for the McLymont Project, $1.5 million for the Cogeneration II project and $2.1 million for various renewable power development projects.

The Utility business reported growth capital of $819.9 million from the SEMCO acquisition and $20.9 million from other utilities.

The Corporate segment reported an increase in capital of $1.2 million related to the change in fair value of AltaGas' investment in Alterra and $0.3 million for other projects.

Maintenance and administrative capital expenditures in third quarter 2012 were $2.3 million and $1.0 million, respectively (third quarter 2011 - $0.6 million and $1.4 million, respectively).

Invested Capital - Use					**Three Months Ended September 30, 2012**
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Maintenance	**1.6**	**0.7**	**-**	**-**	**2.3**
Growth	**121.3**	**92.8**	**840.8**	**1.5**	**1,056.4**
Administrative	**1.0**	**-**	**-**	**-**	**1.0**
Invested capital	**123.9**	**93.5**	**40.8**	**1.5**	**1,059.7**

Invested Capital - Use					Three Months Ended September 30, 2011
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	0.6	-	-	-	0.6
Growth	62.1	33.8	14.5	(3.0)	107.4
Administrative	0.2	-	-	1.2	1.4
Invested capital	62.9	33.8	14.5	(1.8)	109.4

For the nine months ended September 30, 2012, growth capital expenditures was $1,451.0 million (same period 2011 - $313.5 million).

In the Gas business, growth capital comprised $152.0 million for construction of Gordondale, $76.1 million for construction of the Co-stream Project, $48.7 million for the Blair Creek expansion, $20.6 million for the Quatro asset purchase and $16.1 million for various Gas related projects.

In the Power business, growth capital projects included $182.9 million for the Forrest Kerr Project, $34.7 million for the acquisition of Decker International Inc. (DEI), $25.2 million for Busch Ranch offset by the expected U.S. government grant of $7.4 million, $12.1 million for the buyout of the Maxim capital lease, $9.4 million for the Cogeneration II project, $3.3 million for the Crowsnest Pass project, $3.1 million for the McLymont Project, $3.5 million for gas-fired peakers at Gordondale and $10.2 million for various renewable power development projects.

The Utility business reported growth capital of $819.9 million from the SEMCO acquisition and $38.4 million from other utilities.

The Corporate segment reported an increase in capital of $1.8 million related to the change in fair value of AltaGas' investment in Alterra and $0.4 million for other projects.

Maintenance and administrative capital expenditures for the nine months ended September 30, 2012 were $5.6 million and $2.9 million, respectively (same period 2011 - $2.3 million and $9.7 million, respectively).

Invested Capital - Use — **Nine Months Ended September 30, 2012**

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	**3.7**	**1.9**	**-**	**-**	**5.6**
Growth	**313.5**	**277.0**	**858.3**	**2.2**	**1,451.0**
Administrative	**2.2**	**-**	**-**	**0.7**	**2.9**
Invested capital	**319.4**	**278.9**	**858.3**	**2.9**	**1,459.5**

Invested Capital - Use — Nine Months Ended September 30, 2011

($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	2.2	0.1	-	-	2.3
Growth	130.5	175.3	23.3	(15.6)	313.5
Administrative	0.9	-	-	8.8	9.7
Invested capital	133.6	175.4	23.3	(6.8)	325.5

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 third quarter 2012, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 8 of the interim Consolidated Financial Statements:

- Commodity forward contracts: The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The energy services division transacts primarily on this basis. Prior to spring of 2011, PNG 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. In accordance with revised price risk management procedures approved by the BCUC, PNG has not entered into any new hedging arrangements since that time 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 $1,000.00/MWh in third quarter 2012 and $0.00/MWh to $999.99/MWh in third quarter 2011. The average Alberta spot price was $78.09/MWh in third quarter 2012 (third quarter 2011 - $94.70/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 $66.91/MWh in third quarter 2012 (third quarter 2011 - $80.67/MWh). For fourth quarter 2012, AltaGas has hedged approximately 74 percent of volumes exposed to Alberta power price at an average price of $67/MWh. For 2013, AltaGas has hedged approximately one-third of power at an average price of $66/MWh.

  NGL frac spread hedges: The Corporation executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During third 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 third quarter 2012 was an estimated $23/Bbl (third quarter 2011 – $42/Bbl). The average NGL frac spread realized by AltaGas in third quarter 2012 was $28.59/Bbl after deducting extraction premiums (third quarter 2011 - $22.95/Bbl which was impacted by the 2011 Younger turnaround). 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 35 percent of its estimated 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 September 30, 2012, the Corporation had no interest rate swaps outstanding. At September 30, 2012, the Corporation had fixed the interest rate on 76.8 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 third quarter 2012, AltaGas entered in a back-to-back swap transaction for a notional amount of US$192.5 million which was settled on August 23, 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 September 28, 2012, AltaGas issued $350 million of senior unsecured medium-term notes. The notes carry a coupon rate of 3.72 percent and mature on September 28, 2021.

On September 28, 2012, AltaGas extended its US$300 million unsecured credit facility with three Canadian chartered banks. The credit facility's term was extended with a new maturity date of September 2, 2014.

On August 30, 2012, AltaGas issued 13,915,000 common shares on conversion of the subscription receipts issued in February 2012 to fund the SEMCO acquisition, with net proceeds of $378.4 million.

On August 30, 2012, SEMCO entered into an agreement for a new US$100 million unsecured credit facility which is available for working capital purposes and expires on August 30, 2014.

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 September 30		Nine Months Ended September 30	
($ millions)	**2012**	2011 (restated)	**2012**	2011 (restated)
Cash from operations	**17.0**	63.3	**154.3**	149.8
Investing activities	**(1,056.1)**	(113.0)	**(1,485.6)**	(237.7)
Financing activities	**1,095.2**	41.1	**1,386.9**	88.1
Change in cash	**56.1**	(8.6)	**55.6**	0.2

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $17.0 million in third quarter 2012 compared to $63.3 million in third quarter 2011. The decrease in cash from operations was primarily a result of lower net change in non-cash working capital and slightly lower funds from operations in the quarter as compared to third quarter 2011, due to the cash used for transaction costs and foreign exchange loss related to the SEMCO acquisition.

Working Capital	As at September 30	
($ millions except current ratio)	**2012**	2011 (restated)
Current assets	**506.9**	280.2
Current liabilities	**468.7**	450.4
Working capital	**38.2**	(170.2)
Current ratio	**1.08**	0.62

Working capital was $38.2 million as at September 30, 2012, compared to a deficit position of $170.2 million as at September 30, 2011. The working capital ratio was 1.08 at the end of third quarter 2012 compared to 0.62 at the end of same quarter 2011. The working capital ratio increased due to an increase in cash, inventory and accounts receivable and a decrease in current portion of long-term debt. This was partially offset by an increase in accounts payable, short-term debt and customer deposits.

Investing Activities

Cash used for investing activities in third quarter 2012 was $1,056.1 million compared to $113.0 million in third quarter 2011. Investing activities in third quarter 2012 were primarily comprised of $774.5 million related to the SEMCO acquisition, $230.6 million of property, plant and equipment expenditures, $43.1 million on acquisition of intangible assets, and $6.4 million of changes in regulatory and other assets and liabilities. Investment activities in third quarter 2011 were comprised of $90.1 million of property, plant and equipment expenditures, $18.1 million on acquisition of intangible assets and $4.8 million of changes in regulatory and other assets and liabilities.

Financing Activities

Cash received from financing activities was $1,095.2 million in third quarter 2012 compared to $41.1 million in third quarter 2011. Financing activities in third quarter 2012 were primarily comprised of $826.0 million from issuance of MTNs and other long-term debts, repayment of long-term debt of $102.7 million and net proceeds from issuance of common shares of $391.4 million compared to the draw-downs of $60.8 million of short-term debt and net proceeds from issuance of common shares of $10.7 million in third quarter 2011. Dividends paid in third quarter 2012 were $35.7 million, compared to $30.1 million in third 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 September 30, 2012, AltaGas had total debt outstanding of $2,586.4 million, up from $1,337.1 million at December 31, 2011. As at September 30, 2012, AltaGas had $1,925 million in MTNs outstanding, PNG debenture notes of $85.7 million and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances, and letters of credit through bank credit facilities of $1,621 million. As at September 30, 2012, AltaGas had drawn bank debt of $531.9 million and letters of credit outstanding of $138.9 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 September 30, 2012, the Corporation had $904.1 million in available credit facilities and $58.4 million in cash and cash equivalents.

On September 28, 2012, AltaGas issued $350 million of senior unsecured MTNs. 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, as well as for general corporate purposes.

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$1.156 billion acquisition of SEMCO closed on August 30, 2012 including US$371 million in assumed debt. The transaction was funded through the net proceeds of the equity offering, together with funds drawn on existing credit facilities.

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 were released from escrow on August 30, 2012 and each receipt was automatically exchanged, for one common share of

AltaGas and a dividend equivalent payment of $0.69 per common share in respect of the dividends declared by AltaGas since the initial deal close.

As at September 30, 2012, AltaGas' current portion of long-term debt was $4.4 million (September 30, 2011 - $101.6 million).

AltaGas' earnings interest coverage for the rolling 12 months ended September 30, 2012 was 2.56 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 non-controlling interests), short-term and long-term debt (including current portion) less cash and cash equivalents to comprise its capital structure.

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. AltaGas' debt-to-total capitalization ratio as at September 30, 2012, was 56.0 percent (December 31, 2011 - 49.5 percent).

	September 30 2012	December 31 2011 (restated)
Debt		
Short-term debt	**$ 30,168**	$ 16,824
Current portion of long-term debt	**4,371**	105,962
Long-term debt	**2,551,827**	1,214,298
Less cash and cash equivalent	**(58,429)**	(2,875)
	2,527,937	1,334,209
Shareholders' equity	**1,951,303**	1,355,362
Non-controlling interests	**36,905**	5,426
Total capitalization	**$ 4,516,145**	$ 2,694,997
Debt-to-total capitalization ratio (%)	**56.0**	49.5

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

Ratios	Debt covenant requirements
Debt-to-capitalization	For 2 full quarters post SEMCO acquisition - not greater than 65 percent
	Afterwards - 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 September 30 2012**	Drawn at December 31 2011
Demand operating facilities	71.0	**3.4**	3.4
Extendible revolving letter of credit facility	75.0	**52.8**	67.7
PNG operating facility	25.0	**17.6**	13.9
PNG term revolver	35.0	**20.0**	20.0
Bilateral letter of credit facility	125.0	**78.8**	124.3
AltaGas Ltd. revolving credit facility (1) (2))	600.0	**266.7**	8.0
Utility Group revolving credit facility	200.0	**27.5**	30.4
USD unsecured credit facility (1) (2)	300.0	**169.2**	-
SEMCO Energy USD unsecured credit facility (1) (2)	100.0	**12.3**	-
CINGSA USD secured construction and term loan facility (1) (2))	90.0	**68.6**	-
	1,621.0	**716.9**	267.7

(1) Borrowing capacity assumed at par.

(2) Drawn in U.S. dollars converted at September month-end rate (1 U.S. Dollar = 0.9837 Canadian Dollar).

As at September 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 September 30, 2012, AltaGas had draws and letters of credit of $3.4 million (December 31, 2011 - $3.4 million) outstanding against these demand facilities.

As at September 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 September 30, 2012, AltaGas had letters of credit of $52.8 million (December 31, 2011 - $67.7 million) outstanding against the extendible revolving letter of credit facility.

As at September 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 September 30, 2012 were $17.6 million (December 31, 2011 - $13.9 million).

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

As at September 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 September 30, 2012, AltaGas had $78.8 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 September 30, 2012, AltaGas had US$226.5 million and $44.0 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 September 30, 2012, AltaGas had $27.5 million (December 31, 2011 - $30.4 million) of debt outstanding under the facility.

AltaGas has a US$300 million, unsecured credit facility maturing on September 2, 2014. Borrowings on the facility can be by way of prime loans, US base-rate loans, LIBOR loans or bankers' acceptance equivalent loans. At September 30, 2012, AltaGas had US$172.0 million outstanding under the facility.

SEMCO Energy has a US$100 million, unsecured credit facility maturing on August 30, 2014. Borrowings on the facility can be by way of US base-rate loans, letters of credit and LIBOR loans. As at September 30, 2012 SEMCO had US$12.5 million letters of credit and draws outstanding against the facility.

CINGSA has a US$90 million, secured construction and term loan facility maturing on November 14, 2015. Borrowings on the facility can be by way of LIBOR loans or alternative base rate loans, with the proceeds being used to fund 50 percent of the anticipated costs of the CINGSA Storage Project of which SEMCO owns 65 percent. The facility is non-recourse to the CINGSA joint venture partners. As at September 30, 2012 CINGSA had US$69.7 million in draws outstanding against 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 (third quarter 2011 - $750 thousand).

SHARE INFORMATION

As at September 30, 2012, AltaGas had 104.66 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 $3.9 billion based on a closing trading price on September 30, 2012, of $33.75 per common share, $25.90 per series A preferred share and $25.05 per series C USD preferred share. As at September 30, 2012, there were 5.4 million options outstanding and 1.9 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 September 10, 2012, the Board of Directors approved an increase in the monthly dividend to $0.12 per common share from $0.115 per common share effective with the September dividend.

On 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 effective with the November dividend.

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	**0.35**	0.33
Fourth quarter	**-**	0.34
Total	**1.04**	1.33

Series A 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**	0.3125
Fourth quarter	**-**	0.3125
Total	**0.9375**	1.25

Series C Preferred Share Dividends

Years ended December 31 (US$ per preferred share)	**2012**	2011
Third quarter	**0.3473**	-
Fourth quarter	**-**	-
Total	**0.3473**	-

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 September 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, 2014.

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, British Columbia (PNG) 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 depreciation, depletion and amortization expense, asset retirement obligations, asset impairment assessment, financial instruments, income taxes, employee future benefits, litigation, share-based compensation and regulatory 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 nine months ended September 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 (DC&P) 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 third 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)	**Q3-12**	Q2-12	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11	Q4-10
Total revenue	**311.3**	271.7	376.5	399.8	339.2	322.8	384.5	362.2
Net revenue(2)	**147.3**	144.9	167.4	156.9	116.5	107.2	136.1	130.8
Operating income(2)	**33.4**	29.4	69.6	49.2	33.4	34.2	58.3	47.6
Net income before taxes	**18.8**	37.9	57.8	44.6	18.0	11.8	38.5	35.4
Net income applicable to common shares(3)	**8.0**	25.8	41.3	31.7	11.1	13.3	26.7	26.5

($ per share)	**Q3-12**	Q2-12	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11	Q4-10
Net income applicable to common shares								
Basic(3)	**0.08**	0.29	0.46	0.38	0.13	0.16	0.32	0.32
Diluted(3)	**0.08**	0.28	0.46	0.37	0.13	0.16	0.32	0.32
Dividends declared	**0.35**	0.345	0.345	0.34	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:

- 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;
- In second quarter 2012, AltaGas reported $22.3 million of revenue as a result of mark-to-market accounting; and
- In third quarter 2012, AltaGas completed the acquisition of SEMCO for total consideration of US$1.156 billion including US$371 million in assumed debt, adding approximately US$725 million in regulated rate base. In the quarter, AltaGas recorded $12.5 million in pre-tax transaction costs primarily related to the acquisition of SEMCO and other business development related activities.

Consolidated Balance Sheets

(unaudited)

($ thousands)	September 30 2012	December 31 2011 (restated)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 58,429**	$ 2,875
Accounts receivable	**258,374**	234,534
Inventory *(note 4)*	**94,700**	12,467
Restricted cash holdings from customers	**24,848**	19,672
Regulatory assets	**2,372**	5,141
Risk management assets *(note 8)*	**48,141**	68,404
Prepaid expense and other current assets	**19,989**	8,642
	506,853	351,735
Property, plant and equipment	**3,803,070**	2,486,050
Intangible assets	**207,095**	177,516
Goodwill *(note 5)*	**714,827**	281,123
Regulatory assets	**270,556**	125,271
Risk management assets *(note 8)*	**14,570**	21,642
Long-term investments and other assets *(note 8)*	**36,383**	25,406
Investments accounted for by equity method	**143,435**	87,483
	$ 5,696,789	$ 3,556,226
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 7)*	**$ 324,789**	$ 314,422
Dividends payable	**12,556**	10,264
Short-term debt	**30,168**	16,824
Current portion of long-term debt *(notes 6 - 8)*	**4,371**	105,962
Customer deposits	**52,394**	25,570
Regulatory liabilities	**977**	503
Risk management liabilities *(note 8)*	**35,175**	72,973
Other current liabilities	**8,312**	11,352
	468,742	557,870
Long-term debt *(notes 6 - 8)*	**2,551,827**	1,214,298
Asset retirement obligations	**57,042**	44,318
Deferred income taxes	**374,649**	265,834
Regulatory liabilities	**98,967**	26,686
Risk management liabilities *(note 8)*	**7,967**	20,608
Other long-term liabilities	**29,479**	28,810
Future employee obligations	**119,908**	37,014
	3,708,581	2,195,438

($ thousands)	**September 30 2012**	December 31 2011 (restated)
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 104.66 million issued and outstanding *(note 9)*	**1,621,043**	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)*	**198,978**	-
Contributed surplus	**9,704**	7,441
Accumulated deficit	**(59,290)**	(38,635)
Accumulated other comprehensive loss	**(13,258)**	(11,839)
	1,951,303	1,355,362
Non-controlling interests	**36,905**	5,426
	$ 5,696,789	$ 3,556,226

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(unaudited)

($ thousands except per share amounts)	Three Months Ended September 30 **2012**	Three Months Ended September 30 2011 (restated)	Nine Months Ended September 30 **2012**	Nine Months Ended September 30 2011 (restated)
REVENUE				
Operating	**$ 284,941**	$ 314,734	**$ 895,788**	$ 1,023,847
Unrealized gain (loss) on risk management contracts *(note 8)*	**6,011**	(2,536)	**30,811**	(18,060)
Other (expenses) revenue	**643**	(1,561)	**1,158**	(8,093)
Income from equity investments	**19,655**	28,568	**31,720**	48,803
	311,250	339,205	**959,477**	1,046,497
EXPENSES				
Cost of sales	**163,989**	222,711	**499,796**	686,592
Operating and administrative	**81,046**	64,309	**224,546**	189,432
Accretion of asset retirement obligations	**770**	608	**2,353**	1,824
Depreciation, depletion and amortization	**26,023**	20,708	**69,649**	60,767
	271,828	308,336	**796,344**	938,615
Foreign exchange loss	**6,791**	65	**8,940**	77
Interest expense				
Short-term debt	**391**	1,449	**1,296**	4,360
Long-term debt	**13,468**	11,320	**38,390**	35,027
Income before income taxes	**18,772**	18,035	**114,507**	68,418
Income tax expense				
Current	**101**	495	**4,071**	3,707
Deferred	**5,018**	3,937	**23,495**	6,098
Net income after taxes	**13,653**	13,603	**86,941**	58,613
Net income applicable to non-controlling interests	**967**	-	**1,604**	-
Net income applicable to the controlling interests	**12,686**	13,603	**85,337**	58,613
Preferred share dividends	**4,643**	2,500	**10,233**	7,500
Net income applicable to common shares	**$ 8,043**	$ 11,103	**$ 75,104**	$ 51,113
Net income per common share (note 10)				
Basic	**$ 0.08**	$ 0.13	**$ 0.82**	$ 0.61
Diluted	**$ 0.08**	$ 0.13	**$ 0.81**	$ 0.61
Weighted average number of common shares outstanding (notes 9 and 10) *(thousands)*				
Basic	**95,332**	83,628	**91,638**	83,188
Diluted	**96,677**	84,813	**92,917**	84,242

See accompanying notes to the Consolidated Financial Statements.

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

(unaudited)

($ thousands)	Three Months Ended September 30 **2012**	Three Months Ended September 30 2011 (restated)	Nine Months Ended September 30 **2012**	Nine Months Ended September 30 2011 (restated)
Net income after taxes	**$ 13,653**	$ 13,603	**$ 86,941**	$ 58,613
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	**(442)**	(1)	**(335)**	(3)
Effective portion of gains on derivative instruments that qualifies as cash flow hedge (net of tax)	**728**	68	**1,301**	898
Unrealized income (loss) on available-for-sale financial assets (net of tax)	**457**	(1,282)	**738**	(6,510)
Hedge of net investment in foreign operations	**2,554**	-	**2,554**	-
Translation of net investment in foreign operations	**(5,676)**	-	**(5,676)**	-
	(2,379)	(1,215)	**(1,418)**	(5,615)
Comprehensive income attributable to common shareholders and non-controlling interests	**$ 11,274**	$ 12,388	**$ 85,523**	$ 52,998
Accumulated other comprehensive loss, beginning of period	**$ (10,879)**	$ (8,130)	**$ (11,840)**	$ (3,730)
Other comprehensive income (loss), net of tax	**(2,379)**	(1,215)	**(1,418)**	(5,615)
Accumulated other comprehensive loss, end of period	**$ (13,258)**	$ (9,345)	**$ (13,258)**	$ (9,345)

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(unaudited)

($ thousands)		September 30 2012		Nine Months Ended September 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		**11,495**		3,186
Shares issued under DRIP [1]		**26,877**		26,661
Shares issued on conversion of subscription receipts		**378,402**		-
Balance, end of period		**1,621,043**		1,052,880
Preferred shares *(note 9)*				
Balance, beginning of period		**194,126**		194,126
Series C issued		**198,978**		-
Balance, end of period		**393,104**		194,126
Contributed surplus				
Balance, beginning of period		**7,440**		5,672
Amortization of share options		**2,920**		1,334
Exercise of share options		**(452)**		(1,892)
Forfeiture of share options		**(204)**		(159)
Balance, end of period		**9,704**		4,955
Accumulated deficit				
Balance, beginning of period		**(38,635)**		(9,210)
Net income applicable to the controlling interests		**85,337**		58,613
Acquisition of non-controlling interest		**(405)**		-
Common share dividends		**(95,354)**		(82,417)
Preferred share dividends - Series A		**(7,500)**		(7,500)
Preferred share dividends - Series C		**(2,733)**		-
Balance, end of period		**(59,290)**		(40,514)
Accumulated other comprehensive loss				
Balance, beginning of period		**(11,840)**		(3,730)
Other comprehensive loss attributable to common shareholders and non-controlling interests		**(1,418)**		(5,615)
Balance, end of period		**(13,258)**		(9,345)
Total shareholders' equity		**1,951,303**		1,202,102
Non-controlling interests				
Balance, beginning of period		**5,426**		-
Net income applicable to non-controlling interests		**1,604**		-
Business acquisition *(note 3)*		**36,447**		-
Acquisition of non-controlling interests		**(230)**		-
Redemption of non-controlling interests		**(5,208)**		-
Distribution by subsidiaries to non-controlling interests		**(1,134)**		-
Balance, end of period		**36,905**		-
Total equity	$	**1,988,208**	$	1,202,102

[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 September 30 2012	Three Months Ended September 30 2011 (restated)	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011 (restated)
Cash from operations				
Net income after taxes	**$ 13,653**	$ 13,603	**$ 86,941**	$ 58,613
Items not involving cash:				
Depreciation, depletion and amortization	**26,023**	20,708	**69,649**	60,767
Accretion of asset retirement obligations	**770**	608	**2,353**	1,824
Share-based compensation	**953**	(236)	**2,265**	(717)
Deferred income tax expense	**5,018**	3,937	**23,495**	6,098
Gain on sale of assets	**-**	-	**-**	(6,172)
Income from equity investments	**(19,655)**	(28,568)	**(31,720)**	(48,803)
Unrealized (gains) losses on risk management contracts	**(6,011)**	2,536	**(30,811)**	18,060
Unrealized (gains) losses on held-for-trading investments	**(604)**	1,553	**(949)**	8,113
Other	**(825)**	556	**934**	2,171
Asset retirement obligations settled	**144**	-	**(373)**	(195)
Distributions from equity investments	**22,295**	29,579	**33,697**	58,798
Contributions to equity investments	**(98)**	(790)	**(531)**	(7,132)
Changes in components of working capitals				
Accounts receivable	**(47,330)**	(2,163)	**5,956**	7,773
Inventory	**(9,611)**	(6,391)	**(10,776)**	5,194
Other current assets	**(2,794)**	1,144	**(1,496)**	(749)
Regulatory assets (current)	**(1,745)**	(384)	**2,447**	(680)
Accounts payable and accrued liabilities	**51,206**	66,829	**(32,335)**	35,659
Dividends payable	**2,177**	49	**2,292**	144
Customer deposits	**(1,312)**	53	**5,125**	1,625
Regulatory liabilities (current)	**(496)**	(435)	**474**	291
Other current liabilities	**(2,405)**	2,006	**(5,823)**	(3,599)
Net changes for accruals related to property, plant and equipment and intangible assets	**(5,849)**	(43,798)	**31,574**	(47,720)
Other non-cash working capital	**(6,527)**	2,872	**1,886**	393
	16,977	63,268	**154,274**	149,756
Investing activities				
Change in restricted cash holdings from customers	**(126)**	(53)	**(6,985)**	(1,845)
Acquisition of property, plant, and equipment	**(230,631)**	(90,081)	**(614,886)**	(221,770)
Acquisition of intangible assets	**(43,095)**	(18,104)	**(43,112)**	(23,252)
Changes in regulatory and other assets and liabilities	**(6,375)**	(4,774)	**(215)**	(4,196)
Disposition of property, plant, and equipment	**-**	(20)	**-**	13,400
Acquisition of long-term investments	**(500)**	-	**(4,500)**	-
Business acquisitions, net of cash acquired	**(774,529)**	-	**(809,234)**	-
Distribution to non-controlling interest	**(547)**	-	**(1,134)**	-
Acquisition of non-controlling interest	**(322)**	-	**(5,522)**	-
	(1,056,125)	(113,032)	**(1,485,588)**	(237,663)

($ thousands)	Three Months Ended September 30 2012	Three Months Ended September 30 2011 (restated)	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011 (restated)
Financing activities				
Net issuance (repayment) of short-term debt	**16,747**	60,781	**13,344**	(49,964)
Issuance of long-term debt	**825,950**	-	**1,188,631**	198,888
Repayment of long-term debt	**(102,743)**	(275)	**(327,549)**	(1,125)
Dividends - common shares	**(31,137)**	(27,570)	**(93,062)**	(82,272)
Dividends - preferred shares	**(4,643)**	(2,500)	**(10,233)**	(7,500)
Net proceeds from issuance of common shares	**391,395**	10,674	**416,775**	30,100
Net proceeds from issuance of preferred shares	**(356)**	-	**198,978**	-
	1,095,213	41,110	**1,386,884**	88,127
Effect of exchange rate changes on cash and cash equivalents	**(16)**	-	**(16)**	-
Change in cash and cash equivalents	**56,049**	(8,654)	**55,554**	220
Cash and cash equivalents, beginning of period	**2,380**	9,897	**2,875**	1,023
Cash and cash equivalents, end of period	**$ 58,429**	$ 1,243	**$ 58,429**	$ 1,243

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

	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
Interest paid	**$ 18,251**	$ 14,260	**$ 42,981**	$ 35,459
Income taxes paid	**$ 3,210**	$ 160	**$ 9,974**	$ 2,910

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 Services (U.S.) Inc., 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 construction of the Harmattan Co-stream (Co-stream Project) and the Gordondale Gas Processing Facility (Gordondale).

The Power business includes 585 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 (PPA), 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. In Canada, 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 in Canada 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 August 30, 2012, AltaGas and AltaGas Utility Holdings (U.S.) LLC (AUH(US)) acquired from Continental Energy Systems LLC (Continental) all of the issued and outstanding shares of Semco Holding Corporation (SEMCO) for aggregate consideration of US$1.156 billion, subject to adjustment, including approximately US$371 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 and natural gas storage operations in Alaska and Michigan.

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), Inuvik Gas Ltd. (Inuvik Gas), Ikhil Joint Venture, Craven LP, LLC, Grayling Generating Station Limited Partnership and Eaton Rapids Gas Storage. 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 "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. For a full discussion of the accounting policies and disclosures, refer to the AltaGas 2011 annual Consolidated Financial Statements.

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 as incurred. The excess of the consideration transferred over the fair value of the assets and liabilities acquired is recognized as goodwill.

Rate-Regulated Operations

SEMCO Energy, AUI, Heritage Gas, PNG and Inuvik Gas (collectively "Utilities") engage in the delivery and sale of natural gas and are regulated by the Michigan Public Service Commission (MPSC) and Regulatory Commission of Alaska (RCA), 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 MPSC, RCA, 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 MPSC, RCA, 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 are expected to 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 expected 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 and NGL, which are valued at the lower of cost or net realizable value. Cost of inventory is assigned using a weighted average cost formula. The gas inventory held in storage is reported at average cost. In general, commodity costs and variable transportation costs are capitalized as gas in underground storage. Fixed costs, primarily pipeline demand charges and storage charges, are expensed as incurred through the cost of gas.

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. Included in depreciation expense at SEMCO Energy is an amount allowed for regulatory purposes for future removal and site restoration.

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future expense when it is refunded or collected in rates.

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. 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 and PNG are not depreciated until the year after they are brought into active service and net additions to utility assets at AUI and SEMCO Energy 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 for rate setting purposes.

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 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.

Energy services relationships are amortized on a straight-line basis over the 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. If an impairment test of goodwill shows that the carrying amount of the goodwill is in excess of the fair value, a corresponding impairment loss would be recorded in the Consolidated Statement of Income.

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.

AltaGas designated some of its US dollar-denominated long-term debt as a foreign currency hedge of some of its investment in foreign operations. Accordingly, foreign exchange gains and losses, from the dates of designation, on the translation of the US dollar-denominated long-term debt are also included in Other Comprehensive Income (Loss).

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 or 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.

Foreign Currency Translation

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

For foreign entities with a functional currency other than Canadian dollars, AltaGas' reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in Other Comprehensive Income (Loss).

The exchange rate used to convert a US dollar to a Canadian dollar for the period ending September 30, 2012 was 0.9837 (September 30, 2011 - 1.0482).

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 average number of common shares that could potentially dilute earnings 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 instruments. These anti-dilutive instruments 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, depletion and amortization expense, asset retirement obligations, asset impairment assessment, financial instruments, income taxes, employee future benefits, litigation, share-based compensation and regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate which often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

CHANGE IN ACCOUNTING POLICIES

Balance Sheet Disclosures - 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.

In July 2012, FASB issued ASU 2012-02, an amendment to ASC 350-30 whereby an entity first assesses qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test, which results in a guidance similar to the goodwill impairment testing. This amendment does not have any impact for the preparation and presentation of AltaGas consolidated financial statements.

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

SEMCO

On August 30, 2012, AltaGas, through a wholly-owned subsidiary, acquired 100 percent of SEMCO from Continental.

SEMCO owns SEMCO Energy a regulated public utility headquartered in Port Huron, Michigan. SEMCO's primary business is the transmission, distribution, and sale of natural gas to its customers. SEMCO's gas distribution business distributes and transports natural gas for approximately 286,000 customers in Michigan and approximately 134,000 customers in Alaska. The Gas Distribution Business is subject to regulation by the MPSC in Michigan and the RCA in Alaska. SEMCO's other businesses primarily include operations and investments in propane distribution, intrastate natural gas pipelines, and natural gas storage facilities. SEMCO is currently developing the Cook Inlet Natural Gas Storage Alaska, LLC (CINGSA) in-field storage facility in the Cook Inlet area of Alaska.

AltaGas paid an aggregate purchase price of $1,140.2 million including $365.7 million in assumed debt. Transaction costs related to the acquisition amounted to $6.6 million, which have been expensed in the Consolidated Statement of Income, within operating and administrative expenses.

Below is a provisional purchase price allocation based on the Statement of Financial Position as at August 30, 2012, using an exchange rate of 0.9863 to convert US dollar to Canadian dollar.

		SEMCO
Cash consideration	$	780,703
Less cash acquired		(6,168)
Total consideration		774,535
Purchase price allocation		
Assets acquired		
Current assets	$	112,894
PPE		801,425
Regulatory assets		140,209
Goodwill		434,850
Long-term investments and other assets		40,248
		1,529,626
Less liabilities assumed		
Current liabilities	$	67,184
Long-term debt		365,696
Deferred income taxes		95,511
Regulatory liabilities		75,443
Other long-term liabilities		125,329
		729,163
Non-controlling interest	$	25,928
	$	774,535

For the month of September 2012, SEMCO recorded revenues of $28.9 million and net income of $41 thousand. Had the acquisition occurred on January 1, 2012, AltaGas pro forma consolidated revenue would have been approximately $1,322.5 million and consolidated net income of $91.7 million for the nine months ended September 30, 2012 (respectively $358.8 million and $6.4 million for the three months ended September 30, 2012). This pro forma financial information is solely presented for informational purposes only, does not include other anticipated financial benefits from such items as potential cost savings or synergies arising from the acquisition and is not necessarily indicative of what the financial results of operations would have been had the acquisition been completed at the dates indicated.

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. Power generated from these assets is fully contracted with long-term 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, within operating and administrative expenses.

		DEI
Cash consideration	$	34,724
Less cash acquired		(25)
Total consideration		34,699
Purchase price allocation		
Assets acquired		
Current assets	$	389
Long-term investments and other assets		46,551
		46,940
Less liabilities assumed		
Current liabilities	$	1,725
Non-controlling interest	$	10,516
	$	34,699

4. INVENTORY

		September 30 2012		December 31 2011 (restated)
Natural gas held in storage		**85,883**		10,081
Inventory utilities		**8,037**		1,663
Inventory gas plants		**780**		723
	$	**94,700**	$	12,467

5. GOODWILL

		September 30 2012		December 31 2011 (restated)
Balance, beginning of period	**$**	**281,123**	$	222,602
Business Acquisition		**434,851**		58,595
US GAAP transitional adjustment *(note 18)*		**-**		(74)
Foreign exchange translation		**(1,147)**		-
Balance, as at September 30, 2012	**$**	**714,827**	$	281,123

6. LONG-TERM DEBT

	Maturity date	**September 30 2012**	December 31 2011 (restated)
Credit facilities			
$200 million Utility Group[1]	17-Nov-2015	**27,460**	30,962
$600 million Unsecured extendible revolving[1] [2]	30-May-2016	**266,665**	8,000
US$300 million Unsecured [1]	02-Sep-2014	**169,196**	-
US$90 million CINGSA secured construction and term loan[3]	14-Nov-2015	**68,564**	-
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**	-
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**350,000**	-
US$5 million SEMCO unsecured - 7.03 percent	11-Oct-2013	**4,984**	-
US$300 million SEMCO Senior secured - 5.15 percent [4]	21-Apr-2020	**295,110**	-
Debentures notes			
PNG 5 years revolver - 4.38 percent[5]	30-Jan-2015	**20,000**	20,000
PNG RoyNat Debenture - 3.72 percent[5]	15-Sep-2017	**12,500**	13,400
PNG 2018 Series Debenture - 8.75 percent[5]	15-Nov-2018	**12,200**	12,200
PNG 2024 CFI Debenture - 7.39 percent[6]	01-Nov-2024	**8,461**	8,775
PNG 2025 Series Debenture - 9.30 percent[5]	18-Jul-2025	**15,500**	16,000
PNG 2027 Series Debenture - 6.90 percent[5]	02-Dec-2027	**17,000**	17,000
Loan from Province of Nova Scotia[7]	31-Jul-2017	**3,896**	4,815
Capital lease obligations - 6.85 percent[8]	31-Aug-2014	**-**	4,567
SEMCO capital lease obligation - 3.50 percent	05-Jan-2040	**440**	-
Promissory notes	25-Oct-2015	**3,352**	3,839
Other long-term debt		**5,870**	5,702
		2,556,198	1,320,260
Less current portion		**4,371**	105,962
		$ 2,551,827	$ 1,214,298

(1) Borrowings on the facilities can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facilities have fees and interest at rates relevant to the nature of the draw made.

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

(3) Borrowings on the facility can be by way of LIBOR loans or alternative base rate loans. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. The facility is non-recourse to the CINGSA joint venture partners.

(4) Collaterals for the USD medium-term note are certain SEMCO assets.

(5) Collateral for the 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.

(6) 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 in partnership interests and shares in McNair Creek.

(7) 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.

(8) 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 September 30, 2012, AltaGas is obligated to pay approximately $28.8 million over the next nine months to BC Hydro in support of the construction and operation of the Northwest Transmission Line. The amount of $28.8 million is recorded in accounts payable and accrued 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 following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Cash, Cash Equivalents, Accounts Receivable, Accounts Payable and Notes Payable. The carrying amount approximates fair value because of the short maturity of these instruments.

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

Summary of Fair Values		**September 30 2012**		December 31 2011
Current portion of long-term debt				
Carrying amount	**$**	**4,371**	$	105,962
Fair value of current portion of long-term debt		**4,890**		103,997

Summary of Fair Values	**September 30 2012**	December 31 2011
Long-term debt excluding non-financial instruments		
Carrying amount	**$ 2,551,827**	$ 1,214,298
Fair value of long-term debt excluding non-financial instruments	**2,726,232**	1,255,562

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.

September 30, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Financial Assets				
Cash and cash equivalents	**58,429**	**-**	**-**	**58,429**
Risk management assets - current	**-**	**48,141**	**-**	**48,141**
Risk management assets - non-current	**-**	**14,570**	**-**	**14,570**
Long-term investments and other assets	**9,259**	**-**	**-**	**9,259**
Financial Liabilities				
Risk management liabilities - current	**-**	**35,175**	**-**	**35,175**
Risk management liabilities - non-current	**-**	**7,967**	**-**	**7,967**
Current portion of long-term debt	**-**	**4,890**	**-**	**4,890**
Long-term debt	**-**	**2,726,232**	**-**	**2,726,232**
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
Current portion of long-term debt	-	103,997	-	103,997
Long-term debt	-	1,255,562	-	1,255,562

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

	Three Months Ended September 30 2012	Three Months Ended September 30 2011 (restated)	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011 (restated)
Natural gas	**$ 621**	$ (1,773)	**$ (11,464)**	$ (6,030)
Storage optimization	**2,173**	(79)	**2,189**	(1,329)
NGL Frac Spread	**(8,344)**	(1,508)	**24,321**	(5,099)
Power	**11,249**	110	**16,221**	(6,003)
Heat rate	**(222)**	406	**(582)**	602
Interest rate swaps	**61**	(26)	**7**	(205)
Foreign exchange	**473**	334	**119**	4
	$ 6,011	$ (2,536)	**$ 30,811**	$ (18,060)

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

	Unrealized gains	**Tax expense**	**For Nine Months Ended September 30 2012**	Unrealized gains (losses)	Tax (expense) recovery	For Nine Months Ended September 30 2011 (restated)
NGL Frac Spread	**$ 1,062**	**$ (265)**	**$ 797**	$ 609	$ (177)	$ 432
Bond forward	**505**	**-**	**505**	467	-	467
Available-for-sale	**825**	**(88)**	**737**	(7,459)	949	(6,510)
OCI	**$ 2,392**	**$ (353)**	**$ 2,039**	$ (6,383)	$ 772	$ (5,611)

Long-term Investments and Other Assets

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (Alterra), (formerly Magma Energy Corp.), 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 $5.9 million as at September 30, 2012 (September 30, 2011 - unrealized pre-tax loss of $6.0 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 a second 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. The investments classified as available-for-sale also include funds under trust, acquired with SEMCO, with unrealized pre-tax loss of $55 thousand as at September 30, 2012.

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

	Three Months Ended **September 30 2012**	Three Months Ended September 30 2011	Nine Months Ended **September 30 2012**	Nine Months Ended September 30 2011
Financial assets held-for-trading	**$ 604**	$ (1,553)	**$ 949**	$ (8,113)

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**	**$**	**1,204,269**
Shares issued for cash on exercise of options	**547,324**		**11,495**
Shares issued under DRIP	**948,587**		**26,877**
Shares issued on conversion of subscription receipts	**13,915,000**		**378,402**
Issued and outstanding at September 30, 2012	**104,659,285**	**$**	**1,621,043**

	Three Months Ended September 30		Nine Months Ended September 30	
Weighted Average Shares Outstanding	**2012**	2011	**2012**	2011
Number of shares - basic	**95,331,853**	83,628,314	**91,637,549**	83,187,526
Dilutive equity instruments [(1)]	**1,344,920**	1,185,120	**1,279,264**	1,054,025
Number of shares - diluted	**96,676,773**	84,813,434	**92,916,813**	84,241,551

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

For the three and nine months ended September 30, 2012, 7,000 and 259,500 options, respectively, were excluded from the computation of diluted earnings per share because their effects were not dilutive (three and nine months ended September 30, 2011 - 533,000 and 734,800 options, respectively).

Subscription Receipts

On February 22, 2012, AltaGas closed approximately $403.0 million in gross proceeds which were held in trust in consideration of a subscription receipt offering of 13,915,000 common shares. The subscription receipts offering represented the holder's right to receive one common share of the issuer contingent upon acquisition close. On August 30, 2012 each holder of a subscription receipt received one common share for each subscription receipt held, without payment of additional consideration or further action, plus an amount per common share equal to the amount per common share of cash dividends declared by AltaGas on the common shares to holders of record on the dates during the period from and including the closing date up to but not including the transaction closing date, net of any applicable withholding taxes.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at September 30, 2012, 5,070,948 shares were reserved for issuance under the plan. As at September 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 September 30, 2012, outstanding options were exercisable at various dates within the next ten years. As at September 30, 2012, the unexpensed fair value of share option compensation cost associated with future periods was $5.6 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	**809,000**	**29.59**
Exercised	**(547,325)**	**20.17**
Forfeited	**(216,775)**	**21.77**
Share options outstanding, September 30, 2012	**5,382,605**	**$ 23.69**
Share options exercisable, September 30, 2012	**1,868,068**	**$ 22.01**

1) *Weighted average.*

The following table summarizes the employee share option plan as at September 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	546,180	$ 14.21	6.14	290,055	$ 14.18
$15.26 to $25.08	2,470,975	20.53	7.26	1,036,563	21.23
$25.09 to $31.82	2,365,450	29.19	8.21	541,450	27.70
	5,382,605	$ 23.69	7.56	1,868,068	$ 22.01

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 third quarter 2012 in respect of this plan was $2.0 million (third quarter 2011 - $2.3 million). For the nine months ended September 30, 2012, the compensation expense recorded was $4.6 million (nine months ended September 30, 2011 - $5.8 million). As at September 30, 2012, the unexpensed fair value of equity-based compensation costs associated with future periods was $14.3 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 September 30		Nine Months Ended September 30	
	2012	2011 (restated)	**2012**	2011 (restated)
Numerator:				
Net income applicable to common shares - basic	**$ 8,043**	$ 11,103	**$ 75,104**	$ 51,113
Net income applicable to common shares - diluted	**$ 8,043**	$ 11,103	**$ 75,104**	$ 51,113
Denominator:				
Weighted-average number of common shares outstanding	**95,332**	83,628	**91,638**	83,188
Dilutive equity instruments(1)	**1,345**	1,185	**1,279**	1,054
Number of shares outstanding - diluted	**96,677**	84,813	**92,917**	84,242
Basic net income applicable per common share	**$ 0.08**	$ 0.13	**$ 0.82**	$ 0.61
Diluted net income applicable per common share	**$ 0.08**	$ 0.13	**$ 0.81**	$ 0.61

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

11. COMMITMENTS

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 $11.6 million over the next 9 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 September 30, 2012, AltaGas is committed to pay approximately $172.0 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 September 30	**2012**	2011 (restated)	**2012**	2011 (restated)
Current service cost	**$ 1,568**	$ 1,188	**$ 182**	$ 92
Interest cost	**1,769**	1,108	**322**	131
Expected return on plan assets	**(1,552)**	(944)	**(254)**	(11)
Amortization of transitional obligation	**-**	-	**-**	31
Amortization of past service cost	**23**	19	**-**	-
Amortization of net actuarial loss	**455**	106	**30**	19
Amortization of regulatory asset	**139**	-	**109**	-
Net benefit cost recognized	**$ 2,402**	$ 1,477	**$ 389**	$ 262

	Defined Benefit Plans		Post-retirement Benefit Plans	
For the nine months ended September 30	**2012**	2011 (restated)	**2012**	2011 (restated)
Current service cost	**$ 3,867**	$ 3,564	**$ 386**	$ 277
Interest cost	**4,078**	3,324	**593**	393
Expected return on plan assets	**(3,272)**	(2,832)	**(283)**	(34)
Amortization of transitional obligation	**-**	-	**-**	94
Amortization of past service cost	**62**	58	**-**	-
Amortization of net actuarial loss	**840**	317	**68**	57
Amortization of regulatory asset	**139**	-	**109**	-
Net benefit cost recognized	**$ 5,714**	$ 4,431	**$ 873**	$ 787

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 LIABILITIES

Environmental Matters

Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured from processes involving coal, coke or oil. Residual byproducts of these processes may have caused environmental conditions that require investigation and remediation. As of September 30, 2012, an AltaGas subsidiary, SEMCO, owned three sites in Michigan where such manufactured gas plants (MGP) were formerly located. SEMCO predecessors operated MGP facilities at two of the sites. SEMCO operated MGP facilities at a third site for only a brief period of time. In July 2012 SEMCO donated its MGP site in Albion, Michigan, to the City of Albion, Michigan, Building Authority. SEMCO remains responsible, however, for the investigation and remediation of this site, including areas adjacent to the site. A settlement related to four other MGP sites previously owned by SEMCO is discussed in more detail below.

SEMCO is subject to federal, state and local laws and regulations that require, among other things, the investigation and, if necessary, the remediation of contamination associated with these sites, irrespective of fault, legality of initial activity, or ownership, and which may impose liability for damage to natural resources. SEMCO has complied with the applicable Michigan Department of Environmental Quality (MDEQ) requirements, which mandate that current landowners mitigate unacceptable risks to human health from the byproducts of MGP operations and notify the MDEQ and adjacent property owners of potential contaminant migration. SEMCO is currently investigating and remediating two of these MGP sites and anticipates conducting any necessary additional investigatory and remediation activities at these two sites as appropriate. SEMCO has already investigated, remediated and closed a site related to one of these two MGP sites, with the MDEQ's approval. SEMCO believes that the investigation and remediation of a third MGP site is the responsibility, in whole or in part, of another potentially responsible person.

SEMCO is pursuing recovery of the costs of its MGP site-related investigatory and remediation activities from insurance carriers. SEMCO is unable to predict, however, whether and to what extent it will be successful in securing additional insurance recoveries for costs and liabilities associated with current or former MGP sites.

SEMCO accrues for costs associated with environmental investigation and remediation obligations when such costs are probable and reasonably estimable. Accruals for estimated costs for environmental remediation obligations are generally recognized no later than the completion of SEMCO's Remedial Action Plan (RAP) or submission of a no further action (NFA) letter for a site. As a result of investigational work performed to date, the consolidated statements of financial position include an accrual and a corresponding regulatory asset in the amount of $4.6 million at September 30, 2012, for estimated environmental investigation and remediation costs that SEMCO believes are probable. The accrual is not discounted to its present value and expected to be paid out over the next three years.

The accrual of $4.6 million represents what SEMCO believes is probable and reasonably estimable. SEMCO also believes, however, that it is reasonably possible that there could be up to an additional $3.6 million of environmental investigation and remediation costs associated with these MGP sites. It is also reasonably possible that the amount accrued or the estimated range of additional costs may change in the future as SEMCO's investigation of these sites continues, any remediation and other activities are undertaken, and SEMCO seeks to involve another potentially responsible person in these activities at one MGP site (including securing a financial contribution from that person for site investigation and remediation activities, seeking to transfer the site to that person, or both). SEMCO's environmental investigation and remediation costs associated with these MGP sites (including the $2.5 million paid in connection with the settlement involving the four MGP sites that were conveyed to a prior owner in 2011) are deferred and amortized over ten years. Rate recognition of the related amortization expense does not begin until the costs are subject to review by the MPSC in a base rate case.

Other Contingencies

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. A resolution to this matter is expected in fourth quarter 2012. AltaGas recorded $15.6 million in revenue for the duration of the outage which is recorded as an accounts receivable from the operator of the Sundance B Unit 3.

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 increase during the winter 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 Michigan, Alaska, Alberta, British Columbia and Nova Scotia – regulated and unregulated natural gas storage in Michigan and Alaska – 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 September 30, 2012 (unaudited)	**Gas**	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	$ 194,359	$ 53,965	$ 57,724	$ 643	$ (21,107)	$ 285,584
Unrealized gain on risk management	-	-	-	6,011	-	6,011
Income from equity investments	121	19,448	86	-	-	19,655
Cost of sales	(119,928)	(44,686)	(20,315)	-	20,940	(163,989)
Operating and administrative	(41,570)	(3,951)	(24,193)	(11,499)	167	(81,046)
Accretion of asset retirement obligations	(759)	(7)	(4)	-	-	(770)
Depreciation, depletion and amortization	(14,537)	(2,901)	(7,761)	(824)	-	(26,023)
Foreign exchange loss	-	-	-	(6,791)	-	(6,791)
Interest expense	-	-	-	(13,859)	-	(13,859)
Income (loss) before income taxes	$ 17,686	$ 21,868	$ 5,537	$ (26,319)	-	$ 18,772
Net additions (reductions) to:						
Property, plant and equipment [(1)]	124,800	93,720	825,905	(2,674)	-	$ 1,041,751
Intangible assets	(1,949)	(88)	11,499	1,822	-	$ 11,284
Long-term investment and other assets	(11,368)	26,288	5,981	9,884	-	$ 30,785
Goodwill	-	-	433,705	-	-	$ 433,705
Segmented assets	$ 94,433	$ 147,033	$ 1,566,710	$ 43,788	-	$ 1,851,964

Nine Months Ended September 30, 2012 (unaudited)	**Gas**	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	$ 642,633	$ 161,538	$ 172,289	$ 1,158	$ (80,672)	$ 896,946
Unrealized gain on risk management	-	-	-	30,811	-	30,811
Income from equity investments	345	31,216	159	-		31,720
Cost of sales	(405,044)	(108,207)	(65,085)	-	78,540	(499,796)
Operating and administrative	(125,924)	(13,595)	(60,556)	(26,603)	2,132	(224,546)
Accretion of asset retirement obligations	(2,275)	(62)	(16)	-	-	(2,353)
Depreciation, depletion and amortization	(42,411)	(8,111)	(16,577)	(2,550)	-	(69,649)
Foreign exchange loss	-	-	-	(8,940)	-	(8,940)
Interest expense	-	-	-	(39,686)	-	(39,686)
Income (loss) before income taxes	$ 67,324	$ 62,779	$ 30,214	$ (45,810)	-	$ 114,507
Net additions (reductions) to:						
Property, plant and equipment[(1)]	316,213	245,045	805,958	(1,638)	-	$ 1,365,578
Intangible assets	(3,841)	699	30,755	1,966	-	$ 29,579
Long-term investment and other assets	(5,482)	54,589	2,113	15,709	-	$ 66,929
As at September 30, 2012:						
Goodwill	161,402	-	553,425	-	-	$ 714,827
Segmented assets	$ 2,122,737	$ 1,027,450	$ 2,369,643	$ 176,959	-	$ 5,696,789

[(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 September 30, 2011 (unaudited and restated)		Gas		Power		Utilities		Corporate	Intersegment Elimination		Total
Revenue	$	270,231	$	43,859	$	22,727	$	(1,496) $	(22,148)	$	313,173
Unrealized loss on risk management		-		-		-		(2,536)	-		(2,536)
Income from equity investments		83		28,520		(35)		-	-		28,568
Cost of sales		(193,147)		(44,592)		(6,754)		-	21,782		(222,711)
Operating and administrative		(44,463)		(3,722)		(10,012)		(6,478)	366		(64,309)
Accretion of asset retirement obligations		(596)		(12)		-		-	-		(608)
Depreciation, depletion and amortization		(13,697)		(2,578)		(3,065)		(1,368)	-		(20,708)
Foreign exchange loss		-		-		-		(65)	-		(65)
Interest expense		-		-		-		(12,769)	-		(12,769)
Income (loss) before income taxes	$	18,411	$	21,475	$	2,861	$	(24,712)	-	$	18,035
Net additions (reductions) to:											
Property, plant and equipment[(1)]		63,315		33,864		14,399		610	-	$	112,188
Intangible assets		(1,007)		(32)		-		-	-	$	(1,039)
Long-term investment and other assets		(6,296)		2,051		904		235	-	$	(3,106)
Goodwill		-		-		-		-	-		-
Segmented assets	$	47,970	$	36,358	$	15,595	$	(2,128)	-	$	97,795

Nine Months Ended September 30, 2011 (unaudited and restated)		Gas		Power		Utilities		Corporate	Intersegment Elimination		Total
Revenue	$	878,608	$	122,363	$	117,295	$	(8,039) $	(94,473)	$	1,015,754
Unrealized loss on risk management		-		-		-		(18,060)	-		(18,060)
Income from equity investments		280		48,298		225		-	-		48,803
Cost of sales		(633,559)		(89,370)		(56,600)		-	92,937		(686,592)
Operating and administrative		(128,973)		(9,946)		(32,340)		(19,709)	1,536		(189,432)
Accretion of asset retirement obligations		(1,788)		(36)		-		-	-		(1,824)
Depreciation, depletion and amortization		(40,758)		(7,721)		(9,152)		(3,136)	-		(60,767)
Foreign exchange loss		-		-		-		(77)	-		(77)
Interest expense		-		-		-		(39,387)	-		(39,387)
Income (loss) before income taxes	$	73,810	$	63,588	$	19,428	$	(88,408)	-	$	68,418
Net additions to:											
Property, plant and equipment[(1)]		124,525		84,492		30,711		1,689	-	$	241,417
Intangible assets		(22,115)		89,904		-		-	-	$	67,789
Long-term investment and other assets		6,398		63,005		2,283		1,358	-	$	73,044
As at September 30, 2011:											
Goodwill		161,403		-		61,198		-	-	$	222,601
Segmented assets	$	1,725,920	$	636,973	$	500,501	$	112,400	-	$	2,975,794

(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 September 2012, AcSB extended the deferral option of the mandatory changeover for entities with rate-regulated activity by one year to January 1, 2014.

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 nine months ended September 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 March 30 2011	6 months ended June 30 2011	9 months ended September 30 2011	Year ended December 31 2011
Net income applicable to common shares - Canadian GAAP	$ 16,569	$ 43,120	$ 53,699	$ 83,602
C. Pension and other post-retirement benefits	(32)	(66)	(98)	392
D. Natural gas held in storage	29	-	31	1,598
E. De-designation of cash flow hedges	(3,080)	(2,671)	(1,956)	(2,114)
G. Income tax on preferred share dividends	(188)	(375)	(563)	(750)
Total transition adjustments	(3,271)	(3,112)	(2,586)	(874)
Net income applicable to common shares - US GAAP	$ 13,298	$ 40,008	$ 51,113	$ 82,728
Net income applicable to common shares - basic per share - Canadian GAAP	$ 0.20	$ 0.52	$ 0.65	$ 0.99
Effect of US GAAP transition	(0.04)	(0.04)	(0.04)	(0.01)
Net income applicable to common shares - basic per share - US GAAP	$ 0.16	$ 0.48	$ 0.61	$ 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 September 30, 2011 *($ thousands)*	Notes		Canadian GAAP	Effect of transition to US GAAP		US GAAP
ASSETS						
Current assets						
Cash and cash equivalents	B	$	2,946	(1,703)	$	1,243
Accounts receivable	B		221,831	(22,022)		199,809
Inventory	B & E		7,873	(864)		7,009
Restricted cash holdings from customers			19,470	-		19,470
Regulatory assets			682	-		682
Risk management assets			45,576	-		45,576
Prepaid expense and other current assets	B, C & F		6,248	195		6,443
			304,626	(24,394)		280,232
Property, plant and equipment	A & B		2,157,707	(52,835)		2,104,872
Intangible assets	B		204,505	(56,693)		147,812
Goodwill	A, B & C		199,497	23,105		222,602
Regulatory assets	C		87,119	2,620		89,739
Risk management assets			19,093	-		19,093
Long-term investments and other assets	B, C & F		15,080	8,118		23,198
Investments accounted for by equity method	B		-	88,246		88,246
		$	2,987,627	(11,833)	$	2,975,794
LIABILITIES AND SHAREHOLDERS' EQUITY						
Current liabilities						
Accounts payable and accrued liabilities	B		270,286	(21,255)		249,031
Dividends payable			9,222	-		9,222
Short-term debt			2,662	-		2,662
Current portion of long-term debt			101,593	-		101,593
Customer deposits			23,057	-		23,057
Regulatory liabilities			1,785	-		1,785
Risk management liabilities			54,352	-		54,352
Other current liabilities	B & C		8,681	(30)		8,651
			471,638	(21,285)		450,353
Long-term debt	G		948,028	11,941		959,969
Asset retirement obligations			41,145	-		41,145
Deferred income taxes	A, B, C, D & G		242,308	(6,653)		235,655
Regulatory liabilities			20,059	-		20,059
Risk management			19,155	-		19,155
Other long-term liabilities			28,821	-		28,821
Future employee obligations	C		12,598	5,937		18,535
			1,783,752	(10,060)		1,773,692
Common shares			1,052,880	-		1,052,880
Preferred shares			194,126	-		194,126
Contributed surplus			4,955	-		4,955
Accumulated other comprehensive loss	C & E		(10,320)	975		(9,345)
Accumulated deficit	A, C, D, E & G		(37,766)	(2,748)		(40,514)
		$	2,987,627	(11,833)	$	2,975,794

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 September 30, 2011 equity are as follows:

($ thousands)	Common Shares	Preferred Shares	Contributed Surplus	Accumulated OCI	Retained Earnings	Total Equity
Canadian GAAP	**1,052,880**	**194,126**	**4,955**	**(10,320)**	**(37,766)**	**$ 1,203,875**
A. Business combinations	-	-	-	-	3,214	3,214
C. Pension and other post-retirement benefits	-	-	-	(1,693)	(1,841)	(3,534)
D. Natural gas held in storage	-	-	-	-	(617)	(617)
E. De-designation of cash flow hedges	-	-	-	2,666	(2,666)	-
G. Income tax on preferred share dividends	-	-	-	-	(838)	(838)
US GAAP	**1,052,880**	**194,126**	**4,955**	**(9,347)**	**(40,514)**	**$ 1,202,100**

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

For the three months ended September 30, 2011 *($ thousands except per share amounts)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
REVENUE				
Operating	B	374,628	(59,894)	314,734
Unrealized (loss) on risk management contracts	D & E	(3,531)	995	(2,536)
Other (expenses) revenue	B	(1,496)	(65)	(1,561)
Income from equity investments	B	-	28,568	28,568
		369,601	(30,396)	339,205
EXPENSES				
Cost of sales	B	251,693	(28,982)	222,711
Operating and administrative	B & C	65,004	(695)	64,309
Accretion of asset retirement obligations		608	-	608
Depreciation, depletion and amortization	B	22,403	(1,695)	20,708
		339,708	(31,372)	308,336
Foreign exchange loss		65	-	65
Interest expense				
Short-term debt		1,449	-	1,449
Long-term debt		11,320	-	11,320
Income before income taxes		17,059	976	18,035
Income tax expense (recovery)				
Current	B & G	(518)	1,013	495
Future	C, D, E & G	4,250	(313)	3,937
Net income from operations		13,327	276	13,603
Preferred share dividends	G	2,750	(250)	2,500
Net income applicable to common shares		10,577	526	11,103
Net income per share				
Basic		0.13	-	0.13
Diluted		0.12	0.01	0.13
Weighted average number of shares outstanding				
Basic		83,628	-	83,628
Diluted		84,813	-	84,813

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

For the nine months ended September 30, 2011 *($ thousands except per share amounts)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
REVENUE				
Operating	B	1,164,673	(140,826)	1,023,847
Unrealized (loss) on risk management contracts	D & E	(15,514)	(2,546)	(18,060)
Other (expenses) revenue	B	(8,039)	(54)	(8,093)
Income from equity investments	B	-	48,803	48,803
		1,141,120	(94,623)	1,046,497
EXPENSES				
Cost of sales	B	771,797	(85,205)	686,592
Operating and administrative	B & C	191,140	(1,708)	189,432
Accretion of asset retirement obligations		1,824	-	1,824
Depreciation, depletion and amortization	B	65,743	(4,976)	60,767
		1,030,504	(91,889)	938,615
Foreign exchange loss		77	-	77
Interest expense				
Short-term debt		4,360	-	4,360
Long-term debt		35,027	-	35,027
Income before income taxes		71,152	(2,734)	68,418
Income tax expense (recovery)				
Current	B & G	797	2,910	3,707
Future	C, D, E & G	8,406	(2,308)	6,098
Net income from operations		61,949	(3,336)	58,613
Preferred share dividends	G	8,250	(750)	7,500
Net income applicable to common shares		53,699	(2,586)	51,113
Net income per share				
Basic		0.65	(0.04)	0.61
Diluted		0.64	(0.03)	0.61
Weighted average number of shares outstanding				
Basic		83,188	-	83,188
Diluted		84,242	-	84,242

The statements of comprehensive income and accumulated other comprehensive loss for the three and nine months ended September 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 September 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net Income applicable to the controlling interest		13,327	276	13,603
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	C	-	(1)	(1)
Effective portion of gains (loss) on derivative instruments that qualifies as cash flow hedge (net of tax)	E	783	(715)	68
Unrealized income (loss) gain on available-for-sale financial assets (net of tax)		(1,282)	-	(1,282)
		(499)	(716)	(1,215)
Comprehensive income		12,828	(440)	12,388
Accumulated other comprehensive loss, beginning of period	C & E	(9,821)	1,691	(8,130)
Other comprehensive loss, net of tax		(499)	(716)	(1,215)
Accumulated other comprehensive loss, end of period		(10,320)	975	(9,345)

For the nine months ended September 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net Income applicable to the controlling interest		61,949	(3,336)	58,613
Other comprehensive (loss) income, net of tax				
Defined benefit plans - Unamortized actuarial gain or loss (net of tax)	C	-	(3)	(3)
Effective portion of gains (loss) on derivative instruments that qualifies as cash flow hedge (net of tax)	E	(1,058)	1,956	898
Unrealized income (loss) gain on available-for-sale financial assets (net of tax)		(6,510)	-	(6,510)
		(7,568)	1,953	(5,615)
Comprehensive income		54,381	(1,383)	52,998
Accumulated other comprehensive loss, beginning of period	C & E	(2,752)	(978)	(3,730)
Other comprehensive loss, net of tax		(7,568)	1,953	(5,615)
Accumulated other comprehensive loss, end of period		(10,320)	975	(9,345)

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 nine months ended September 30, 2011 reconciled from Canadian GAAP to US GAAP are as follows:

For the three months ended September 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net cash used in operating activities	B, C, D & E	64,963	(1,695)	63,268
Net cash used in investing activities	B	(112,679)	(353)	(113,032)
Net cash provided by financing activities		40,112	998	41,110
Change in cash and cash equivalents		(7,604)	(1,050)	(8,654)
Cash and cash equivalents, beginning of period	B	10,550	(653)	9,897
Cash and cash equivalents, end of period	B	2,946	(1,703)	1,243

For the nine months ended September 30, 2011 *($ thousands)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net cash used in operating activities	B, C, D & E	151,498	(1,742)	149,756
Net cash used in investing activities	B	(235,788)	(1,875)	(237,663)
Net cash provided by financing activities		85,127	3,000	88,127
Change in cash and cash equivalents		837	(617)	220
Cash and cash equivalents, beginning of period	B	2,109	(1,086)	1,023
Cash and cash equivalents, end of period	B	2,946	(1,703)	1,243

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	C	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	C	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)	**Q3-12**	Q2-12	Q1-12	Q4-11	Q3-11
FINANCIAL HIGHLIGHTS[1]					
Net Revenue[2]					
Gas	**74.6**	75.8	87.5	92.6	77.2
Power	**28.7**	21.3	34.6	31.7	27.8
Utilities	**37.5**	26.6	43.3	24.7	15.9
Corporate	**6.7**	22.3	3.0	8.3	(4.0)
Intersegment Elimination	**(0.2)**	(1.1)	(0.9)	(0.4)	(0.4)
	147.3	144.9	167.5	156.9	116.5
EBITDA[2]					
Gas	**33.0**	34.3	44.7	45.9	32.7
Power	**24.8**	16.7	29.5	25.0	24.1
Utilities	**13.3**	9.1	24.4	10.1	5.9
Corporate	**(10.9)**	(8.6)	(6.0)	(8.6)	(8.0)
	60.2	51.5	92.6	72.4	54.7
Operating Income (Loss)[2]					
Gas	**17.7**	19.5	30.1	31.4	18.4
Power	**21.9**	14.0	26.9	22.4	21.5
Utilities	**5.5**	5.2	19.4	4.7	2.9
Corporate	**(11.7)**	(9.3)	(6.8)	(9.4)	(9.4)
	33.4	29.4	69.6	49.1	33.4

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

(2) *Non-GAAP financial measure.*

Supplementary Quarterly Operating Information

(unaudited)

	Q3-12	Q2-12	Q1-12	Q4-11	Q3-11
OPERATING HIGHLIGHTS					
GAS					
E&T					
Extraction inlet gas processed (Mmcf/d)(1)	**850**	829	944	923	871
Extraction volumes (Bbls/d)(1)	**40,061**	34,547	45,186	43,454	39,781
Frac spread - realized ($/Bbl)(1)(2)	**28.59**	27.64	34.11	42.00	22.95
Frac spread - average spot price ($/Bbl)(1)(3)	**22.75**	26.85	40.42	46.59	42.15
FG&P					
Processing Throughput (gross Mmcf/d)(1)	**362**	351	400	391	404
Energy Services					
Average volumes transacted (GJ/d)(1)(4)	**334,973**	318,738	376,071	357,105	340,396
POWER					
Volume of power sold (GWh)(1)	**843**	802	816	774	760
Average price realized on sale of power ($/MWh)(1)	**73.34**	58.54	72.56	79.14	80.67
Alberta Power Pool average spot price ($/MWh)(1)	**78.09**	40.03	60.12	76.42	94.70
UTILITIES					
Utilities Canada					
Natural gas deliveries - end-use (PJ)(5)	**2.6**	4.6	10.8	21.8	2.3
Natural gas deliveries - transportation (PJ)(5)	**1.4**	1.7	2.0	4.6	1.1
Utilities USA					
Natural gas deliveries end use (Mmcf)	**2,624.1**	-	-	-	-
Natural gas deliveries transportation (Mmcf)	**2,879.2**	-	-	-	-
Service sites(6)	**543,261**	115,437	115,623	115,932	75,126
Degree day variance from normal - AUI (%)(7)	**(53.6)**	(2.9)	(11.5)	-	(33.7)
Degree day variance from normal - Heritage Gas (%)(7)	**(38.8)**	(9.7)	(8.6)	(11.8)	(20.9)
Degree day variance from normal SEMCO Michigan (%)(7)	**41.7**	-	-	-	-
Degree day variance from normal SEMCO Alaska (%)(7)	**3.5**	-	-	-	-

(1) *Average for the period.*

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

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

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

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

(6) *Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and SEMCO Michigan and Alaska, including transportation and non-regulated business lines.*

(7) *Degree days relate to AUI, Heritage Gas and SEMCO 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 materially affect the results of PNG for its residential and small commercial customers due to a BCUC approved rate stabilization mechanism. For SEMCO degree days are a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior fifteen years for Michigan and during the prior ten years for Alaska.*

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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