NEWS RELEASE
ALTAGAS REPORTS FOURTH QUARTER AND YEAR-END RESULTS

Calgary, Alberta (February 24, 2011) – AltaGas Ltd. (AltaGas) (TSX: ALA) today reported net income applicable to common shares for the three months ended December 31, 2010 of $26.5 million ($0.32 per share). Net income applicable to common shares for 2010 was $97.2 million ($1.19 per share). Excluding mark-to-market accounting net income for the three and twelve months ended December 31, 2010 was $31.4 million ($0.38 per share) and $101.7 million ($1.25 per share) respectively.

Earnings before interest, taxes, depreciation and amortization (EBITDA) adjusted for the impact of mark-to-market accounting was $75.7 million ($0.92 per share) in fourth quarter 2010 compared to $68.2 million ($0.85 per share) in the same period last year. Funds from operations for the three months ended December 31, 2010 was $57.9 million ($0.70 per share) compared to $51.0 million ($0.64 per share) in fourth quarter 2009.

Excluding the effect of mark-to-market accounting, EBITDA was $249.5 million ($3.06 per share) in 2010 compared to $242.0 million ($3.08 per share) in 2009. Funds from operations was $195.0 million ($2.39 per share) in 2010 compared to $202.3 million ($2.58 per share) in 2009.

Operating income adjusted for mark-to-market accounting for fourth quarter, 2010 was $52.7 million compared to $47.4 million for the same period in 2009. Operating income adjusted for mark-to-market accounting for 2010 was $157.5 million compared to $164.8 million for 2009.

“Our diversified gas, power and utility asset base produced stable operating results for fourth quarter and full year 2010,” said David Cornhill, Chairman and Chief Executive Officer of AltaGas. "We made excellent progress on our growth plans this year by securing $1.4 billion in committed growth projects that are supported by long term contracts. As we enter 2011 we remain focused on constructing these projects on-time and on-budget and creating significant value for our shareholders.”

Fourth Quarter Growth Highlights

During the fourth quarter 2010, AltaGas made progress on several projects in support of its planned $2 billion of organic growth in the next five years. Notable developments include:

- Continued construction site preparation for the Forrest Kerr run-of-river hydroelectric project. Base camp and roadworks are nearly complete. Construction workforce mobilization expected to be underway in first quarter 2011.
- Received regulatory approval of the Harmattan Co-stream Project in December 2010. The Co-stream Project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western Alberta System to be processed using spare capacity at the Harmattan Complex to recover ethane and NGLs. The project is expected to commence operations in first quarter 2012. The capital cost estimate is $130 million.
- Announced plans to construct a 120 Mmcf/d gas processing facility and an associated gas gathering system in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The project is subject to regulatory approval. The plant will also be equipped with liquids extraction facilities. The facility and associated gas gathering system is expected to cost approximately $235 million and be in-service in late 2012. By using existing infrastructure in the area and building the Henderson Pipeline to connect to the Pouce Coupe facility, AltaGas anticipates providing processing for early production by mid-2011. The facility is supported by a long-term gathering and processing agreement with Encana Corporation to supply natural gas to the facility.
- Completed under budget and on time the construction of a 15 MW gas fired cogeneration facility at the Harmattan Complex. Plans to construct a second 15 MW cogeneration unit are underway.

- Completed year 1 of the AltaGas Utilities system betterment rejuvenation program and expansion of the Heritage Gas distribution system. The Utility business increased rate base by 15 percent in 2010.

Fourth Quarter Financial Highlights

- Completed its $175 million issue of senior unsecured medium term notes on November 26, 2010. The notes carry a coupon rate of 4.6 percent and mature on January 15, 2018.
- AltaGas' debt-to-total capitalization ratio as at December 31, 2010 was 42.8 percent compared to 42.3 percent at September 30, 2010 and 49.2 percent at December 31, 2009.
- AltaGas declared dividends for the three months ended December 31, 2010 of $0.33 per share.
- AltaGas has determined the tax characterization for distributions made in the first six months of 2010 when AltaGas was under a trust structure (AltaGas Income Trust or the Trust). For income tax purposes, assuming a unit of the Trust was held for the first six months of 2010, AltaGas expects 86.4 percent of the total distributions declared to be taxed as income and 13.6 percent as return of capital. Investors should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units of the Trust.

Monthly Common Share Dividend and Quarterly Preferred Share Dividend

- AltaGas announced the March common share dividend of $0.11 for each share will be paid on April 15, 2011 to holders of record on March 25, 2011. The ex-dividend date is March 23, 2011. This dividend is an eligible dividend for Canadian income tax purposes.
- AltaGas' Board also approved a preferred share dividend of $0.3125 per Series A Preferred Share for the period commencing January 1, 2011 and ending March 31, 2011. The dividend will be paid on March 31, 2011, to Series A Preferred Shareholders of record on March 17, 2011.

CONFERENCE CALL AND WEBCAST DETAILS:

AltaGas will hold a conference call today, February 24, 2011, at 8:30 a.m. MT (10:30 a.m. ET) to discuss the fourth quarter 2010 financial and operating results and other general issues and developments.

Members of the investment community, media and other interested parties may dial (416) 340-8530 or call toll free at 1-877-240-9772. No pass code is required. Please note that the conference call will also be webcast. A live audio webcast will also be available at http://www.altagas.ca/investors/presentations_and_webcasts.

Shortly after the conclusion of the call, a replay will be accessible at (905) 694-9451 or 1-800-408-3053. The pass code is 3614307. The replay will expire at midnight (ET) on March 3, 2011. The webcast will be archived for one year.

FORWARD-LOOKING INFORMATION

The audited consolidated annual financial statements and annual Management's Discussion and Analysis, which contain additional notes and disclosures, are expected to be filed with SEDAR on or about March 2, 2010, at which time a press release to that effect will be issued. The material will also be available on the AltaGas website on that same day (www.altagas.ca).

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

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

Many factors could cause AltaGas' or any of its reporting segment's actual results, performance or achievements to vary from those described in this news release, 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 news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this news release herein should not be unduly relied upon. These statements speak only as of the date of this release. 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 news release are expressly qualified as cautionary statements.

Financial outlook information contained in this news release 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 news release 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 Ltd. 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.

CONSOLIDATED FINANCIAL RESULTS	Three Months Ended			Year Ended
(unaudited)		Dec 31		Dec 31
($ millions)	**2010**	2009	**2010**	2009
Revenue	**362.2**	336.4	**1,354.1**	1,268.3
Net revenue	**130.8**	115.4	**485.5**	456.6
EBITDA	**70.7**	59.6	**243.8**	251.5
EBITDA adjusted for mark-to-market accounting	**75.7**	68.2	**249.5**	242.0
Operating income	**47.7**	38.8	**151.8**	174.3
Operating income adjusted for mark-to-market accounting	**52.7**	47.4	**157.5**	164.8
Net income applicable to common shares	**26.5**	32.1	**97.2**	141.3
Net income applicable to common shares adjusted for mark-to-market accounting	**31.4**	38.3	**101.7**	132.7
Total assets	**2,751.7**	2,628.9	**2,751.7**	2,628.9
Total long-term liabilities	**1,217.4**	719.1	**1,217.4**	719.1
Net additions to capital assets	**81.1**	322.3	**220.1**	486.4
Distributions declared(1)	**-**	43.9	**87.0**	170.2
Dividends declared (2)	**27.1**	-	**54.1**	-
Funds from operations	**57.9**	51.0	**195.0**	202.3

	Three Months Ended			Year Ended
		Dec 31		Dec 31
($ per share)	**2010**	2009	**2010**	2009
EBITDA	**0.86**	0.75	**2.99**	3.20
EBITDA adjusted for mark-to-market accounting	**0.92**	0.85	**3.06**	3.08
Net income - basic	**0.32**	0.40	**1.19**	1.80
Net income - diluted	**0.32**	0.40	**1.19**	1.79
Net income applicable to common shares adjusted for mark-to-market accounting	**0.38**	0.48	**1.25**	1.69
Distributions declared(1)	**-**	0.54	**1.08**	2.16
Dividends declared (2)	**0.33**	-	**0.66**	-
Funds from operations	**0.70**	0.64	**2.39**	2.58
Shares outstanding - basic (millions)				
During the period(3)	**82.2**	80.0	**81.5**	78.5
End of period	**82.5**	80.3	**82.5**	80.3

(1) *Distributions declared of $0.18 per trust unit and exchangeable unit per month during 2009 and for the first six months of 2010.*

(2) *Dividends declared of $0.11 per common share per month commencing July 2010.*

(3) *Weighted-average.*

CONSOLIDATED FINANCIAL REVIEW

The fourth quarter press release follows the continuity of interest basis of accounting whereby the Corporation is considered a continuation of AltaGas Income Trust (the Trust). As a result, the report includes the Trust's results of operations for the period up to and including June 30, 2010 and the Corporation's results of operations thereafter.

Three Months Ended December 31

Net income applicable to common shares for fourth quarter 2010 was $26.5 million ($0.32 per share) compared to $32.1 million ($0.40 per share) in the same period in 2009. Adjusting for the impact of mark-to-market accounting, net income applicable to common shares in fourth quarter 2010 was $31.4 million ($0.38 per share) compared to $38.3 million ($0.48 per share) for the same period last year. Adjusted for the impact of mark-to-market accounting, earnings reported by the operating segments, including the Corporate reporting segment were strong at $52.7 million in the quarter compared to $47.4 million in fourth quarter last year. Operating results were strong, driven by the addition of full quarter contribution from the Utility business, higher fees earned at some facilities and higher frac spreads which partially offset the impact of weaker realized power prices in Alberta and lower volumes at some processing facilities. The Gas, Power and Utility businesses reported operating income of $56.7 million in fourth quarter 2010 compared to $54.8 million in fourth quarter last year.

The Gas business reported higher operating income primarily due to higher extraction and transmission fees and realized frac spreads and lower amortization. The Power business reported lower earnings as a result of the continued weaker power markets in Alberta but benefited from higher earnings at the gas-fired peakers. The Utility business reported higher operating income primarily due to a full quarter of Heritage Gas Limited (Heritage Gas) and AltaGas Utility Group Inc. (Utility Group) compared to 2009. Corporate reporting segment reported a loss of $4.0 million in fourth quarter 2010 compared to a loss of $7.4 million in the same quarter last year, adjusted for mark-to-market accounting.

On a cash flow basis, funds from operations for the three months ended December 31, 2010 was $57.9 million ($0.70 per share) compared to $51.0 million ($0.64 per share) in fourth quarter 2009. EBITDA adjusted for the impact of mark-to-market accounting in fourth quarter 2010 was $75.7 million ($0.92 per share) compared to $68.2 million ($0.85 per share) in the same period last year.

On a consolidated basis, net revenue for fourth quarter 2010 was $130.8 million compared to $115.4 million in same period 2009. The Gas reporting segment's net revenue was largely unchanged from the prior year as higher extraction and transmission revenues and gas marketing sales were offset by lower gas processing results and lower storage margins. Net revenue in the Power reporting segment was slightly higher due to larger contributions from gas-fired peakers and the Harmattan cogeneration, lower PPA costs offset by lower realized power prices in Alberta. The Utility business reported higher net revenue due to a full quarter contribution compared to a partial quarter in fourth quarter 2009 when AltaGas acquired the Utility business. The Corporate reporting segment recorded higher net revenue due to lower unrealized losses on risk management contracts, mark-to-market valuation of investments, offset partially by lower investment income.

Operating and administrative expense for fourth quarter 2010 was $60.1 million, up from $55.5 million in same quarter 2009. The increase was due to incremental costs associated with AltaGas’ growth including the addition of the Utility business and higher operating costs at extraction facilities due to higher volumes. These increases were partially offset by lower operating costs related to the gas processing businesses due to lower volumes processed and cost control measures.

Amortization expense for fourth quarter 2010 was $22.4 million compared to $20.3 million in the same period 2009. The increase was due to the growth in AltaGas' asset base from acquisition and construction activities, primarily the addition of the Utility business and Bear Mountain Wind Park, offset by lower amortization due to a change in estimates for the expected remaining useful lives of some assets within the Gas business. Accretion for asset retirement obligations for fourth quarter 2010 was $0.7 million compared to $0.8 million in the same period 2009. The decrease was due to the impact of revised estimates to some property, plant and equipment useful lives offset by growth in AltaGas' asset base from acquisition and construction activities.

Interest expense in fourth quarter 2010 was $12.1 million compared to $9.3 million for the same period 2009. The increase was due to a higher average borrowing rate offset by lower average debt balances of $0.9 billion as a result of the preferred share offering during third quarter 2010 (2009 - $1.0 billion). The average borrowing rate was 6.1 percent in fourth quarter 2010 compared to 4.9 percent in fourth quarter 2009.

In fourth quarter 2010, an income tax expense of $6.2 million was reported compared to a recovery of $2.9 million in fourth quarter 2009. The increase was due to higher income subject to tax as a result of conversion to a corporate structure. Income subject to tax in a trust structure was based on income for accounting purposes less the amount distributed to unitholders of the Trust. As a corporation, income tax expense is based on income for accounting purposes.

Full Year 2010

Net income applicable to common shares for 2010 was $97.2 million ($1.19 per share) compared to $141.3 million ($1.80 per share) in 2009. Effective July 1, 2010, AltaGas commenced operations as a corporation, whereby the tax obligations of the organization were expensed. For the first six months of 2010, AltaGas operated under a trust structure, whereby the majority of tax obligations were passed to its securityholders. For purposes of comparison, had AltaGas operated as a trust for all of 2010, net income applicable to common shares for 2010 would have been $118.3 million ($1.45 per share). Adjusting for the impact of mark-to-market accounting, net income applicable to common shares for 2010 was $101.7 million ($1.25 per share) compared to $132.7 million ($1.69 per share) in 2009. Adjusting for the impact of mark-to-market accounting, operating income for all reporting segments for 2010 was $157.5 million compared to $164.8 million in 2009.

Operating income for 2010 from the Gas, Power and Utility businesses was $197.1 million similar to $198.3 million reported in 2009. Results were impacted by the 2009 reduction in liabilities related to natural gas transactions and the reversal of deferred revenue related to the Suffield pipeline reported in 2009. Results were further impacted by lower power prices in Alberta and the impact of lower throughput at some of the processing facilities, partially offset by the addition of the Utility business and Bear Mountain Wind Park, higher frac spreads and lower amortization as a result of change in estimates for the expected remaining useful lives of certain assets. Corporate costs excluding the impact of mark-to-market accounting were $39.5 million in 2010 compared to $33.5 million in 2009. Corporate costs were higher due to a full year of operations in the Utility business, costs associated with conversion to a corporation and general increases.

On a cash flow basis, funds from operations for 2010 was $195.0 million ($2.39 per share) compared to $202.3 million ($2.58 per share) in 2009. The decrease in funds from operations is primarily attributed to lower Alberta power prices and higher interest expense partially offset by the contribution from the full year operations of the Utility business and stronger results in the extraction business. EBITDA adjusted for the impact of mark-to-market accounting was $249.5 million ($3.06 per share) compared to $242.0 million ($3.08 per share) in 2009.

On a consolidated basis, net revenue for 2010 was $485.5 million compared to $456.6 million in 2009. Net revenue from the Gas business increased due to higher realized frac spreads, expiration of a legacy gas marketing contract in late 2009 and higher extraction and transmission operating cost recoveries. These increases were partially offset by lower gas processing fees and volumes processed at some facilities, the reduction in liabilities related to natural gas transactions and the reversal of deferred revenue related to the Suffield pipeline reported in 2009, lower volumes exposed to frac spreads, lower storage margins and a provision for doubtful customer accounts. Net revenue in the Power business decreased due to higher PPA costs and lower realized power prices in Alberta partially offset by contributions from the addition of Bear Mountain Wind Park, addition of the Commercial and Industrial (C&I) power retail business and higher revenues from the Company's gas-fired peakers. The Corporate segment recorded unrealized losses on risk management contracts and investments compared to unrealized gains last year and no investment income from the Utility Group since it is now fully consolidated due to the acquisition of the shares that were not already owned by AltaGas in fourth quarter 2009. Net revenue in the Utility business increased due to a full year of results since the Utility Group and Heritage Gas were acquired during fourth quarter 2009.

Operating and administrative expenses for 2010 were $241.5 million, up from $205.1 million in 2009. The increase was due to incremental costs associated with AltaGas' growth including the addition of the Utility business, higher environmental costs, conversion to a corporation, regulatory compliance initiatives and increases in general administration costs. These increases were partially offset by lower operating costs related to the gas processing business due to lower volumes processed as well as cost control measures.

Accretion for asset retirement obligations for 2010 was $2.9 million compared to $3.1 million in 2009. The decrease was due to the expectation that cash outlays to fund these obligations would be later than originally estimated.

Amortization expense for 2010 was $89.2 million compared to $74.1 million in 2009. The increase was due to the growth in AltaGas' asset base from acquisition and construction activities, partially offset by the adjustment to amortization expense as a result of change in estimates for the expected remaining useful lives of certain assets.

Interest expense for 2010 was $48.8 million compared to $31.8 million in 2009. The increase was due to higher average debt balances of $988.0 million arising from AltaGas' growth compared to $691.5 million in 2009. Interest capitalized in 2010 was $4.4 million compared to $7.1 million in 2009. The average borrowing rate was 5.4 percent in 2010 compared to 5.6 percent in 2009.

Income tax expense for 2010 was $1.7 million compared to $1.2 million in 2009. The increase in expense was primarily associated with higher income subject to tax reported since July 1, 2010 since AltaGas' conversion to a corporation offset by lower taxes incurred by the Utility business and the 2009 nonrecurring tax expense related to an acquisition. For purposes of comparison, had AltaGas operated as a trust for all of 2010, the Company would have reported an income tax recovery of $19.4 million for 2010.

CONSOLIDATED OUTLOOK

AltaGas expects to report stronger results from its operating businesses in 2011 compared to 2010. On a net income basis, the Company expects to report higher future income tax expense based on being a corporation for a full year, partially offset by using a lower effective corporate tax rate of approximately 23 percent. With tax pools in excess of $1 billion, AltaGas does not expect to be cash taxable until approximately 2016. However, net income before taxes is expected to be higher in 2011 compared to 2010 due to stronger results from its diversified portfolio of energy assets.

Higher earnings are expected from higher volumes processed at some field and extraction facilities driven by producer activity to capitalize on high NGL content gas plays or light oil plays. Stronger results are expected in gas despite turnarounds at Younger and Harmattan and lower daily take-or-pay volumes on Suffield. The Gas business is also expected to benefit from continued strong frac spreads on volumes exposed to spot frac spreads.

Recent supply uncertainty in the Alberta power market together with changes to the Rate Regulated Option used for setting power prices by the utilities has increased power prices and power price volatility. With approximately two-thirds of generation hedged in first quarter 2011 at an average price of $63.50 and approximately one-third hedged at $64.50 for the rest of the year and recent increases in forward power prices, AltaGas expects earnings in its power business to be at or slightly lower than the 2010 results. The addition of the new Harmattan Cogeneration facility and the gas-fired peakers are all expected to benefit from higher power prices in 2011.

AltaGas also expects to report stronger earnings from its Utility business as the utilities in Alberta and Nova Scotia continue to increase rate base at 16 percent and 25 percent respectively in 2011.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2011 to be approximately $425 million, of which the allocation is expected to be 50 percent for Power, 40 percent for Gas and 10 percent for Utility. To date, approximately $400 million of capital has been committed for 2011.

AltaGas is well positioned to fund its committed capital program through its growing internally-generated cash flow, its dividend reinvestment plan and its continued strong access to capital markets. At December 31, 2010 the Company had approximately $775 million of available credit facilities. In 2010 AltaGas declared dividends to common shareholders of approximately 76 percent of funds from operations, after reductions for preferred share dividends and maintenance capital. Based on the new dividend policy on conversion to a corporation on July 1, 2010, the Company expects the payout ratio as a percentage of funds from operations to be in the range of 50 to 55 percent for 2011.

The following projects have an expected in-service date after 2011.

Northwest Hydroelectric Projects

AltaGas signed a 60-year CPI indexed EPA with BC Hydro for its 195 MW Forrest Kerr run-of-river hydro electricity generation project. As disclosed by BC Hydro, the average price contracted is in the range of $120 to $130 per MWh. The Forrest Kerr project is estimated to cost approximately $700 million and is expected to be in commercial operation by mid-2014. Normal course permitting and licensing will occur as construction proceeds. The project is supported by 40 years of hydrologic data and analysis at the Forrest Kerr site.

AltaGas has also entered into an agreement with the Tahltan First Nations providing employment and business opportunities as well as economic participation. In addition, there is an agreement in place for transmission infrastructure with the B.C. government.

Construction is underway, with the construction camp completed. AltaGas expects to obtain the occupancy permit for the camp in March and begin mobilizing the workforce shortly thereafter. The turbine package and initial tunnel excavation contracts for the access and surge tunnels are expected to be awarded by the end of first quarter 2011. Tunneling of the surge and powerhouse access tunnels is expected to begin in March 2011 with completion of the tunnels expected in third quarter 2011. At the close of 2010, approximately 20 percent of the cost of the project had been fixed. AltaGas expects to have 75 percent of the project cost contractually committed to fixed price contracts by December 31, 2011 and 90 percent contractually fixed by the end of 2012. AltaGas' plans to mitigate project cost escalation and schedule risk through its procurement and contracting strategies.

AltaGas continues to be in discussions related to the McLymont Creek and Volcano Creek projects. These two projects will add 82 MW of run-of-river hydroelectric power to the region.

Harmattan Co-stream Project

On December 8, 2010, AltaGas' application for the Harmattan Co-stream Project received approval from the Energy Resources Conservation Board (ERCB). The project is expected to cost approximately $130 million and includes an incremental $8 million for an enhanced refrigeration modernization project. The Harmattan Co-stream project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western System to be processed using spare capacity at the Harmattan Complex to recover ethane and other NGLs. AltaGas expects to commence construction in early 2011 and to commence operations in first quarter 2012. Based on current capital cost estimates AltaGas expects the annual EBITDA contribution to be in the range of $20 million to $25 million once completed.

AltaGas entered into a Memorandum of Understanding with NOVA Chemicals Corporation (NOVA Chemicals). The agreement is for an initial term of 20 years whereby AltaGas would deliver all natural gas liquids extracted from co-stream gas on a full cost-of-service basis to NOVA Chemicals, and would provide that all capital expenditures and operating costs related to the project be fully recovered through fees under normal operations.

AltaGas expects to procure materials and services in first quarter 2011 and begin pipeline construction in June 2011. Major equipment tie-in is planned to occur during the planned plant turnaround in September 2011. To date approximately $15 million of costs are fixed. AltaGas expects a further $50 million to be contractually fixed by April 2011 and another $15 million to be contractually fixed by third quarter 2011. In total, AltaGas expects approximately 60 percent of the total project cost to be fixed. The remainder will be subject to cost escalation and labour productivity risk. AltaGas plans to mitigate project cost escalation and schedule risk through its procurement and contracting strategies.

In early January 2011, the parties that initially intervened in AltaGas' application filed a notice of motion for leave to appeal. AltaGas believes that the grounds set forth for leave to appeal are without merit and remains committed to the schedule as outlined above.

Gordondale Gas Plant Project

On November 4, 2010 AltaGas announced it will construct a 120 Mmcf/d gas processing facility and an associated gas gathering system in the Gordondale area of the Montney resource play, approximately 100 km northwest of Grande Prairie, Alberta. The project is subject to regulatory approval. The plant will also be equipped with liquids extraction facilities. The facility and associated gas gathering system is expected to cost approximately $235 million and be in-service in late 2012. By using existing infrastructure in the area and building the Henderson Pipeline to connect to the Pouce Coupe facility, AltaGas expects to provide processing services for early production by mid-2011. The facility is supported by a long-term gathering and processing agreement with Encana Corporation to supply natural gas to the facility. Based on current production and natural gas reserve estimates, AltaGas expects the annual average EBITDA contribution to range between $30 million and $35 million once completed.

The project is subject to regulatory approval by Alberta Environment (AENV) and ERCB. AltaGas has filed the AENV application and expects to file the regulatory application with the ERCB in first quarter 2011. Based on the expected timeline for filing and receiving regulatory approvals, the Company expects $70 million to $80 million of costs to be contractually fixed by September 2011. In total, approximately two-thirds of costs are expected to be contractually fixed over the course of construction. The remainder will be subject to cost escalation and labour productivity risk. AltaGas plans to mitigate project cost escalation and schedule risk through its procurement and contracting strategies.

Harmattan Cogeneration #2 Project

Following on the success of the 15 MW Harmattan Cogeneration project that was commissioned in late 2010, AltaGas plans to construct a second 15 MW cogeneration unit at the Harmattan Plant as a means of supplying power for the Co-stream project. Having two independent generating units on-site will provide a reliable source of low-cost power and steam to the facility while reducing the Harmattan facility's reliance on the grid and its power boilers. The project also includes adding the distribution system within the Harmattan facility. The project is estimated to cost $24 million and be in-service at the same time as the Harmattan Co-stream Project comes on-line.

Alton Natural Gas Storage Project

AltaGas completed the acquisition of Landis Energy Corporation in first quarter 2010. The most advanced project under development by Landis is the Alton Natural Gas Storage Project, of which AltaGas has a 50 percent interest, located near Truro, Nova Scotia that is expected to serve customers seeking to manage natural gas supply requirements in eastern Canada and the northeast United States. The Alton project has the potential capacity of 10 Bcf of natural gas storage.

Wind-generation Power Projects

The 67 MW Walker Ridge project in northern California is currently under development. AltaGas has selected the turbines and a preliminary layout and has completed preliminary engineering studies. The project is located near existing transmission lines and requires limited system upgrades to interconnect. It is located in Lake and Colusa counties, close to San Francisco load. This project is proceeding with the environmental permitting process. AltaGas is actively seeking bilateral agreements for sale of the power output.

The 100 MW Glenridge project in southeast Alberta is currently under development. AltaGas has secured a 17,000 acre land package. AltaGas is in the third stage of the Alberta Electricity System Operator (AESO) customer connection process and has begun the facilities study. AltaGas is actively seeking a market for its prospective green credits. Once in-service, the project will use these green credits to offset compliance costs associated with AltaGas' Sundance B PPAs.

The 90 MW Roughrider project in North Dakota is currently under development. The project holds easements of approximately 27,000 acres on private land. AltaGas is currently in the Western Area Power Administration (WAPA) and Midwest Independent System Operator (ISO) transmission queues and has determined that there are limited transmission upgrades required to interconnect to the WAPA transmission system. AltaGas is seeking green credit and energy markets with local and out-of-state utilities.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income	Three Months Ended		Year Ended	
(unaudited)		Dec 31		Dec 31
($ millions)	**2010**	2009	**2010**	2009
Gas	**25.9**	24.5	**95.9**	102.9
Power	**20.9**	22.9	**76.4**	88.0
Utility	**9.9**	7.4	**24.8**	7.4
Sub-total: Operating Businesses	**56.7**	54.8	**197.1**	198.3
Corporate	**(9.0)**	(16.0)	**(45.3)**	(24.0)
	47.7	38.8	**151.8**	174.3

GAS

Three Months Ended December 31

The Gas reporting segment recorded operating income of $25.9 million in fourth quarter 2010 compared to $24.5 million for the same quarter in 2009. The Gas segment's operating income was comprised of approximately 93 percent from Extraction and Transmission (E&T), approximately 4 percent from Field Gathering and Processing (FG&P) and Energy Services (ES) contributed the remainder. Operating income increased due to higher extraction fee-for-service revenues, higher realized frac spreads, higher marketing and commodity sales, and lower amortization. The increases were partially offset by lower gas processing throughput and rates and lower margins realized on natural gas storage.

Net revenue in the Gas reporting segment for fourth quarter 2010 was $79.4 million compared to $80.5 million for the same period in 2009. Net revenue declined due to lower volumes at some processing facilities and lower margins on natural gas storage partially offset by higher extraction fee-for-service revenues, higher realized frac spread and higher gas sales volumes and margins.

Operating and administrative expense in fourth quarter 2010 was $38.7 million compared to $39.7 million in same period last year. Costs were generally lower due to cost saving measures offset by higher costs within extraction due to increased NGL volumes produced.

Amortization expense in fourth quarter 2010 was $14.2 million compared to $15.6 million in 2009. Accretion for asset retirement obligations in fourth quarter 2010 was $0.7 million compared to $0.8 million in 2009. The decreases were due to the impact of revised estimates to some property, plant and equipment useful lives offset by growth in AltaGas' asset base from construction activities.

Full Year 2010

Operating income from the Gas reporting segment for 2010 was $95.9 million compared to $102.9 million in 2009. In 2010, approximately 93 percent (2009 - 86 percent) was contributed by the E&T business. The FG&P business contributed approximately 6 percent (2009 - 6 percent), with the remainder contributed by the ES business. Operating income decreased due to non-recurring adjustments to liabilities related to natural gas transactions, lower volumes processed at some extraction and FG&P facilities and the reversal of deferred revenue related to the Suffield pipeline reported in 2009. Operating income was also impacted by the movement of C&I power retail business to the Power reporting segment and increased provision for doubtful customer accounts. These decreases were partially offset by higher realized frac spread, the expiration of a legacy gas marketing contract in fourth quarter 2009, which resulted in losses in previous quarters, lower amortization as a result of change in estimates for the expected remaining useful lives for certain facilities, and lower operating and administrative expenses at some of the processing facilities.

Net revenue in the Gas reporting segment for 2010 was $312.7 million compared to $327.1 million in 2009. Net revenue decreased due to a non-recurring $9.4 million adjustment to liabilities related to natural gas transactions reported in 2009, $5.4 million decrease in FG&P fee-for-service revenues and volumes processed, $3.3 million decrease due to the reversal of Suffield revenue deferral in third quarter 2009, $3.6 million of C&I power retail sales revenues moved to the Power reporting segment, $2.4 million from lower extraction volumes and $1.0 million incremental provision for doubtful customer accounts. These increases were partially offset by $5.2 million from higher realized frac spreads and $4.7 million due to the expiration of a legacy gas marketing contract.

Operating and administrative expense for 2010 was $154.8 million compared to $159.9 million in 2009. The decrease was largely due to lower volumes at certain gas processing and extraction facilities and cost saving measures implemented, partially offset by costs associated with assets that were added or expanded during the year.

Amortization expense for 2010 was $59.1 million compared to $61.3 million in 2009. Accretion expense for 2010 was $2.8 million compared to $3.1 million in 2009. The decreases were due to revisions in estimates in the lives of certain facilities partially offset by the impact of growth in AltaGas' asset base from construction activities.

GAS OPERATING STATISTICS	Three Months Ended Dec 31		Year Ended Dec 31	
	2010	2009	**2010**	2009
E&T				
Extraction inlet gas processed (Mmcf/d)(1)	**870**	844	**798**	841
Extraction ethane volumes (Bbls/d)(1)	**25,792**	26,922	**25,453**	26,817
Extraction NGL volumes (Bbls/d)(1)	**13,537**	12,890	**12,654**	13,236
Total Extraction volumes (Bbls/d)(1)	**39,329**	39,812	**38,107**	40,053
Frac spread - realized ($/Bbl)(1) (2)	**27.59**	25.96	**27.27**	23.46
Frac spread - average spot price ($/Bbl)(1)	**34.74**	26.87	**31.95**	19.51
Transmission volumes (Mmcf/d)(1) (3)	**251**	320	**286**	324
FG&P				
Processing throughput (gross Mmcf/d)(1)	**401**	423	**423**	453
Capacity utilization (%)(4)	**34**	36	**35**	39
Energy Services				
Average volumes transacted (GJ/d)(5)	**428,669**	377,580	**386,004**	354,513

(1) *Average for the period.*

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

(3) *Excludes NGL pipeline volumes.*

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

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

During fourth quarter 2010 average ethane in the extraction business decreased by 1,130 Bbls/d and NGL volumes increased 647 Bbls/d compared to fourth quarter 2009. Growth occurred in liquids-rich gas areas; however declines in other areas have offset these increases. During 2010 average ethane and NGL volumes in the extraction business decreased by 1,364 Bbls/d and 582 Bbls/d, respectively, compared to 2009. Volumes declined due to lower gas supply at the Empress extraction facilities as a result of declining exports of natural gas east of Alberta. These decreases were partially offset by slightly higher inlet volumes and NGL yields at the Joffre facility and higher NGL processing at Harmattan. Natural gas volumes transported in the transmission business in fourth quarter 2010 and for the year 2010 decreased from the 2009 comparable periods primarily due to lower volumes moved on the Suffield system. However, in the transmission business, pipeline throughput has minimal impact on the financial results due to cost-of-service and take-or-pay contractual arrangements in place.

In FG&P, throughput in fourth quarter 2010 averaged 401 Mmcf/d compared to 423 Mmcf/d in the same quarter 2009. Throughput in 2010 averaged 423 Mmcf/d compared to 453 Mmcf/d in 2009. Although certain areas have experienced volume growth, the lack of producer activity in 2009 and 2010 in response to low natural gas prices has resulted in overall lower processing volumes.

Gas Outlook

The Gas Division is expected to deliver stronger results in 2011 than in 2010. Stronger results are expected from the field processing and extraction assets as producers look to increase net backs from liquids-rich gas. These increases are expected to be partially offset by lower volumes in areas where there are fewer opportunities for producers to benefit from liquids-rich gas and lower daily contract quantity on the Suffield system.

AltaGas expects higher volumes within the field processing business as a result of 2010 expansion projects at the existing Pouce Coupe, Ante Creek and Acme gas processing plants and the expected acquisition of Groundbirch. Expansions and plant modifications at Alder Flats and Blair Creek, connection of the new Henderson pipeline to the Pouce Coupe plant and higher producer activity in the Bantry and Princess areas are expected to more than offset the volume declines at some of the other facilities. Areas experiencing higher activity levels are being driven by producers focusing on high NGL content gas plays or light oil plays which create significant solution gas.

Throughput at the extraction assets is expected to increase in 2011 over 2010 despite the scheduled turnarounds at the Harmattan and Younger facilities. Drilling activity in northeast B.C. has increased as producers continue the development of tight and shale gas plays within the area. Development in this area is expected to result in higher volumes being processed at the Younger Extraction Plant. Higher extraction volumes through our Empress facilities are expected due to successful contracting of gas supply to increase utilization at these facilities. In addition, operating income within the Gas business during 2011 is expected to be greater than 2010 due to lower amortization, which has been estimated to be $7 million, as a result of changes in expected lives at certain facilities. Offsetting these gains will be the 2011 turnarounds that are expected to result in an operating income impact of $8.5 million. The turnarounds at the Younger and Harmattan facilities are expected to occur in second and third quarter, respectively. In addition, the lower daily contract quantity on the Suffield system is expected to result in lower operating income of approximately $6 million in 2011 compared to 2010.

Based on management's analysis of historical NGL prices, along with NGL published commodity prices and the current forward curve for 2011, management expects NGL frac spread prices to average approximately $35/Bbl. In 2011, the Company estimates that 13 percent of total extraction volumes will be exposed to frac spread. In 2011, approximately 70 percent of the exposure has been hedged at an average price of $26.85/Bbl.

POWER

Three Months Ended December 31

Operating income for fourth quarter 2010 was $20.9 million compared to $22.9 million for the same period in 2009. Operating income decreased due to lower realized power prices, higher environmental costs and higher amortization costs for the Bear Mountain Wind Park. These decreases were partially offset by lower PPA costs, increased contributions from gas-fired peaking plants and Alberta commercial and industrial power retail business.

Net revenue for fourth quarter 2010 was $27.4 million compared to $26.5 million for the same period in 2009. Net revenue increased due to lower PPA costs, higher revenues received from the gas-fired peaking plants and additional contributions from the power retail business. These increases were partially offset by lower realized power prices and higher Sundance B environmental costs.

Operating and administrative expense was $2.7 million for fourth quarter 2010 compared to $1.6 million for the same period in 2009. The increase was due to costs related to the development of renewable energy projects and the addition of the commercial and industrial power retail business.

Amortization expense was $3.9 million in fourth quarter 2010 compared to $2.0 million in fourth quarter 2009. The increase was due to the full quarter amortization of Bear Mountain Wind Park.

Full Year 2010

Operating income in the Power Segment in 2010 was $76.4 million compared to $88.0 million in 2009. Operating income decreased primarily as a result of lower realized power prices, higher PPA costs and higher environmental costs. The decreases were partially offset by the addition of Bear Mountain Wind Park, and contributions from the Alberta commercial and industrial power retail business.

Net revenue for 2010 was $101.8 million compared to $102.2 million for 2009. Net revenue decreased due to the $7.6 million impact of lower realized power prices, $5.6 million due to higher PPA costs and $3.9 million from higher environmental costs included as a reduction of revenue. These decreases were partially offset by $9.7 million from Bear Mountain Wind Park, $3.6 million from the C&I power retail business, $2.1 million higher contribution from gas-fired peaking plants and commencement of operations at the Harmattan cogeneration plant.

Operating and administrative expense was $10.0 million for 2010 compared to $6.1 million for 2009. The increase was due to costs related to the development of renewable energy projects, the addition of the commercial and industrial power retail business, and the commencement of commercial operations at Bear Mountain Wind Park in fourth quarter 2009.

Amortization expense was $15.3 million in 2010 compared to $8.2 million in 2009. The increase was largely due to the addition of Bear Mountain Wind Park.

POWER OPERATING STATISTICS	Three Months Ended Dec 31		Year Ended Dec 31	
	2010	2009	**2010**	2009
Volume of power sold (GWh)(1)(2)	**752**	707	**2,828**	2,725
Average price realized on the sale of power ($/MWh)(1)(2)	**64.43**	67.54	**66.79**	68.97
Alberta Power Pool average spot price ($/MWh)(1)	**45.90**	46.32	**50.76**	47.84

(1) *Average for the period.*

(2) *Includes only Alberta volumes and prices realized on the sale of power.*

Bear Mountain Wind Park wind volumes were below historical averages for the three months and year ended December 31, 2010. The operating income impact of the weaker wind for the three months ended and year ended December 31, 2010 was approximately $2.0 million and $7.8 million, respectively, compared to expectations. A portion of 2010 green attributes associated with Bear Mountain Wind Park was sold in a deal completed in 2009 at prices in-line with management's expectations.

Power Outlook

AltaGas has altered its approach to hedging its Alberta power generation. Changes in the Alberta power market, particularly the changes to the Rate Regulated Option (RRO) have focused liquidity into the prompt month while decreasing liquidity for longer term products. For first quarter 2011, AltaGas has hedged approximately two-thirds of the expected Alberta-based power generation at an average price of $63.50 per MWh. For the second through fourth quarters of 2011, AltaGas has hedged approximately one-third at an average price of $65 per MWh. On a full-year basis, AltaGas is approximately 40 percent hedged at an average price of $64.50 per MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to long-term averages, as it has successfully done to date in 2011.

On February 8, TransAlta announced its intentions to terminate the Sundance A PPA, which will have the effect of permanently removing approximately 560 MW, or 4 percent of the generation supply in Alberta. The Sundance B PPA generating units, which support AltaGas' PPA generation, are approximately five years newer than the Sundance A generating units, the term of the Sundance B PPAs is three years longer, and unit 4 of Sundance B saw a significant capital investment by its owner in 2007 when its capacity was increased by approximately 53 MW. Therefore, management does not believe the risk of a similar event happening with Sundance B is significant. Upon announcement of the potential termination of the Sundance A PPA, forward prices immediately increased, marking a fundamental shift in the market that results in a more sustainable supply/demand/price balance in the province. Current forward prices, as published in daily broker reports, are in the low $60's per MWh for the balance of 2011 as well as 2012 and 2013.

The impact of the addition of the Harmattan cogeneration facility in late 2010 will also help strengthen results from the power business in 2011. According to AESO, if the demand for power and the rate of growth in Alberta continues as forecast, the addition of up to 3,800 MW of new generation may be required by 2016. Improved economic conditions in Alberta are expected to bring increased power demand to the province and provide further support to prices over the long term.

UTILITY

Three Months Ended December 31

The Utility business commenced operations with the acquisition of Utility Group on October 8, 2009 and the remaining 75.1 percent of Heritage Gas on November 18, 2009. Net income is highly seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. Earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. Increases in the number of customers or changes in customer usage are examples of other factors that might typically affect volumes and hence earned returns. Operating income for fourth quarter 2010 was $9.9 million compared to $7.4 million for the same period in 2009.

The Utility business predominantly comprises rate regulated utilities, which net income is based on an allowed return on rate base invested. Rate regulated cost of service entities such as AltaGas Utilities Inc. (AUI) and Heritage Gas generally collect operating and administrative, depreciation, interest expenses and income taxes paid in the rates charged to customers, and therefore changes in these costs do not normally impact the net income of the business. Consequently, this discussion of financial results focuses on net income.

The net income from the Utility reporting segment was $7.9 million for fourth quarter 2010 compared to $5.1 million for the same period in 2009, primarily due to AltaGas owning Utility Group and all of Heritage Gas for the full quarter in 2010. The Utility business grew its rate base by 15 percent in 2010 to $277.0 million which increased fourth quarter net income by $0.5 million. Warmer weather in fourth quarter 2010 compared to 2009 for both Alberta and Nova Scotia reduced 2010 net income by $0.3 million.

After deducting natural gas costs of $24.1 million (2009 - $30.5 million), net revenue for fourth quarter 2010 was $22.1 million compared to $13.0 million for the same period in 2009. The increase in fourth quarter 2010 net revenue was primarily due to the full year impact of AltaGas' acquisitions of Utility Group and the 75.1 percent of Heritage Gas it did not already own, on October 8, 2009 and November 18, 2009, respectively. Net revenue growth of $0.6 million from the higher 2010 rate base was partially offset by warmer weather in fourth quarter 2010 in Alberta and Nova Scotia which decreased net revenue by $0.4 million.

Operating and administrative expense was $8.8 million for fourth quarter 2010 compared to $3.4 million for the same period in 2009. Depreciation, depletion and amortization expense was $3.4 million in fourth quarter 2010 compared to $2.2 million in fourth quarter 2009. Interest expense was $2.5 million in fourth quarter 2010 compared to $1.0 million in fourth quarter 2009. The increased expenses were primarily a result of the late 2009 acquisitions of Utility Group and Heritage Gas.

Income tax recovery was $0.5 million in fourth quarter 2010 compared to an expense of $1.1 million in same period of 2009. The income tax recovery in fourth quarter 2010 was mainly due to the recovery of cash income tax at AUI due to deductions available from a software investment.

Full Year 2010

For 2010 the Utility reporting segment recorded $24.8 million in operating income compared to $7.4 million in 2009. Net income from the Utility reporting segment was $16.7 million in 2010 compared to $5.4 million in 2009, primarily due to AltaGas owning Utility Group and all of Heritage Gas for a full year compared to only twelve and six weeks respectively in 2009. The Utility business grew its rate base by 15 percent in 2010 to $277.0 million which increased net income by $1.8 million on a full year basis. Warmer than normal weather in both Alberta and Nova Scotia reduced 2010 net income by $0.7 million on a full year basis.

After deducting natural gas costs of $79.8 million (2009 - $30.5 million) net revenue reported by the Utility business grew to $71.9 million (2009 - $13.0 million). The increase in 2010 net revenue was primarily due to the full year impact of AltaGas' acquisitions of Utility Group and the 75.1 percent of Heritage Gas it did not already own, on October 8, 2009 and November 18, 2009, respectively. Net revenue growth of $1.9 million from the higher 2010 rate base was partially offset by warmer than normal weather in Alberta and Nova Scotia which decreased net revenue by $0.8 million.

Operating and administrative expense increased from $3.4 million in 2009 to $35.5 million in 2010. Depreciation, depletion and amortization expense increased from $2.2 million in 2009 to $11.6 million in 2010. Interest expense increased from $1.0 million in 2009 to $7.7 million in 2010. Income tax decreased from $1.0 million in 2009 to $0.4 million in 2010. The increased expenses were primarily a result of the late 2009 acquisitions of Utility Group and Heritage Gas.

UTILITY OPERATING STATISTICS	Three Months Ended Dec 31		Year Ended Dec 31	
	2010	2009	**2010**	2009[1]
Natural gas deliveries - end-use (PJ)[2]	**7.0**	6.6	**19.9**	6.6
Natural gas deliveries - transportation (PJ)[2]	**1.3**	0.6	**5.3**	0.6
Service sites [3]	**74,664**	72,717	**74,664**	72,717
Degree day variance - AUI (%) [4]	**4.4**	9.9	**(1.6)**	9.9
Degree day variance - Heritage Gas (%) [4]	**(11.0)**	(1.0)	**(13.2)**	(1.0)

[1] Reflect Utility Group as of October 8, 2009 when the Company obtained control and 100% of the deliveries of Heritage Gas as of November 18, 2009.

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

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

[4] Degree days relate to AUI and Heritage Gas service areas. A degree day is the cumulative extent to which the daily mean temperature falls below 15 degree Celsius. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations.

Utility Outlook

AltaGas expects to grow the rate bases within its utility businesses in Alberta and Nova Scotia during 2011 resulting in growth in earnings. AltaGas expects the utilities in Alberta and Nova Scotia to perform according to their respective 2011 General Rate Applications (GRA). In 2011, AUI is forecast to spend approximately $26 million, growing mid-year rate base by 16 percent to $164 million. Heritage Gas is forecast to spend approximately $20 million to expand its system in 2011 which, along with the growth in the Revenue Deficiency Account (RDA), is expected to grow rate base by 25 percent.

AltaGas will continue to pursue growth in its existing franchise areas and is well positioned to capture opportunities arising in its service areas in Alberta. AltaGas expects that new business growth in 2011 will be approximately two percent at the Alberta utility.

The Alberta utility (AUI) is operating in regulatory lag for a number of items including 2011 return on equity, debt rates on all of AUI's debt and its 2010-2012 GRA including costs-of-service and capital programs. The 2010 capital incurred and plans for 2011 and 2012 are subject to regulatory approval which is not expected until late 2011 at the earliest. Should AUI receive a decision on any of these matters during the year, the impact of the decision will be recorded in 2011.

The Nova Scotia utility (Heritage Gas) offers strong growth potential in its franchise areas. Examples include the continued expansion of its system in the Halifax Regional Municipality (HRM) and ongoing conversion of customers with existing access to natural gas. Heritage Gas expects to activate approximately 750 new customers in 2011.

The 13 percent allowed return on equity and the 8.75 percent allowed debt rate at Heritage Gas are approved by the NSUARB through 2011. Heritage Gas will file a GRA by mid-year 2011 to apply for rates and terms beginning January 2012. The GRA is comprehensive, and will provide a number of studies requested by the NSUARB, including cost-of-capital, capital structure, cost-of-service and rate-design studies. The hearing is set for Fall 2011 and a decision from the NSUARB is expected before the end of 2011.

CORPORATE

Three Months Ended December 31

The operating loss for fourth quarter 2010 was $9.0 million compared to $16.0 million for fourth quarter 2009. The lower loss was due to unrealized losses from risk management contracts of $7.2 million in the prior year quarter, gain on mark-to-market adjustments for investments of $0.8 million compared to a loss of $2.2 million last year and lower administration expenses of $2.0 due to cost cutting measures. These increases were partially offset by lower investment income of $1.9 million during the quarter compared to $7.2 million in the prior year quarter. Adjusting for mark-to-market accounting, the Corporate Segment reported costs of $4.0 million in fourth quarter 2010 compared to $7.4 million in the same quarter last year.

Net revenue was higher in fourth quarter 2010 compared to the same period in 2009 due to changes in unrealized losses on risk management contracts of $7.2 million and lower mark-to-market losses on investments of $3.0 million. These increases were offset by lower investment income of $4.9 million.

Operating and administrative expense was $10.7 million in fourth quarter 2010 compared to $12.0 million in fourth quarter 2009. Lower expenses were a result of cost saving initiatives implemented during the quarter.

Amortization expense was $0.9 million in fourth quarter 2010 compared to $0.6 million in the same quarter 2009. Higher amortization was due to costs incurred for information systems.

Full Year 2010

The operating loss for 2010 was $45.2 million compared to $24.1 million for 2009. The increased loss was due to unrealized losses on investments of $4.3 million compared to gains of $5.8 million last year, unrealized losses from risk management contracts of $1.3 million compared to gains of $3.7 million in the prior year, investment income for 2010 of $7.1 million compared to $10.3 million in 2009 and higher administration expenses related to AltaGas' growth, conversion to a corporation and costs to comply with regulatory requirements.

Net revenue was $1.6 million in 2010 compared to $18.6 million in 2009. Net revenue decreased due to the $10.1 million difference between mark-to-market losses on investments reported in the current year compared to unrealized gains in the prior year, $5.0 million due to unrealized losses on risk management contracts compared to gains in the prior year and lower investment income of $1.9 million.

Operating and administrative expense was $43.7 million in 2010 compared to $40.1 million in 2009. Increased expenses were incurred to support the conversion to a corporation, regulatory requirements and growth of the Company partially offset by several initiatives to reduce general and administrative expenses.

Amortization expense was $3.1 million in 2010 compared to $2.5 million in 2009. The increase was primarily due to the deployment of information systems to support the growth of the Company.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2011 is expected to be lower than the loss reported in 2010. During 2010, the Company incurred costs to convert from a trust structure to a corporation and support activities related to compliance with the Harmonized Sales Tax in Ontario and British Columbia. The Company expects to incur costs to transition to IFRS or US GAAP during 2011 based on the outcome of management's decision to be finalized during the first quarter of 2011. The Corporate reporting segment is also expected to report lower income from other investments during 2011.

The Company expects to report higher future income tax expense based on being a corporation for a full year, partially offset by using a lower effective corporate tax rate of approximately 23 percent. The tax rate at the consolidated level is lower than the expected statutory rate as a result of the lower effective tax rate at the Utility business. Taxes recoverable or payable by the Utility businesses are recorded as regulatory assets or liabilities until such time as the taxes are collectible or payable from or to the utility customers. With tax pools in excess of $1 billion, AltaGas does not expect to be cash taxable until approximately 2016.

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 2011 results. However, the impact of the accounting standards is expected to be relatively low since AltaGas uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked in margins. AltaGas does not execute financial instruments for speculative purposes.

Consolidated Balance Sheets

(unaudited)

($ thousands)	December 31 2010	December 31 2009
ASSETS		
Current assets		
Cash and cash equivalents	**$ 2,109**	$ 3,584
Short-term investment	**-**	19,436
Accounts receivable	**224,370**	203,673
Inventory	**13,107**	1,401
Restricted cash holdings from customers	**17,624**	27,228
Regulatory assets	**2**	2,567
Risk management	**41,226**	66,271
Prepaid expense and other current assets	**5,587**	7,505
	304,025	331,665
Capital assets	**1,995,632**	1,857,095
Energy arrangements, contracts and relationships	**120,848**	128,949
Goodwill	**199,497**	201,728
Regulatory assets	**76,515**	60,885
Risk management	**22,587**	18,132
Long-term investments and other assets	**32,588**	30,487
	$ 2,751,692	$ 2,628,941
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 228,772**	$ 158,319
Dividends payable	**9,078**	15,110
Short-term debt	**9,478**	14,471
Current portion of long-term debt	**1,508**	591,944
Customer deposits	**21,432**	30,678
Regulatory liabilities	**1,494**	1,403
Risk management	**39,209**	34,200
Other current liabilities	**12,302**	14,830
	323,273	860,955
Long-term debt	**893,498**	408,170
Asset retirement obligations	**39,516**	41,771
Future income taxes	**233,763**	228,596
Regulatory liabilities	**18,518**	16,610
Risk management	**20,598**	14,491
Future employee obligations	**11,495**	9,491
	1,540,661	1,580,084
Shareholders' equity	**1,211,031**	1,048,857
	$ 2,751,692	$ 2,628,941

Consolidated Statements of Income

(unaudited)

($ thousands except per share amounts)	Three Months Ended December 31 2010	Three Months Ended December 31 2009	Year Ended December 31 2010	Year Ended December 31 2009
REVENUE				
Operating	**$ 359,462**	$ 339,884	**$ 1,352,427**	$ 1,249,649
Unrealized gain (loss) on risk management	**(25)**	(7,206)	**(1,337)**	3,697
Other revenue	**2,728**	3,756	**2,962**	14,919
	362,165	336,434	**1,354,052**	1,268,265
EXPENSES				
Cost of sales	**231,334**	220,993	**868,554**	811,688
Operating and administrative	**60,081**	55,548	**241,540**	205,081
Accretion of asset retirement obligations	**720**	807	**2,880**	3,138
Amortization:				
Capital assets	**19,929**	17,818	**79,216**	64,157
Energy arrangements, contracts and relationships	**2,491**	2,491	**9,964**	9,964
	314,555	297,657	**1,202,154**	1,094,028
Foreign exchange loss	**82**	260	**67**	1
Interest expense				
Short-term debt	**280**	245	**1,533**	1,283
Long-term debt	**11,802**	9,035	**47,309**	30,476
Income before income taxes	**35,446**	29,237	**102,989**	142,477
Income tax expense (recovery)				
Current income tax	**(1,163)**	814	**(222)**	981
Future income tax	**7,378**	(3,723)	**1,949**	187
Net income	**29,231**	32,146	**101,262**	141,309
Preferred share dividends (net of tax)	**2,773**	-	**4,038**	-
Net income applicable to common shares	**$ 26,458**	$ 32,146	**$ 97,224**	$ 141,309
Net income per share				
Basic	**$ 0.32**	$ 0.40	**$ 1.19**	$ 1.80
Diluted	**$ 0.32**	$ 0.40	**$ 1.19**	$ 1.79
Weighted average number of shares outstanding (thousands)				
Basic	**82,189**	80,042	**81,512**	78,540
Diluted	**83,133**	80,536	**81,891**	79,371

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

(unaudited)

For the Three Months Ended	Three Months Ended December 31		Year Ended December 31	
($ thousands)	**2010**	2009	**2010**	2009
Net income	**$ 29,231**	$ 32,146	**$ 101,262**	$ 141,309
Other comprehensive income (loss), net of tax				
Unrealized net gain (loss) on available-for-sale financial assets	**2,159**	(701)	**(2,421)**	3,877
Unrealized net gains (loss) on derivatives designated as cash flow hedges	**(15,986)**	3,028	**(25,369)**	15,088
Reclassification to net income of net gain (loss) on derivatives designated as cash flow hedges pertaining to prior periods	**10,950**	(8,623)	**3,813**	(29,309)
	(2,877)	(6,296)	**(23,977)**	(10,344)
Comprehensive income	**$ 26,354**	$ 25,850	**$ 77,285**	$ 130,965
Accumulated other comprehensive income, beginning of period	**$ 125**	$ 27,521	**$ 21,225**	$ 31,569
Other comprehensive income loss, net of tax	**(2,877)**	(6,296)	**(23,977)**	(10,344)
Accumulated other comprehensive (loss) income, end of period	**$ (2,752)**	$ 21,225	**$ (2,752)**	$ 21,225

Consolidated Statements of Shareholders' Equity

(unaudited)

($ thousands)		Year Ended December 31 2010		2009
Common shares				
Balance, beginning of period	**$**	**982,662**	$	850,992
Shares issued for cash on exercise of options		**4,915**		1,246
Shares issued under DRIP [(1)]		**32,062**		34,169
Shares issued on exercise of warrants		**3,394**		-
Shares issued on conversion of convertible debentures		**-**		71
Shares issued on public offering (net of issuance costs and tax benefit)		**-**		96,184
Balance, end of period		**1,023,033**		982,662
Preferred shares				
Balance, beginning of period		**-**		-
Shares issued on public offering (net of issuance costs)		**194,126**		-
Balance, end of period		**194,126**		-
Contributed surplus				
Balance, beginning of period		**5,621**		4,261
Amortization of share options		**546**		376
Exercise of share options		**(1,511)**		(318)
Cancellation of share options		**(90)**		(213)
Other adjustments		**1,106**		1,515
Balance, end of period		**5,672**		5,621
Warrants				
Balance, beginning of period		**4,500**		4,500
Exercised		**(4,500)**		-
Balance, end of period		**-**		4,500
Accumulated earnings				
Balance, beginning of period		**34,849**		64,547
Net income		**101,262**		141,309
Distributions		**(86,982)**		(170,831)
Common share dividends		**(54,139)**		-
Preferred share dividends (net of tax)		**(4,038)**		-
Transition adjustment resulting from adopting new financial instruments accounting standards		**-**		(176)
Balance, end of period		**(9,048)**		34,849
Accumulated other comprehensive income				
Balance, beginning of period		**21,225**		31,569
Other comprehensive loss		**(23,977)**		(10,344)
Balance, end of period		**(2,752)**		21,225
Total shareholders' equity	**$**	**1,211,031**	$	1,048,857

(1) *Dividend Reinvestment and Optional Share Purchase Plan*.

Consolidated Statements of Cash Flows

(unaudited)

($ thousands)	Three Months Ended December 31 2010	2009	Year Ended December 31 2010	2009
Cash from operations				
Net income	**$ 29,231**	$ 32,146	**$ 101,262**	$ 141,309
Items not involving cash:				
Amortization	**22,420**	20,309	**89,180**	74,121
Accretion of asset retirement obligations	**720**	807	**2,880**	3,138
Share-based compensation	**138**	(1,679)	**145**	(195)
Future income tax expense (recovery)	**7,378**	(3,813)	**1,949**	187
Gain on sale of investments	**(1,864)**	-	**(6,898)**	(6,804)
Equity (income) loss	**(73)**	741	**(328)**	(158)
Unrealized (gains) losses	**(214)**	9,464	**6,144**	(9,468)
Goodwill impairment	**-**	150	**-**	150
Other	**275**	111	**1,628**	2,788
Non-operating investment income	**(83)**	(7,224)	**(923)**	(2,809)
Asset retirement obligations settled	**(245)**	(239)	**(518)**	(384)
Net change in non-cash working capital	**(7,293)**	(5,341)	**(1,939)**	(17,729)
	50,390	45,432	**192,582**	184,146
Investing activities				
Increase (decrease) in customer deposits	**4,586**	1,096	**9,604**	(3,211)
Capital expenditures	**(64,632)**	(84,678)	**(157,027)**	(242,970)
Disposition of capital assets	**14**	-	**334**	-
Acquisition of energy services arrangements, contracts and relationships	**-**	-	**(1,863)**	-
Investment in regulatory assets	**(1,227)**	(6,014)	**(10,335)**	(6,014)
Distributions from equity investments	**96**	46	**384**	427
Disposition (acquisition) of short-term investments	**5,720**	30,540	**21,204**	(8,198)
Income from short-term investment	**83**	1,034	**923**	2,809
Business acquisition	**-**	(191,277)	**(22,720)**	(191,277)
Acquisition of long-term investments and other assets	**(401)**	-	**(5,240)**	(15,658)
Disposition of long-term investments and other assets	**-**	565	**2,871**	-
	(55,761)	(248,688)	**(161,865)**	(464,092)
Financing activities				
Issuance (repayment) of short-term debt	**(14,609)**	13,867	**(9,469)**	9,978
Net issuance (repayment) of revolving long-term debt	**(135,691)**	207,523	**(372,028)**	16,132
Issuance of long-term debt	**174,105**	(66)	**372,974**	295,080
Repayment of long-term debt	**(449)**	(365)	**(101,733)**	(18,017)
Dividends and distributions	**(29,973)**	(43,173)	**(151,843)**	(168,666)
Net proceeds from issuance of common shares	**10,521**	10,594	**35,781**	130,719
Net proceeds from issuance of preferred shares	**-**	-	**194,126**	-
	3,904	188,380	**(32,192)**	265,226
Change in cash and cash equivalents	**(1,467)**	(14,876)	**(1,475)**	(14,720)
Cash and cash equivalents, beginning of period (1)	**3,576**	18,460	**3,584**	18,304
Cash and cash equivalents, end of period	**$ 2,109**	$ 3,584	**$ 2,109**	$ 3,584

(1) Balance of cash and cash equivalents as at January 1, 2010 was adjusted to reflect a prior period adjustment to a non-operated joint venture.

1. 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. In accordance with the CICA Handbook Section 1700, in the year ended December 31, 2010, AltaGas changed the composition of its reportable segments as a result of modifications and growth of the enterprise. Comparative periods have been restated based on the current reportable segments. The following describes the Company'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 sale of natural gas and electricity – natural gas storage facilities
Power	– coal-fired and gas-fired power output under power purchase arrangements and other agreements – gas-fired power plants – wind and run-of-river power plants – sale of power to commercial and industrial users in Alberta
Utility	– regulated natural gas distribution assets
Corporate	– the costs 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 December 31, 2010	Gas	Power	Utility	Corporate	Intersegment Elimination	Total
Revenue	**$ 279,863**	**$ 66,689**	**$ 46,114**	**$ 2,728**	**$ (33,204)**	**$ 362,190**
Unrealized losses on risk management	**-**	**-**	**-**	**(25)**	**-**	**(25)**
Cost of sales	**(200,427)**	**(39,293)**	**(24,065)**	**-**	**32,451**	**(231,334)**
Operating and administrative	**(38,720)**	**(2,660)**	**(8,763)**	**(10,691)**	**753**	**(60,081)**
Accretion of asset retirement obligations	**(710)**	**(9)**	**(1)**	**-**	**-**	**(720)**
Amortization	**(14,179)**	**(3,868)**	**(3,399)**	**(974)**	**-**	**(22,420)**
Foreign exchange loss	**-**	**-**	**-**	**(82)**	**-**	**(82)**
Interest expense	**-**	**-**	**(2,540)**	**(9,542)**	**-**	**(12,082)**
Income (loss) before income taxes	**$ 25,827**	**$ 20,859**	**$ 7,346**	**$ (18,586)**	**-**	**$ 35,446**
Net additions (reductions) to:						
Capital assets[(1)]	**$ 32,917**	**$ 26,855**	**$ 19,407**	**$ 1,914**	**-**	**$ 81,093**
Long-term investment and other assets[(1)]	**-**	**$ (23)**	**-**	**$ 6,757**	**-**	**$ 6,734**
Goodwill	**$ 143,726**	**-**	**$ 55,771**	**-**	**-**	**$ 199,497**
Segmented assets	**$ 1,712,141**	**$ 466,341**	**$ 475,968**	**$ 97,242**	**-**	**$ 2,751,692**

[(1)] *Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.*

Year Ended December 31, 2010	**Gas**	**Power**	**Utility**	**Corporate**	**Intersegment Elimination**	**Total**
Revenue	**$ 1,064,297**	**$ 261,563**	**$ 151,697**	**$ 2,962**	**$ (125,130)**	**$ 1,355,389**
Unrealized losses on risk management	**-**	**-**	**-**	**(1,337)**	**-**	**(1,337)**
Cost of sales	**(751,647)**	**(159,719)**	**(79,768)**	**-**	**122,580**	**(868,554)**
Operating and administrative	**(154,823)**	**(10,044)**	**(35,494)**	**(43,729)**	**2,550**	**(241,540)**
Accretion of asset retirement obligations	**(2,839)**	**(33)**	**(8)**	**-**	**-**	**(2,880)**
Amortization	**(59,072)**	**(15,332)**	**(11,648)**	**(3,128)**	**-**	**(89,180)**
Foreign exchange loss	**-**	**-**	**-**	**(67)**	**-**	**(67)**
Interest expense	**-**	**-**	**(7,723)**	**(41,119)**	**-**	**(48,842)**
Income (loss) before income taxes	**$ 95,916**	**$ 76,435**	**$ 17,056**	**$ (86,418)**	**-**	**$ 102,989**
Net additions (reductions) to:						
Capital assets[1]	**$ 108,221**	**$ 51,375**	**$ 54,687**	**$ 5,838**	**-**	**$ 220,121**
Energy service arrangements, contracts and relationships	**-**	**$ 1,863**	**-**	**-**	**-**	**$ 1,863**
Long-term investment and other assets[1]	**-**	**$ (54)**	**$ (1,890)**	**$ 3,794**	**-**	**$ 1,850**
Goodwill	**$ 143,726**	**-**	**$ 55,771**	**-**	**-**	**$ 199,497**
Segmented assets	**$ 1,712,141**	**$ 466,341**	**$ 475,968**	**$ 97,242**	**-**	**$ 2,751,692**

[1] Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.

Three Months Ended December 31, 2009	Gas	Power	Utility	Corporate	Intersegment Elimination	Total
Revenue	$ 288,834	$ 48,330	$ 43,538	$ 3,757	$ (40,819)	$ 343,640
Unrealized losses on risk management	-	-	-	(7,206)	-	(7,206)
Cost of sales	(208,303)	(21,819)	(30,513)	-	39,642	(220,993)
Operating and administrative	(39,702)	(1,644)	(3,419)	(11,960)	1,177	(55,548)
Accretion of asset retirement obligations	(803)	(3)	(1)	-	-	(807)
Amortization	(15,568)	(1,952)	(2,153)	(636)	-	(20,309)
Foreign exchange loss	-	-	-	(260)	-	(260)
Interest expense	-	-	(1,036)	(8,244)	-	(9,280)
Income (loss) before income taxes	$ 24,458	$ 22,912	$ 6,416	$ (24,549)	-	$ 29,237
Net additions to:						
Capital assets[1]	$ 13,676	$ 36,882	$ 271,373	$ 362	-	$ 322,293
Long-term investment and other assets[1]	-	$ (347)	$ (12,300)	$ 479	-	$ (12,168)
Goodwill	$ 143,691	-	$ 58,037	-	-	$ 201,728
Segmented assets	$ 1,623,120	$ 425,899	$ 430,057	$ 149,865	-	$ 2,628,941

[1] Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.

Year Ended December 31, 2009	Gas	Power	Utility	Corporate	Intersegment Elimination	Total
Revenue	$ 1,098,873	$ 188,508	$ 43,538	$ 14,919	$ (81,270)	$ 1,264,568
Unrealized gains on risk management	-	-	-	3,697	-	3,697
Cost of sales	(771,749)	(86,280)	(30,513)	-	76,854	(811,688)
Operating and administrative	(159,886)	(6,059)	(3,419)	(40,133)	4,416	(205,081)
Accretion of asset retirement obligations	(3,127)	(10)	(1)	-	-	(3,138)
Amortization	(61,274)	(8,167)	(2,153)	(2,527)	-	(74,121)
Foreign exchange gain	-	-	-	(1)	-	(1)
Interest expense	-	-	(1,036)	(30,723)	-	(31,759)
Income (loss) before income taxes	$ 102,837	$ 87,992	$ 6,416	$ (54,768)	-	$ 142,477
Net additions to:						
Capital assets(1)	$ 52,406	$ 159,544	$ 271,373	$ 3,073	-	$ 486,396
Long-term investment and other assets(1)	-	$ (367)	$ (12,300)	$ 24,410	-	$ 11,743
Goodwill	$ 143,691	-	$ 58,037	-	-	$ 201,728
Segmented assets	$ 1,623,120	$ 425,899	$ 430,057	$ 149,865	-	$ 2,628,941

(1) *Net additions to capital assets and long-term investments and other assets may not agree to other financial statements due to classification of acquisitions.*

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 one of Canada's largest and fastest growing integrated energy infrastructure organizations. AltaGas creates value by growing and optimizing gas and power infrastructure, including a focus on renewable energy sources. For more information visit: www.altagas.ca.

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