AltaGas

# NEWS RELEASE
# ALTAGAS LTD. REPORTS STRONG THIRD QUARTER RESULTS AND ANNOUNCES FINAL INVESTMENT DECISION FOR THE NORTH PINE FACILITY

**Calgary, Alberta (October 20, 2016)**

(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

**Highlights**

- Strong normalized EBITDA in the third quarter of $176 million, a 41 percent increase over the third quarter of 2015;
- 34 percent increase in normalized funds from operations to $137 million;
- Reached a positive Final Investment Decision (FID) on the North Pine NGL Facility (the North Pine Facility);
- Commenced commercial operations of the 198 Mmcf/d Townsend Facility with processing volumes increasing as expected;
- Significantly advanced plans for the expansion of Townsend which would include an additional 100 Mmcf/d shallow-cut processing capability;
- Signed a 10-year Energy Storage Resource Adequacy Purchase Agreement (Energy Storage Agreement or ESA) with Southern California Edison (SCE) for 20 megawatts (MW) of energy storage at the Pomona Facility (the Pomona Energy Storage Project);
- Public comment period for the Environmental Evaluation Document for the proposed Ridley Island Propane Export Terminal was successfully completed;
- Approval received for a 25-year licence from the National Energy Board (NEB) to export up to 1.35 million tonnes per annum of propane to support Ridley Island Propane Export Terminal;
- 18 percent increase in generation at Forrest Kerr compared to the third quarter of 2015; and
- On a U.S. GAAP basis, net income applicable to common shares for the third quarter was $46 million ($0.28 per share), an increase of 87 percent on a per share basis as compared to the same quarter in 2015.

AltaGas Ltd. (AltaGas) (TSX:ALA) today reported third quarter 2016 normalized EBITDA of $176 million, an increase of 41 percent over the same quarter of 2015. Normalized funds from operations were $137 million ($0.84 per share) for the third quarter of 2016, compared to $102 million ($0.75 per share) in the same period of 2015. On a U.S. GAAP basis, net income applicable to common shares for the third quarter of 2016 was $46 million ($0.28 per share) compared to $20 million ($0.15 per share) for the same quarter in 2015. Normalized net income was $38 million ($0.23 per share) for the third quarter of 2016, compared to $19 million ($0.14 per share) in the same period of 2015.

“Our strong third quarter results continue to highlight the strength of AltaGas’ business and the significant growth we achieved in our power segment with the addition of the San Joaquin assets and our Northwest Hydro Facilities reaching the highest quarterly recorded generation to date,” said David Harris, President and CEO of AltaGas. “We also had great success over the quarter advancing our northeast B.C. strategy. Our Townsend Facility came online ahead of schedule and under budget and Painted Pony has been steadily increasing volumes through the facility. We are moving forward with an expansion of Townsend and expect to announce a final investment decision on this in early 2017. We are also excited to move forward with our North Pine Facility. North Pine is a key component of our energy value chain and brings forward a significant new and competitive option for producers in the Montney. Together with our proposed Ridley Island Propane Export Terminal, we can offer producers superb service to existing and new markets. As we move into the last couple months of the year we expect to hit our financial targets and bring our Ridley Island Propane Export Terminal investment decision to fruition.”

The increase in normalized EBITDA for the third quarter of 2016 was mainly due to the San Joaquin Facilities acquired late in 2015, which contributed approximately $25 million of EBITDA, higher contributions from the Northwest Hydro Facilities as a result of McLymont entering commercial service in the fourth quarter of 2015 and strong performance at Forrest Kerr, commencement of commercial operations at the Townsend Facility and the absence of equity losses from the Sundance B Power Purchase Arrangements (the Sundance B PPAs) terminated in the first quarter of 2016. These increases were partially offset by lower gains from frac hedges, lower earnings from Petrogas Energy Corp. (Petrogas), the impact from the expiration of the Pomona PPA at the end of 2015, lower incremental fee-for-service revenues at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels, and the impact of the sale of non-core assets to Tidewater Midstream and Infrastructure Ltd. on February 29, 2016 (the Tidewater Gas Asset Disposition).

The increase in normalized funds from operations in the third quarter of 2016 was driven by the same factors as normalized EBITDA, as well as higher common share dividends from Petrogas, partially offset by higher interest and current income tax expense.

For the third quarter of 2016, AltaGas recorded income tax expense of $17 million compared to $5 million in the same quarter of 2015. The increase was mainly due to higher taxable earnings in the third quarter of 2016, including higher taxable earnings from U.S. operations which bear higher corporate income tax rates.

On a U.S. GAAP basis, net income applicable to common shares for the third quarter of 2016 was $46 million ($0.28 per share) compared to $20 million ($0.15 per share) for the same quarter in 2015.

The increase in normalized net income in the third quarter of 2016 was driven by the same factors as normalized EBITDA as well as higher depreciation and amortization expense, interest expense and preferred share dividends. In the third quarter of 2016, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, and recovery of development costs for the PNG Pipeline Looping Project. In the third quarter of 2015, normalizing items included after-tax amounts related to unrealized gains on risk management contracts, energy export development costs, and provision on long-lived assets.

For the nine months ended September 30, 2016, AltaGas reported normalized EBITDA of $507 million compared to $409 million for the same period in 2015. The increase was primarily due to EBITDA generated from the San Joaquin Facilities, higher contributions from the Northwest Hydro Facilities, rate base and customer growth at the Utilities, the impact of the stronger US dollar on reported results of the U.S. assets, the absence of turnarounds at the Younger and Harmattan facilities, commencement of commercial operations at the Townsend Facility, and lower equity losses from the Sundance B PPAs. This was partially offset by the impact of significantly warmer weather experienced at all of AltaGas' Utilities during the winter heating season, lower gains from frac hedges, the impact from the Tidewater Gas Asset Disposition, the impact from the expiration of the Pomona PPA at the end of 2015, and lower incremental fee-for-service revenues at the Gordondale facility due to lower volumes delivered in excess of take-or-pay.

Normalized funds from operations for the nine months ended September 30, 2016 were $383 million ($2.48 per share), compared to $311 million ($2.30 per share) for the same period in 2015, driven by the same factors impacting normalized EBITDA as well as higher common share dividends from Petrogas, partially offset by higher interest and current income tax expense.

For the nine months ended September 30, 2016, AltaGas recorded income tax expense of $27 million compared to $45 million for the same period in 2015. Income tax expense decreased primarily due to the absence of the one-time, non-cash $14 million charge in the second quarter of 2015 related to the increase in the Alberta corporate income tax rate, and the $10 million tax recovery related to the Tidewater Gas Asset Disposition recorded in the first quarter of 2016.

On a U.S. GAAP basis, net income applicable to common shares for the nine months ended September 30, 2016 was $118 million ($0.76 per share) compared to $64 million ($0.48 per share) for the same period in 2015.

Normalized net income for the nine months ended September 30, 2016 was $105 million ($0.68 per share), compared to $84 million ($0.62 per share) reported for the same period in 2015. The variance was driven by the same factors impacting normalized EBITDA as well as higher depreciation and amortization expense, interest expense and preferred share dividends. For the nine months ended September 30, 2016, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, transaction costs related to acquisitions, gains on sale of assets and related tax recovery, a dilution loss recognized on an investment accounted for by the equity method, provisions on investments accounted for by the equity method, restructuring costs, and recovery of development costs for the PNG Pipeline Looping Project. For the nine months ended September 30, 2015, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, development costs incurred for energy export projects, provisions on certain long-lived assets, and a statutory tax rate change.

Based on projects currently under review, development or construction, AltaGas now expects capital expenditures in the range of $550 to $600 million for 2016. Gas and Power maintenance capital is expected to be approximately $25 million of total capital expenditures. With the completion of the Townsend Facility and associated infrastructure, a significant portion of the 2016 committed growth capital has already been incurred. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas maintains financial strength and flexibility, investment grade credit ratings, and ready access to capital markets. AltaGas' 2016 committed capital program is expected to be funded through internally-generated cash flow and the Premium DividendTM, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP). In addition, as at September 30, 2016, the Corporation had approximately $1.3 billion available under its credit facilities.

**Project Updates**

***North Pine NGL Project***

On October 19, 2016, the Board of Directors approved a positive Final Investment Decision for the construction, ownership and operation of the North Pine Facility, to be located approximately 40 km northwest of Fort St. John, British Columbia. The North Pine Facility will be connected to existing AltaGas infrastructure in the region and will have access to the CN rail network, allowing for the transportation of propane from the North Pine Facility to the proposed Ridley Island Propane Export Terminal. The permit from the B.C. Oil and Gas Commission (BCOGC) to construct, own and operate the North Pine Facility was issued on September 23, 2016. AltaGas will be constructing the North Pine Facility with two separate NGL separation trains each capable of processing up to 10,000 Bbls/d of propane plus NGL mix (C3+), for a total of 20,000 Bbls/d. The first phase will also include 6,000 Bbls/d of condensate (C5+) terminalling capacity, with ultimate capacity for up to 20,000 Bbls/d. Site preparation for the first NGL separation train is expected to begin in the first quarter of 2017, with an expected commercial on-stream date in the second quarter of 2018. The second 10,000 Bbls/d NGL separation train is expected to follow after completion of the first train.

Two eight inch diameter NGL supply pipelines (the North Pine Pipelines), each approximately 40 km in length, will also be constructed and will run from the existing Alaska Highway truck terminal (the Truck Terminal) to the North Pine Facility. One supply line will carry C3+ with the other carrying C5+. At the Truck Terminal, the two existing 30 km NGL egress pipelines (the Townsend NGL Egress Pipelines) currently delivering product from AltaGas’ Townsend Facility will be connected to the North Pine Pipelines to enable shipment of NGL produced at the Townsend Facility directly to the North Pine Facility. The BCOGC permit for the North Pine Pipelines is expected in the fourth quarter of 2016, and site work would commence in the first quarter of 2017 with a target commercial on-stream date in the second quarter of 2018.

The capital cost of the first train and associated pipelines is estimated to be approximately $125 to $135 million. This investment will be backstopped by long-term supply agreements with Painted Pony for a portion of the total capacity, and will include dedication of all of its NGL produced at the Townsend and Blair Creek facilities.

TM Denotes trademark of Canaccord Genuity Corp.

### *Townsend Gas Processing Facility*

The Townsend Facility is a key component of AltaGas' northeast British Columbia energy strategy. Commercial operations commenced early in the third quarter of 2016 at the integrated midstream complex at Townsend, located approximately 100 km north of Fort St. John and 20 km southeast of AltaGas' Blair Creek facility in northeast British Columbia. This complex includes the 198 Mmcf/d shallow-cut gas processing facility (the Townsend Facility), gas gathering line, NGL egress pipelines and truck terminal. The $430 million project was completed ahead of schedule and under budget. Painted Pony has reserved all of the firm capacity under a 20-year take-or-pay agreement.

Associated with the Townsend Facility is a 25 km gas gathering line, which connects the Blair Creek field gathering area to the Townsend Facility. In addition, the Townsend NGL Egress Pipelines run from the Townsend Facility to a newly constructed truck terminal on the Alaska Highway. The Townsend NGL Egress Pipelines can move initial NGL volumes of up to 10,000 Bbls/d each, and with pumping modifications, can accommodate up to 30,000 Bbls/d each. Painted Pony has reserved all of the firm service for the gas gathering line and reserved firm NGL transport capacity on the Townsend NGL Egress Pipelines for all the NGL from the first phase of the Townsend Facility under separate 20-year take-or-pay agreements.

### *Townsend Gas Processing Facility Expansion*

AltaGas is developing an expansion (Townsend Phase 2) of the existing Townsend Facility. AltaGas expects Townsend Phase 2 will be a 100 Mmcf/d shallow-cut gas processing facility to be located on the existing Townsend site, adjacent to the currently operating Townsend Facility. The estimated cost of Townsend Phase 2 will be approximately $85 to $95 million. In addition, incremental field compression equipment, estimated to cost between $35 to $45 million, will be required to move raw gas production from the Blair Creek area to Townsend. NGL produced from Townsend Phase 2 is expected to be transported approximately 70 km to AltaGas' proposed North Pine Facility via existing and planned NGL pipelines owned by AltaGas. An application to permit Townsend Phase 2 is expected to be submitted to the BCOGC by the end of October 2016, with approval expected by the second quarter of 2017. Subject to stakeholder engagement and regulatory approvals, the commercial on-stream date is expected in the fourth quarter of 2017.

The regulatory application to build the new Townsend Phase 2 gas processing facility will also include a plan to modify the existing Townsend Facility to enhance liquids recovery.

### *Ridley Island Propane Export Terminal*

AltaGas signed a sublease and related agreements with Ridley Terminals Inc. in the fourth quarter of 2015, to develop, build, own and operate the proposed Ridley Island Propane Export Terminal located near Prince Rupert, British Columbia on lands leased from Ridley Terminals Inc. and the Prince Rupert Port Authority. The proposed Ridley Island Propane Export Terminal is estimated to cost approximately $400 to $500 million and is to be designed to ship 1.2 million tonnes of propane per annum. It will be built on a brownfield site with a history of industrial development, connections to existing rail lines and an existing marine jetty with deep water access to the Pacific Ocean. Propane from British Columbia and Alberta will be transported to the facility using the existing CN rail network.

AltaGas began the formal environmental review process earlier in 2016 and the public comment period for the Environmental Evaluation Document was successfully completed in September 2016. AltaGas has also engaged closely with First Nations as well as the local municipalities. On October 18, 2016, AltaGas LPG General Partner Inc., on behalf of AltaGas LPG Limited Partnership, was granted approval from the NEB for a 25-year licence to export up to 1.35 million tonnes per annum of propane. The FEED study has been completed and request for proposals for supply and installation of major equipment have been issued. AltaGas expects to reach FID in the fourth quarter of 2016, subject to First Nations engagement and necessary approvals.

On May 24, 2016, AltaGas LPG Limited Partnership, a wholly owned subsidiary, entered into a Memorandum of Understanding with Astomos Energy Corporation (Astomos) setting out key commercial terms for the sale and purchase of liquefied petroleum gas (LPG) from the proposed Ridley Island Propane Export Terminal. Under the terms of a contemplated multi-year agreement, it is anticipated that Astomos will purchase at least 50 percent of the 1.2 million tonnes of propane available to be shipped from the export terminal each year. Active commercial discussions are continuing for additional capacity commitments.

***Early Stage Deep Basin NGL Facility***

AltaGas is in the early stages of development of a NGL facility which will serve producers in the Deep Basin region of northwest Alberta. The facility is being designed with capacity to process up to 10,000 Bbls/d of C3+ and handle up to 4,000 Bbls/d of C5+. The Deep Basin facility will have access to existing rail and can be connected to AltaGas' proposed Ridley Island Propane Export Terminal. Active discussions with producers to contractually underpin the base capacity are continuing, and engagement with First Nations and key stakeholders is underway. A facility application was submitted to the Alberta Energy Regulator in May 2016. FID is subject to completing commercial arrangements, stakeholder engagement, and regulatory approvals. Based on current preliminary estimates, the NGL facility is expected to cost approximately $60 to $80 million.

***Blythe Energy Center (Blythe)***

The Blythe Facility, and the Blythe II Facility (Sonoran) currently under development, are well situated to serve a larger western regional transmission organization comprised of several western U.S. states. AltaGas expects several request for proposals (RFPs) to emerge from these states throughout 2017 and beyond, and expects to bid both the potential re-contracting of its Blythe Facility after its PPA expires July 31, 2020, and the potential Sonoran Facility, into these upcoming RFPs. Separately, AltaGas continues to have bilateral discussions with utilities, municipalities, and corporations for multi-year capacity agreements, while also considering Resource Adequacy market pricing, potential energy and ancillary service offerings, and alternative configurations (gas, combined with solar and energy storage) for the Blythe facilities using the multiple transmission options available to best serve our potential customers in the west. It is expected that up to 15,000 megawatts (MW) will need to be replaced in California due to retirements over the next decade. As utilities, non-utilities and large generators continue to determine their future resource needs to achieve California's 50 percent renewable portfolio standard, sufficient flexible, fast ramping gas-fired capability will be required to help backstop intermittent, non-dispatchable, low capacity factor renewable energy sources and meet peak load requirements.

***Pomona Energy Storage Project***

In August 2016, AltaGas, through its subsidiary, AltaGas Pomona Energy Storage Inc., signed a 10-year ESA with SCE for 20 MW of energy storage at the existing Pomona facility, located in the east Los Angeles Basin of Southern California. AltaGas will build, own and operate the Pomona Energy Storage Project, which is expected to cost between US$40 to $45 million and will be among the largest battery storage projects in North America when it comes on-line as anticipated by the end of December 2016. Under the terms of the ESA, AltaGas will provide SCE with 20 MW of resource adequacy capacity for a continuous four hour period, which represents the equivalent of 80 MWh of energy discharging capacity. AltaGas will receive fixed monthly resource adequacy payments under the ESA and will retain the rights to earn additional revenue from the energy and ancillary services provided by the lithium-ion batteries.

In conjunction with the ESA, AltaGas is working with Greensmith Energy Management Systems, Inc., a leading provider of energy storage software and integration services, to provide and integrate its software control platform in addition to the batteries and power conversion technology. AltaGas will retain control for the overall project management, execution and operations.

***Repowering of Pomona Facility***

AltaGas is continuing to work on repowering the existing Pomona facility. In the first quarter of 2016 AltaGas, through its subsidiary AltaGas Pomona Energy Inc., submitted an application with the California Energy Commission to repower the Pomona facility to a flexible, fast ramping peaking facility under the small power plant exemption process. It is anticipated that the application review process will be approximately 12 months and include a review of the emissions profile by the local air district. The existing Pomona facility is a 44.5 MW gas-fired peaking plant strategically located in the east Los Angeles Basin load pocket. The repowered facility could be comprised of more efficient gas-fired technology with capacity of up to 100 MW. Following approval, AltaGas will be ready to bid the proposed repowered facility into upcoming RFPs or enter into other bilateral contract arrangements.

**2016 Outlook**

AltaGas continues to expect to deliver overall normalized EBITDA growth of approximately 20 percent in 2016 compared to 2015. The majority of the annual growth in 2016 is expected to be driven by the Power segment, with the Utilities segment also expected to increase by a moderate amount from 2015, while the Gas segment is expected to see a small decline compared to 2015 mainly due to the Tidewater Gas Asset Disposition. The most significant driver of normalized EBITDA growth is a full year contribution from the San Joaquin Facilities acquired on November 30, 2015. 2016 will also be the first year that all three Northwest Hydro Facilities provide a full year contribution as McLymont entered commercial service in the fourth quarter of 2015. AltaGas' integrated northeast British Columbia strategy began adding EBITDA in the second half of 2016 with the first phase of the Townsend Facility entering commercial operations in July 2016. The Townsend Facility is expected to generate normalized EBITDA of approximately $20 million for 2016 as volumes from Painted Pony Petroleum Ltd. (Painted Pony) progressively increase through year-end. Despite the warm winter weather experienced in early 2016, the Utilities segment is expected to report increased normalized EBITDA in 2016 driven by rate base and customer growth while also benefitting from a favorable US dollar exchange rate. The overall forecasted growth in normalized EBITDA includes lower commodity hedge gains in the Gas segment compared with 2015 as well as higher operating and administrative costs due to new assets placed into service.

AltaGas continues to expect normalized funds from operations to grow by approximately 15 percent in 2016, driven by the factors noted above for normalized EBITDA growth, partially offset by higher financing costs related to new assets acquired as well as new assets in service and higher current tax expenses. AltaGas' $150 million investment in the Petrogas cumulative redeemable convertible preferred shares made in June 2016 (the Petrogas Preferred Shares) contributed to funds from operations as dividends are expected to be paid quarterly. In the third quarter of 2016, AltaGas received $6 million in common share dividends and approximately $3 million in preferred share dividends from Petrogas and currently expects to receive similar amounts in the fourth quarter of 2016. For the nine months ended September 30, 2016, AltaGas received $18 million in common share dividends and approximately $3 million in preferred share dividends from Petrogas. For the full year of 2015, AltaGas received $11 million in common share dividends from Petrogas.

The Workforce Restructuring is expected to reduce operating and administrative expenses by approximately $7 million on an annualized basis.

In the Power segment, increased earnings are expected to be driven by a full-year contribution from the San Joaquin Facilities and McLymont. The earnings and cash flows from the Northwest Hydro Facilities were seasonally stronger through the end of the third quarter and are expected to decline in the fourth quarter based on seasonal water flow patterns. Actual seasonal water flows will vary with regional temperatures and precipitation levels.

In the Utilities segment, AltaGas expects the fourth quarter to be seasonally stronger due to the winter heating season. The Utilities segment is expected to report increased earnings in 2016 driven by rate base and customer growth. SEMCO Gas expects approximately $8 million of revenue in 2016 as a result of a full year contribution from its Main Replacement Program (MRP). In July 2016, the Regulatory Commission of Alaska approved an interim refundable rate increase of approximately US$5 million (annualized) for ENSTAR effective August 1, 2016 with final rates to be set in 2017. In September 2016, the NSUARB approved Heritage Gas' Customer Retention Program application to decrease distribution rates for certain commercial and residential customers, suspend depreciation and to increase the capitalization rate for operating, maintenance and administrative expenses effective March 22, 2016. Heritage Gas' normalized EBITDA is expected to decrease by approximately $3 million in 2016 as a result of its Customer Retention Program. Earnings at all of the utilities (except PNG) are affected by weather in their franchise areas, with colder weather generally benefiting earnings. If the weather varies from normal weather, earnings at the utilities would be affected.

In the Gas segment, additional earnings in 2016 are expected to be driven by the first phase of the Townsend Facility, which entered commercial operations in July 2016, the absence of turnarounds at the Harmattan and Younger facilities, and higher earnings at Petrogas. The additional earnings are expected to be offset by lower commodity hedge gains, the Tidewater Gas Asset Disposition, moderately lower volumes at certain non-core gas facilities and moderately lower volumes above take-or-pay levels at the Gordondale facility. The Tidewater Gas Asset Disposition represented approximately 5 percent of 2015 normalized EBITDA for the Gas segment and less than 2 percent of AltaGas' expected 2016 normalized EBITDA. Based on recent strength in commodity prices, AltaGas is increasing the amount of frac exposed volumes for the remainder of 2016 to capitalize on the higher prices and now estimates an average of approximately 7,500 Bbls/d will be exposed to frac spreads prior to hedging activities. For the remainder of 2016, AltaGas has frac hedges in place with volumes which range between 1,700 to 3,900 Bbls/d at an average price of approximately $21/Bbl excluding basis differentials.

For the first nine months of 2016, EBITDA generated from U.S. assets benefitted from the strengthening of the US dollar compared to the same period in 2015. If the US dollar remains strong in the fourth quarter of 2016 compared to the fourth quarter of 2015, EBITDA reported for AltaGas' U.S. assets will benefit accordingly. Some of this benefit will be offset by US dollar denominated depreciation, interest on US dollar denominated debt, dividends on US dollar denominated preferred shares and U.S. income tax expense.

**Monthly Common Share Dividend and Quarterly Preferred Share Dividend**

- The Board of Directors approved a dividend of $0.175 per common share. The dividend will be paid on December 15, 2016, to common shareholders of record on November 25, 2016. The ex-dividend date is November 23, 2016. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board of Directors approved a dividend of $0.21125 per share for the period commencing September 30, 2016 and ending December 30, 2016, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on December 30, 2016 to shareholders of record on December 14, 2016. The ex-dividend date is December 12, 2016;
- The Board of Directors approved a dividend of $0.19921 per share for the period commencing September 30, 2016 and ending December 30, 2016, on AltaGas' outstanding Series B Preferred Shares. The dividend will be paid on December 30, 2016 to shareholders of record on December 14, 2016. The ex-dividend date is December 12, 2016;
- The Board of Directors approved a dividend of US$0.275 per share for the period commencing September 30, 2016 and ending December 30, 2016, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on December 30, 2016 to shareholders of record on December 14, 2016. The ex-dividend date is December 12, 2016;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing September 30, 2016, and ending December 30, 2016, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on December 30, 2016 to shareholders of record on December 14, 2016. The ex-dividend date is December 12, 2016;
- The Board of Directors approved a dividend of $0.296875 per share for the period commencing September 30, 2016, and ending December 30, 2016, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on December 30, 2016 to shareholders of record on December 14, 2016. The ex-dividend date is December 12, 2016; and
- The Board of Directors approved a dividend of $0.328125 per share for the period commencing September 30, 2016, and ending December 30, 2016, on AltaGas' outstanding Series I Preferred Shares. The dividend will be paid on December 30, 2016 to shareholders of record on December 14, 2016. The ex-dividend date is December 12, 2016.

**Consolidated Financial Review**

| ($ millions) | Three Months Ended September 30 2016 | 2015 | Nine Months Ended September 30 2016 | 2015 |
|---|---|---|---|---|
| Revenue | **492** | 452 | **1,528** | 1,613 |
| Normalized EBITDA[(1)] | **176** | 125 | **507** | 409 |
| Net income applicable to common shares | **46** | 20 | **118** | 64 |
| Normalized net income[(1)] | **38** | 19 | **105** | 84 |
| Total assets | **9,952** | 8,959 | **9,952** | 8,959 |
| Total long-term liabilities | **4,541** | 4,208 | **4,541** | 4,208 |
| Net additions to property, plant and equipment | **80** | 164 | **284** | 417 |
| Dividends declared[(2)] | **85** | 65 | **233** | 188 |
| Cash flows | | | | |
| Normalized funds from operations[(1)] | **137** | 102 | **383** | 311 |

| ($ per share, except shares outstanding) | Three Months Ended September 30 2016 | 2015 | Nine Months Ended September 30 2016 | 2015 |
|---|---|---|---|---|
| Normalized EBITDA[(1)] | **1.07** | 0.92 | **3.29** | 3.03 |
| Net income per common share - basic | **0.28** | 0.15 | **0.77** | 0.48 |
| Net income per common share - diluted | **0.28** | 0.14 | **0.76** | 0.47 |
| Normalized net income - basic[(1)] | **0.23** | 0.14 | **0.68** | 0.62 |
| Dividends declared[(2)] | **0.52** | 0.48 | **1.51** | 1.39 |
| Cash flows | | | | |
| Normalized funds from operations[(1)] | **0.84** | 0.75 | **2.48** | 2.30 |
| Shares outstanding - basic (millions) | | | | |
| During the period[(3)] | **164** | 136 | **154** | 135 |
| End of period | **165** | 145 | **165** | 145 |

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

*(2) Dividends declared per common share per month $0.1475 beginning on May 26, 2014, $0.16 beginning on May 26, 2015, $0.165 beginning on October 26, 2015, and $0.175 beginning on August 25, 2016.*

*(3) Weighted average.*

**Conference Call and Webcast Details:**

AltaGas will hold a conference call, October 20, 2016 at 9:00 a.m. MT (11:00 a.m. ET) to discuss third quarter financial results, progress on projects and other corporate developments.

Members of the investment communities and other interested parties may dial (416) 340-2216 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 8772250. The replay will expire at midnight (Eastern) on October 27, 2016.

Additional information relating to AltaGas' results can be found in the Management's Discussion and Analysis and unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2016 available through AltaGas' website at www.altagas.ca or through SEDAR at www.sedar.com.

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

Investment Community
1-877-691-7199
investor.relations@altagas.ca

Media
(403) 691-7197
media.relations@altagas.ca

**TM** denotes trademark of Canaccord Genuity Corp.

*This news release contains forward-looking statements. When used in this news release, the words "may", "can" "would", "could", "will", "intend", "plan", "anticipate", "bring", "believe", "seek", "contemplate", "continue", "projection", "propose", "focus", "estimate", "target", "potential, "on track", "expect", and similar expressions, as they relate to AltaGas or an affiliate of AltaGas, are intended to identify forward-looking statements. This news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities, capital expenditures, and financial results. In particular this news release contains forward looking statements with respect to the projected growth or decline in normalized EBITDA and normalized funds from operations (including per business segment); expectations with respect to AltaGas' ability to hit its financial targets; expectations with respect to the Townsend Facility and related projects including, expected earnings and impact on earnings, ability to increase capacity on Townsend NGL Egress Pipelines, ability to make modifications to the facility and expectations regarding Painted Pony's delivery of gas volumes; expectations with respect to the Townsend Gas Processing Facility Expansion including design specifications, location, capacity, cost, transportation network and connection capability to North Pine Facility, expected timeline for permitting, final investment decision and commercial on-stream and content of regulatory application; expectations with respect to the development of the proposed Ridley Island Propane Export Terminal including development costs, propane transport capability, initial shipment capacity, sale and purchase of liquefied petroleum gas from the terminal, entering into a multi-year agreement with Astomos and timing of final investment decision and commercial operations; expectations relating to the development of the North Pine Facility and NGL supply pipelines including bringing forward new and competitive options for producers and access to markets, construction plans, phased development, connection capability to rail, existing AltaGas infrastructure, the proposed Ridley Island Propane Export Terminal and Alaska highway truck terminal, facility specifications, handling capability, service area, cost, product mix, timeline for site preparation, permitting and commercial operation and expectations regarding Painted Pony's gas volumes, commitment and contract; expectations with respect to the development of the Deep Basin NGL facility including facility specifications, design and handling capacity, access to rail, connection capability to the proposed Ridley Island Propane Export Terminal, ability to underpin and target for final investment decision, completion of studies and permitting; expectations that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise; expectations relating to AltaGas' ability to fund its projects and business; expectations relating to the energy needs of California; the potential for, and timing of, RFPs from western U.S. states, the ability to bid the Blythe and Sonoran facilities into these upcoming RFPs, and to reconfigure, recontract, use multiple transmission options and pursue other opportunities; expectations with respect to the AltaGas Pomona Energy Storage Project including AltaGas' ability to build, own and operate the project, expected energy storage capacity and available resource adequacy, the facility being among the largest in North America, battery run time, estimated cost and in-service date, expectations regarding resource adequacy payments and AltaGas' ability to earn additional revenue from energy from batteries, AltaGas' expectations with respect to Greensmith's ability to integrate battery and PCS hardware, and AltaGas' expectation to retain overall project management and execution; expectations with respect to the existing Pomona facility including ability to repower, increase capacity, reconfigure, application review process and timeline, ability to bid into future RFPs and pursue other bilateral arrangements or opportunities; expectations relating to the San Joaquin Facilities including expected contributions to growth and impact on earnings; expectations relating to the Northwest Hydro Facilities including expected contributions to earnings and seasonality impacts (including water flow patterns); expected impact on earnings of the Tidewater Gas Asset Disposition; expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including earnings and dividends from Petrogas and contributions to growth of AltaGas; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains and operating and administrative costs; expected impact the Workforce Restructuring will have on operating* *and administrative expenses; expected earnings from the utilities segment including from rate base and customer growth, from SEMCO Gas as a result of its Main Replacement Program, from ENSTAR in connection with its 2016 rate case and from Heritage Gas from its customer retention program; expected decision date on ENSTAR's rates; expectations regarding the payment of dividends and expectations regarding timing of the conference call.*

*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, aboriginal or regulatory developments, changes in tax legislation, fluctuations in commodity prices, interest or foreign exchange rates, access to capital markets, general economic conditions, changes in the political environment, changes to environmental and other laws and regulations, cost for labour, equipment and materials and other factors set out in AltaGas' continuous disclosure documents, including the Annual Information Form and the MD&A as at and for the year ended December 31, 2015.*

*Many factors could cause AltaGas' 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, forecasted, expected, projected or targeted, and such forward-looking statements included in, or incorporated by reference in this news release, should not be unduly relied upon. Such statements speak only as of the date of this news release. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.*

*Financial outlook information contained in this news release about prospective financial performance, 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 purposes other than for which it is disclosed herein.*

*This news release 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 in AltaGas' Management's Discussion and Analysis (MD&A) as at and for the three and nine months ended September 30, 2016. These non-GAAP 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 in AltaGas' MD&A as at and for the three and nine months ended September 30, 2016. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP.*

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*The Management's Discussion and Analysis (MD&A) of operations and unaudited condensed interim Consolidated Financial Statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (AltaGas or the Corporation) as at and for the three and nine months ended September 30, 2016. This MD&A, dated October 19, 2016, should be read in conjunction with the accompanying unaudited condensed interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three and nine months ended September 30, 2016, and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2015.*

*The unaudited condensed interim Consolidated Financial Statements and comparative information have been prepared in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP or GAAP) and in Canadian dollars, unless otherwise indicated.*

*Abbreviations, acronyms and other capitalized terms used in this MD&A without express definition shall have the same meanings given to those terms in the MD&A as at and for the year ended December 31, 2015.*

*This MD&A contains forward-looking statements. When used in this MD&A the words "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "contemplate", "continue", "estimate", "forecast", "expect", "project", "target", "potential" and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, the anticipated benefits of acquisitions and other major projects, the anticipated timing of commercial operations, investment decisions, expenditures and licensing and permitting, expected growth, capital expenditures, results of operations, operational and financial performance, business projects, opportunities and financial results.*

*Specifically, such forward-looking statements are set forth under the headings: "2016 Outlook", "Growth Capital" and "Future Changes in Accounting Principles" and under those headings specifically include expectations with respect to the projected growth or decline in normalized EBITDA and normalized funds from operations (including per business segment); expectations with respect to the Townsend Facility and related projects including, expected earnings and impact on earnings, ability to increase capacity on Townsend NGL Egress Pipelines, ability to make modifications to the facility and expectations regarding Painted Pony's delivery of gas volumes; expectations with respect to the Townsend Gas Processing Facility Expansion including design specifications, location, capacity, cost, transportation network and connection capability to North Pine Facility, expected timeline for permitting and commercial on-stream and content of regulatory application; expectations with respect to the development of the proposed Ridley Island Propane Export Terminal including development costs, propane transport capability, initial shipment capacity, sale and purchase of liquefied petroleum gas from the terminal, entering into a multi-year agreement with Astomos and timing of final investment decision and commercial operations; expectations relating to the development of the North Pine Facility and NGL supply pipelines including construction plans, phased development, connection capability to rail, existing AltaGas infrastructure, the proposed Ridley Island Propane Export Terminal and Alaska highway truck terminal, facility specifications, handling capability, service area, cost, product mix, timeline for site preparation, permitting and commercial operation and expectations regarding Painted Pony's gas volumes, commitment and contract; expectations with respect to the development of the Deep Basin NGL facility including facility specifications, design and handling capacity, access to rail, connection capability to the proposed Ridley Island Propane Export Terminal, ability to underpin and target for final investment decision, completion of studies and permitting; expectations that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise; expectations relating to AltaGas' ability to fund its projects and business; expectations relating to the energy needs of California; the potential for, and timing of, RFPs from western U.S. states, the ability to bid the Blythe and Sonoran facilities into these upcoming RFPs, and to reconfigure, recontract, use multiple transmission options and pursue other opportunities; expectations with respect to the AltaGas Pomona Energy Storage Project including AltaGas' ability to build, own and operate the project, expected energy storage capacity and available resource adequacy, the facility being among the largest in North America, battery run time, estimated cost and in-service date, expectations regarding resource adequacy payments and AltaGas' ability to earn additional revenue from the energy and ancillary services provided by* *the batteries, AltaGas' expectations with respect to Greensmith's ability to integrate battery and PCS hardware, and AltaGas' expectation to retain overall project management and execution; expectations with respect to the existing Pomona facility including ability to repower, increase capacity, reconfigure, application review process and timeline, ability to bid into future RFPs and pursue other bilateral arrangements or opportunities; expectations relating to the San Joaquin Facilities including expected contributions to growth and impact on earnings; expectations relating to the Northwest Hydro Facilities including expected contributions to earnings and seasonality impacts (including water flow patterns); expected impact on earnings of the Tidewater Gas Asset Disposition; expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including earnings and dividends from Petrogas and contributions to growth of AltaGas; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains and operating and administrative costs; expected impact the Workforce Restructuring will have on operating and administrative expenses; expected earnings from the utilities segment including from rate base and customer growth, from SEMCO Gas as a result of its Main Replacement Program, from ENSTAR in connection with its 2016 rate case and from Heritage Gas from its customer retention program; expected decision date on ENSTAR's rates; expectations with respect to the Alton Natural Gas Storage Project including expected natural gas storage capacity, construction and brining timeline and storage in service date; and expectations regarding the adoption of changes in accounting principles and impact on financial statements.*

*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, aboriginal or regulatory developments, changes in tax legislation, fluctuations in commodity prices, interest or foreign exchange rates, access to capital markets, general economic conditions, changes in the political environment, changes to environmental and other laws and regulations, cost for labour, equipment and materials and other factors set out in AltaGas' continuous disclosure documents, including the Annual Information Form and the MD&A as at and for the year ended December 31, 2015.*

*Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this MD&A including, without limitation, those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this MD&A 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 by these cautionary statements.*

*Financial outlook information contained in this MD&A about prospective financial performance, 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 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 documents of AltaGas, including its audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2015, Annual Information Form, Management Information Circular, material change reports and press releases, are also available through AltaGas' website or through SEDAR at www.sedar.com.*

## ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, Harmattan Gas Processing Limited Partnership, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), Coast Mountain Hydro Limited Partnership, AltaGas Services (U.S.) Inc., Blythe Energy Inc. (Blythe), AltaGas San Joaquin Energy Inc., and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

## OVERVIEW OF THE BUSINESS

AltaGas, a Canadian corporation, is a North American diversified energy infrastructure business with a focus on owning and operating assets to provide clean and affordable energy to its customers. AltaGas has three business segments:

- Gas, which transacts more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and separation, transmission, storage, and natural gas marketing, as well as the Corporation's indirectly held one-third interest in Petrogas Energy Corp. (Petrogas);
- Power, which includes generation assets located across North America with 1,688 MW of capacity, all from natural gas and renewable sources, and 20 MW of energy storage currently under construction; and
- Utilities, serving over 560,000 customers through ownership of regulated natural gas distribution utilities across North America and a regulated natural gas storage utility in the United States, delivering clean and affordable natural gas to homes and businesses.

## THIRD QUARTER FINANCIAL HIGHLIGHTS (1)

- Normalized EBITDA was $176 million, an increase of 41 percent compared to $125 million in the third quarter of 2015;
- Normalized funds from operations were $137 million ($0.84 per share), an increase of 34 percent compared to $102 million ($0.75 per share) in the third quarter of 2015;
- Net income applicable to common shares was $46 million ($0.28 per share), an increase of 130 percent compared to $20 million ($0.15 per share) in the third quarter of 2015;
- Net debt was $3.8 billion as at September 30, 2016, compared to $3.0 billion as at September 30, 2015, and $3.9 billion as at December 31, 2015;
- Debt-to-total capitalization ratio was 45 percent as at September 30, 2016, compared to 42 percent as at September 30, 2015, and 48 percent as at December 31, 2015;
- Commercial operations commenced early in the third quarter of 2016 at the integrated midstream complex at Townsend in northeast British Columbia, including the Townsend Facility, gas gathering line, NGL egress pipelines and truck terminal;
- On July 20, 2016, the Board of Directors approved an increase in the monthly dividend by $0.01 per common share to $0.175 ($2.10 per common share annualized) effective for the August dividend, a 6.1 percent increase;
- In July 2016, the Regulatory Commission of Alaska approved an interim refundable rate increase for ENSTAR effective August 1, 2016 with final rates to be set in 2017;
- In August 2016, AltaGas, through its subsidiary AltaGas Pomona Energy Storage Inc., signed a 10-year Energy Storage Resource Adequacy Purchase Agreement (ESA) with Southern California Edison (SCE) for 20 MW of energy storage at the Pomona facility (the Pomona Energy Storage Project);
- In September 2016, the Nova Scotia Utility and Review Board (NSUARB) approved Heritage Gas' Customer Retention Program;
- In September 2016, AltaGas received the permit from the British Columbia Oil and Gas Commission (BCOGC) to construct, own and operate AltaGas' proposed North Pine NGL Separation Facility (the North Pine Facility); and
- In September 2016, the public comment period for the Environmental Evaluation Document for the proposed Ridley Island Propane Export Terminal was successfully completed.

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

## CONSOLIDATED FINANCIAL REVIEW

| ($ millions) | Three Months Ended September 30 2016 | 2015 | Nine Months Ended September 30 2016 | 2015 |
|---|---|---|---|---|
| Revenue | **492** | 452 | **1,528** | 1,613 |
| Normalized EBITDA(1) | **176** | 125 | **507** | 409 |
| Net income applicable to common shares | **46** | 20 | **118** | 64 |
| Normalized net income(1) | **38** | 19 | **105** | 84 |
| Total assets | **9,952** | 8,959 | **9,952** | 8,959 |
| Total long-term liabilities | **4,541** | 4,208 | **4,541** | 4,208 |
| Net additions to property, plant and equipment | **80** | 164 | **284** | 417 |
| Dividends declared(2) | **85** | 65 | **233** | 188 |
| Cash flows | | | | |
| Normalized funds from operations(1) | **137** | 102 | **383** | 311 |

| ($ per share, except shares outstanding) | Three Months Ended September 30 2016 | 2015 | Nine Months Ended September 30 2016 | 2015 |
|---|---|---|---|---|
| Normalized EBITDA(1) | **1.07** | 0.92 | **3.29** | 3.03 |
| Net income per common share - basic | **0.28** | 0.15 | **0.76** | 0.48 |
| Net income per common share - diluted | **0.28** | 0.14 | **0.76** | 0.47 |
| Normalized net income - basic(1) | **0.23** | 0.14 | **0.68** | 0.62 |
| Dividends declared(2) | **0.52** | 0.48 | **1.51** | 1.39 |
| Cash flows | | | | |
| Normalized funds from operations(1) | **0.84** | 0.75 | **2.48** | 2.30 |
| Shares outstanding - basic (millions) | | | | |
| During the period(3) | **164** | 136 | **154** | 135 |
| End of period | **165** | 145 | **165** | 145 |

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

*(2) Dividends declared per common share per month $0.1475 beginning on May 26, 2014, $0.16 beginning on May 26, 2015, $0.165 beginning on October 26, 2015, and $0.175 beginning on August 25, 2016.*

*(3) Weighted average.*

### Three Months Ended September 30

Normalized EBITDA for the third quarter of 2016 was $176 million, compared to $125 million for the same quarter in 2015. The increase was mainly due to the San Joaquin Facilities acquired on November 30, 2015, which contributed to EBITDA growth of approximately $25 million, higher contributions from the Northwest Hydro Facilities as a result of McLymont entering commercial service in the fourth quarter of 2015 and strong performance at Forrest Kerr, commencement of commercial operations at the Townsend Facility, and the absence of equity losses from the Sundance B Power Purchase Arrangements (the Sundance B PPAs) terminated in the first quarter of 2016. These increases were partially offset by lower gains from frac hedges, lower earnings from Petrogas, the impact of the expiration of the Pomona PPA at the end of 2015, lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels, and the impact of the sale of non-core assets to Tidewater Midstream and Infrastructure Ltd. (Tidewater) on February 29, 2016 (the Tidewater Gas Asset Disposition).

Normalized funds from operations for the third quarter of 2016 were $137 million ($0.84 per share), compared to $102 million ($0.75 per share) for the same quarter in 2015, reflecting the same drivers as normalized EBITDA as well as higher common share dividends from Petrogas, partially offset by higher current income tax and interest expense.

Operating and administrative expenses for the third quarter of 2016 were $114 million, compared to $134 million for the same quarter in 2015. The decrease was primarily due to the Tidewater Gas Asset Disposition and savings from the non-utility workforce restructuring in June 2016, which reduced the non-utility workforce by approximately 10 percent (the Workforce Restructuring), partially offset by higher operating and administrative costs incurred by the Power segment due to new assets placed into service or acquired. Depreciation and amortization expense for the third quarter of 2016 was $67 million, compared to $53 million for the same quarter in 2015. The increase was mainly due to new assets placed into service or acquired, partially offset by the deferral of depreciation at Heritage Gas as a result of the Customer Retention Program and lower depreciation and amortization expense as a result of the Tidewater Gas Asset Disposition. Interest expense for the third quarter of 2016 was $39 million, compared to $31 million for the same quarter in 2015. The increase was mainly due to higher average debt outstanding and lower capitalized interest, partially offset by lower interest rates.

AltaGas recorded income tax expense of $17 million for the third quarter of 2016, compared to $5 million in the same quarter of 2015. The increase was mainly due to higher taxable earnings in the third quarter of 2016, including higher taxable earnings from U.S. operations which bear higher corporate income tax rates.

During the third quarter of 2016, PNG recognized revenue of approximately $7 million related to the recovery of development costs from Triton LNG Limited Partnership for the pipeline looping project, a development project to expand the capacity of PNG's natural gas transmission line (the PNG Pipeline Looping Project). Triton LNG Limited Partnership is a wholly-owned subsidiary of AltaGas Idemitsu Joint Venture Limited Partnership.

Net income applicable to common shares for the third quarter of 2016 was $46 million ($0.28 per share) compared to $20 million ($0.15 per share) for the same quarter in 2015.

Normalized net income was $38 million ($0.23 per share) for the third quarter of 2016, compared to $19 million ($0.14 per share) reported for the same quarter in 2015. The variance was driven by the same factors impacting normalized EBITDA as well as higher depreciation and amortization expense, interest expense and preferred share dividends. In the third quarter of 2016, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, and recovery of development costs for the PNG Pipeline Looping Project. In the third quarter of 2015, normalizing items included after-tax amounts related to unrealized gains on risk management contracts, energy export development costs, and provision on long-lived assets.

**Nine Months Ended September 30**

Normalized EBITDA for the nine months ended September 30, 2016 was $507 million, compared to $409 million for the same period in 2015. The increase was primarily due to EBITDA generated from the San Joaquin Facilities, higher contributions from the Northwest Hydro Facilities, rate base and customer growth at the Utilities, the impact of the stronger US dollar on reported results of the U.S. assets, the absence of turnarounds at the Younger and Harmattan facilities, commencement of commercial operations at the Townsend Facility, and lower equity losses from the Sundance B PPAs. These increases were partially offset by the impact of significantly warmer weather experienced at all of AltaGas' Utilities during the winter heating season, lower gains from frac hedges, the impact from the Tidewater Gas Asset Disposition, the impact from the expiration of the Pomona PPA at the end of 2015, and lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels.

Normalized funds from operations for the nine months ended September 30, 2016 were $383 million ($2.48 per share), compared to $311 million ($2.30 per share) for the same period in 2015 driven by the same factors impacting normalized EBITDA as well as higher common share dividends from Petrogas, partially offset by higher interest and current income tax expense.

Operating and administrative expenses for the nine months ended September 30, 2016 were $378 million, compared to $372 million for the same period in 2015. The increase was primarily due to higher operating and administrative costs incurred by the Power segment due to new assets placed into service or acquired, the impact of the stronger US dollar, and restructuring costs of approximately $7 million recorded in the second quarter of 2016 related to the Workforce Restructuring. This was partially offset by the decrease in operating and administrative expenses associated with the Tidewater Gas Asset Disposition.

Depreciation and amortization expense for the nine months ended September 30, 2016 increased to $202 million, compared to $153 million for the same period in 2015, mainly due to new assets placed into service or acquired and the impact of the stronger US dollar, partially offset by lower depreciation and amortization expense as a result of the Tidewater Gas Asset Disposition. Interest expense for the nine months ended September 30, 2016 months was $111 million, compared to $92 million for the same period in 2015. The increase was mainly due to higher average debt outstanding and lower capitalized interest, partially offset by lower interest rates.

In the first quarter of 2016, ASTC Power Partnership (ASTC) exercised its right to terminate the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provision of the Sundance B PPAs as a result of recent changes in law regarding the Alberta Specified Gas Emitters Regulation and as a result, AltaGas recognized a pre-tax provision of $4 million on its investment in ASTC to settle the working capital deficiency in the first quarter of 2016.

On February 29, 2016, AltaGas completed the sale of certain non-core natural gas gathering and processing assets located primarily in central and north central Alberta totaling approximately 490 Mmcf/d of gross licensed natural gas processing capacity to Tidewater for $30 million of cash and approximately 43.7 million common shares of Tidewater. At the time of disposition, the volumes processed at these facilities totaled approximately 120 Mmcf/d. A pre-tax gain of $5 million was recognized on the sale for the nine months ended September 30, 2016.

AltaGas recorded income tax expense of $27 million for the nine months ended September 30, 2016 compared to $45 million for the same period in 2015. Income tax expense decreased primarily due to the absence of the one-time, non-cash $14 million charge recorded in the second quarter of 2015 related to the increase in the Alberta corporate income tax rate, and the $10 million tax recovery related to the Tidewater Gas Asset Disposition recorded in the first quarter of 2016.

Net income applicable to common shares for the nine months ended September 30, 2016 was $118 million ($0.76 per share) compared to $64 million ($0.48 per share) for the same period in 2015.

Normalized net income for the nine months ended September 30, 2016 was $105 million ($0.68 per share), compared to $84 million ($0.62 per share) reported for the same period in 2015. The variance was driven by the same factors impacting normalized EBITDA as well as higher depreciation and amortization expense, interest expense and preferred share dividends. For the nine months ended September 30, 2016, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, transaction costs related to acquisitions, gains on sale of assets and related tax recovery, a dilution loss recognized on an investment accounted for by the equity method, provisions on investments accounted for by the equity method, restructuring costs, and recovery of development costs for the PNG Pipeline Looping Project. For the nine months ended September 30, 2015, normalizing items included after-tax amounts related to unrealized gains on risk management contracts and long-term investments, development costs incurred for energy export projects, provisions on certain long-lived assets, and a statutory tax rate change.

**2016 OUTLOOK**

AltaGas continues to expect to deliver overall normalized EBITDA growth of approximately 20 percent in 2016 compared to 2015. The majority of the annual growth in 2016 is expected to be driven by the Power segment, with the Utilities segment also expected to increase by a moderate amount from 2015, while the Gas segment is expected to see a small decline compared to 2015 mainly due to the Tidewater Gas Asset Disposition. The most significant driver of normalized EBITDA growth is a full year contribution from the San Joaquin Facilities acquired on November 30, 2015. 2016 will also be the first year that all three Northwest Hydro Facilities provide a full year contribution as McLymont entered commercial service in the fourth quarter of 2015. AltaGas' integrated northeast British Columbia strategy began adding EBITDA in the second half of 2016 with the first phase of the Townsend Facility entering commercial operations in July 2016. The Townsend Facility is expected to generate normalized EBITDA of approximately $20 million for 2016 as volumes from Painted Pony Petroleum Ltd. (Painted Pony) progressively increase through year-end. Despite the warm winter weather experienced in early 2016, the Utilities segment is expected to report increased normalized EBITDA in 2016 driven by rate base and customer growth while also benefitting from a favorable US dollar exchange rate. The overall forecasted growth in normalized EBITDA includes lower commodity hedge gains in the Gas segment compared with 2015 as well as higher operating and administrative costs due to new assets placed into service.

AltaGas continues to expect normalized funds from operations to grow by approximately 15 percent in 2016, driven by the factors noted above for normalized EBITDA growth, partially offset by higher financing costs related to new assets acquired as well as new assets in service and higher current tax expenses. AltaGas' $150 million investment in the Petrogas cumulative redeemable convertible preferred shares made in June 2016 (the Petrogas Preferred Shares) contributed to funds from operations as dividends are expected to be paid quarterly. In the third quarter of 2016, AltaGas received $6 million in common share dividends and approximately $3 million in preferred share dividends from Petrogas and currently expects to receive similar amounts in the fourth quarter of 2016. For the nine months ended September 30, 2016, AltaGas received $18 million in common share dividends and approximately $3 million in preferred share dividends from Petrogas. For the full year of 2015, AltaGas received $11 million in common share dividends from Petrogas.

The Workforce Restructuring is expected to reduce operating and administrative expenses by approximately $7 million on an annualized basis.

In the Power segment, increased earnings are expected to be driven by a full-year contribution from the San Joaquin Facilities and McLymont. The earnings and cash flows from the Northwest Hydro Facilities were seasonally stronger through the end of the third quarter and are expected to decline in the fourth quarter based on seasonal water flow patterns. Actual seasonal water flows will vary with regional temperatures and precipitation levels.

In the Utilities segment, AltaGas expects the fourth quarter to be seasonally stronger due to the winter heating season. The Utilities segment is expected to report increased earnings in 2016 driven by rate base and customer growth. SEMCO Gas expects approximately $8 million of revenue in 2016 as a result of a full year contribution from its Main Replacement Program (MRP). In July 2016, the Regulatory Commission of Alaska approved an interim refundable rate increase of approximately US$5 million (annualized) for ENSTAR effective August 1, 2016 with final rates to be set in 2017. In September 2016, the NSUARB approved Heritage Gas' Customer Retention Program application to decrease distribution rates for certain commercial and residential customers, suspend depreciation and to increase the capitalization rate for operating, maintenance and administrative expenses effective March 22, 2016. Heritage Gas' normalized EBITDA is expected to decrease by approximately $3 million in 2016 as a result of its Customer Retention Program. Earnings at all of the utilities (except PNG) are affected by weather in their franchise areas, with colder weather generally benefiting earnings. If the weather varies from normal weather, earnings at the utilities would be affected.

In the Gas segment, additional earnings in 2016 are expected to be driven by the first phase of the Townsend Facility, which entered commercial operations in July 2016, the absence of turnarounds at the Harmattan and Younger facilities, and higher earnings from Petrogas. The additional earnings are expected to be offset by lower commodity hedge gains, the Tidewater Gas Asset Disposition, moderately lower volumes at certain non-core gas facilities and moderately lower volumes above take-or-pay levels at the Gordondale facility. The Tidewater Gas Asset Disposition represented approximately 5 percent of 2015 normalized EBITDA for the Gas segment and less than 2 percent of AltaGas' expected 2016 normalized EBITDA. Based on recent strength in commodity prices, AltaGas is increasing the amount of frac exposed volumes for the remainder of 2016 to capitalize on the higher prices and now estimates an average of approximately 7,500 Bbls/d will be exposed to frac spreads prior to hedging activities. For the remainder of 2016, AltaGas has frac hedges in place with volumes which range between 1,700 to 3,900 Bbls/d at an average price of approximately $21/Bbl excluding basis differentials.

For the first nine months of 2016, EBITDA generated from U.S. assets benefitted from the strengthening of the US dollar compared to the same period in 2015. If the US dollar remains strong in the fourth quarter of 2016 compared to the fourth quarter of 2015, EBITDA reported for AltaGas' U.S. assets will benefit accordingly. Some of this benefit will be offset by US dollar denominated depreciation, interest on US dollar denominated debt, dividends on US dollar denominated preferred shares and U.S. income tax expense.

## GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas now expects capital expenditures in the range of $550 to $600 million for 2016. Gas and Power maintenance capital is expected to be approximately $25 million of total capital expenditures. With the completion of the Townsend Facility and associated infrastructure, a significant portion of the 2016 committed growth capital has already been incurred. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets. For the nine months ended September 30, 2016, AltaGas incurred approximately $399 million of capital expenditures for property, plant and equipment and intangible assets. Please refer to the *Invested Capital* section in this MD&A for further details.

AltaGas' 2016 committed capital program is expected to be funded through internally-generated cash flow and the Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP). In addition, as at September 30, 2016, the Corporation had approximately $1.3 billion available under its credit facilities.

### Townsend Gas Processing Facility

The Townsend Facility is a key component of AltaGas' northeast British Columbia energy strategy. Commercial operations commenced early in the third quarter of 2016 at the integrated midstream complex at Townsend, located approximately 100 km north of Fort St. John and 20 km southeast of AltaGas' Blair Creek facility in northeast British Columbia. This complex includes the 198 Mmcf/d shallow-cut gas processing facility (the Townsend Facility), gas gathering line, NGL egress pipelines and truck terminal. The $430 million project was completed ahead of schedule and under budget. Painted Pony has reserved all of the firm capacity under a 20-year take-or-pay agreement.

Associated with the Townsend Facility is a 25 km gas gathering line, which connects the Blair Creek field gathering area to the Townsend Facility. In addition, two 30 km NGL egress pipelines (the Townsend NGL Egress Pipelines) run from the Townsend Facility to a newly constructed truck terminal on the Alaska Highway. The Townsend NGL Egress Pipelines can move initial NGL volumes of up to 10,000 Bbls/d each, and with pumping modifications, can accommodate up to 30,000 Bbls/d each. Painted Pony has reserved all of the firm service for the gas gathering line and reserved firm NGL transport capacity on the Townsend NGL Egress Pipelines for all the NGL from the first phase of the Townsend Facility under separate 20-year take-or-pay agreements.

### Townsend Gas Processing Facility Expansion

AltaGas is developing an expansion (Townsend Phase 2) of the existing Townsend Facility. AltaGas expects Townsend Phase 2 will be a 100 Mmcf/d shallow-cut gas processing facility to be located on the existing Townsend site, adjacent to the currently operating Townsend Facility. The estimated cost of Townsend Phase 2 will be approximately $85 to $95 million. In addition, incremental field compression equipment, estimated to cost between $35 to $45 million, will be required to move raw gas production from the Blair Creek area to Townsend. NGL produced from Townsend Phase 2 is expected to be transported approximately 70 km to AltaGas' proposed North Pine Facility via existing and planned NGL pipelines owned by AltaGas. An application to permit Townsend Phase 2 is expected to be submitted to the BCOGC by the end of October 2016, with approval expected by the second quarter of 2017. Subject to stakeholder engagement and regulatory approvals, the commercial on-stream date is expected in the fourth quarter of 2017.

The regulatory application to build the new Townsend Phase 2 gas processing facility will also include a plan to modify the existing Townsend Facility to enhance liquids recovery.

### North Pine NGL Project

On October 19, 2016, the Board of Directors approved a positive Final Investment Decision (FID) for the construction, ownership and operation of the North Pine Facility to be located approximately 40 km northwest of Fort St. John, British Columbia. The North Pine Facility will be connected to existing AltaGas infrastructure in the region and will have access to the CN rail network, allowing for the transportation of propane from the North Pine Facility to the proposed Ridley Island Propane Export Terminal.

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The permit from the BCOGC to construct, own and operate the North Pine Facility was issued on September 23, 2016. AltaGas will be constructing the North Pine Facility with two separate NGL separation trains each capable of processing up to 10,000 Bbls/d of propane plus NGL mix (C3+), for a total of 20,000 Bbls/d. The first phase will also include 6,000 Bbls/d of condensate (C5+) terminalling capacity, with ultimate capacity for up to 20,000 Bbls/d. Site preparation for the first NGL separation train is expected to begin in the first quarter of 2017, with an expected commercial on-stream date in the second quarter of 2018. The second 10,000 Bbls/d NGL separation train is expected to follow after completion of the first train.

Two eight inch diameter NGL supply pipelines (the North Pine Pipelines), each approximately 40 km in length, will also be constructed and will run from the existing Alaska Highway truck terminal (the Truck Terminal) to the North Pine Facility. One supply line will carry C3+ with the other carrying C5+. At the Truck Terminal, the existing Townsend NGL Egress Pipelines currently delivering product from AltaGas' Townsend Facility will be connected to the North Pine Pipelines to enable shipment of NGL produced at the Townsend Facility directly to the North Pine Facility. The BCOGC permit for the North Pine Pipelines is expected in the fourth quarter of 2016, and site work would commence in the first quarter of 2017 with a target commercial on-stream date in the second quarter of 2018.

The capital cost of the first train and associated pipelines is estimated to be approximately $125 to $135 million. This investment will be backstopped by long-term supply agreements with Painted Pony for a portion of the total capacity, and will include dedication of all of its NGL produced at the Townsend and Blair Creek facilities.

On August 8, 2016, Blueberry River First Nations (BRFN) applied for an interlocutory injunction restraining the Province of British Columbia from, among other things, permitting oil and gas activities within BRFN's traditional territory in northeast British Columbia pending resolution of an earlier BRFN action alleging breaches by the Province of British Columbia of BRFN's treaty rights. In the unlikely event the injunction is granted, there could be delays in approvals for the Townsend Phase 2 and the North Pine Pipelines and a potential reduction in the future volumes of natural gas available for processing at AltaGas' facilities in this area. The interlocutory injunction is scheduled to be heard on October 31, 2016.

**Ridley Island Propane Export Terminal**

AltaGas signed a sublease and related agreements with Ridley Terminals Inc. in the fourth quarter of 2015, to develop, build, own and operate the proposed Ridley Island Propane Export Terminal located near Prince Rupert, British Columbia on lands leased from Ridley Terminals Inc. and the Prince Rupert Port Authority. The proposed Ridley Island Propane Export Terminal is estimated to cost approximately $400 to $500 million and is to be designed to ship 1.2 million tonnes of propane per annum. It will be built on a brownfield site with a history of industrial development, connections to existing rail lines and an existing marine jetty with deep water access to the Pacific Ocean. Propane from British Columbia and Alberta will be transported to the facility using the existing CN rail network.

AltaGas began the formal environmental review process earlier in 2016 and the public comment period for the Environmental Evaluation Document was successfully completed in September 2016. AltaGas has also engaged closely with First Nations as well as the local municipalities. On October 18, 2016, AltaGas LPG General Partner Inc., on behalf of AltaGas LPG Limited Partnership, received a 25-year licence from the National Energy Board (NEB) to export up to 1.35 million tonnes per annum of propane. This licence is approved as applied for and is subject to Governor in Council approval in accordance with the legislation. The FEED study has been completed and request for proposals for supply and installation of major equipment have been issued. AltaGas expects to reach FID in the fourth quarter of 2016, subject to First Nations engagement and necessary approvals.

On May 24, 2016, AltaGas LPG Limited Partnership, a wholly owned subsidiary, entered into a Memorandum of Understanding with Astomos Energy Corporation (Astomos) setting out key commercial terms for the sale and purchase of liquefied petroleum gas (LPG) from the proposed Ridley Island Propane Export Terminal. Under the terms of a contemplated multi-year agreement, it is anticipated that Astomos will purchase at least 50 percent of the 1.2 million tonnes of propane available to be shipped from the export terminal each year. Active commercial discussions are continuing for additional capacity commitments.

**Alton Natural Gas Storage Project**

In January 2016, the Government of Nova Scotia issued permits to resume construction of the Alton Natural Gas Storage Project, located near Truro, Nova Scotia. To allow more time for discussions and public engagement, AltaGas deferred major civil construction until summer 2016. Construction resumed on July 5, 2016 and brining for cavern development is now scheduled for 2017. The Alton Natural Gas Storage Project is expected to provide up to 10 Bcf of natural gas storage capacity. Storage service is expected to commence in 2019.

**Early Stage Deep Basin NGL Facility**

AltaGas is in the early stages of development of a NGL facility which will serve producers in the Deep Basin region of northwest Alberta. The facility is being designed with capacity to process up to 10,000 Bbls/d of C3+ and handle up to 4,000 Bbls/d of C5+. The Deep Basin facility will have access to existing rail and can be connected to AltaGas' proposed Ridley Island Propane Export Terminal. Active discussions with producers to contractually underpin the base capacity are continuing, and engagement with First Nations and key stakeholders is underway. A facility application was submitted to the Alberta Energy Regulator in May 2016. FID is subject to completing commercial arrangements, stakeholder engagement, and regulatory approvals. Based on current preliminary estimates, the NGL facility is expected to cost approximately $60 to $80 million.

**Blythe Energy Center (Blythe)**

The Blythe Facility, and the Blythe II Facility (Sonoran) currently under development, are well situated to serve a larger western regional transmission organization comprised of several western U.S. states. AltaGas expects several request for proposals (RFPs) to emerge from these states throughout 2017 and beyond, and expects to bid both the potential re-contracting of its Blythe Facility after its PPA expires July 31, 2020, and the potential Sonoran Facility, into these upcoming RFPs. Separately, AltaGas continues to have bilateral discussions with utilities, municipalities, and corporations for multi-year capacity agreements, while also considering Resource Adequacy market pricing, potential energy and ancillary service offerings, and alternative configurations (gas, combined with solar and energy storage) for the Blythe facilities using the multiple transmission options available to best serve our potential customers in the west. It is expected that up to 15,000 megawatts (MW) will need to be replaced in California due to retirements over the next decade. As utilities, non-utilities and large generators continue to determine their future resource needs to achieve California's 50 percent renewable portfolio standard, sufficient flexible, fast ramping gas-fired capability will be required to help backstop intermittent, non-dispatchable, low capacity factor renewable energy sources and meet peak load requirements.

**Pomona Energy Storage Project**

In August 2016, AltaGas, through its subsidiary, AltaGas Pomona Energy Storage Inc., signed a 10-year ESA with SCE for 20 MW of energy storage at the existing Pomona facility, located in the east Los Angeles Basin of Southern California. AltaGas will build, own and operate the Pomona Energy Storage Project, which is expected to cost between US$40 to $45 million and will be among the largest battery storage projects in North America when it comes on-line as anticipated by the end of December 2016. Under the terms of the ESA, AltaGas will provide SCE with 20 MW of resource adequacy capacity for a continuous four hour period, which represents the equivalent of 80 MWh of energy discharging capacity. AltaGas will receive fixed monthly resource adequacy payments under the ESA and will retain the rights to earn additional revenue from the energy and ancillary services provided by the lithium-ion batteries.

In conjunction with the ESA, AltaGas is working with Greensmith Energy Management Systems, Inc., a leading provider of energy storage software and integration services, to provide and integrate its software control platform in addition to the batteries and power conversion technology. AltaGas will retain control for the overall project management, execution and operations.

**Repowering of Pomona Facility**

AltaGas is continuing to work on repowering the existing Pomona facility. In the first quarter of 2016, AltaGas, through its subsidiary AltaGas Pomona Energy Inc., submitted an application with the California Energy Commission to repower the Pomona facility to a flexible, fast ramping peaking facility under the small power plant exemption process. It is anticipated that the application review process will be approximately 12 months and include a review of the emissions profile by the local air district. The existing Pomona facility is a 44.5 MW gas-fired peaking plant strategically located in the east Los Angeles Basin load pocket. The repowered facility could be comprised of more efficient gas-fired technology with capacity of up to 100 MW. Following approval, AltaGas will be ready to bid the proposed repowered facility into upcoming RFPs or enter into other bilateral contract arrangements.

**NON-GAAP FINANCIAL MEASURES**

This MD&A contains references to certain financial measures used by AltaGas that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures provide additional information that management believes is meaningful in describing 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 normalized EBITDA, normalized net income and normalized funds from operations throughout this MD&A have the meanings as set out in this section.

**Normalized EBITDA**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ millions)* | **2016** | 2015 | **2016** | 2015 |
| Normalized EBITDA | **$ 176** | $ 125 | **$ 507** | $ 409 |
| Add (deduct): | | | | |
| Transaction costs related to acquisitions | **—** | — | **(2)** | — |
| Unrealized gains on risk management contracts | **4** | 11 | **1** | 2 |
| Unrealized gains on long-term investments | **1** | — | **2** | 1 |
| Gains on sale of assets | **—** | — | **4** | — |
| Provisions on long-lived assets | **—** | (11) | **—** | (11) |
| Dilution loss on investment accounted for by the equity method | **—** | — | **(1)** | — |
| Provisions on investments accounted for by the equity method | **(1)** | — | **(5)** | — |
| Energy export development costs | **—** | (1) | **(1)** | (2) |
| Restructuring costs | **—** | — | **(7)** | — |
| Accretion expenses | **(3)** | (3) | **(8)** | (8) |
| Foreign exchange gains | **—** | — | **4** | — |
| Recovery of pipeline looping project development costs at PNG | **7** | — | **7** | — |
| EBITDA | **$ 184** | $ 121 | **$ 501** | $ 391 |
| Add (deduct): | | | | |
| Depreciation and amortization | **(67)** | (53) | **(202)** | (153) |
| Interest expense | **(39)** | (31) | **(111)** | (92) |
| Income tax expense | **(17)** | (5) | **(27)** | (45) |
| Net income after taxes (GAAP financial measure) | **$ 61** | $ 32 | **$ 161** | $ 101 |

EBITDA is a measure of AltaGas' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. EBITDA is calculated from the Consolidated Statements of Income using net income adjusted for pre-tax depreciation and amortization, interest expense, and income tax expense.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on risk management contracts and long-term investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, accretion expenses, foreign exchange gains (losses), provision on investments accounted for by the equity method, provisions on certain long-lived assets, restructuring costs, dilution loss on investment accounted for by the equity method, and recovery of development costs for the PNG Pipeline Looping Project. Normalized EBITDA also includes an adjustment for certain non-capitalizable project development costs related to energy export projects. AltaGas presents normalized EBITDA as a supplemental measure. Normalized EBITDA is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets and the capital structure.

**Normalized Net Income**

| ($ millions) | Three Months Ended September 30 **2016** | Three Months Ended September 30 2015 | Nine Months Ended September 30 **2016** | Nine Months Ended September 30 2015 |
|---|---|---|---|---|
| Normalized net income | **$ 38** | $ 19 | **$ 105** | $ 84 |
| Add (deduct) after-tax: | | | | |
| Transaction costs related to acquisitions | **—** | — | **(1)** | — |
| Unrealized gains on risk management contracts | **2** | 8 | **1** | 1 |
| Unrealized gains on long-term investments | **1** | — | **1** | 1 |
| Gains on sale of assets | **—** | — | **15** | — |
| Provisions on long-lived assets | **—** | (6) | **—** | (6) |
| Dilution loss on investment accounted for by the equity method | **—** | — | **(1)** | — |
| Provisions on investments accounted for by equity method | **—** | — | **(2)** | — |
| Energy export development costs | **—** | (1) | **—** | (2) |
| Restructuring costs | **—** | — | **(5)** | — |
| Statutory tax rate change | **—** | — | **—** | (14) |
| Recovery of pipeline looping project development costs at PNG | **5** | — | **5** | — |
| Net income applicable to common shares (GAAP financial measure) | **$ 46** | $ 20 | **$ 118** | $ 64 |

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts and long-term investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on investments accounted for by the equity method, provisions on certain long-lived assets, restructuring costs, dilution loss on investment accounted for by the equity method, recovery of development costs for the PNG Pipeline Looping Project, and statutory tax rate changes. Normalized net income also includes an adjustment for certain non-capitalizable project development costs related to energy export projects. This measure is presented in order to enhance the comparability of AltaGas' earnings, as it reflects the underlying performance of AltaGas' business activities.

**Normalized Funds from Operations**

| ($ millions) | Three Months Ended September 30 **2016** | Three Months Ended September 30 2015 | Nine Months Ended September 30 **2016** | Nine Months Ended September 30 2015 |
|---|---|---|---|---|
| Normalized funds from operations | **$ 137** | $ 102 | **$ 383** | $ 311 |
| Add (deduct): | | | | |
| Transaction costs related to acquisitions | **—** | — | **(2)** | — |
| Restructuring costs | **—** | — | **(7)** | — |
| Recovery of pipeline looping project development costs at PNG | **5** | — | **5** | — |
| Funds from operations | **142** | 102 | **379** | 311 |
| Add (deduct): | | | | |
| Net change in operating assets and liabilities | **(65)** | (42) | **(56)** | 101 |
| Asset retirement obligations settled | **(1)** | — | **(2)** | (2) |
| Cash from operations (GAAP financial measure) | **$ 76** | $ 60 | **$ 321** | $ 410 |

Normalized funds from operations is used to assist management and investors in analyzing the liquidity of the Corporation without regard to changes in operating assets and liabilities in the period and non-operating related expenses such as transaction costs related to acquisitions, recovery of development costs for the PNG Pipeline Looping Project (net of current taxes), and restructuring costs.

Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities and expenditures incurred to settle asset retirement obligations. Management uses this measure to understand the ability to generate funds for capital investments, debt repayment, dividend payments and other investing activities.

Funds from operations and normalized 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.

**RESULTS OF OPERATIONS BY REPORTING SEGMENT**

| **Normalized EBITDA** [1] | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ millions)* | **2016** | 2015 | **2016** | 2015 |
| Gas | **$ 42** | $ 43 | **$ 114** | $ 128 |
| Power | **104** | 59 | **222** | 125 |
| Utilities | **33** | 32 | **187** | 177 |
| Sub-total: Operating Segments | **179** | 134 | **523** | 430 |
| Corporate | **(3)** | (9) | **(16)** | (21) |
| | **$ 176** | $ 125 | **$ 507** | $ 409 |

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

**GAS**

**OPERATING STATISTICS**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Extraction inlet gas processed (Mmcf/d)[1] | **989** | 912 | **900** | 911 |
| FG&P inlet gas processed (Mmcf/d)[1] [2] | **286** | 381 | **294** | 393 |
| Total inlet gas processed (Mmcf/d)[1] [2] | **1,275** | 1,293 | **1,194** | 1,304 |
| Extraction ethane volumes (Bbls/d)[1] | **32,159** | 30,241 | **29,532** | 30,539 |
| Extraction NGL volumes (Bbls/d)[1] | **33,350** | 30,922 | **33,139** | 30,665 |
| Total extraction volumes (Bbls/d)[1] [3] | **65,509** | 61,163 | **62,671** | 61,204 |
| Frac spread - realized ($/Bbl)[1] [4] | **6.29** | 34.58 | **8.02** | 19.21 |
| Frac spread - average spot price ($/Bbl)[1] [5] | **6.29** | 11.11 | **8.21** | 5.12 |

*(1) Average for the period.*

*(2) FG&P inlet gas volumes processed at the facilities sold to Tidewater on February 29, 2016 were approximately 120 Mmcf/d for the three months ended September 30, 2015 and approximately 130 Mmcf/d for the nine months ended September 30, 2015.*

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

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

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

Inlet gas volumes processed at the extraction facilities for the three months ended September 30, 2016 increased by 77 Mmcf/d, compared to the same period in 2015. The increase was due to higher processed volumes at Harmattan Co-stream and the Younger facility. Inlet gas volumes processed at the field gathering and processing (FG&P) facilities for the three months ended September 30, 2016 decreased by 95 Mmcf/d primarily due to the Tidewater Gas Asset Disposition and lower volumes from the Gordondale facility, partially offset by volumes received at the Townsend Facility, which entered commercial operations in July 2016.

Inlet gas volumes processed at the extraction facilities for the nine months ended September 30, 2016 decreased by 11 Mmcf/d, compared to the same period in 2015. The decrease was mainly due to temporary plant shut-ins at the Edmonton Ethane Extraction Plant (EEEP), the Joffre Ethane Extraction Plant (JEEP) and the Empress Gas Liquids Joint Venture (EGLJV) plant, as low commodity prices made extraction of certain NGL at some of the facilities uneconomical in the first half of 2016. The decrease was partially offset by higher volumes at the Younger and Harmattan facilities primarily due to major turnarounds in the prior year. Inlet gas volumes processed at the FG&P facilities for the nine months ended September 30, 2016 decreased by 99

Mmcf/d mainly due to the Tidewater Gas Asset Disposition and lower volumes from the Gordondale facility, partially offset by volumes received at the Townsend Facility.

Average ethane and NGL volumes for the three months ended September 30, 2016 increased by 1,918 Bbls/d and 2,428 Bbls/d respectively, compared to the same period in 2015. Higher ethane volumes were largely due to higher inlet volumes and recovery factors at the Harmattan facility. Higher NGL volumes were due to temporary plant shut-ins in the third quarter of 2015 as low commodity prices made extraction of certain NGL at some of the facilities uneconomical.

Average ethane volumes for the nine months ended September 30, 2016 decreased by 1,007 Bbls/d, while average NGL volumes increased by 2,474 Bbls/d, compared to the same period in 2015. Lower ethane volumes were due to lower produced volumes at JEEP, EEEP, and the Younger facility, partially offset by higher volumes at the Harmattan facility due to the turnaround in the prior year. Higher NGL volumes were due to turnarounds at the Younger and Harmattan facilities during the second quarter of 2015 and low commodity prices making extraction of certain NGL at some of the facilities uneconomical during the first nine months of 2015.

**Three Months Ended September 30**

The Gas segment reported normalized EBITDA of $42 million in the third quarter of 2016, compared to $43 million for the same quarter in 2015. In the third quarter of 2016, normalized EBITDA decreased due to lower realized frac spreads as a result of lower hedging gains, lower Petrogas earnings, the Tidewater Gas Asset Disposition, and lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels, partially offset by revenues from the Townsend Facility commencing operations in July 2016. During the third quarter of 2016, AltaGas recorded equity earnings of $nil from Petrogas, compared to $5 million for the same quarter in 2015. Earnings from Petrogas decreased due to weaker netbacks on export shipments from Ferndale specific to cargoes exported in July and August, and lower results in the wellsite fluids and fuels business driven by reduced activity in the upstream sector, partially offset by dividend income earned by AltaGas from the investment in Petrogas Preferred Shares in June 2016.

During the third quarter of 2016, AltaGas hedged approximately 790 Bbls/d of NGL volumes at an average price of $23/Bbl, inclusive of basis differentials. During the third quarter of 2015, AltaGas hedged 3,000 Bbls/d of NGL at an average price of $27/Bbl, inclusive of basis differentials. The average indicative spot NGL frac spread in the third quarter of 2016 was approximately $6/Bbl compared to $11/Bbl in the same quarter of 2015. The realized frac spread of approximately $6/Bbl in the third quarter of 2016 (2015 - $35/Bbl) was lower than the same quarter in 2015 due to realized gains on NGL frac hedges in the third quarter of 2015.

**Nine Months Ended September 30**

The Gas segment reported normalized EBITDA of $114 million for the nine months ended September 30, 2016, compared to $128 million for the same period in 2015. The decrease in normalized EBITDA was due to lower hedging gains on frac hedges, the Tidewater Gas Asset Disposition, and lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels, partially offset by the completion of major turnarounds at the Younger and Harmattan facilities during the second quarter of 2015 and the addition of the Townsend Facility. During the nine months ended September 30, 2016, AltaGas recorded equity earnings of $7 million from Petrogas, consistent with the same period in 2015. Following strong results in the first half of 2016, earnings from Petrogas were impacted in the third quarter of 2016 by the weaker netbacks on export shipments from Ferndale specific to cargoes exported in July and August, and lower results in the wellsite fluids and fuels business driven by reduced activity in the upstream sector, partially offset by dividend income earned by AltaGas from the investment in Petrogas Preferred Shares in June 2016.

During the nine months ended September 30, 2016, AltaGas hedged approximately 440 Bbls/d of NGL volumes at an average price of $21/Bbl, inclusive of basis differentials. During the nine months ended September 30, 2015, AltaGas hedged approximately 3,100 Bbls/d of NGL at an average price of $27/Bbl, inclusive of basis differentials. The average indicative spot NGL frac spread for the nine months ended September 30, 2016 was approximately $8/Bbl compared to $5/Bbl in the same period of 2015. The realized frac spread of approximately $8/Bbl for the nine months ended September 30, 2016 (2015 - $19/Bbl) was lower than the same period in 2015 due to realized gains on NGL frac hedges in 2015.

As a result of the Tidewater Gas Asset Disposition, AltaGas recognized a pre-tax gain of $5 million (after-tax gain of $15 million) for the nine months ended September 30, 2016.

**POWER**

**OPERATING STATISTICS**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Renewable power sold (GWh) | **670** | 488 | **1,356** | 991 |
| Conventional power sold (GWh) | **587** | 1,210 | **1,576** | 3,144 |
| Renewable capacity factor (%) | **70.2** | 57.5 | **45.9** | 37.4 |
| Contracted conventional equivalent availability factor (%) (1) | **99.3** | 99.5 | **96.5** | 95.9 |

*(1) Calculated as the availability factor contracted under long-term tolling arrangements adjusted for occasions where partial or excess capacity payments have been added or deducted.*

During the third quarter of 2016, the volume of renewable power sold increased by 182 GWh and the volume of conventional power sold decreased by 623 GWh, compared to the same quarter in 2015. The increase in renewable volumes was due to record volumes from the Northwest Hydro Facilities as a result of McLymont entering commercial service in the fourth quarter 2015 and improvements in operational efficiency at Forrest Kerr. The decrease in conventional volumes was primarily due to ASTC exercising its right to terminate the Sundance B PPAs effective March 8, 2016, as well as the expiration of the Pomona PPA, and lower volumes at Blythe, partially offset by the volumes provided by the San Joaquin Facilities and the addition of the third gas-fired cogeneration facility at Harmattan. Blythe earns fixed capacity payments under its PPA with SCE, and as a result, volumes of power sold at Blythe have a minimal impact on EBITDA. Normalized EBITDA for conventional power assets increased in the third quarter of 2016 compared to the same quarter in 2015 notwithstanding the lower conventional power volumes.

The renewable capacity factor for the third quarter of 2016 increased due to McLymont being in-service and improved performance capability at Forrest Kerr after a full year of operations. The contracted conventional equivalent availability factor is consistent with the prior year as these facilities have been running well with no operational issues.

During the nine months ended September 30, 2016, the volume of renewable power sold increased by 365 GWh and the volume of conventional power sold decreased by 1,568 GWh compared to the same period in 2015. The increase in renewable volumes was due to McLymont being in-service, as well as higher river flow at the Northwest Hydro Facilities. The decrease in conventional volumes was primarily due to ASTC exercising its right to terminate the Sundance B PPAs effective March 8, 2016, as well as lower dispatch at Blythe, and the expiration of the Pomona PPA, partially offset by the volumes provided by the San Joaquin Facilities.

The renewable capacity factor for the nine months ended September 30, 2016 increased due to the same reasons as noted above for the third quarter of 2016. The contracted conventional equivalent availability factor for the nine months ended September 30, 2016 was higher due to the acquisition of the San Joaquin Facilities in November 2015.

With ASTC exercising its right to terminate the Sundance B PPAs, AltaGas' power portfolio in Alberta has been reduced to 65 MW, representing 4 percent of AltaGas' total generation capacity. AltaGas' overall power portfolio now consists of 1,688 MW from clean natural gas-fired or renewable generation sources, and is approximately 95 percent contracted under long term power purchase agreements.

**Three Months Ended September 30**

The Power segment reported normalized EBITDA of $104 million in the third quarter of 2016, compared to $59 million in the same quarter of 2015. Normalized EBITDA increased as a result of the acquisition of the San Joaquin Facilities in November

2015, record Northwest Hydro Facilities generation resulting from both McLymont entering commercial service in the fourth quarter of 2015 and strong performance at Forrest Kerr, and the absence of equity losses from the Sundance B PPAs, partially offset by the expiration of the Pomona PPA at the end of 2015.

**Nine Months Ended September 30**

The Power segment reported normalized EBITDA of $222 million for the nine months ended September 30, 2016, compared to $125 million in the same period of 2015. Normalized EBITDA increased as a result of the acquisition of the San Joaquin Facilities in November 2015, higher Northwest Hydro Facilities volumes resulting from McLymont entering commercial service in the fourth quarter of 2015, strong performance at Forrest Kerr and an earlier start to seasonally higher river flow, the stronger US dollar, and lower equity losses from the Sundance B PPAs. These increases were partially offset by the expiration of the Pomona PPA at the end of 2015 and continued lower Alberta conventional power prices and volumes.

In the first quarter of 2016, ASTC exercised its right to terminate the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provision of the Sundance B PPAs and as a result, AltaGas recognized a pre-tax provision of $4 million on its investment in ASTC to settle the working capital deficiency. Under the Balancing Pool Regulation, the Balancing Pool is required to conduct an investigation and make a determination on ASTC's right to terminate. On July 22, 2016, ASTC referred the matter to be resolved by binding arbitration pursuant to the dispute resolution provisions of the Sundance B PPAs (the Arbitration). On July 25, 2016 the Attorney General of Alberta filed an originating application for declaratory relief and judicial review which names ASTC as one of the respondents (the Originating Application). The Originating Application seeks, among other things, a determination as to the validity of certain aspects of the change in law provision as well as the circumstances under which a PPA buyer such as ASTC is entitled to terminate its PPA pursuant to that provision. To date the Balancing Pool has not confirmed termination of the Sundance B PPAs and proceedings relating to the Arbitration and the Originating Application remain ongoing. The outcome of the Originating Application may affect the resolution of the Arbitration. If ASTC is unable to terminate the Sundance B PPAs, AltaGas may be required to refund the Balancing Pool for its share of the net PPA costs incurred from March 8, 2016 to when the matter is resolved.

## UTILITIES

### OPERATING STATISTICS

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Canadian utilities | | | | |
| Natural gas deliveries - end-use (PJ)(1) | **3.2** | 3.3 | **19.2** | 21.6 |
| Natural gas deliveries - transportation (PJ)(1) | **1.1** | 1.6 | **4.5** | 5.0 |
| U.S. utilities | | | | |
| Natural gas deliveries - end-use (Bcf)(1) | **5.4** | 5.9 | **42.5** | 48.0 |
| Natural gas deliveries - transportation (Bcf)(1) | **11.0** | 10.5 | **37.3** | 34.2 |
| Service sites (2) | **568,628** | 562,301 | **568,628** | 562,301 |
| Degree day variance from normal - AUI (%) (3) | **(8.4)** | 3.9 | **(19.4)** | (10.0) |
| Degree day variance from normal - Heritage Gas (%) (3) | **(7.4)** | (42.0) | **(4.4)** | 11.9 |
| Degree day variance from normal - SEMCO Gas (%) (4) | **(57.6)** | (28.4) | **(6.1)** | 10.9 |
| Degree day variance from normal - ENSTAR (%) (4) | **(36.1)** | (9.6) | **(23.8)** | (10.6) |

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

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

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

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

**Three Months Ended September 30**

The Utilities segment reported normalized EBITDA of $33 million in the third quarter of 2016, compared to $32 million in the same quarter of 2015. The increase was mainly due to the stronger US dollar, favorable services revenue, and rate base and customer growth, partially offset by the impact of the approved Customer Retention Program at Heritage Gas (earnings adjusted retroactively to March 22, 2016), warmer weather in Michigan, Alaska and Alberta, and higher costs associated with employee benefits at the U.S. utilities.

During the third quarter of 2016, PNG recognized revenue of approximately $7 million related to the PNG Pipeline Looping Project.

**Nine Months Ended September 30**

The Utilities segment reported normalized EBITDA of $187 million for the nine months ended September 30, 2016, compared to $177 million for the same period in 2015. The increase was mainly due to the impact of the stronger US dollar, rate base and customer growth, and favorable services revenue. These variances were partially offset by significantly warmer weather experienced at all of AltaGas' Utilities during the winter heating season and the impact of the approved Customer Retention Program at Heritage Gas.

## CORPORATE

**Three Months Ended September 30**

In the Corporate segment, normalized EBITDA for the third quarter of 2016 was a loss of $3 million, compared to $9 million for the same period in 2015. The decrease was mainly due to the Workforce Restructuring in June 2016 as well as ongoing cost saving initiatives.

**Nine Months Ended September 30**

In the Corporate segment, normalized EBITDA for nine months ended September 30, 2016 was a loss of $16 million, compared to $21 million for the same period in 2015. The decrease was due to the same reasons discussed above.

## INVESTED CAPITAL

During the third quarter of 2016, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $108 million, compared to $181 million in the same quarter of 2015. There were no disposals of property, plant and equipment in the third quarter of 2016 and 2015.

During the third quarter of 2016, the Power segment paid $11 million (2015 - $11 million) to BC Hydro in support of the construction and operation of the Northwest Transmission Line.

The invested capital in the third quarter of 2016 included maintenance capital of $1 million (2015 - $6 million) in the Gas segment and $2 million (2015 - $1 million) in the Power segment.

| | | | | | Three Months Ended September 30, 2016 |
|---|---|---|---|---|---|
| *($ millions)* | **Gas** | **Power** | **Utilities** | **Corporate** | **Total** |
| Invested capital: | | | | | |
| Property, plant and equipment | **$ 31** | **$ 23** | **$ 25** | **$ 1** | **$ 80** |
| Intangible assets | **—** | **12** | **1** | **1** | **14** |
| Long-term investments | **14** | **—** | **—** | **—** | **14** |
| Invested capital | **45** | **35** | **26** | **2** | **108** |
| Disposals: | | | | | |
| Property, plant and equipment | **—** | **—** | **—** | **—** | **—** |
| Net invested capital | **$ 45** | **$ 35** | **$ 26** | **$ 2** | **$ 108** |

| ($ millions) | | Gas | | Power | | Utilities | | Corporate | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | Three Months Ended September 30, 2015 |
| Invested capital: | | | | | | | | | | |
| Property, plant and equipment | $ | 53 | $ | 54 | $ | 54 | $ | 3 | $ | 164 |
| Intangible assets | | — | | 11 | | 1 | | 2 | | 14 |
| Long-term investments | | 3 | | — | | — | | — | | 3 |
| Invested capital | | 56 | | 65 | | 55 | | 5 | | 181 |
| Disposals: | | | | | | | | | | |
| Property, plant and equipment | | — | | — | | — | | — | | — |
| Net invested capital | $ | 56 | $ | 65 | $ | 55 | $ | 5 | $ | 181 |

For the nine months ended September 30, 2016, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $634 million, compared to $462 million for the same period in 2015. The increase in property, plant and equipment reflects the costs incurred related to the construction of the Townsend Facility and associated infrastructure and the purchase of the remaining 51 percent interest in EEEP. The increase in long-term investments mainly relates to the investment in Petrogas Preferred Shares and the investment in Tidewater. As part of the Tidewater Gas Asset Disposition, AltaGas received non-cash consideration of approximately $65 million in the form of Tidewater common shares as at February 29, 2016. The net invested capital was $539 million for the nine months ended September 30, 2016, compared to $462 million in the same period of 2015.

The invested capital for the nine months ended September 30, 2016 included maintenance capital of $1 million (2015 - $18 million) in the Gas segment and $11 million (2015 - $2 million) in the Power segment. Gas segment maintenance capital included $8 million related to the Harmattan facility turnaround in 2015, while there were no major turnaround activities for the nine months ended September 30, 2016.

| ($ millions) | | **Gas** | | **Power** | | **Utilities** | | **Corporate** | | **Total** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | **Nine Months Ended September 30, 2016** |
| Invested capital: | | | | | | | | | | |
| Property, plant and equipment | **$** | **262** | **$** | **45** | **$** | **69** | **$** | **3** | **$** | **379** |
| Intangible assets | | **2** | | **14** | | **1** | | **3** | | **20** |
| Long-term investments | | **235** | | **—** | | **—** | | **—** | | **235** |
| Invested capital | | **499** | | **59** | | **70** | | **6** | | **634** |
| Disposals: | | | | | | | | | | |
| Property, plant and equipment | | **(94)** | | **—** | | **(1)** | | **—** | | **(95)** |
| Net invested capital | **$** | **405** | **$** | **59** | **$** | **69** | **$** | **6** | **$** | **539** |

| ($ millions) | | Gas | | Power | | Utilities | | Corporate | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | Nine Months Ended September 30, 2015 |
| Invested capital: | | | | | | | | | | |
| Property, plant and equipment | $ | 124 | $ | 163 | $ | 125 | $ | 5 | $ | 417 |
| Intangible assets | | 2 | | 20 | | 2 | | 12 | | 36 |
| Long-term investments | | 9 | | — | | — | | — | | 9 |
| Invested capital | | 135 | | 183 | | 127 | | 17 | | 462 |
| Disposals: | | | | | | | | | | |
| Property, plant and equipment | | — | | — | | — | | — | | — |
| Net invested capital | $ | 135 | $ | 183 | $ | 127 | $ | 17 | $ | 462 |

## RISK MANAGEMENT

AltaGas is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. At times, AltaGas will enter into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates, and foreign exchange rates. The Board of Directors of AltaGas has established a risk management policy for the Corporation establishing AltaGas' risk management control framework. Financial derivative instruments are governed under, and subject to, this policy. As at September 30, 2016 and December 31, 2015, the fair values of the Corporation's derivatives were as follows:

| *($ millions)* | **September 30, 2016** | December 31, 2015 |
|---|---|---|
| Natural gas | **$ 2** | $ 3 |
| Storage optimization | **(1)** | 3 |
| NGL frac spread | **(3)** | — |
| Power | **34** | 20 |
| Foreign exchange | **—** | (1) |
| Net derivative asset | **$ 32** | $ 25 |

### Commodity Price Contracts

From time to time, the Corporation executes gas, power, and other commodity contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. The fair value of power, natural gas, and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. Quoted market rates were used in the calculation of the fair value of foreign exchange derivatives. AltaGas has not elected hedge accounting for any of its derivative contracts currently in place. Changes in the fair value of these derivative contracts are recorded in the Consolidated Statements of Income in the period in which the change occurs.

The Power segment has various fixed price power purchase and sale contracts in the Alberta market, which are expected to be settled over the next five years. During the third quarter of 2016, the average Alberta spot price was approximately $18/MWh (2015 – $26/MWh).

The Corporation also 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. The average indicative spot NGL frac spread in the third quarter of 2016 was an estimated $6/Bbl (2015 – $11/Bbl). For the remainder of 2016, AltaGas has frac hedges in place with volumes which range between 1,700 to 3,900 Bbls/d at an average price of approximately $21/Bbl excluding basis differentials. In addition, AltaGas also has frac hedges in place for 2017 to hedge approximately 2,800 Bbls/d at an average price of $23/Bbl, excluding basis differentials.

### Foreign Exchange

AltaGas has foreign operations whereby the functional currency is the US dollar. As a result, the Corporation's earnings, cash flows, and other comprehensive income are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated by AltaGas' US dollar-denominated debt and preferred shares. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. As at September 30, 2016, AltaGas had outstanding foreign exchange forward contracts for US$7 million at an average rate of $1.26 Canadian per US dollar and are expected to be settled over the next seven months.

In addition, as at September 30, 2016, management designated US$322 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2015 - US$724 million). US dollar denominated long-term debt instruments have been designated as a hedge of the net investment in foreign subsidiaries. This designation has the effect of mitigating volatility on net income by offsetting foreign exchange gains and losses on US dollar denominated long-term debt and foreign net investment. For the three and nine months ended September 30, 2016, AltaGas incurred an after-tax unrealized loss of $4 million and an after-tax unrealized gain of $41 million arising from the translation of debt in other comprehensive income (2015 – after-tax unrealized loss of $33 million and $63 million, respectively).

**The Effects of Derivative Instruments on the Consolidated Statements of Income**

The following table presents the unrealized gains (losses) on derivative instruments as recorded in the Corporation's Consolidated Statements of Income:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ millions)* | **2016** | 2015 | **2016** | 2015 |
| Natural gas | **$ (1)** | $ 3 | **$ (2)** | $ 6 |
| Storage optimization | **1** | 1 | **(3)** | — |
| NGL frac spread | **(1)** | (6) | **(3)** | 2 |
| Power | **5** | 12 | **8** | (6) |
| Heat rate | **—** | 1 | **—** | — |
| Foreign exchange | **—** | — | **1** | — |
| | **$ 4** | $ 11 | **$ 1** | $ 2 |

Please refer to Note 19 of the 2015 Annual Consolidated Financial Statements and Note 10 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2016 for further details regarding AltaGas' risk management activities.

## LIQUIDITY

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ millions)* | **2016** | 2015 | **2016** | 2015 |
| Cash from operations | **$ 76** | $ 60 | **$ 321** | $ 410 |
| Investing activities | **(136)** | (181) | **(618)** | (431) |
| Financing activities | **(13)** | 239 | **8** | 55 |
| Effect of exchange rate | **—** | 3 | **—** | 6 |
| Increase (decrease) in cash and cash equivalents | **$ (73)** | $ 121 | **$ (289)** | $ 40 |

**Cash from Operations**

Cash from operations decreased by $89 million for the nine months ended September 30, 2016 compared to the same period in 2015 primarily due to the unfavorable variance in the net change in operating assets and liabilities, partially offset by higher earnings and distributions from equity investments. The net change in operating assets and liabilities was a net cash outflow of $56 million for the nine months ended September 30, 2016 compared to a net cash inflow of $101 million during the same period in 2015. The net reduction in cash inflow was primarily due to lower cash flows derived from movements in accounts receivable, inventory and regulatory assets related to the Utilities segment due to warmer weather in 2016. In addition, other operating assets increased in 2016 due to the acquisition of the San Joaquin Facilities.

**Working Capital**

| *($ millions except current ratio)* | **September 30, 2016** | December 31, 2015 |
|---|---|---|
| Current assets | **$ 576** | $ 1,038 |
| Current liabilities | **863** | 948 |
| Working capital (deficiency) | **$ (287)** | $ 90 |
| Working capital ratio | **0.67** | 1.09 |

The decrease in working capital ratio was primarily due to the decrease in cash and cash equivalents and accounts receivable, as well as a higher current portion of long-term debt due, partially offset by the decrease in accounts payable and short-term debt compared to December 31, 2015. Cash was primarily used to repay short-term borrowings and U.S. Libor loans under the $1.4

billion revolving credit facility during the nine months ended September 30, 2016. In addition, the completion of the Tidewater Gas Asset Disposition, which was classified as assets held for sale also impacted the working capital ratio as a part of the consideration received for the sale was non-cash. AltaGas' working capital will fluctuate in the normal course of business and the working capital deficiency will be funded using cash flow from operations, DRIP and available credit facilities as required.

**Investing Activities**

Cash used in investing activities for the nine months ended September 30, 2016 was $618 million, compared to $431 million in the same period of 2015. Investing activities for the nine months ended September 30, 2016 primarily included AltaGas' $150 million investment in Petrogas Preferred Shares, a $40 million loan to Petrogas under the $100 million interest bearing secured loan facility provided to Petrogas, approximately $21 million for the purchase of EEEP, approximately $400 million in additions to property, plant, and equipment, approximately $19 million in additions to intangible assets, partially offset by cash inflow of approximately $29 million, net of transaction costs, from the Tidewater Gas Asset Disposition. Investing activities for the nine months ended September 30, 2015 primarily comprised of expenditures of approximately $409 million in additions to property, plant, and equipment, approximately $33 million in additions to intangible assets, and approximately $34 million for a business acquisition, partially offset by a cash inflow of $50 million relating to the maturity of a short-term investment.

**Financing Activities**

Cash from financing activities for the nine months ended September 30, 2016 was $8 million, compared to $55 million in the same period of 2015. Financing activities for the nine months ended September 30, 2016 were primarily comprised of net proceeds from the issuance of common shares of $545 million (including common shares issued through the DRIP), net proceeds from the issuance of senior unsecured medium-term notes (MTNs) of $348 million, and borrowings from credit facilities of $293 million, partially offset by the repayment of $851 million of long-term debt and $55 million of short-term debt. Financing activities for the nine months ended September 30, 2015 were primarily comprised of net proceeds from issuance of common shares of $367 million, net proceeds from the issuance of MTNs of $156 million, and borrowings from credit facilities of $230 million, partially offset by repayments of long-term and short-term debt of $411 million and $67 million, respectively. Total dividends paid to common and preferred shareholders of AltaGas for the nine months ended September 30, 2016 were $265 million, compared to $216 million for the same period in 2015, of which $116 million was reinvested through the DRIP during the nine months ended September 30, 2016 (2015 - $69 million). The increase in dividends paid was due to more common shares and preferred shares outstanding and dividend increases on common shares declared in 2015 and 2016.

## CAPITAL RESOURCES

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

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with operations and cash flow stability and sustainability.

| ($ millions) | | September 30, 2016 | | December 31, 2015 |
|---|---|---|---|---|
| Short-term debt | $ | **70** | $ | 131 |
| Current portion of long-term debt | | **380** | | 288 |
| Long-term debt(1) | | **3,343** | | 3,732 |
| Total debt | | **3,793** | | 4,151 |
| Less: cash and cash equivalents | | **(5)** | | (293) |
| Net debt | $ | **3,788** | $ | 3,858 |
| Shareholders' equity | | **4,512** | | 4,168 |
| Non-controlling interests | | **36** | | 35 |
| Total capitalization | $ | **8,336** | $ | 8,061 |
| | | | | |
| Debt-to-total capitalization (%) | | **45** | | 48 |

*(1) Net of debt issuance costs of $15 million as at September 30, 2016 (December 31, 2015 - $15 million).*

On April 7, 2016, AltaGas issued $350 million of MTNs. The MTNs carry a coupon rate of 4.12 percent and will mature on April 7, 2026. Net proceeds were used to pay down existing indebtedness under AltaGas' credit facility and for general corporate purposes.

On June 6, 2016, AltaGas closed a public offering of 14,685,000 common shares, on a bought deal basis, at an issue price of $30 per common share, for total gross proceeds of approximately $440 million. Net proceeds were used to partially fund AltaGas' capital growth program, reduce existing indebtedness under AltaGas' credit facility and for general corporate purposes.

As at September 30, 2016, AltaGas' total debt primarily consisted of outstanding MTNs of $2.8 billion (December 31, 2015 - $2.8 billion), PNG debenture notes of $45 million (December 31, 2015 - $47 million), SEMCO long-term debt of $489 million (December 31, 2015 - $522 million) and $440 million drawn under the bank credit facilities (December 31, 2015 - $811 million). In addition, AltaGas had $169 million of letters of credit (December 31, 2015 - $147 million) outstanding.

As at September 30, 2016, AltaGas' total market capitalization was approximately $5.6 billion based on approximately 165 million of common shares and a closing trading price on September 30, 2016 of $33.74 per common share.

AltaGas' earnings interest coverage for the rolling 12 months ended September 30, 2016 was 1.8 times.

**Credit Facilities**

| ($ millions) | | Borrowing capacity | | Drawn at September 30, 2016 | | Drawn at December 31, 2015 |
|---|---|---|---|---|---|---|
| Demand operating facilities | $ | 70 | $ | **4** | $ | 4 |
| Extendible revolving letter of credit facility | | 150 | | **61** | | 56 |
| Letter of credit demand facility | | 150 | | **99** | | 80 |
| PNG operating facility | | 25 | | **5** | | 10 |
| AltaGas Ltd. revolving credit facility (1) | | 1,400 | | **365** | | 690 |
| SEMCO Energy US$ unsecured credit facility (1) (2) | | 150 | | **75** | | 118 |
| | $ | 1,945 | $ | **609** | $ | 958 |

*(1) Amount drawn at September 30, 2016 converted at the month-end rate of 1 US dollar = 1.3117 Canadian dollar (December 31, 2015 - 1 US dollar = 1.3840 Canadian dollar).*

*(2) Borrowing capacity assumed at par.*

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

The following table summarizes the Corporation's primary financial covenants as defined by the credit facility agreements:

| Ratios | Debt covenant requirements | **As at September 30, 2016** |
|---|---|---|
| Bank debt-to-capitalization[1] | not greater than 65 percent | 45.4% |
| Bank EBITDA-to-interest expense [1] [2] | not less than 2.5x | 4.4 |
| Bank debt-to-capitalization (SEMCO)[3] | not greater than 60 percent | 44.0% |
| Bank EBITDA-to-interest expense (SEMCO)[3] | not less than 2.25x | 6.3 |

*(1) Calculated in accordance with the Corporation's credit facility agreement, which is available on SEDAR at www.sedar.com.*

*(2) Estimated, subject to final adjustments.*

*(3) Bank EBITDA-to-interest expense (SEMCO) and Bank debt-to-capitalization (SEMCO) are calculated based on SEMCO's consolidated financial statements and are calculated similar to Bank debt-to-capitalization and Bank EBITDA-to-interest expense.*

On August 10, 2015, a $5 billion base shelf prospectus was filed. The purpose of the base shelf prospectus is to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25-month period that the base shelf prospectus remains effective, by disclosing standardized information required for such issuances. As at September 30, 2016, $3.7 billion remains available under the base shelf prospectus.

## RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Other than as described in Note 17 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2016, there were no significant changes in the nature of the related party transactions described in Note 26 of the 2015 Annual Consolidated Financial Statements.

## SHARE INFORMATION

| | As at October 17, 2016 |
|---|---|
| **Issued and outstanding** | |
| Common shares | 165,635,453 |
| Preferred Shares | |
| Series A | 5,511,220 |
| Series B | 2,488,780 |
| Series C | 8,000,000 |
| Series E | 8,000,000 |
| Series G | 8,000,000 |
| Series I | 8,000,000 |
| **Issued** | |
| Share options | 4,188,011 |
| Share options exercisable | 2,980,509 |

## DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends on preferred shares are paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

On July 20, 2016, the Board of Directors approved an increase in the monthly dividend to $0.175 per common share from $0.165 per common share effective with the August 2016 dividend.

The following table summarizes AltaGas' dividend declaration history:

**Dividends**

| Years ended December 31<br>*($ per common share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.49500** | $ | 0.44250 |
| Second quarter | | **0.49500** | | 0.46750 |
| Third quarter | | **0.51500** | | 0.48000 |
| Fourth quarter | | **—** | | 0.49500 |
| **Total** | **$** | **1.50500** | $ | 1.88500 |

**Series A Preferred Share Dividends**

| Years ended December 31<br>*($ per preferred share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.21125** | $ | 0.31250 |
| Second quarter | | **0.21125** | | 0.31250 |
| Third quarter | | **0.21125** | | 0.31250 |
| Fourth quarter | | **—** | | 0.21125 |
| **Total** | **$** | **0.63375** | $ | 1.14875 |

**Series B Preferred Share Dividends**

| Years ended December 31<br>*($ per preferred share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.19269** | $ | — |
| Second quarter | | **0.19393** | | — |
| Third quarter | | **0.20109** | | — |
| Fourth quarter | | **—** | | 0.19156 |
| **Total** | **$** | **0.58771** | $ | 0.19156 |

**Series C Preferred Share Dividends**

| Years ended December 31<br>*(US$ per preferred share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.27500** | $ | 0.27500 |
| Second quarter | | **0.27500** | | 0.27500 |
| Third quarter | | **0.27500** | | 0.27500 |
| Fourth quarter | | **—** | | 0.27500 |
| **Total** | **$** | **0.82500** | $ | 1.10000 |

**Series E Preferred Share Dividends**

| Years ended December 31<br>*($ per preferred share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.31250** | $ | 0.31250 |
| Second quarter | | **0.31250** | | 0.31250 |
| Third quarter | | **0.31250** | | 0.31250 |
| Fourth quarter | | **—** | | 0.31250 |
| **Total** | **$** | **0.93750** | $ | 1.25000 |

**Series G Preferred Share Dividends**

Years ended December 31

| *($ per preferred share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.296875** | $ | 0.296875 |
| Second quarter | | **0.296875** | | 0.296875 |
| Third quarter | | **0.296875** | | 0.296875 |
| Fourth quarter | | **—** | | 0.296875 |
| **Total** | **$** | **0.890625** | $ | 1.187500 |

**Series I Preferred Share Dividends**

Years ended December 31

| *($ per preferred share)* | | **2016** | | 2015 |
|---|---|---|---|---|
| First quarter | **$** | **0.463870** | $ | — |
| Second quarter | | **0.328125** | | — |
| Third quarter | | **0.328125** | | — |
| Fourth quarter | | **—** | | — |
| **Total** | **$** | **1.120120** | $ | — |

## CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of AltaGas' Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. Other than as described below, AltaGas' significant accounting policies have remained unchanged and are contained in the notes to the audited Consolidated Financial Statements as at and for the year ended December 31, 2015. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain, and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be financial instruments, depreciation and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessments, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities. For a full discussion of these accounting estimates, refer to the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2015.

## ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2016, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU):

- ASU No. 2014-12, "Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period", which requires a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2015-01, "Income Statement – Extraordinary and Unusual Items", which eliminates the concept of extraordinary items. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2015-02, "Consolidation: Amendments to Consolidation Analysis". The amendments in this ASU affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

**FUTURE CHANGES IN ACCOUNTING PRINCIPLES**

In May 2014, FASB issued ASU No. 2014-09 "Revenue from Contracts with Customers". The core principle of the amendments in this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, FASB issued ASU No. 2016-08 "Revenue from Contracts with Customers: Principal versus Agent Consideration". The amendments in this ASU clarify the implementation guidance on the principal versus agent considerations in the new revenue recognition standard. In April 2016, FASB issued ASU No. 2016-10 "Revenue from Contracts with Customers: Identifying Performance Obligation and Licensing", which reduces the complexity when applying the guidance for identifying performance obligations and improves the operability and understandability of the license implementation guidance. In May 2016, FASB issued ASU No. 2016-12 "Revenue from Contracts with Customers: Narrow Scope Improvements and Practical Expedients", clarifying several implementation issues, including collectability, presentation of sales taxes, non-cash consideration, contract modification, completed contracts, and transition. The new revenue recognition standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Early adoption prior to that date would not be permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

In January 2016, FASB issued ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revises an entity's accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Upon adoption, entities will be required to make a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard. Upon adoption, AltaGas will no longer be able to classify equity securities with readily determinable fair values as available-for-sale and any changes in fair value will be reported through earnings instead of other comprehensive income. The remaining provisions of this ASU are not expected to have a material impact on AltaGas' financial statements.

In February 2016, FASB issued ASU No. 2016-02 "Leases", which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability for all leases with lease terms greater than 12 months. Lessor accounting remains substantially unchanged. The ASU also requires additional disclosures regarding leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-05 "Derivatives and Hedging: Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships". The amendments in this ASU apply to all entities for which there is a change in the counterparty to a derivative instrument that has been designated as a hedging instrument. This ASU clarifies that a change in the counterparty does not require de-designation of that hedging relationship. The amendments in this ASU are effective for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity has an option to apply for amendments in this ASU on either a prospective basis or a modified retrospective basis. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-06 “Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments”. The amendments in this ASU clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. An entity performing the assessment under the amendments in this ASU is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity should apply the amendment in this ASU on a modified retrospective basis, early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-07 “Equity Method and Joint Ventures Investments: Simplifying the Transition to the Equity Method of Accounting”. The amendments in this ASU eliminate the requirement to retrospectively apply the equity method as a result of an increase in the level of ownership interest or degree of influence. The amendments in this ASU are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. The amendments should be applied prospectively upon their effective date to increases in level of ownership interest or degree of influence. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In March 2016, FASB issued ASU No. 2016-09 “Stock Compensation: Improvements to Employee Share-Based Payment Accounting”. The amendments in this ASU focuses on simplifying several areas of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory withholding requirements, as well as the classification on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2016, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In June 2016, FASB issued ASU No. 2016-13 “Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments”. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2020, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In August 2016, FASB issued ASU No. 2016-15 “Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments”. The amendments in this ASU clarify the classification of certain cash flow transactions on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2017, and interim periods within those fiscal periods. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

## OFF-BALANCE SHEET ARRANGEMENTS

Reference should be made to the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2015 for information on off-balance sheet arrangements.

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

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

AltaGas’ management, including the Chief Executive Officer and the Chief Financial Officer, have designed, or caused to be designed under their supervision, DCP and ICFR to provide reasonable assurance that information required to be disclosed by AltaGas in its annual filings, interim filings or other reports to be filed or submitted by it under securities legislation 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 U.S. GAAP.

The ICFR has been designed based on the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR as at September 30, 2016 and concluded that as at September 30, 2016, AltaGas' DCP and ICFR were effective.

During the third quarter of 2016, there were no changes made to AltaGas’ ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

Pursuant to Section 3.3(1)(b) of National Instrument 52-109, the Chief Executive Officer and Chief Financial Officer of AltaGas, with the assistance of AltaGas employees, have limited the scope of AltaGas’ design of DCP and ICFR to exclude the controls, policies and procedures relating to the San Joaquin Facilities acquired on November 30, 2015. Summary financial information related to the San Joaquin Facilities, which have been included in the unaudited condensed interim Consolidated Financial Statements as at and for the three and nine months ended September 30, 2016, is as follows:

| *($ millions)* | **Three Months Ended September 30, 2016** | **Nine Months Ended September 30, 2016** |
|---|---|---|
| Revenues | $ 30 | $ 94 |
| Pre-tax income | $ 15 | $ 49 |

| *($ millions)* | **As at September 30, 2016** |
|---|---|
| Current assets | $ 107 |
| Non-current assets | $ 908 |
| Current liabilities | $ 10 |
| Non-current liabilities | $ 105 |

It should be noted that a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues, including instances of fraud, if any, have been detected. The design of any system of controls is also based in part on certain assumptions about the likelihood of future events, and there can be no assurances that any design will succeed in achieving its stated goals under all potential conditions.

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

| *($ millions)* | **Q3-16** | Q2-16 | Q1-16 | Q4-15 | Q3-15 | Q2-15 | Q1-15 | Q4-14 |
|---|---|---|---|---|---|---|---|---|
| Total revenue | **492** | 426 | 611 | 580 | 452 | 416 | 744 | 667 |
| Normalized EBITDA(2) | **176** | 153 | 178 | 173 | 125 | 107 | 178 | 155 |
| Net income (loss) applicable to common shares | **46** | 16 | 55 | (54) | 20 | (22) | 66 | 10 |
| *($ per share)* | **Q3-16** | Q2-16 | Q1-16 | Q4-15 | Q3-15 | Q2-15 | Q1-15 | Q4-14 |
| Net income (loss) per common share | | | | | | | | |
| Basic | **0.28** | 0.10 | 0.38 | (0.37) | 0.15 | (0.16) | 0.49 | 0.08 |
| Diluted | **0.28** | 0.10 | 0.38 | (0.37) | 0.14 | (0.16) | 0.49 | 0.08 |
| Dividends declared | **0.52** | 0.50 | 0.50 | 0.50 | 0.48 | 0.47 | 0.44 | 0.44 |

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

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

AltaGas' quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, the US/Canadian dollar exchange rate, planned and unplanned plant outages, timing of in-service dates of new projects, and acquisition and divestiture activities.

Revenue for the Utilities is generally the highest in the first and fourth quarter of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March. Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The commissioning of the hydroelectric power generating facilities, Forrest Kerr and Volcano during the latter part of 2014 and McLymont in the fourth quarter of 2015. These run-of-river hydroelectric facilities are impacted by seasonal precipitation and snowpack melt, which create periods of high flow during the spring and summer months;
- The acquisition of three natural gas-fired power assets (Ripon, Pomona and Brush II) in the U.S. with a total capacity of 164 MW in the first quarter of 2015;
- The Harmattan and Younger turnarounds in the second quarter of 2015;
- The weak NGL commodity prices throughout 2015 and 2016;
- The San Joaquin Facilities acquired on November 30, 2015;
- The closing of the Tidewater Gas Asset Disposition on February 29, 2016;
- The stronger US dollar on translated results of the U.S. assets throughout 2015 and year-to-date 2016;
- The weak Alberta power pool prices throughout the first nine months of 2016;
- The seasonally warmer weather experienced at all of the Utilities in the first quarter of 2016;
- The commencement of commercial operations early in the third quarter of 2016 at the integrated midstream complex at Townsend in northeast British Columbia, including the Townsend Facility, gas gathering line, NGL egress pipelines and truck terminal; and
- The recovery of $7 million of development costs related to the PNG Pipeline Looping Project in the third quarter of 2016.

Net income (loss) applicable to common shares is also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provision on assets and gains or losses on the sale of assets. In addition, net income (loss) applicable to common shares is also impacted by preferred share dividends. For these reasons, the net income (loss) may not necessarily reflect the same trends as revenue. Net income (loss) applicable to common shares during the periods noted was impacted by:

- Higher depreciation and amortization expense due to new assets placed into service or acquired, partially offset by lower depreciation and amortization expense as a result of the Tidewater Gas Asset Disposition on February 29, 2016;
- Higher interest expense mainly due to new assets placed into service and interest no longer eligible for capitalization, and a higher average debt balance since the fourth quarter of 2015 as a result of the acquisition of the San Joaquin Facilities;
- An after-tax provision of $52 million for certain gas processing assets in the fourth quarter of 2014;
- A one-time non-cash expense of $14 million related to the revaluation of deferred income tax liabilities based on the increased Alberta corporate income tax rate from 10 to 12 percent in the second quarter of 2015;
- An after-tax provision of $6 million related to the planned sale of certain development stage wind assets in northern California in the third quarter of 2015;
- After-tax provisions totaling $114 million in the fourth quarter of 2015 related to AltaGas' investment in common shares of Painted Pony, investment in ASTC, investment in its joint ventures with Idemitsu Kosan Co.,Ltd. and the DC LNG Project, certain wind development projects, certain gas processing assets that were held for sale, and AltaGas' one third interest in Inuvik Gas Ltd. and assets in the Ikhil Joint Venture;
- An after-tax gain on sale of $14 million in the first quarter of 2016 related to the sale of certain non-core natural gas gathering and processing assets located primarily in central and north central Alberta;
- The termination of the Sundance B PPAs effective March 8, 2016; and
- After-tax restructuring charges of $5 million in the second quarter of 2016 related to the Workforce Restructuring.

# Consolidated Balance Sheets

(condensed and unaudited)

| **As at** *($ millions)* | **September 30, 2016** | December 31, 2015 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | **$ 4.9** | $ 293.4 |
| Accounts receivable, net of allowances | **248.5** | 333.3 |
| Inventory *(note 5)* | **241.6** | 204.0 |
| Restricted cash holdings from customers | **3.7** | 5.4 |
| Regulatory assets | **1.9** | 4.3 |
| Risk management assets *(note 10)* | **44.3** | 50.4 |
| Prepaid expenses and other current assets | **31.4** | 48.3 |
| Assets held for sale *(note 4)* | **—** | 98.7 |
| | **576.3** | 1,037.8 |
| **Property, plant and equipment** | **6,688.3** | 6,597.9 |
| **Intangible assets** | **690.8** | 735.1 |
| **Goodwill** *(note 6)* | **845.9** | 877.3 |
| **Regulatory assets** | **328.6** | 333.3 |
| **Risk management assets** *(note 10)* | **30.0** | 23.5 |
| **Deferred income taxes** | **2.8** | 4.5 |
| **Restricted cash holdings from customers** | **9.8** | 12.5 |
| **Long-term investments and other assets** *(note 17)* | **154.1** | 64.3 |
| **Investments accounted for by the equity method** *(notes 4 and 7)* | **625.5** | 413.3 |
| | **$ 9,952.1** | $ 10,099.5 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current liabilities** | | |
| Accounts payable and accrued liabilities | **$ 277.9** | $ 383.1 |
| Dividends payable | **28.9** | 24.1 |
| Short-term debt | **69.5** | 130.7 |
| Current portion of long-term debt *(notes 8 and 10)* | **379.5** | 287.5 |
| Customer deposits | **36.6** | 41.0 |
| Regulatory liabilities | **23.1** | 21.3 |
| Risk management liabilities *(note 10)* | **25.6** | 33.5 |
| Other current liabilities | **22.3** | 17.8 |
| Liabilities associated with assets held for sale *(note 4)* | **—** | 8.7 |
| | **863.4** | 947.7 |
| **Long-term debt** *(notes 8 and 10)* | **3,343.4** | 3,732.4 |
| **Asset retirement obligations** | **79.5** | 67.9 |
| **Deferred income taxes** | **610.0** | 621.7 |
| **Regulatory liabilities** | **164.4** | 167.6 |
| **Risk management liabilities** *(note 10)* | **16.9** | 15.7 |
| **Other long-term liabilities** | **197.7** | 206.7 |
| **Future employee obligations** *(note 15)* | **129.2** | 136.9 |
| | **$ 5,404.5** | $ 5,896.6 |

| **As at** *($ millions)* | **September 30, 2016** | December 31, 2015 |
|---|---|---|
| **Shareholders' equity** | | |
| Common shares, no par values, unlimited shares authorized; 2016 - 165.0 million and 2015 - 146.3 million issued and outstanding *(note 11)* | **$ 3,714.3** | $ 3,168.1 |
| Preferred shares *(note 11)* | **985.1** | 985.1 |
| Contributed surplus | **17.2** | 16.7 |
| Accumulated deficit | **(550.9)** | (435.4) |
| Accumulated other comprehensive income (AOCI) *(note 9)* | **346.1** | 433.5 |
| **Total shareholders' equity** | **4,511.8** | 4,168.0 |
| **Non-controlling interests** | **35.8** | 34.9 |
| **Total equity** | **4,547.6** | 4,202.9 |
| | **$ 9,952.1** | $ 10,099.5 |

*Commitments and contingencies (notes 13 and 14).*
*Subsequent events (note 21).*

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Income

(condensed and unaudited)

| ($ millions except per share amounts) | Three Months Ended September 30 **2016** | Three Months Ended September 30 2015 | Nine Months Ended September 30 **2016** | Nine Months Ended September 30 2015 |
|---|---|---|---|---|
| **REVENUE** | | | | |
| Sales | **$ 101.0** | $ 88.5 | **$ 194.0** | $ 301.5 |
| Services | **234.9** | 208.9 | **617.1** | 560.1 |
| Regulated operations | **146.2** | 143.4 | **709.7** | 749.3 |
| Other revenue | **6.7** | 0.6 | **6.8** | 0.4 |
| Unrealized gains on risk management contracts *(note 10)* | **3.5** | 10.8 | **0.8** | 1.6 |
| | **492.3** | 452.2 | **1,528.4** | 1,612.9 |
| **EXPENSES** | | | | |
| Cost of sales, exclusive of items shown separately | **196.0** | 179.9 | **648.9** | 832.4 |
| Operating and administrative | **113.6** | 134.1 | **378.3** | 372.2 |
| Accretion expenses | **2.8** | 2.7 | **8.3** | 8.2 |
| Depreciation and amortization | **67.0** | 52.9 | **201.7** | 152.5 |
| Provision on assets | **—** | 10.5 | **—** | 10.5 |
| | **379.4** | 380.1 | **1,237.2** | 1,375.8 |
| **Income (loss) from equity investments** *(notes 4, 7 and 13)* | **1.6** | (5.0) | **(3.4)** | (5.4) |
| **Other income** *(note 4)* | **2.4** | 1.1 | **8.3** | 5.3 |
| **Foreign exchange gains** | **0.1** | — | **3.6** | 0.4 |
| **Interest expense** | | | | |
| Short-term debt | **(1.9)** | (0.5) | **(2.1)** | (1.2) |
| Long-term debt | **(36.8)** | (30.9) | **(109.1)** | (90.4) |
| **Income before income taxes** | **78.3** | 36.8 | **188.5** | 145.8 |
| **Income tax expense (recovery)** *(notes 4 and 16)* | | | | |
| Current | **13.4** | 2.2 | **33.2** | 17.2 |
| Deferred | **3.9** | 2.4 | **(6.0)** | 27.7 |
| **Net income after taxes** | **61.0** | 32.2 | **161.3** | 100.9 |
| **Net income applicable to non-controlling interests** | **2.5** | 2.1 | **7.7** | 6.2 |
| **Net income applicable to controlling interests** | **58.5** | 30.1 | **153.6** | 94.7 |
| **Preferred share dividends** | **(12.1)** | (10.3) | **(36.0)** | (30.5) |
| **Net income applicable to common shares** | **$ 46.4** | $ 19.8 | **$ 117.6** | **$** 64.2 |
| **Net income per common share** *(note 12)* | | | | |
| Basic | **$ 0.28** | $ 0.15 | **$ 0.76** | $ 0.48 |
| Diluted | **$ 0.28** | $ 0.14 | **$ 0.76** | $ 0.47 |
| **Weighted average number of common shares outstanding** (millions) *(note 12)* | | | | |
| Basic | **164.1** | 135.8 | **154.2** | 135.0 |
| Diluted | **164.6** | 136.6 | **154.6** | 136.2 |

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Comprehensive Income

(condensed and unaudited)

| ($ millions) | Three Months Ended September 30 2016 | Three Months Ended September 30 2015 | Nine Months Ended September 30 2016 | Nine Months Ended September 30 2015 |
|---|---|---|---|---|
| **Net income after taxes** | **$ 61.0** | $ 32.2 | **$ 161.3** | $ 100.9 |
| Other comprehensive income (loss), net of taxes | | | | |
| Gain (loss) on foreign currency translation | **22.2** | 143.3 | **(148.2)** | 277.8 |
| Unrealized gain (loss) on net investment hedge | **(3.5)** | (32.9) | **40.7** | (62.6) |
| Unrealized losses on cash flow hedges | **—** | — | **—** | (0.2) |
| Reclassification of gains on cash flow hedges to net income | **—** | — | **—** | (13.1) |
| Reclassification of actuarial losses and prior service costs on defined benefit and post-retirement benefit (PRB) plans to net income | **0.2** | 0.4 | **0.5** | 0.9 |
| Unrealized gain (loss) on available-for-sale assets | **3.0** | (11.0) | **19.1** | (16.0) |
| Other comprehensive income (loss) from equity investees | **1.5** | (0.3) | **0.5** | 4.6 |
| **Total other comprehensive income (loss) (OCI), net of taxes** | **23.4** | 99.5 | **(87.4)** | 191.4 |
| **Comprehensive income attributable to controlling interests and non-controlling interests, net of taxes** | **$ 84.4** | $ 131.7 | **$ 73.9** | $ 292.3 |
| | | | | |
| **Comprehensive income attributable to:** | | | | |
| Non-controlling interests | **$ 2.5** | $ 2.1 | **$ 7.7** | $ 6.2 |
| Controlling interests | **81.9** | 129.6 | **66.2** | 286.1 |
| | **$ 84.4** | $ 131.7 | **$ 73.9** | $ 292.3 |

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Equity

(condensed and unaudited)

| ($ millions) | Nine Months Ended September 30 2016 | 2015 |
|---|---|---|
| **Common shares** *(note 11)* | | |
| Balance, beginning of period | **$ 3,168.1** | $ 2,759.9 |
| Shares issued for cash on exercise of options | **7.6** | 11.8 |
| Shares issued under DRIP [1] | **116.2** | 68.5 |
| Deferred taxes on share issuance costs | **0.2** | 3.1 |
| Shares issued on public offering, net of issuance costs | **422.2** | 288.0 |
| Balance, end of period | **$ 3,714.3** | $ 3,131.3 |
| **Preferred shares** *(note 11)* | | |
| Balance, beginning of period | **$ 985.1** | $ 788.4 |
| Series A converted to Series B | **—** | (60.9) |
| Series B issued | **—** | 60.9 |
| Balance, end of period | **$ 985.1** | $ 788.4 |
| **Contributed surplus** | | |
| Balance, beginning of period | **$ 16.7** | $ 14.9 |
| Share options expense | **1.4** | 2.6 |
| Exercise of share options | **(0.7)** | (1.1) |
| Forfeiture of share options | **(0.2)** | (0.3) |
| Balance, end of period | **$ 17.2** | $ 16.1 |
| **Accumulated deficit** | | |
| Balance, beginning of period | **$ (435.4)** | $ (185.2) |
| Net income applicable to controlling interests | **153.6** | 94.7 |
| Common share dividends | **(233.1)** | (187.9) |
| Preferred share dividends | **(36.0)** | (30.5) |
| Balance, end of period | **$ (550.9)** | $ (308.9) |
| **AOCI** (*note 9*) | | |
| Balance, beginning of period | **$ 433.5** | $ 163.1 |
| Other comprehensive income (loss) | **(87.4)** | 191.4 |
| Balance, end of period | **$ 346.1** | $ 354.5 |
| **Total shareholders' equity** | **$ 4,511.8** | $ 3,981.4 |
| | | |
| **Non-controlling interests** | | |
| Balance, beginning of period | **$ 34.9** | $ 33.1 |
| Net income applicable to non-controlling interests | **7.7** | 6.2 |
| Sale of interest in a subsidiary | **—** | 1.8 |
| Distribution by subsidiaries to non-controlling interests | **(6.8)** | (4.7) |
| Balance, end of period | **35.8** | 36.4 |
| **Total equity** | **$ 4,547.6** | $ 4,017.8 |

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

*See accompanying notes to the Consolidated Financial Statements.*

# Consolidated Statements of Cash Flows

(condensed and unaudited)

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *($ millions)* | **2016** | 2015 | **2016** | 2015 |
| **Cash from operations** | | | | |
| Net income after taxes | **$ 61.0** | $ 32.2 | **$ 161.3** | $ 100.9 |
| Items not involving cash: | | | | |
| Depreciation and amortization | **67.0** | 52.9 | **201.7** | 152.5 |
| Provision on assets | **—** | 10.5 | **—** | 10.5 |
| Accretion expenses | **2.8** | 2.7 | **8.3** | 8.2 |
| Share-based compensation *(note 11)* | **0.3** | 0.7 | **1.2** | 2.3 |
| Deferred income tax expense (recovery) *(notes 4 and 16)* | **3.9** | 2.4 | **(6.0)** | 27.7 |
| Gain on sale of assets *(note 4)* | **(0.1)** | — | **(4.2)** | — |
| Loss (income) from equity investments *(notes 4, 7 and 13)* | **(1.6)** | 5.0 | **3.4** | 5.4 |
| Unrealized gains on risk management contracts *(note 10)* | **(3.5)** | (10.8) | **(0.8)** | (1.6) |
| Gain on long-term investments | **(1.4)** | — | **(1.7)** | (0.9) |
| Other | **0.6** | 1.5 | **1.9** | 5.8 |
| Asset retirement obligations settled | **(0.7)** | (0.3) | **(2.3)** | (2.0) |
| Net distributions from (contributions to) equity investments | **11.9** | 4.8 | **13.6** | (0.1) |
| Changes in operating assets and liabilities *(note 18)* | **(64.5)** | (41.8) | **(55.8)** | 100.8 |
| | **$ 75.7** | $ 59.8 | **$ 320.6** | $ 409.5 |
| **Investing activities** | | | | |
| Business acquisitions, net of cash acquired *(note 3)* | **—** | — | **(20.0)** | (33.6) |
| Acquisition of property, plant and equipment | **(94.7)** | (165.3) | **(399.7)** | (409.1) |
| Acquisition of intangible assets | **(13.4)** | (14.0) | **(19.4)** | (32.5) |
| Contributions to equity investments | **(13.5)** | (2.9) | **(20.2)** | (9.0) |
| Maturity of short-term investment | **—** | — | **—** | 50.0 |
| Change in restricted cash holdings from customers | **0.3** | (0.7) | **1.4** | 0.8 |
| Investment in Petrogas preferred shares *(note 7)* | **—** | — | **(150.0)** | — |
| Loan to affiliate *(note 17)* | **(15.0)** | — | **(40.0)** | — |
| Proceeds from disposition of assets, net of transaction costs *(note 4)* | **0.7** | 0.1 | **30.4** | 0.2 |
| Sale of interest in a subsidiary | **—** | 1.8 | **—** | 1.8 |
| | **$ (135.6)** | **$** (181.0) | $ **(617.5)** | **$** (431.4) |
| **Financing activities** | | | | |
| Net issuance (repayment) of short-term debt | **46.9** | (2.7) | **(55.1)** | (66.6) |
| Issuance of long-term debt, net of debt issuance costs | **28.9** | 10.3 | **640.9** | 386.2 |
| Repayment of long-term debt | **(51.0)** | (7.0) | **(850.8)** | (410.7) |
| Dividends - common shares | **(82.7)** | (65.1) | **(228.3)** | (185.9) |
| Dividends - preferred shares | **(12.1)** | (10.3) | **(37.1)** | (30.5) |
| Distributions to non-controlling interest | **(1.6)** | (0.7) | **(6.8)** | (4.7) |
| Net proceeds from shares issued on exercise of options | **4.7** | 0.3 | **6.9** | 10.7 |
| Net proceeds from issuance of common shares | **54.3** | 313.7 | **538.4** | 356.5 |
| | **$ (12.6)** | $ 238.5 | **$ 8.1** | $ 55.0 |
| **Change in cash and cash equivalents** | **(72.5)** | 117.3 | **(288.8)** | 33.1 |
| **Effect of exchange rate changes on cash and cash equivalents** | **—** | 3.0 | **0.3** | 5.8 |
| **Cash and cash equivalents, beginning of period** | **77.4** | 289.6 | **293.4** | 371.0 |
| **Cash and cash equivalents, end of period** | **$ 4.9** | $ 409.9 | **$ 4.9** | $ 409.9 |

*See accompanying notes to the Consolidated Financial Statements.*

# Notes to the Condensed Interim Consolidated Financial Statements (unaudited)

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

## 1. ORGANIZATION AND OVERVIEW OF THE BUSINESS

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, Harmattan Gas Processing Limited Partnership, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), Coast Mountain Hydro Limited Partnership, AltaGas Services (U.S.) Inc., Blythe Energy Inc. (Blythe), AltaGas San Joaquin Energy Inc., and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

AltaGas, a Canadian corporation, is a North American diversified energy infrastructure business with a focus on owning and operating assets to provide clean and affordable energy to its customers. AltaGas has three business segments: Gas, Power and Utilities.

AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and separation, gas transmission, gas storage and natural gas marketing, and the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas).

The Power segment includes 1,688 MW of generating capacity from natural gas-fired, wind, biomass and hydro assets in Canada and the United States, along with 20 MW of energy storage currently under construction and an additional 1,253 MW of assets under development.

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

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### BASIS OF PRESENTATION

These unaudited condensed interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP). As a result, these condensed interim Consolidated Financial Statements do not include all of the information and disclosures required in the annual Consolidated Financial Statements and should be read in conjunction with the Corporation's 2015 annual audited Consolidated Financial Statements prepared in accordance with U.S. GAAP. In management's opinion, the condensed interim Consolidated Financial Statements include all adjustments that are all of a recurring nature and necessary to present fairly the financial position of the Corporation.

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2019, the date to which AltaGas ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standard for rate-regulated accounting.

**PRINCIPLES OF CONSOLIDATION**

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

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

**USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY**

The preparation of Consolidated Financial Statements in accordance with U.S. 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 and amortization expense, asset retirement obligations, assets impairment assessment, fair value of financial instruments, income taxes, employee future benefits, contingencies, 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 require 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.

**SIGNIFICANT ACCOUNTING POLICIES**

Except as noted below, these condensed interim Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2015 annual audited Consolidated Financial Statements.

**ADOPTION OF NEW ACCOUNTING STANDARDS**

Effective January 1, 2016, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU):

- ASU No. 2014-12, "Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period", which requires a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2015-01, "Income Statement – Extraordinary and Unusual Items", which eliminates the concept of extraordinary items. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2015-02, "Consolidation: Amendments to Consolidation Analysis". The amendments in this ASU affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

**FUTURE CHANGES IN ACCOUNTING PRINCIPLES**

In May 2014, FASB issued ASU No. 2014-09 "Revenue from Contracts with Customers". The core principle of the amendments in this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, FASB issued ASU No. 2016-08 "Revenue from Contracts with Customers: Principal versus Agent Consideration". The amendments in this ASU clarify the implementation guidance on the principal versus agent considerations in the new revenue recognition standard. In April 2016, FASB issued ASU No. 2016-10 "Revenue from Contracts with Customers: Identifying Performance Obligation and Licensing", which reduces the complexity when applying the guidance for identifying performance obligations and improves the operability and understandability of the license implementation guidance. In May 2016, FASB issued ASU No. 2016-12 "Revenue from Contracts with Customers: Narrow Scope Improvements and Practical Expedients", clarifying several implementation issues, including collectability, presentation of sales taxes, non-cash consideration, contract modification, completed contracts, and transition. The new revenue recognition standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Early adoption prior to that date would not be permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

In January 2016, FASB issued ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revises an entity's accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Upon adoption, entities will be required to make a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard. Upon adoption, AltaGas will no longer be able to classify equity securities with readily determinable fair values as available-for-sale and any changes in fair value will be reported through earnings instead of other comprehensive income. The remaining provisions of this ASU are not expected to have a material impact on AltaGas' financial statements.

In February 2016, FASB issued ASU No. 2016-02 "Leases", which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability for all leases with lease terms greater than 12 months. Lessor accounting remains substantially unchanged. The ASU also requires additional disclosures regarding leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-05 "Derivatives and Hedging: Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships". The amendments in this ASU apply to all entities for which there is a change in the counterparty to a derivative instrument that has been designated as a hedging instrument. This ASU clarifies that a change in the counterparty does not require de-designation of that hedging relationship. The amendments in this ASU are effective for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity has an option to apply for amendments in this ASU on either a prospective basis or a modified retrospective basis. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-06 “Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments”. The amendments in this ASU clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. An entity performing the assessment under the amendments in this ASU is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity should apply the amendment in this ASU on a modified retrospective basis, early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-07 “Equity Method and Joint Ventures Investments: Simplifying the Transition to the Equity Method of Accounting”. The amendments in this ASU eliminate the requirement to retrospectively apply the equity method as a result of an increase in the level of ownership interest or degree of influence. The amendments in this ASU are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. The amendments should be applied prospectively upon their effective date to increases in level of ownership interest or degree of influence. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In March 2016, FASB issued ASU No. 2016-09 “Stock Compensation: Improvements to Employee Share-Based Payment Accounting”. The amendments in this ASU focuses on simplifying several areas of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory withholding requirements, as well as the classification on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2016, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In June 2016, FASB issued ASU No. 2016-13 “Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments”. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2020, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In August 2016, FASB issued ASU No. 2016-15 “Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments”. The amendments in this ASU clarify the classification of certain cash flow transactions on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2017, and interim periods within those fiscal periods. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

## 3. ACQUISITIONS

**GWF Energy Holdings LLC (San Joaquin Facilities)**

On November 30, 2015 AltaGas completed the acquisition of GWF Energy Holdings LLC, which holds a portfolio of three natural gas-fired electrical generation facilities in northern California totaling 523 MW, for approximately US$642 million before working capital adjustments. Subsequent to the acquisition, GWF Energy Holdings LLC and the other entities acquired were restructured ultimately resulting in the sole successor being AltaGas San Joaquin Energy Inc. For the three and nine months ended September 30, 2016, transaction costs, such as legal, accounting, valuation and other professional fees of $0.1 million and $1.7 million before taxes, respectively, were incurred and included in the Consolidated Statement of Income, within “Operating and administrative expenses”. Acquisition costs of $3.5 million before taxes have been incurred on the acquisition to date. The purchase price allocation representing the consideration paid and the fair value of the net assets acquired as at November 30, 2015 is substantially complete except for the amounts related to deferred income taxes. Below is the purchase price allocation using an exchange rate of 1.3333 to convert US dollars to Canadian dollars.

| | | |
|---|---|---|
| Cash consideration | $ | 881.4 |
| Total consideration | $ | 881.4 |

| **Fair value of net assets acquired** | | |
|---|---|---|
| Current assets | $ | 31.8 |
| Property, plant and equipment | | 591.3 |
| Intangible assets | | 355.4 |
| Current liabilities | | (13.0) |
| Deferred income taxes | | (84.1) |
| | $ | 881.4 |

The consolidated results for the three and nine months ended September 30, 2016 incorporate the results of operations from the San Joaquin Facilities. If the acquisition had occurred on January 1, 2015, revenues and pre-tax income would have increased by approximately $31.0 million (US$23.6 million) and $25.0 million (US$19.1 million), respectively, for the three months ended September 30, 2015 and approximately $89.4 million (US$70.9 million) and $72.1 million (US$57.2 million), respectively, for the nine months ended September 30, 2015.

**Edmonton Ethane Extraction Plant (EEEP)**

Effective January 1, 2016, AltaGas acquired the remaining 51 percent interest in EEEP for cash consideration of approximately $21.0 million, increasing its ownership interest to 100 percent. AltaGas accounted for the acquisition as a business combination achieved in stages and remeasured the previously held 49 percent interest in EEEP at fair value on the acquisition date using the discounted cash flow approach. The significant inputs include contracted cash flows for the facility, forecasted commodity prices, and projected operating costs based on historical pattern. No gain or loss was recorded as a result of the remeasurement. Upon the acquisition of control, AltaGas began consolidating the results of EEEP. Prior to the acquisition, AltaGas proportionately consolidated the 49 percent interest in EEEP.

Below is the provisional purchase price allocation of the estimated fair values of the net assets acquired as at the acquisition date:

| **Fair value of net assets acquired** | | |
|---|---|---|
| Property, plant and equipment | $ | 67.1 |
| Asset retirement obligations | | (15.0) |
| Deferred income taxes | | (3.3) |
| | $ | 48.8 |

The total estimated fair value of $48.8 million included $21.0 million of cash paid to acquire the remaining 51 percent interest and $27.8 million related to the previously held interest.

The consolidated results for the three and nine months ended September 30, 2016 incorporate the results of operations from the additional ownership interest in EEEP. If the acquisition of the additional interest had occurred on January 1, 2015, changes to revenues and pre-tax income for the three and nine months ended September 30, 2015 would have been nominal.

## 4. ASSETS HELD FOR SALE

| As at | September 30, 2016 | December 31, 2015 |
|---|---|---|
| **Assets held for sale** | | |
| Property, plant and equipment | **$ —** | $ 97.7 |
| Intangible assets | **—** | 1.0 |
| | **$ —** | $ 98.7 |

| | | |
|---|---|---|
| **Liabilities associated with assets held for sale** | | |
| Asset retirement obligations | **$ —** | $ 8.7 |
| | **$ —** | $ 8.7 |

On February 29, 2016, AltaGas completed the disposition of certain non-core natural gas gathering and processing assets in the Gas segment to Tidewater Midstream and Infrastructure Ltd. (Tidewater) for total gross consideration of $30.0 million in cash and approximately 43.7 million of common shares of Tidewater valued at $1.48 per share. AltaGas accounted for its investment in Tidewater common shares using the equity method and recognized an increase of approximately $64.7 million to "Investments accounted for by the equity method" on the Consolidated Balance Sheet. The assets were located primarily in central and north central Alberta and totaled approximately 490 Mmcf/d of gross licensed natural gas processing capacity. AltaGas recognized a pre-tax gain on disposition of $0.5 million and $4.5 million in the Consolidated Statement of Income under the line item "Other income" for the three and nine months ended September 30, 2016, respectively. In addition, AltaGas recorded a tax recovery of $0.1 million and $10.3 million related to the asset sale for the three and nine months ended September 30, 2016, respectively.

For the nine months ended September 30, 2016, AltaGas recognized a pre-tax dilution loss of approximately $0.7 million in the Consolidated Statement of Income under the line item "Income (loss) from equity investments" as a result of AltaGas' interest in Tidewater being diluted from 19.9 percent on February 29, 2016 to approximately 15.4 percent as at September 30, 2016.

## 5. INVENTORY

| As at | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Natural gas held in storage | **$ 191.6** | $ 166.0 |
| Other inventory | **50.0** | 38.0 |
| | **$ 241.6** | $ 204.0 |

## 6. GOODWILL

| As at | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Balance, beginning of period | **$ 877.3** | $ 785.1 |
| Provision on assets | **—** | (5.1) |
| Foreign exchange translation | **(31.4)** | 97.3 |
| Balance, end of period | **$ 845.9** | $ 877.3 |

## 7. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

AltaGas, indirectly through its investment in AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) holds a one-third equity interest in Petrogas Energy Corp. (Petrogas). On June 29, 2016, AltaGas, directly invested $150.0 million to subscribe for 6,000,000 cumulative redeemable convertible preferred shares of Petrogas. These preferred shares form part of AltaGas' overall investment in Petrogas and entitle AltaGas to a fixed, cumulative, preferential cash dividend at a rate of 8.5 percent per annum payable quarterly. These preferred shares are, in the normal course, redeemable at any time on or after January 1, 2018 and convertible into a specified number of common shares at the option of either holder at any time on or after April 19, 2018. For the three and nine months ended September 30, 2016, AltaGas received dividend income of $2.7 million from the Petrogas preferred shares, which has been included in the Consolidated Statement of Income under the line item “Income (loss) from equity investments”.

## 8. LONG-TERM DEBT

| As at | Maturity date | | **September 30, 2016** | | December 31, 2015 |
|---|---|---|---|---|---|
| Credit facilities | | | | | |
| $1,400 million unsecured extendible revolving[(a)] | 15-Dec-2019 | **$** | **364.7** | $ | 689.9 |
| Medium-term notes (MTNs) | | | | | |
| $200 million Senior unsecured - 5.49 percent | 27-Mar-2017 | | **200.0** | | 200.0 |
| $175 million Senior unsecured - 4.60 percent | 15-Jan-2018 | | **175.0** | | 175.0 |
| $200 million Senior unsecured - 4.55 percent | 17-Jan-2019 | | **200.0** | | 200.0 |
| $200 million Senior unsecured - 4.07 percent | 1-Jun-2020 | | **200.0** | | 200.0 |
| $350 million Senior unsecured - 3.72 percent | 28-Sep-2021 | | **350.0** | | 350.0 |
| $300 million Senior unsecured - 3.57 percent | 12-Jun-2023 | | **300.0** | | 300.0 |
| $200 million Senior unsecured - 4.40 percent | 15-Mar-2024 | | **200.0** | | 200.0 |
| $300 million Senior unsecured - 3.84 percent | 15-Jan-2025 | | **299.9** | | 299.9 |
| $100 million Senior unsecured - 5.16 percent | 13-Jan-2044 | | **100.0** | | 100.0 |
| $300 million Senior unsecured - 4.50 percent | 15-Aug-2044 | | **299.8** | | 299.8 |
| $350 million Senior unsecured - 4.12 percent | 7-Apr-2026 | | **349.8** | | — |
| US$200 million Senior unsecured - floating[(b)] | 24-Mar-2016 | | — | | 276.8 |
| US$125 million Senior unsecured - floating[(c)] | 17-Apr-2017 | | **164.0** | | 173.0 |
| SEMCO long-term debt | | | | | |
| US$300 million SEMCO Senior secured - 5.15 percent[(d)] | 21-Apr-2020 | | **393.5** | | 415.2 |
| US$82 million CINGSA Senior secured - 4.48 percent[(e)] | 2-Mar-2032 | | **95.3** | | 107.0 |
| Debenture notes | | | | | |
| PNG RoyNat Debenture - 3.38 percent[(f)] | 15-Sep-2017 | | **7.7** | | 8.6 |
| PNG 2018 Series Debenture - 8.75 percent[(f)] | 15-Nov-2018 | | **9.0** | | 9.0 |
| PNG 2025 Series Debenture - 9.30 percent[(f)] | 18-Jul-2025 | | **13.5** | | 14.0 |
| PNG 2027 Series Debenture - 6.90 percent[(f)] | 2-Dec-2027 | | **15.0** | | 15.0 |
| Loan from Province of Nova Scotia[(g)] | 31-Jul-2017 | | **—** | | 1.1 |
| CINGSA capital lease - 3.50 percent | 1-May-2040 | | **0.5** | | 0.6 |
| CINGSA capital lease - 4.48 percent | 4-Jun-2068 | | **0.2** | | 0.2 |
| | | **$** | **3,737.9** | $ | 4,035.1 |
| Less debt issuance costs | | | **(15.0)** | | (15.2) |
| | | | **3,722.9** | | 4,019.9 |
| Less current portion | | | **(379.5)** | | (287.5) |
| | | **$** | **3,343.4** | $ | 3,732.4 |

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

*(b) The notes carried a floating rate coupon of three months LIBOR plus 0.72 percent.*

*(c) The notes carry a floating rate coupon of three months LIBOR plus 0.85 percent.*

*(d) Collateral for the US$ MTNs is certain SEMCO assets.*

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

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

*(g) The loan was non-interest bearing and, if certain prescribed revenue targets were 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. As at September 30, 2016, the loan has been fully repaid.*

## 9. ACCUMULATED OTHER COMPREHENSIVE INCOME

| ($ millions) | Available-for-sale | Cash flow hedges | Defined benefit pension and PRB plans | Hedge net investments | Translation foreign operations | Equity Investee | Total |
|---|---|---|---|---|---|---|---|
| **Opening balance, January 1, 2016** | **$ (2.4)** | **$ —** | **$ (9.6)** | **$ (169.6)** | **$ 610.5** | **$ 4.6** | **$ 433.5** |
| OCI before reclassification | **22.1** | **—** | **—** | **54.7** | **(148.2)** | **0.5** | **(70.9)** |
| Amounts reclassified from OCI | **—** | **—** | **0.7** | **—** | **—** | **—** | **0.7** |
| Current period OCI (pre-tax) | **22.1** | **—** | **0.7** | **54.7** | **(148.2)** | **0.5** | **(70.2)** |
| Income tax on amounts retained in AOCI | **(3.0)** | **—** | **—** | **(14.0)** | **—** | **—** | **(17.0)** |
| Income tax on amounts reclassified to earnings | **—** | **—** | **(0.2)** | **—** | **—** | **—** | **(0.2)** |
| Net current period OCI | **19.1** | **—** | **0.5** | **40.7** | **(148.2)** | **0.5** | **(87.4)** |
| **Ending balance, September 30, 2016** | **$ 16.7** | **$ —** | **$ (9.1)** | **$ (128.9)** | **$ 462.3** | **$ 5.1** | **$ 346.1** |
| Opening balance, January 1, 2015 | $ (12.0) | $ 13.3 | $ (9.6) | $ (70.9) | $ 242.3 | $ — | $ 163.1 |
| OCI before reclassification | (15.9) | (0.4) | — | (64.8) | 277.8 | 4.6 | 201.3 |
| Amounts reclassified from OCI | — | (17.5) | 1.3 | — | — | — | (16.2) |
| Current period OCI (pre-tax) | (15.9) | (17.9) | 1.3 | (64.8) | 277.8 | 4.6 | 185.1 |
| Income tax on amounts retained in AOCI | (0.1) | 0.2 | — | 2.2 | — | — | 2.3 |
| Income tax on amounts reclassified to earnings | — | 4.4 | (0.4) | — | — | — | 4.0 |
| Net current period OCI | (16.0) | (13.3) | 0.9 | (62.6) | 277.8 | 4.6 | 191.4 |
| Ending balance, September 30, 2015 | $ (28.0) | $ — | $ (8.7) | $ (133.5) | $ 520.1 | $ 4.6 | $ 354.5 |

**Reclassification From Accumulated Other Comprehensive Income**

| AOCI components reclassified | Income statement line item | **Three Months Ended September 30, 2016** | **Nine Months Ended September 30, 2016** |
|---|---|---|---|
| Defined benefit pension and PRB plans | Operating and administrative expense | **$ 0.3** | **$ 0.7** |
| Deferred income taxes | Income tax expenses – deferred | **(0.1)** | **(0.2)** |
| | | **$ 0.2** | **$ 0.5** |

| AOCI components reclassified | Income statement line item | Three Months Ended September 30, 2015 | Nine Months Ended September 30, 2015 |
|---|---|---|---|
| Cash flow hedges - commodity contracts | | | |
| Commodity contracts - NGL (realized effective portion) | Service revenue | $ — | $ (7.2) |
| Commodity contracts - NGL (discontinuation of hedge accounting) | Unrealized gains on risk management contracts | — | (10.3) |
| Defined benefit pension and PRB plans | Operating and administrative expense | 0.5 | 1.3 |
| | Total before income taxes | 0.5 | (16.2) |
| Deferred income taxes | Income tax expenses – deferred | (0.1) | 4.0 |
| | | $ 0.4 | $ (12.2) |

## 10. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation's financial instruments consist of cash and cash equivalents, accounts receivable, risk management contracts, certain long-term investments and other assets, accounts payable and accrued liabilities, dividends payable, short-term and long-term debt and certain current and long-term liabilities.

**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 valuation models and techniques where inputs other than quoted prices included within level 1 are observable for the asset or liability either directly or indirectly. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity prices, 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, and currency exchange. 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.

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

*Cash and cash equivalents, Accounts receivable, Accounts payable, Short-term debt and Dividends payable* - the carrying amounts approximate fair value because of the short maturity of these instruments.

*Current portion of long-term debt, Long-term debt and Other long-term liabilities* - the fair value of these liabilities has been estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

*Risk management assets and liabilities* - the fair values of power, natural gas and NGL derivative contracts were calculated using discounted cash flow analysis based upon forward prices from published sources for the relevant period. The fair value of foreign exchange derivative contracts was calculated using quoted market rates.

| | September 30, 2016 | | | | |
|---|---|---|---|---|---|
| | **Carrying Amount** | **Level 1** | **Level 2** | **Level 3** | **Total Fair Value** |
| Financial assets | | | | | |
| Cash and cash equivalents | **$ 4.9** | **$ 4.9** | **$ —** | **$ —** | **$ 4.9** |
| Risk management assets - current | **44.3** | **—** | **44.3** | **—** | **44.3** |
| Risk management assets - non-current | **30.0** | **—** | **30.0** | **—** | **30.0** |
| Long-term investments and other assets [(a)] | **88.1** | **47.0** | **41.1** | **—** | **88.1** |
| | **$ 167.3** | **$ 51.9** | **$ 115.4** | **$ —** | **$ 167.3** |
| Financial liabilities | | | | | |
| Risk management liabilities - current | **$ 25.6** | **$ —** | **$ 25.6** | **$ —** | **$ 25.6** |
| Risk management liabilities - non-current | **16.9** | **—** | **16.9** | **—** | **16.9** |
| Current portion of long-term debt | **379.5** | **—** | **383.3** | **—** | **383.3** |
| Long-term debt | **3,343.4** | **—** | **3,518.1** | **—** | **3,518.1** |
| Other current liabilities [(b)] | **11.3** | **—** | **11.3** | **—** | **11.3** |
| Other long-term liabilities [(b)] | **145.1** | **—** | **148.6** | **—** | **148.6** |
| | **$ 3,921.8** | **$ —** | **$ 4,103.8** | **$ —** | **$ 4,103.8** |

*(a) Excludes non-financial assets.*
*(b) Excludes non-financial liabilities.*

| | December 31, 2015 | | | | |
|---|---|---|---|---|---|
| | Carrying Amount | Level 1 | Level 2 | Level 3 | Total Fair Value |
| Financial assets | | | | | |
| Cash and cash equivalents | $ 293.4 | $ 293.4 | $ — | $ — | $ 293.4 |
| Risk management assets - current | 50.4 | — | 50.4 | — | 50.4 |
| Risk management assets - non-current | 23.5 | — | 23.5 | — | 23.5 |
| Long-term investments and other assets [(a)] | 24.0 | 24.0 | — | — | 24.0 |
| | $ 391.3 | $ 317.4 | $ 73.9 | $ — | $ 391.3 |
| Financial liabilities | | | | | |
| Risk management liabilities - current | $ 33.5 | $ — | $ 33.5 | $ — | $ 33.5 |
| Risk management liabilities - non-current | 15.7 | — | 15.7 | — | 15.7 |
| Current portion of long-term debt | 287.5 | — | 286.2 | — | 286.2 |
| Long-term debt | 3,732.4 | — | 3,787.5 | — | 3,787.5 |
| Other current liabilities [(b)] | 11.0 | — | 11.0 | — | 11.0 |
| Other long-term liabilities [(b)] | 151.2 | — | 144.9 | — | 144.9 |
| | $ 4,231.3 | $ — | $ 4,278.8 | $ — | $ 4,278.8 |

*(a) Excludes non-financial assets.*
*(b) Excludes non-financial liabilities.*

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

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Natural gas | **$ (1.1)** | $ 3.0 | **$ (1.5)** | $ 6.0 |
| Storage optimization | **0.5** | 0.8 | **(3.4)** | (0.1) |
| NGL frac spread | **(1.0)** | (5.9) | **(3.4)** | 1.7 |
| Power | **5.1** | 12.4 | **8.1** | (6.1) |
| Heat rate | **—** | 0.7 | **(0.1)** | (0.2) |
| Foreign exchange | **—** | (0.1) | **0.9** | 0.3 |
| Embedded derivative | **—** | (0.1) | **0.2** | — |
| | **$ 3.5** | $ 10.8 | **$ 0.8** | $ 1.6 |

### Offsetting of Derivative Assets and Derivative Liabilities

Certain AltaGas risk management contracts are subject to master netting arrangements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities.

| | **September 30, 2016** | | |
|---|---|---|---|
| Risk management assets [(a)] | **Gross amounts of recognized assets/liabilities** | **Gross amounts offset in balance sheet** | **Net amounts presented in balance sheet** |
| Natural gas | **$ 26.4** | **$ (2.3)** | **$ 24.1** |
| Storage optimization | **0.1** | **(0.1)** | **—** |
| NGL frac spread | **1.0** | **—** | **1.0** |
| Power | **48.9** | **(0.1)** | **48.8** |
| Foreign exchange | **2.2** | **(1.8)** | **0.4** |
| | **$ 78.6** | **$ (4.3)** | **$ 74.3** |
| Risk management liabilities [(b)] | | | |
| Natural gas | **$ 24.6** | **$ (2.3)** | **$ 22.3** |
| Storage optimization | **1.0** | **(0.1)** | **0.9** |
| NGL frac spread | **4.5** | **—** | **4.5** |
| Power | **14.9** | **(0.1)** | **14.8** |
| Foreign exchange | **1.8** | **(1.8)** | **—** |
| | **$ 46.8** | **$ (4.3)** | **$ 42.5** |

*(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $44.3 million and risk management assets (non-current) balance of $30.0 million.*

*(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $25.6 million and risk management liabilities (non-current) balance of $16.9 million.*

| | December 31, 2015 | | |
|---|---|---|---|
| Risk management assets [(a)] | Gross amounts of recognized assets/liabilities | Gross amounts offset in balance sheet | Net amounts presented in balance sheet |
| Natural gas | $ 40.1 | $ (1.9) | $ 38.2 |
| Storage optimization | 3.0 | (0.5) | 2.5 |
| Power | 34.0 | (0.9) | 33.1 |
| Heat rate | 0.1 | — | 0.1 |
| Foreign exchange | 2.2 | (2.2) | — |
| | $ 79.4 | $ (5.5) | $ 73.9 |
| Risk management liabilities [(b)] | | | |
| Natural gas | $ 37.0 | $ (1.9) | $ 35.1 |
| Storage optimization | 0.5 | (0.5) | — |
| Power | 14.5 | (0.9) | 13.6 |
| Foreign exchange | 2.7 | (2.2) | 0.5 |
| | $ 54.7 | $ (5.5) | $ 49.2 |

*(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $50.4 million and risk management assets (non-current) balance of $23.5 million.*

*(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $33.5 million and risk management liabilities (non-current) balance of $15.7 million.*

## 11. SHAREHOLDERS' EQUITY

### Authorization

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

On June 6, 2016, AltaGas closed a public offering of 14,685,000 common shares, on a bought deal basis, at an issue price of $30 per common share, for total gross proceeds of approximately $440 million.

**Dividend Reinvestment Plan (DRIP)**

Effective May 17, 2016, AltaGas replaced in its entirety, its existing plan with the Premium Dividend[TM], Dividend Reinvestment and Optional Cash Purchase Plan (the Plan). The Plan consists of three components: a Premium Dividend™ component, a Dividend Reinvestment component and an Optional Cash Payment component.

The Plan provides eligible holders of common shares with the opportunity to, at their election, either: (1) to reinvest the cash dividends paid by AltaGas on their common shares towards the purchase of new common shares at a 3 percent discount to the average market price (as defined below) of the common shares on the applicable dividend payment date (the Dividend Reinvestment component of the Plan); or (2) to reinvest the cash dividends paid by AltaGas on their common shares towards the purchase of new common shares at a 3 percent discount to the average market price (as defined below) on the applicable dividend payment date and have these additional common shares of AltaGas exchanged for a cash payment equal to 101 percent of the reinvested amount (the Premium Dividend™ component of the Plan).

In addition, the Plan provides shareholders who are enrolled in the Dividend Reinvestment component of the Plan with the opportunity to purchase new common shares at the average market price (with no discount) on the applicable dividend payment date (the Optional Cash Payment component of the Plan).

Each of the components of the Plan is subject to prorating and other limitations on availability of new common shares in certain events. The "average market price", in respect of a particular dividend payment date, refers to the arithmetic average (calculated to four decimal places) of the daily volume weighted average trading prices of common shares on the Toronto Stock Exchange for the trading days on which at least one board lot of common shares is traded during the 10 business days immediately preceding the applicable dividend payment date. Such trading prices will be appropriately adjusted for certain capital changes (including common share subdivisions, common share consolidations, certain rights offerings and certain dividends). Shareholders resident outside of Canada are not entitled to participate in the Plan.

| **Common Shares Issued and Outstanding** | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | 133,941,749 | $ | 2,759.9 |
| Shares issued on public offering, net of issuance costs | 8,760,000 | | 287.9 |
| Shares issued for cash on exercise of options | 834,268 | | 20.8 |
| Deferred taxes on share issuance cost | — | | 3.3 |
| Shares issued under DRIP | 2,745,230 | | 96.2 |
| December 31, 2015 | 146,281,247 | | 3,168.1 |
| Shares issued on public offering, net of issuance costs | 14,685,000 | | 422.2 |
| Shares issued for cash on exercise of options | 275,625 | | 7.6 |
| Deferred taxes on share issuance costs | — | | 0.2 |
| Shares issued under DRIP | 3,799,702 | | 116.2 |
| **Issued and outstanding at September 30, 2016** | **165,041,574** | **$** | **3,714.3** |

**Preferred Shares**

| **Preferred Shares Series A Issued and Outstanding** | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | 8,000,000 | $ | 195.9 |
| Shares converted to Series B | (2,488,780) | | (60.9) |
| December 31, 2015 | 5,511,220 | | 135.0 |
| **Issued and outstanding at September 30, 2016** | **5,511,220** | **$** | **135.0** |

[TM] Denotes trademark of Canaccord Genuity Corp.

| Preferred Shares Series B Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | — | $ | — |
| Shares issued on conversion from Series A | 2,488,780 | | 60.9 |
| December 31, 2015 | 2,488,780 | | 60.9 |
| **Issued and outstanding at September 30, 2016** | **2,488,780** | **$** | **60.9** |

| Preferred Shares Series C Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | 8,000,000 | $ | 200.6 |
| December 31, 2015 | 8,000,000 | | 200.6 |
| **Issued and outstanding at September 30, 2016** | **8,000,000** | **$** | **200.6** |

| Preferred Shares Series E Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | 8,000,000 | $ | 195.8 |
| December 31, 2015 | 8,000,000 | | 195.8 |
| **Issued and outstanding at September 30, 2016** | **8,000,000** | **$** | **195.8** |

| Preferred Shares Series G Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | 8,000,000 | $ | 196.1 |
| December 31, 2015 | 8,000,000 | | 196.1 |
| **Issued and outstanding at September 30, 2016** | **8,000,000** | **$** | **196.1** |

| Preferred Shares Series I Issued and Outstanding | Number of shares | | Amount |
|---|---|---|---|
| January 1, 2015 | — | $ | — |
| Shares issued | 8,000,000 | | 200.0 |
| Share issuance costs, net of taxes | — | | (3.3) |
| December 31, 2015 | 8,000,000 | | 196.7 |
| **Issued and outstanding at September 30, 2016** | **8,000,000** | **$** | **196.7** |

**Share Option Plan**

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at September 30, 2016, 12,306,021 shares were reserved for issuance under the plan. As at September 30, 2016, options granted under the plan have a term between six and ten years until expiry and vest no longer than over a four-year period.

As at September 30, 2016, unexpensed fair value of share option compensation cost associated with future periods was $1.3 million (December 31, 2015 - $2.7 million).

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

| As at | **September 30 2016** | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | **Options outstanding** | | | Options outstanding | | |
| | **Number of options** | | **Exercise price[(a)]** | Number of options | | Exercise price[(a)] |
| Share options outstanding, beginning of period | **4,559,261** | **$** | **32.02** | 5,123,655 | $ | 30.28 |
| Granted | **76,500** | | **31.18** | 470,000 | | 36.94 |
| Exercised | **(275,625)** | | **25.20** | (834,268) | | 22.93 |
| Expired | **(74,875)** | | **34.13** | (19,125) | | 41.67 |
| Forfeited | **(87,125)** | | **36.42** | (181,001) | | 36.88 |
| **Share options outstanding, end of period** | **4,198,136** | **$** | **32.32** | 4,559,261 | $ | 32.02 |
| **Share options exercisable, end of period** | **2,981,009** | **$** | **29.46** | 3,009,946 | $ | 28.71 |

*(a) Weighted average.*

As at September 30, 2016, the aggregate intrinsic value of the total options exercisable was $16.5 million (December 31, 2015 - $12.0 million), the total intrinsic value of options outstanding was $16.9 million (December 31, 2015 - $12.2 million) and the total intrinsic value of options exercised was $2.1 million (December 31, 2015 - $12.0 million).

The following table summarizes the employee share option plan as at September 30, 2016:

| | Options outstanding | | | | Options exercisable | | |
|---|---|---|---|---|---|---|---|
| | Number outstanding | | Weighted average exercise price | Weighted average remaining contractual life | Number exercisable | | Weighted average exercise price |
| $14.24 to $18.00 | 182,750 | $ | 15.09 | 2.50 | 182,750 | $ | 15.09 |
| $18.01 to $25.08 | 600,600 | | 21.35 | 3.63 | 600,600 | | 21.35 |
| $25.09 to $50.89 | 3,414,786 | | 35.18 | 5.02 | 2,197,659 | | 32.87 |
| | **4,198,136** | **$** | **32.32** | **4.58** | **2,981,009** | **$** | **29.46** |

**Medium Term Incentive Plan (MTIP)**

AltaGas' MTIP for employees and executive officers includes two types of awards: restricted units (RUs) and performance units (PUs). Both RUs and PUs have vesting periods between 36 to 44 months from the grant date. Both RUs and PUs are valued based on the dividends declared during the vesting period and the weighted average share price of AltaGas' common shares multiplied by the units outstanding at the end of the vesting period. Upon vesting, the RUs and PUs are paid in cash or at the election of AltaGas, its equivalent in common shares purchased from the market. The PUs are also subject to a performance multiplier ranging from 0 to 2 dependent on the Corporation's performance relative to performance targets agreed between the Corporation and the employees.

| **Performance and Restricted Units** | **September 30, 2016** | December 31, 2015 |
|---|---|---|
| *(number of units)* | | |
| Balance, beginning of period | **409,037** | 282,817 |
| Granted | **22,383** | 196,770 |
| Vested and paid out | **(62,231)** | (71,883) |
| Forfeited | **(12,243)** | (7,133) |
| Units in lieu of dividends | **16,909** | 8,466 |
| Outstanding, end of period | **373,855** | 409,037 |

For the three and nine months ended September 30, 2016, the compensation expense recorded for the MTIP was $1.8 million and $5.1 million, respectively (2015 - $0.2 million and $2.5 million, respectively). As at September 30, 2016, the unrecognized compensation expense relating to the remaining vesting period was $12.5 million (December 31, 2015 - $12.6 million) and is expected to be recognized over the vesting period.

## 12. NET INCOME PER COMMON SHARE

The following table summarizes the computation of net income per common share:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Numerator: | | | | |
| Net income applicable to controlling interests | **$ 58.5** | $ 30.1 | **$ 153.6** | $ 94.7 |
| Less: Preferred share dividends | **(12.1)** | (10.3) | **(36.0)** | (30.5) |
| Net income applicable to common shares | **$ 46.4** | $ 19.8 | **$ 117.6** | $ 64.2 |
| Denominator: | | | | |
| *(millions)* | | | | |
| Weighted average number of common shares outstanding | **164.1** | 135.8 | **154.2** | 135.0 |
| Dilutive equity instruments[(a)] | **0.5** | 0.8 | **0.4** | 1.2 |
| Weighted average number of common shares outstanding - diluted | **164.6** | 136.6 | **154.6** | 136.2 |
| Basic net income per common share | **$ 0.28** | $ 0.15 | **$ 0.76** | $ 0.48 |
| Diluted net income per common share | **$ 0.28** | $ 0.14 | **$ 0.76** | $ 0.47 |

*(a) Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at September 30, 2016 and 2015.*

For the three and nine months ended September 30, 2016, 1.6 million and 2.2 million of share options, respectively (2015 – 1.7 million and 1.6 million, respectively) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

## 13. SUNDANCE B POWER PURCHASE ARRANGEMENTS (PPAs)

In the first quarter of 2016, ASTC Power Partnership (ASTC) exercised its right to terminate the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provisions of the Sundance B PPAs as a result of recent changes in law regarding the Alberta Specified Gas Emitters Regulation and as a result, AltaGas recognized a pre-tax provision of $4.0 million in the Consolidated Statement of Income under the line item ”Income (loss) from equity investments” in the first quarter of 2016 on its investment in ASTC to settle the working capital deficiency.

Under the Balancing Pool Regulation, the Balancing Pool is required to conduct an investigation and make a determination on ASTC’s right to terminate. On July 22, 2016, ASTC referred the matter to be resolved by binding arbitration pursuant to the dispute resolution provisions of the Sundance B PPAs (the Arbitration). On July 25, 2016 the Attorney General of Alberta filed an originating application for declaratory relief and judicial review which names ASTC as one of the respondents (the Originating Application). The Originating Application seeks, among other things, a determination as to the validity of certain aspects of the change in law provision as well as the circumstances under which a PPA buyer such as ASTC is entitled to terminate its PPA pursuant to that provision. To date the Balancing Pool has not confirmed termination of the Sundance B PPAs and proceedings relating to the Arbitration and the Originating Application remain ongoing. The outcome of the Originating Application may affect the resolution of the Arbitration. If ASTC is unable to terminate the Sundance B PPAs, AltaGas may be required to refund the Balancing Pool for its share of the net PPA costs incurred from March 8, 2016 to when the matter is resolved. As at September 30, 2016, no accrual has been recognized, but AltaGas estimates that the possible range of its share of the net PPA costs from March 8 to September 30, 2016 is between $nil and $27.0 million.

## 14. COMMITMENTS AND CONTINGENCIES

### Commitments

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

AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2016 to 2021, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines at the Blythe facility over 116,000 EOH/CT, or 20 years, whichever comes first. As at September 30, 2016, approximately $215.1 million is expected to be paid over the next 18 years, of which $56.3 million is expected to be paid over 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 $3.5 million per annum over the term of the contract for storage services.

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 $11.2 million over the next 6 years, of which $9.4 million is payable in the next five years.

**Guarantees**

On October 2014, Heritage Gas Limited, a wholly-owned subsidiary of AltaGas, entered into a throughput contract with the third party owners of the transportation facility for the use of their pipelines in the U.S. and Canada. The contract will commence at completion of the construction of the pipelines and it will expire 15 years thereafter. AltaGas has two guarantees outstanding that total US $91.7 million to stand by all payment obligations under the transportation agreement.

**Contingencies**

AltaGas is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators. On January 20, 2015, the AUC released a decision concerning the complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology used for the power distribution in Alberta. The AUC will proceed to determine the relief and remedies to be granted in accordance with its findings and conclusions regarding its authority and jurisdiction made in its decision. AltaGas is one of the respondents to the complaint and it has assessed that it may incur additional payments for transmission charges, but the timing and amount, or range of amounts, required to settle the claim cannot be estimated and, accordingly, no accrual of the loss contingency was recognized as at September 30, 2016.

## 15. PENSION PLANS AND RETIREE BENEFITS

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

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

| | **Three Months Ended September 30, 2016** | | | | | |
|---|---|---|---|---|---|---|
| | **Canada** | | **United States** | | **Total** | |
| | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** | **Defined Benefit** | **Post-retirement Benefits** |
| Current service cost | **$ 1.7** | **$ 0.2** | **$ 1.8** | **$ 0.5** | **$ 3.5** | **$ 0.7** |
| Interest cost | **1.4** | **0.2** | **2.9** | **0.9** | **4.3** | **1.1** |
| Expected return on plan assets | **(1.3)** | **(0.1)** | **(3.7)** | **(1.1)** | **(5.0)** | **(1.2)** |
| Amortization of net actuarial loss | **0.2** | **—** | **—** | **—** | **0.2** | **—** |
| Amortization of regulatory asset | **0.3** | **—** | **1.6** | **0.2** | **1.9** | **0.2** |
| Net benefit cost recognized | **$ 2.3** | **$ 0.3** | **$ 2.6** | **$ 0.5** | **$ 4.9** | **$ 0.8** |

| | Nine Months Ended September 30, 2016 | | | | | |
|---|---|---|---|---|---|---|
| | Canada | | United States | | Total | |
| | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits |
| Current service cost | $ 5.3 | $ 0.5 | $ 5.4 | $ 1.4 | $ 10.7 | $ 1.9 |
| Interest cost | 4.2 | 0.5 | 8.8 | 2.9 | 13.0 | 3.4 |
| Expected return on plan assets | (4.0) | (0.1) | (11.3) | (3.4) | (15.3) | (3.5) |
| Cost / income special events | — | — | 0.1 | — | 0.1 | — |
| Amortization of past service cost | 0.1 | — | — | — | 0.1 | — |
| Amortization of net actuarial loss | 0.6 | — | — | — | 0.6 | — |
| Amortization of regulatory asset | 0.9 | — | 4.8 | 0.6 | 5.7 | 0.6 |
| Net benefit cost recognized | $ 7.1 | $ 0.9 | $ 7.8 | $ 1.5 | $ 14.9 | $ 2.4 |

| | Three Months Ended September 30, 2015 | | | | | |
|---|---|---|---|---|---|---|
| | Canada | | United States | | Total | |
| | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits |
| Current service cost | $ 1.7 | $ 0.2 | $ 2.0 | $ 0.5 | $ 3.7 | $ 0.7 |
| Interest cost | 1.3 | 0.1 | 2.7 | 0.9 | 4.0 | 1.0 |
| Expected return on plan assets | (1.3) | — | (3.8) | (1.2) | (5.1) | (1.2) |
| Amortization of net actuarial loss | 0.5 | — | — | — | 0.5 | — |
| Amortization of regulatory asset | 0.4 | — | 1.1 | 0.2 | 1.5 | 0.2 |
| Net benefit cost recognized | $ 2.6 | $ 0.3 | $ 2.0 | $ 0.4 | $ 4.6 | $ 0.7 |

| | Nine Months Ended September 30, 2015 | | | | | |
|---|---|---|---|---|---|---|
| | Canada | | United States | | Total | |
| | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits | Defined Benefit | Post-retirement Benefits |
| Current service cost | $ 5.2 | $ 0.5 | $ 5.7 | $ 1.5 | $ 10.9 | $ 2.0 |
| Interest cost | 3.9 | 0.4 | 7.8 | 2.6 | 11.7 | 3.0 |
| Expected return on plan assets | (3.8) | (0.1) | (10.9) | (3.4) | (14.7) | (3.5) |
| Amortization of net actuarial loss | 1.5 | — | — | — | 1.5 | — |
| Amortization of regulatory asset | 1.1 | 0.1 | 3.2 | 0.5 | 4.3 | 0.6 |
| Net benefit cost recognized | $ 7.9 | $ 0.9 | $ 5.8 | $ 1.2 | $ 13.7 | $ 2.1 |

## 16. INCOME TAX EXPENSE

The effective income tax rates for the three and nine months ended September 30, 2016 were approximately 22.1 percent and 14.5 percent, respectively (2015 – 12.3 percent and 30.8 percent, respectively). The increase in the effective tax rate for the three months ended September 30, 2016 was attributable to a 2016 expense reimbursement deducted in a prior period as well as a higher equity income pick-up in 2015 which did not attract tax. The decrease in the effective tax rate for the nine months ended September 30, 2016 was mainly due to a tax recovery related to the sale of assets to Tidewater as discussed under Note 4 as well as a tax recovery of $2.6 million related to a previous impairment charge becoming tax deductible in the first quarter of 2016. The effective tax rate for the nine months ended September 30, 2015 was impacted by the increase in the Alberta corporate income tax rate from 10 percent to 12 percent effective July 1, 2015, which resulted in an additional $14.0 million of deferred income tax expense being recorded for the nine months ended September 30, 2015.

## 17. RELATED PARTY TRANSACTIONS

AltaGas has provided a $100.0 million interest bearing secured loan facility to Petrogas of which $50.0 million is committed. The facility is available for Petrogas to draw on from time to time for general corporate purposes. The facility is subject to annual renewal and has a maturity date of June 27, 2021. As at September 30, 2016, Petrogas had drawn $40.0 million under the facility, which has been recorded under the line item "Long-term investments and other assets" on the consolidated balance sheet. Interest income was $0.5 million for the three and nine months ended September 30, 2016. In addition, during the second quarter of 2016, AltaGas directly acquired $150.0 million of cumulative redeemable convertible preferred shares of Petrogas (see Note 7).

## 18. SUPPLEMENTAL CASH FLOW INFORMATION

The following table details the changes in operating assets and liabilities from operating activities:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Source (use) of cash: | | | | |
| Accounts receivable | **$ (36.4)** | $ (5.4) | **$ 77.4** | $ 143.8 |
| Inventory | **(37.3)** | (43.5) | **(39.1)** | 7.4 |
| Other current assets | **(10.4)** | (23.8) | **(2.3)** | (9.5) |
| Regulatory assets (current) | **(1.0)** | 3.5 | **2.2** | 12.4 |
| Accounts payable and accrued liabilities | **19.1** | 18.8 | **(54.8)** | (38.1) |
| Customer deposits | **7.2** | 11.7 | **(2.7)** | (1.3) |
| Regulatory liabilities (current) | **(0.9)** | (1.8) | **2.9** | 6.3 |
| Other current liabilities | **2.9** | 5.6 | **0.6** | (6.2) |
| Other operating assets and liabilities | **(7.7)** | (6.9) | **(40.0)** | (14.0) |
| Changes in operating assets and liabilities | **$ (64.5)** | $ (41.8) | **$ (55.8)** | $ 100.8 |

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

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| Interest paid (net of capitalized interest) | **$ 46.7** | $ 51.4 | **$ 116.8** | $ 110.3 |
| Income taxes paid | **$ 6.7** | $ 1.1 | **$ 29.7** | $ 14.8 |

## 19. 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 stronger first and fourth quarter results and weaker second and third quarters.

The power generation at the run-of-river hydro-facilities Forrest Kerr, Volcano Creek, and McLymont Creek occurs substantially from mid second quarter through early fourth quarter, resulting in weaker results in the first and fourth quarters.

## 20. SEGMENTED INFORMATION

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

| | |
|---|---|
| **Gas** | – NGL processing and extraction plants;<br>– transmission pipelines to transport natural gas and NGL;<br>– natural gas gathering lines and field processing facilities;<br>– purchase and sale of natural gas, including to commercial and industrial users;<br>– natural gas storage facilities;<br>– liquefied petroleum gas (LPG) development projects; and<br>– equity investment in a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents. |
| **Power** | – natural gas-fired, wind, biomass and hydro power generation assets, whereby outputs are generally sold under long term power purchase agreements, both operational and under development;<br>– energy storage currently under development; and<br>– sale of power to commercial and industrial users in Alberta. |
| **Utilities** | – rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and<br>– rate-regulated natural gas storage in Michigan and Alaska. |
| **Corporate** | – the cost of providing corporate services, financing and general corporate overhead, investments in public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts. |

The following tables show the composition by segment:

| | Three Months Ended September 30, 2016 | | | | | |
|---|---|---|---|---|---|---|
| | **Gas** | **Power** | **Utilities** | **Corporate** | **Intersegment Elimination**[(a)] | **Total** |
| Revenue | **$ 178.0** | **$ 168.5** | **$ 154.3** | **$ 3.2** | **$ (15.2)** | **$ 488.8** |
| Unrealized gains on risk management | **—** | **—** | **—** | **3.5** | **—** | **3.5** |
| Cost of sales | **(99.2)** | **(47.3)** | **(60.1)** | **—** | **10.6** | **(196.0)** |
| Operating and administrative | **(36.5)** | **(20.2)** | **(55.1)** | **(6.5)** | **4.7** | **(113.6)** |
| Accretion expenses | **(0.9)** | **(1.9)** | **—** | **—** | **—** | **(2.8)** |
| Depreciation and amortization | **(17.4)** | **(27.0)** | **(18.7)** | **(3.9)** | **—** | **(67.0)** |
| Income (loss) from equity investments | **(1.3)** | **2.4** | **0.5** | **—** | **—** | **1.6** |
| Other income (loss) | **0.5** | **(0.1)** | **0.4** | **1.7** | **(0.1)** | **2.4** |
| Foreign exchange gains | **—** | **—** | **—** | **0.1** | **—** | **0.1** |
| Interest expense | **—** | **—** | **—** | **(38.7)** | **—** | **(38.7)** |
| Income (loss) before income taxes | **$ 23.2** | **$ 74.4** | **$ 21.3** | **$ (40.6)** | **$ —** | **$ 78.3** |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[(b)] | **$ 31.0** | **$ 23.2** | **$ 24.6** | **$ 0.8** | **$ —** | **$ 79.6** |
| Intangible assets | **$ 0.5** | **$ 12.2** | **$ 0.6** | **$ 0.5** | **$ —** | **$ 13.8** |

*(a) Intersegment transactions are recorded at market value.*

*(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

| | Nine Months Ended September 30, 2016 | | | | | |
|---|---|---|---|---|---|---|
| | **Gas** | **Power** | **Utilities** | **Corporate** | **Intersegment Elimination[a]** | **Total** |
| Revenue | **$ 563.5** | **$ 432.0** | **$ 724.4** | **$ 10.1** | **$ (202.4)** | **$ 1,527.6** |
| Unrealized gains on risk management | **—** | **—** | **—** | **0.8** | **—** | **0.8** |
| Cost of sales | **(338.2)** | **(136.0)** | **(362.6)** | **—** | **187.9** | **(648.9)** |
| Operating and administrative | **(118.1)** | **(71.9)** | **(171.4)** | **(31.8)** | **14.9** | **(378.3)** |
| Accretion expenses | **(2.9)** | **(5.4)** | **—** | **—** | **—** | **(8.3)** |
| Depreciation and amortization | **(47.4)** | **(80.9)** | **(61.7)** | **(11.7)** | **—** | **(201.7)** |
| Income (loss) from equity investments | **3.3** | **(8.5)** | **1.8** | **—** | **—** | **(3.4)** |
| Other income (loss) | **4.5** | **—** | **1.4** | **2.8** | **(0.4)** | **8.3** |
| Foreign exchange gains | **—** | **—** | **—** | **3.6** | **—** | **3.6** |
| Interest expense | **—** | **—** | **—** | **(111.2)** | **—** | **(111.2)** |
| Income (loss) before income taxes | **$ 64.7** | **$ 129.3** | **$ 131.9** | **$ (137.4)** | **$ —** | **$ 188.5** |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[b] | **$ 168.2** | **$ 44.4** | **$ 68.6** | **$ 3.2** | **$ —** | **$ 284.4** |
| Intangible assets | **$ 1.7** | **$ 14.2** | **$ 1.5** | **$ 2.6** | **$ —** | **$ 20.0** |

*(a) Intersegment transactions are recorded at market value.*

*(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

| | Three Months Ended September 30, 2015 | | | | | |
|---|---|---|---|---|---|---|
| | Gas | Power | Utilities | Corporate | Intersegment Elimination[a] | Total |
| Revenue | $ 180.6 | $ 130.5 | $ 145.4 | $ — | $ (15.1) | $ 441.4 |
| Unrealized gains on risk management | — | — | — | 10.8 | — | 10.8 |
| Cost of sales | (90.1) | (45.1) | (58.4) | — | 13.7 | (179.9) |
| Operating and administrative | (51.2) | (18.4) | (56.3) | (10.0) | 1.8 | (134.1) |
| Accretion expenses | (0.9) | (1.8) | — | — | — | (2.7) |
| Depreciation and amortization | (16.1) | (15.0) | (19.1) | (2.7) | — | (52.9) |
| Provision on assets | — | (10.5) | — | — | — | (10.5) |
| Income (loss) from equity investments | 3.0 | (8.5) | 0.5 | — | — | (5.0) |
| Other income | — | — | 0.9 | 0.6 | (0.4) | 1.1 |
| Interest expense | — | — | — | (31.4) | — | (31.4) |
| Income (loss) before income taxes | $ 25.3 | $ 31.2 | $ 13.0 | $ (32.7) | $ — | $ 36.8 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[b] | $ 53.0 | $ 54.1 | $ 54.4 | $ 2.9 | $ — | $ 164.4 |
| Intangible assets | $ 0.4 | $ 10.9 | $ 1.0 | $ 1.5 | $ — | $ 13.8 |

*(a) Intersegment transactions are recorded at market value.*

*(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

| | Nine Months Ended September 30, 2015 | | | | | |
|---|---|---|---|---|---|---|
| | Gas | Power | Utilities | Corporate | Intersegment Elimination[a] | Total |
| Revenue | $ 642.8 | $ 344.9 | $ 756.1 | $ — | $ (132.5) | $ 1,611.3 |
| Unrealized gains on risk management | — | — | — | 1.6 | — | 1.6 |
| Cost of sales | (381.9) | (162.3) | (416.4) | — | 128.2 | (832.4) |
| Operating and administrative | (137.5) | (50.3) | (166.7) | (22.4) | 4.7 | (372.2) |
| Accretion expenses | (2.8) | (5.4) | — | — | — | (8.2) |
| Depreciation and amortization | (46.6) | (44.0) | (55.9) | (6.0) | — | (152.5) |
| Provision on assets | — | (10.5) | — | — | — | (10.5) |
| Income (loss) from equity investments | 1.3 | (8.1) | 1.4 | — | — | (5.4) |
| Other income | — | — | 2.4 | 3.3 | (0.4) | 5.3 |
| Foreign exchange gains | — | — | — | 0.4 | — | 0.4 |
| Interest expense | — | — | — | (91.6) | — | (91.6) |
| Income (loss) before income taxes | $ 75.3 | $ 64.3 | $ 120.9 | $ (114.7) | $ — | $ 145.8 |
| Net additions (reductions) to: | | | | | | |
| Property, plant and equipment[b] | $ 124.1 | $ 163.4 | $ 124.8 | $ 4.7 | $ — | $ 417.0 |
| Intangible assets | $ 1.5 | $ 20.2 | $ 2.1 | $ 11.5 | $ — | $ 35.3 |

*(a) Intersegment transactions are recorded at market value.*

*(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.*

The following table shows goodwill and total assets by segment:

| | Gas | Power | Utilities | Corporate | Total |
|---|---|---|---|---|---|
| **As at September 30, 2016** | | | | | |
| Goodwill | **$ 156.3** | **$ —** | **$ 689.6** | **$ —** | **$ 845.9** |
| Segmented assets | **$ 2,816.8** | **$ 3,497.0** | **$ 3,390.5** | **$ 247.8** | **$ 9,952.1** |
| As at December 31, 2015 | | | | | |
| Goodwill | $ 156.3 | $ — | $ 721.0 | $ — | $ 877.3 |
| Segmented assets | $ 2,449.0 | $ 3,579.9 | $ 3,576.7 | $ 493.9 | $ 10,099.5 |

## 21. SUBSEQUENT EVENTS

Subsequent events have been reviewed through October 19, 2016, the date these unaudited condensed interim Consolidated Financial Statements were issued. There were no subsequent events requiring disclosure or adjustment to the unaudited condensed interim Consolidated Financial Statements.

# Supplementary Quarterly Operating Information

(unaudited)

| | **Q3-16** | Q2-16 | Q1-16 | Q4-15 | Q3-15 |
|---|---|---|---|---|---|
| **OPERATING HIGHLIGHTS** | | | | | |
| **GAS** | | | | | |
| Total inlet gas processed (Mmcf/d)(1) | **1,275** | 1,083 | 1,222 | 1,298 | 1,293 |
| Extraction volumes (Bbls/d)(1) (2) | **65,509** | 58,065 | 64,408 | 65,465 | 30,241 |
| Frac spread - realized ($/Bbl)(1) (3) | **6.29** | 10.00 | 8.22 | 15.55 | 34.58 |
| Frac spread - average spot price ($/Bbl)(1)(4) | **6.29** | 10.62 | 8.22 | 5.06 | 11.11 |
| **POWER** | | | | | |
| Renewable power sold (GWh) | **670** | 544 | 142 | 310 | 488 |
| Conventional power sold (GWh) | **587** | 293 | 698 | 1,264 | 1,210 |
| Renewable capacity factor (%) | **70.2** | 56.8 | 10.5 | 30.2 | 57.5 |
| Contracted conventional availability factor (%) | **99.3** | 92.4 | 97.6 | 99.1 | 99.5 |
| **UTILITIES** | | | | | |
| Canadian utilities | | | | | |
| Natural gas deliveries - end-use (PJ)(5) | **3.2** | 4.8 | 12.3 | 10.2 | 3.3 |
| Natural gas deliveries - transportation (PJ)(5) | **1.1** | 1.5 | 1.8 | 1.9 | 1.6 |
| U.S. utilities | | | | | |
| Natural gas deliveries end use (Bcf) (5) | **5.4** | 10.3 | 28.2 | 20.2 | 5.9 |
| Natural gas deliveries transportation (Bcf) (5) | **11.0** | 11.8 | 14.2 | 13.5 | 10.5 |
| Service sites(6) | **568,628** | 568,606 | 570,681 | 568,751 | 562,301 |
| Degree day variance from normal - AUI (%)(7) | **(8.4)** | (28.0) | (18.5) | (10.0) | 3.9 |
| Degree day variance from normal - Heritage Gas (%)(7) | **(7.4)** | 3.6 | (6.9) | (8.0) | (42.0) |
| Degree day variance from normal - SEMCO Gas (%)(8) | **(57.6)** | 11.8 | (8.5) | (20.4) | (28.4) |
| Degree day variance from normal - ENSTAR (%)(8) | **(36.1)** | (26.4) | (21.0) | (6.1) | (9.6) |

*(1) Average for the period.*

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

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

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

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

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

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

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

# Other Information

**DEFINITIONS**

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

**ABOUT ALTAGAS**

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

For further information contact:

**Investment Community**
1-877-691-7199
investor.relations@altagas.ca