AltaGas
2015 Annual Report

Facets of Success

Facets of Success

This much is certain: the global demand for clean energy is increasing. The demand has many drivers and multidimensional solutions will be necessary. As a multifaceted energy infrastructure company, AltaGas is ready to meet the challenge.

We are focused on delivering clean and sustainable energy. We process and move natural gas. We generate power from clean and renewable sources. And through our utilities, we deliver clean energy to consumers. Throughout North America, we develop, construct, own, and operate energy infrastructure. One of our greatest strengths is in the relationships and partnerships we have built with companies, local communities, First Nations, and with our employees.

Today, North America presents a bright spectrum of opportunities for growth in clean energy infrastructure. Backed by a substantial, secure asset base and depth of expertise, AltaGas anticipates a strong future. We are profitable, growing, and positioned for success.

AltaGas operates in a safe, reliable manner in close partnership with First Nations and communities. We own and operate a diversified mix of gas, power, and utilities assets and we are continuing to grow in Canada and the United States.

Gas

- Gas Processing
- Gas Processing Under Development
- Gas Processing Under Construction
- Regional LNG Facility Under Construction
- LPG Under Development
- Storage Facility
- Storage Facility Under Construction

Power

- Coal-Fired Power Generation
- Wind Power Generation
- Hydro Power Generation
- Biomass Power Generation
- Gas-Fired Power Generation
- Gas-Fired Power Generation Under Development

Utilities

- Utilities

Our success has been driven by our employees' commitment and the support and trust of our shareholders.

At top: *AltaGas' 102-MW Bear Mountain Wind Park, British Columbia's first wind farm.*

At bottom: *AltaGas Utilities Inc. celebrating AltaGas' 20-year anniversary.*

Letter to Shareholders

This is my 22nd letter to AltaGas shareholders. It will also be my last as CEO of the company. As announced last year, I will be stepping down as CEO on April 15 of this year. I plan to remain as Chairman of the Board and will remain very active in strategy development, capital allocation regarding major investments, financial strategy, and stakeholder relationships. In addition to regular duties as Chairman, I will focus on ensuring our corporate culture is maintained and enhanced.

I hope you will humour me a little as this is my last letter to our shareholders. Over 22 years ago David Mackie, Scott Sarjeant, and I began working on developing a vision for the midstream business that became AltaGas.

The success we achieved was a result of our employees, and the support and trust of our shareholders. From the original 20 employees who blazed the trail at the beginning of AltaGas, to a number of early additional members of the team, we transformed the vision into a true operating company. A number of people made this possible, but to name a few: John McDonald, Patricia Newson and Dennis Dawson; in addition to the Bonnyville crew and Birch Wavy team, played a critical part of our early growth. The employees that joined us when we acquired AltaGas Utilities Inc. provided AltaGas with new skills and capabilities. Their knowledge, support, and hard work made possible all future growth in our utility business, which now serves more than 560,000 customers.

Some of the original employees who blazed the trail when AltaGas first started.

In 2001 we made our first investment in power generation. The team we built to manage this business helped AltaGas develop one of the best power portfolios in the country. Today AltaGas' focus is on renewable power generation and high-efficiency natural gas-fired generation required to support renewable power development.

We have a committed and talented group of employees. They will ensure AltaGas continues to grow and create value for shareholders and communities for years to come.

Our employees will continue to be trailblazers and deliver value to shareholders and communities.

Today, Western Canadian oil and gas producers are facing the toughest times in three decades. The weak commodity price environment coupled with the uncertain regulatory environment, are putting considerable strain on the customers of our gas division. We expect the next couple of years will be challenging for our oil and gas producing customers. We are working with them to become more productive, reduce costs and the environmental footprint, and to access new markets. We are making progress – but it will not be completed overnight.

At AltaGas we are proud of our vision to build a diverse business. More than 75 percent of the company's EBITDA is unrelated to the challenges facing the gas division and more than 50 percent of our EBITDA comes from the United States. This gives AltaGas strength unmatched by its peers and ensures the company's responsible growth plans will occur.

I want to thank the AltaGas shareholders who have supported the company over many years. I have met so many wonderful, intelligent, and interesting people in countless meetings. I enjoyed meeting with you and always came away wiser. In the Chairman's role, I plan to continue to meet with you to ensure the company and Board of Directors are meeting our responsibilities.

As a company, we are committed to working with First Nations to help them create long-term sustainable social value for their communities. I believe that in respecting, trusting, and listening to First Nation communities there is a path to sustainable development. I have seen it happen. Every human activity – whether it is trapping, fishing, logging; building a house, or road, or pipeline – will have some impact on the environment. We need development to ensure people prosper. As well, we need development to be sustainable for the community and the environment. We can meet this standard and we must move forward to create social value for all Canadians.

I want to thank the members of the Board of AltaGas who have served the company well. They steadfastly focused on making the company better and on delivering value to shareholders, employees, and communities. I have valued their counsel, advice, and questions over the past 22 years and look forward to continuing to work with many of them as Chairman of the Board.

I want to thank Myron Kanik for his support over many years. Myron will be leaving the Board and his role as Lead Director at the conclusion of this year's annual meeting. I will deeply miss our discussions and his advice.

Don McMorland, a pioneer in the Canadian natural gas industry, and one of AltaGas' first directors.

In my final letter, I also could not forget to mention one of the first AltaGas directors, Don McMorland. He was a great mentor of mine and a great friend of Myron's. Don's wisdom, smile, and laughter are still missed.

This journey would not have been possible without you. The future is bright and exciting. Thank you for all your support. I did the best I could, and hope to continue to contribute as Chairman of the Board and Founder.

Sincerely,

David W. Cornhill
Chairman and Chief Executive Officer

At top: *AltaGas works closely with First Nation communities to create long-term sustainable value for their communities.*

At bottom: *The 66-MW McLymont Creek Hydroelectric Facility, the last of AltaGas' Northwest Hydroelectric Facilities, began operation in 2015.*

Providing solutions from wellhead to tidewater.

At top: *AltaGas operates the Ferndale liquefied petroleum gas terminal near Ferndale, Washington. British Columbia presents opportunities to export propane from the West Coast, opening up new international markets for natural gas producers in Western Canada.*

At bottom: *In 2015, construction of the 198 Mmcf/d Townsend shallow-cut processing facility began, and is on track to be in service by mid-2016.*

Diverse Growth Opportunities

Over the next five years we are positioned to grow our three business segments and to expand our capabilities to provide clean and affordable energy to more customers.

As a diverse energy infrastructure company with a strong mix of gas, power, and utilities assets, AltaGas has strong opportunities for growth in each of its business segments.

AltaGas' midstream business is positioned to offer producers more options for market access and the potential for higher netbacks. By investing in natural gas processing and export infrastructure, we are working with producers to unlock the value of world class natural gas reserves in Western Canada. We provide solutions from wellhead to tidewater to serve Asian markets with clean energy, while maintaining access to traditional markets to the east or south.

We are doing this through the creation of a new energy hub in northeast British Columbia. Our strategic alliance with Painted Pony Petroleum Ltd. and our 198 Mmcf/d Townsend shallow-cut natural gas processing facility, under construction in the heart of the Montney natural gas play, are the first steps. We are also working on a liquids separation facility near Fort St. John, and the proposed Ridley Island Propane Export Terminal near Prince Rupert. This terminal could export propane from Western Canada and be a game changer for the industry.

AltaGas also has opportunities to grow its power business. In 2015 we grew it by approximately 50 percent to 2,041 MW, through the addition of natural gas-fired facilities in the western United States.

Power generation retirements, and the increasing demand and reliance on renewable power, are driving demand for flexible natural gas-fired generation across North America. AltaGas' strategically-located power assets are in key areas where the demand for cleaner energy is increasing, and we are well positioned to capitalize on opportunities. Our Blythe Energy Center in southern California can benefit from the ambitious climate initiatives that drive the state's need for flexible generation. Through the development of Blythe II and Blythe III, we can provide fast-start, flexible facilities to meet the California Independent System Operator's need for rapid starting units. The facilities could be paired with renewable opportunities that fit well with California's desired energy future. From a transmission perspective, these facilities may be situated to operate in a larger, potential Desert Southwestern regional transmission organization.

TOWNSEND
Expected in service mid-2016

~$1.3 BILLION OF ASSETS
BROUGHT INTO SERVICE IN 2015

AltaGas expects to grow its existing utility infrastructure through continued investment and capital improvements in franchise areas. This will result in rate base growth and continued customer growth, including converting users of alternative energy sources to natural gas. Driven by regulatory regimes that generally provide stable earnings and cash flows, AltaGas' utilities expect to achieve rate base growth in the range of 6 to 7 percent over the next five years.

~$600 MILLION
UNDER CONSTRUCTION
in our Gas and Utilities segments

RATE BASE GROWTH of
6–7 PERCENT
ON AVERAGE
over the
NEXT FIVE YEARS

Operational Excellence

It takes a talented, multidisciplinary team of highly-trained professionals to operate gas, power, and utilities assets in a safe, reliable manner across multiple jurisdictions. We are uncompromising in our approach to safety and we are collaborative in our approach to delivering solutions to customers.

AltaGas operates diverse assets across North America. We are an interdependent organization that leverages the experience and expertise of our more than 1,700 employees to drive consistency, best in class operations, and results across our three business segments. Our highly-trained professionals deliver certainty to our customers by ensuring our operations are safe, reliable, and efficient.

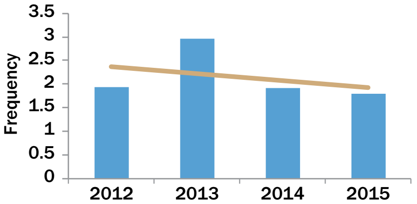
Above all else, safety is AltaGas' priority. We are committed to protecting employees, the public, and the environment at all of our operations and projects. Anyone performing work for AltaGas has the right and responsibility to stop any work that they see being completed in an unsafe manner. We believe all incidents are preventable and that we are each responsible for creating a safe work environment. In all of our business segments, we remain focused on our objective to drive down the number of incidents to zero.

At our major gas and power facilities, we are operating between 96 percent and 100 percent reliability. Our customers can count on AltaGas to deliver the products and services we have committed to delivering. We have a proven track record of optimizing, de-bottlenecking, and adding new lines of business to existing facilities, as well as finding cost competitive advantages for our customers.

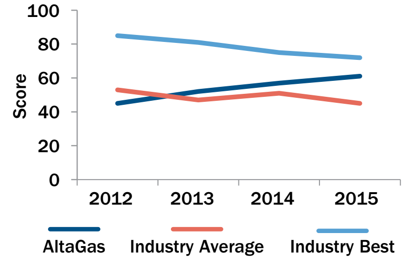
Our natural gas utilities deliver clean, reliable, and affordable natural gas to homes and businesses across North America. We are investing in technology such as Automated Meter Reading and Meter Data Management systems to improve reliability, accuracy, and customer satisfaction. By replacing or reinforcing aging pipelines, and by adding or refurbishing stations, we are maintaining the security of gas supply and improving system safety and reliability.

Through our established, proactive relationships with regulators and through our strong in-house engineering, procurement and construction expertise, AltaGas delivers value to its customers. We have established, and continue to develop, relationships with key vendors across our market segment. Our teams are structured to deliver quality, reliable projects at competitive prices.

Declining Total Recordable Injury Frequency



Improving DJSI[1] Assessment Performance

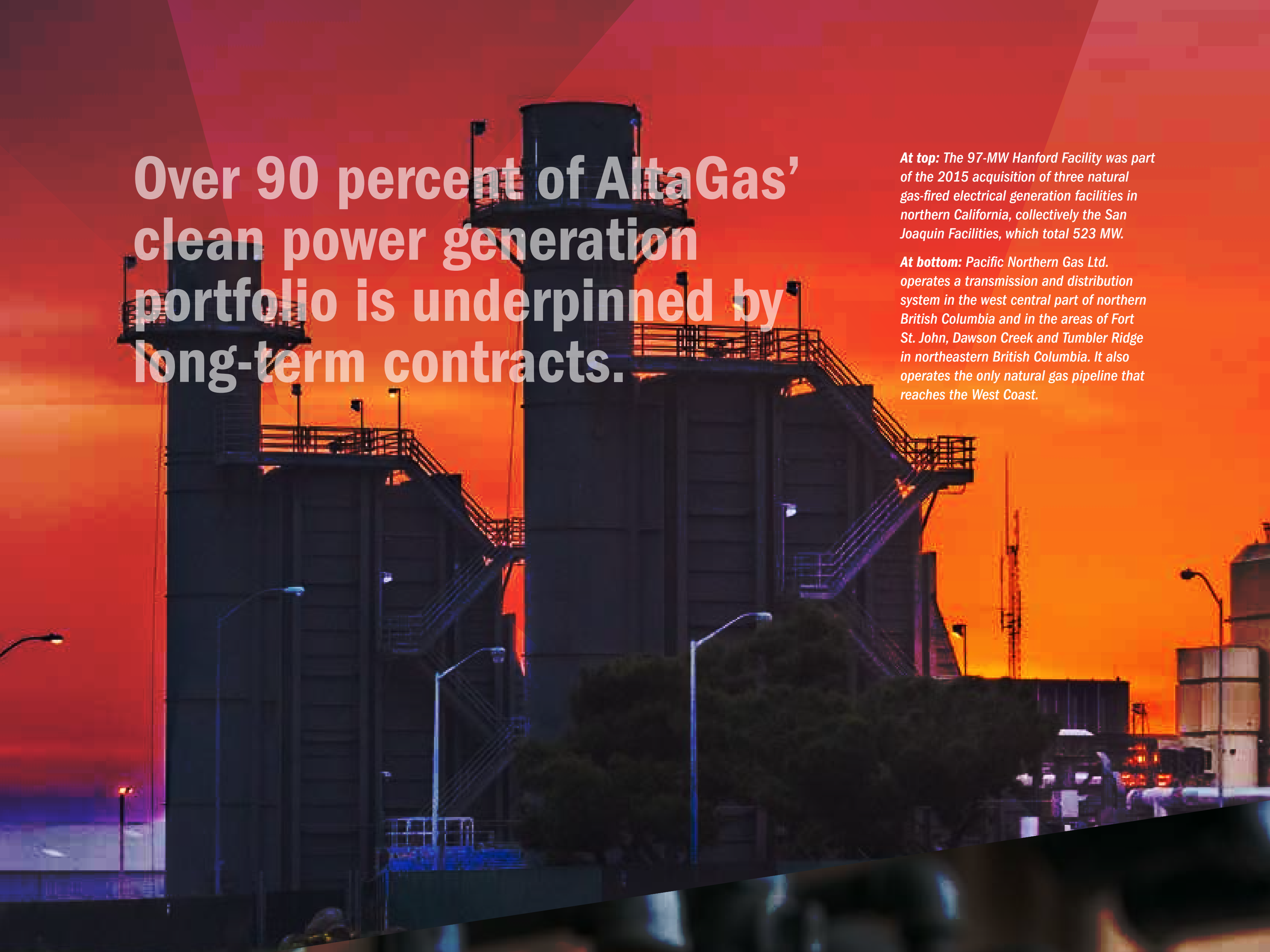


1 Dow Jones Sustainability Index. See "forward-looking statements & information"

Over 90 percent of AltaGas' clean power generation portfolio is underpinned by long-term contracts.

At top: *The 97-MW Hanford Facility was part of the 2015 acquisition of three natural gas-fired electrical generation facilities in northern California, collectively the San Joaquin Facilities, which total 523 MW.*

At bottom: *Pacific Northern Gas Ltd. operates a transmission and distribution system in the west central part of northern British Columbia and in the areas of Fort St. John, Dawson Creek and Tumbler Ridge in northeastern British Columbia. It also operates the only natural gas pipeline that reaches the West Coast.*



Disciplined Financing

Financial discipline and effective risk management are fundamental to our strategy to ensure that we have sufficient liquidity to meet our capital requirements, and to do so at the lowest cost possible.

AltaGas is one of the most diversified energy infrastructure companies among its peers, with assets in gas, power, and utilities. Over the last five years, we have grown our asset base to over $10 billion in 2015 from $3 billion in 2010. Our business segments are underpinned by highly contracted earnings, predictable and stable cash flows and low-risk assets. Our financial strength and flexibility provide strong returns, and balance yield and growth.

In 2016, we expect our normalized earnings before interest, tax, depreciation, and amortization (EBITDA) to grow by approximately 20 percent. Contracted power and regulated utilities are expected to count for approximately 75 percent of total 2016 EBITDA. The average term of our power contracts is 15 years. Our midstream business, which is over 95 percent contracted, makes up the remainder of expected 2016 EBITDA and almost half is through take-or-pay arrangements with an average term of about 13 years. AltaGas' contracted and regulated assets ensure solid, stable earnings and cash flow through economic cycles.

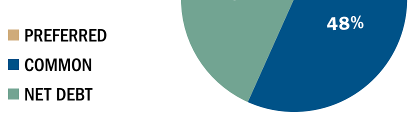
The dividend is also a key part of our value proposition. AltaGas has maintained one of the lowest dividend payout ratios in our peer group, while still achieving a compound annual growth rate of 7 percent over the last five years. In 2015, we grew the dividend by 12 percent and maintained a conservative payout ratio of 55 percent.

We have significant financial flexibility to fund our growth opportunities and we can control the timing of these opportunities. This is key, especially in turbulent times, when being nimble and financially strong are competitive advantages.

We exited 2015 with approximately $293 million in cash and $987 million available on our credit facilities. Maturity on the $1.4 billion syndicated credit facility was extended by one year to 2019. With just 48 percent debt to total capital at the end of 2015, and a BBB investment grade credit rating, we maintain good access to capital markets. We also have a well-balanced debt maturity profile, averaging over eight years in term.

Financial discipline is a key facet of AltaGas' success and we are well positioned with a competitive cost of capital and a diversified growth portfolio to continue to deliver shareholder and social value.

Strong Balance Sheet[1]



Achieved 78% TOTAL CUMULATIVE SHAREHOLDER RETURN over 5 Years

GREW EBITDA *by* 7% *in* 2015

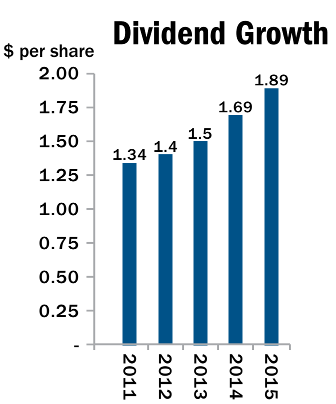
INCREASED DIVIDEND *by* 12% *in* 2015

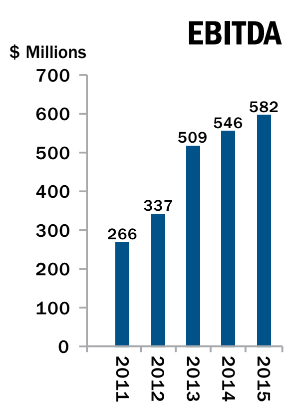
1 Updated for MD&A dated February 24.

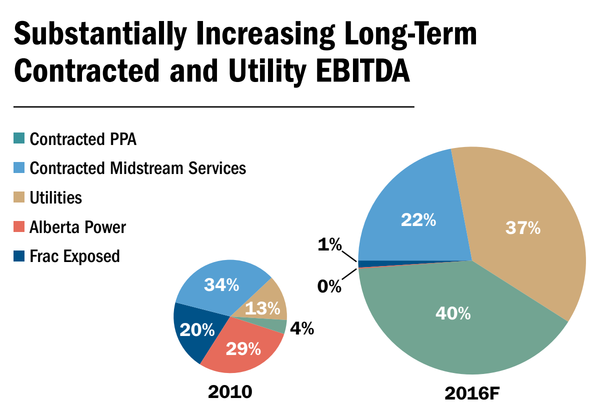
Five-Year Financial Highlights

($ millions except as indicated)	2015	2014	2013	2012	2011
					(Restated)[1]
Revenue	**2,193**	2,406	2,043	1,450	1,280
Net revenue[2]	**996**	1,019	960	665	513
Normalized EBITDA[2]	**582**	546	509	337	266
Normalized operating income[2]	**359**	366	353	235	184
Gas	**105**	167	113	94	99
Power	**106**	65	123	91	89
Utilities	**181**	166	150	80	28
Corporate	**(33)**	(32)	(33)	(30)	(32)
Net income applicable to common shares	**10**	96	182	102	83
Normalized net income[2]	**140**	165	176	110	90
Total assets	**10,100**	8,396	7,271	5,920	3,545
Total long-term liabilities	**4,949**	4,058	3,715	3,357	1,627
Net additions to property, plant and equipment	**1,150**	503	1,145	1,532	643
Dividends declared	**260**	215	174	133	112
Cash Flows					
Normalized funds from operations[2]	**470**	472	402	281	219
($ per basic share, except shares outstanding and debt to capitalization ratio)					
Normalized EBITDA[2]	**4.22**	4.31	4.38	3.55	3.16
Net income – basic	**0.07**	0.75	1.56	1.07	0.98
Net income – diluted	**0.07**	0.74	1.52	1.06	0.97
Normalized net income[2]	**1.02**	1.30	1.51	1.15	1.07
Dividends declared	**1.89**	1.69	1.50	1.40	1.34
Cash flows					
Normalized funds from operations[2]	**3.41**	3.72	3.47	2.96	2.61
Shares outstanding – basic (millions)					
During the period[3]	**138**	127	116	95	84
End of period	**146**	134	122	105	89
Debt-to-total capitalization ratio (%)	**48**	45	53	57	50

1 Financial information for 2011 was restated for the adoption of U.S. Generally Accepted Accounting Principles (GAAP)
2 Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of the MD&A
3 Weighted average







Strong Commitment to Social Value

Creating benefits in communities where we operate is a big part of our company and our beliefs. AltaGas has three guiding principles for developing energy infrastructure: Respect the land, share the benefits, and nurture long-term relationships.

AltaGas works collaboratively with communities to develop energy infrastructure projects. We strive to support communities in our operating areas by contracting directly with suitably qualified local vendors and by contributing to local causes through donations, sponsorships and volunteerism. Through initiatives such as our First Nations Contractor Program and unique agreements such as with the Indian Business Corporation, which promotes start-up First Nations-owned businesses, we continue to develop strong, long-term relationships with the First Nations communities.

AltaGas and its subsidiaries support many local non-profit and charitable organizations. In 2015, AltaGas and its subsidiaries contributed more than $1.4 million to over 520 organizations. The United Way is an important part of AltaGas' culture. Since 1994, AltaGas has received platinum or gold awards in Calgary. In 2015, AltaGas won the Spirits of Gold – President's Award from the United Way of Calgary and area. This award recognizes businesses that are long-standing partners with the United Way that show innovation and commitment in the community. We also continue to support STARS Air Ambulance, an important organization that brings trauma care to people living in rural areas in Western Canada.

In 2015, we renewed our support of Cross Country Canada and Canadian cross-country ski athletes. As part of our sponsorship, in 2016 the Canada-wide AltaGas Ski-at-School Program was launched to bring cross-country skiing to schools and students across Canada. The Program will knit together communities of teachers, students, and local ski clubs, and encourage children to participate in an active lifestyle through cross-country skiing.

Our company's success is the result of our dedicated and talented employees – we started with 20, and now have more than 1,700. We are committed to providing meaningful work, mentorship, opportunities for growth, and a safe working environment. In 2015, for the fifth consecutive year, AltaGas was named one of Canada's Top Employers for Young People, and for the tenth time, one of Alberta's Top Employers.

ALTAGAS is recognized as an EMPLOYER OF CHOICE in CANADA and ALBERTA

Our Aboriginal engagement policy guides decision making across the company. AltaGas is committed to building long-term, mutually beneficial working relationships with Aboriginal peoples, while recognizing and respecting individual values and traditions.

IMAGES AT RIGHT:

At top: *AltaGas has proudly sponsored Cross Country Canada since 2007 and is excited to continue with them along their journey to the 2018 Winter Olympics. PHOTO CREDIT: NORDIC FOCUS.*

At middle: *The Northwest Projects' grand opening ceremony was held on June 2, 2015. AltaGas' Board of Directors, executive team and employees were present to welcome guests from the Tahltan Nation, the BC Government, representatives from BC Hydro, and the many contractor companies who worked on the project.*

At bottom: *Calgary-based Seniors Secret Service coordinates programs designed to enhance the quality of life for seniors who are alone or isolated in the community. In an effort to spread holiday cheer, AltaGas staff helped assemble emergency hampers to ensure all seniors participating in the Secret Santa program received gifts in 2015.*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Corporate Governance

Myron F. Kanik
Lead Director

Independent Director;
Chair of the GC and
Member of the HRCC[1]

The members of the Board of Directors of AltaGas Ltd. are elected by the shareholders to manage, or supervise the management of, its business and affairs. It is the responsibility of the Board of Directors to ensure that the interests of shareholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for the stewardship of, and accountability at, AltaGas, and developed standards and procedures for its operations that meet a high standard of governance. The Board of Directors regularly reviews AltaGas' activities, with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that shareholders expect. The Board of Directors is committed to continuously meeting those high standards.

The annual meeting of shareholders provides AltaGas' executives with the opportunity to communicate AltaGas' goals and strategy to shareholders. The meeting offers shareholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase shareholder value and grow AltaGas. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting of shareholders, either in person in Calgary or through the live webcast that can be viewed at **altagas.ca**.

The annual meeting will be held at 3:30 p.m. MDT on April 20, 2016 at The Calgary Petroleum Club, 319 - 5 Avenue SW, Calgary, Alberta.

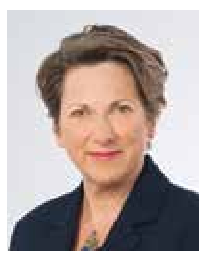
On behalf of the Board of Directors,

Myron F. Kanik
Lead Director

David W. Cornhill
Chairman and
Chief Executive Officer[2]

Catherine M. Best
Director

Independent Director;
Member of the AC
Member of the EOHSC[3]



Victoria A. Calvert
Director

Independent Director;
Member of the GC

Allan L. Edgeworth
Director

Independent Director;
Chair of the EOHSC
Member of the AC

Hugh A. Fergusson
Director

Independent Director;
Member of the AC
and HRCC

Daryl H. Gilbert
Director

Independent Director;
Chair of the HRCC and
Member of the EOHSC

Robert B. Hodgins
Director

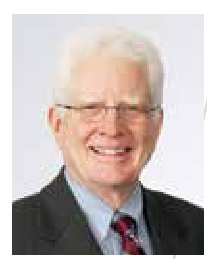
Independent Director;
Chair of the AC and
Member of the GC

Phillip R. Knoll
Director

Independent Director;
Member of the EOHSC

David F. Mackie
Director

Independent Director;
Member of the GC
and HRCC



M. Neil McCrank
Director

Independent Director;
Member of the GC
and EOHSC[4]

1 Mr. Kanik is not standing for re-election at the annual meeting
2 Mr. Cornhill has announced his intention to retire as CEO effective April 15, 2016
3 Effective April 1, 2016, Ms. Best will cease to be a member of the EOHSC and will become a member of the HRCC
4 If re-elected, Mr. McCrank will become Lead Director following the annual meeting, and will become Chair of the GC effective May 1, 2016

Statement of Governance Practices

AltaGas is committed to a high standard of governance in the belief that it improves performance and benefits all shareholders. The following is a summary of AltaGas' governance practices. A more detailed description can be found in AltaGas' Management Information Circular filed on the SEDAR system at www.sedar.com and posted on AltaGas' website at www.altagas.ca.

Mandate of the Board of Directors

The Board of Directors exercises responsibility for the management and supervision of the affairs of AltaGas. This includes the appointment and monitoring of the Chief Executive Officer, the appointment of other senior officers, and the approval of their compensation.

The Board of Directors also reviews and approves the annual strategic plan, which includes key objectives, quantifiable operational and financial targets, and processes for the identification, monitoring and mitigation of principal business risks.

The Board of Directors also establishes a succession plan that includes the appointment, training and monitoring of senior management.

The independent Directors of AltaGas meet in the absence of management and non-independent Directors at each meeting of the Board of Directors.

Composition of the Board of Directors

David W. Cornhill, Chairman and Chief Executive Officer of AltaGas, is the only member of the Board of Directors who is considered not to be independent, as he is a member of management up to his announced retirement date of April 15, 2016, and subsequent to that date will have been a member of management within the prior three years. Myron F. Kanik is the Lead Director up to the time of the annual meeting, and following the annual meeting M. Neil McCrank, if re-elected, will be the Lead Director.

Committees of the Board of Directors

The Board has four standing committees: Governance Committee (GC); Audit Committee (AC); Environment, Occupational Health and Safety Committee (EOHSC); and Human Resources and Compensation Committee (HRCC). The GC, AC, EOHSC, and HRCC are composed exclusively of independent directors. Each of the committees has a mandate that prescribes its composition and responsibilities and that is approved by the Board of Directors.

Governance Committee

The GC reviews Board performance and provides recommendations for improvement with respect to all aspects of governance. The GC identifies and recommends individuals qualified to become members of the Board of Directors. It reviews and recommends compensation for Directors and, on an annual basis, formally assesses the effectiveness of the Committees and the Board of Directors. The GC is also responsible for the orientation and education of new Board members and continuing development of existing members.

The Chair of the GC is Myron F. Kanik, an energy industry consultant and former President of the Canadian Energy Pipeline Association and Deputy Minister in the Alberta Department of Energy. Mr. Kanik is not standing for re-election at the annual meeting and M. Neil McCrank, if re-elected, will become Chair of the GC effective May 1, 2016.

Audit Committee

The AC consists of independent and financially literate Directors who oversee AltaGas' financial reporting process. It reviews and provides recommendations to the Board of Directors on annual and interim financial statements, and examines the adequacy of its risk management processes and internal control system for financial reporting and disclosure.

The AC approves the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every meeting, the AC has the opportunity to meet with the independent and internal auditors without management present.

The Chair of the AC is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Corporation, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada Pipelines Limited.

Environment, Occupational Health and Safety Committee

The EOHSC is responsible for reviewing, reporting and making recommendations to the Board of Directors on AltaGas' policies and procedures with respect to the environment and occupational health and safety.

AltaGas is committed to the health and safety of its employees and to being a steward of the environment.

The Chair of the EOHSC is Mr. Allan L. Edgeworth, an energy industry consultant and former President and Chief Executive Officer of Alliance Pipeline Ltd.

Human Resources and Compensation Committee

The HRCC reviews, reports and provides recommendations to the Board of Directors on the compensation of the Chief Executive Officer, and the appointment and compensation of senior corporate officers. It also reviews succession plans, the compensation policy for all other employees and the approval of all grants of equity-based compensation, including share options.

AltaGas is committed to operating its businesses in an ethical manner. AltaGas has a Code of Business Ethics, which can be viewed on our website.

The Chair of the HRCC is Daryl H. Gilbert, a Managing Director with JOG Capital Inc. and prior to that Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., consultants in reserves evaluation.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and 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 year ended December 31, 2015. This MD&A dated February 24, 2016, should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of AltaGas as at, and for the year ended December 31, 2015.

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

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "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 others things, business objectives, the anticipated benefits of acquisitions and other major projects, the anticipated timing of commercial operations, investment decisions, expenditures, 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: "Overview of the Business", "2015 Growth Highlights", "AltaGas Vision and Objective", "Strategy", "Owning and Operating Energy Infrastructure", "Strategy Execution", "2016 Outlook" and "Growth Capital" and under those headings specifically include AltaGas' expectations relating to natural gas supply, demand for clean energy and resulting opportunities for growth across all of AltaGas' business segments including prospects for growth of the gas segment in British Columbia and Alberta and potential opportunities to expand the power segment in California and across the U.S. and to develop new gas-fired and renewable generation in Alberta to replace coal; the potential for growth through increasing throughput at facilities and increasing interest in existing plants; the potential for growth through acquisition and development of energy infrastructure and the expectation that such growth in infrastructure will enable AltaGas to establish a western energy hub in northeast British Columbia providing access to export markets off the West Coast and access to new markets and higher netbacks to producers in the WCSB; expectations relating to the Townsend Facility and related projects including progress of construction, expected costs, expected in service date, impact on earnings, capacity and connection capability of egress lines with Townsend Facility and truck terminal; AltaGas' belief that investing in low-risk, long-life energy assets will generate superior economic returns; AltaGas' expectations regarding diversification including impact on earnings and cash flow and exposure to commodity market volatility; expectations that expansion of business through acquisitions and organic growth will support dividend and capital growth; expectations that AltaGas will acquire or build gathering and processing infrastructure from, or on behalf of, producers wishing to redeploy capital to exploration and production activities rather than to non-core activities such as gas processing; AltaGas' belief that producers will seek to conserve capital and monetize non-core assets; AltaGas' potential to move natural gas and NGLs to key markets including Asia, AltaGas' ability to provide a fully-integrated midstream service offering to its customers across the energy value chain; expectations that AltaGas is in a position to deliver higher netbacks to producers for NGL by establishing a western energy hub in northeast British Columbia, through its ownership interest in Petrogas and the Ferndale Terminal and the development of the proposed Ridley Island Propane Export Terminal; AltaGas' plan to focus its resources on operating and optimizing AltaGas' larger plants and developing large scale opportunities as part of its northeast British Columbia strategy; expectations that natural gas-fired power generation will provide critical load balancing across North America; expectations regarding the decommissioning of nuclear and coal-fired generation; expectations that renewable power and natural gas-fired power generation will replace nuclear and coal-fired power generation and that AltaGas is in a position to take advantage of such replacement opportunities; expectations for rate base growth in the utilities segment including through the execution of strategic utility acquisitions and addition of customers; expectations that AltaGas' in-house construction expertise provides a competitive advantage; expectations for the increased use of natural gas, providing opportunities for AltaGas to invest in and optimize assets; expectations regarding the decrease in U.S. demand for import of gas, NGLs and crude oil and impact that has on netbacks for Canadian producers; AltaGas' belief that energy market diversification is critical for Canadian producers; expectations regarding the supply of NGL and natural gas reserves, demands from Asia for such products and opportunities such supply and demand presents for investing in infrastructure outside of North America; expectations that AltaGas is uniquely positioned to provide a competitive service to producers; AltaGas' ability to develop the proposed Ridley Island Propane Export Terminal, to operate LPG export terminals and to *provide multiple outlets for producers to access the highest value markets; expectations that access to Asian markets provides diversity to producers; expectations relating to AltaGas' access to Asian markets, through AltaGas' relationship with Idemitsu; expectations for opportunities arising from increased demand for clean sources of power and that AltaGas is in a position to take advantage of such opportunities; expectations regarding expansion and re-contracting opportunities and that AltaGas is in a position to take advantage of such opportunities including in northern California as a result of the acquisition of the San Joaquin Facilities and Ripon and in southern California as a result of the optionality provided by the location of the Blythe Energy Center, Blythe II and Blythe III and if CAISO becomes the Regional Transmission Organization incorporating Nevada and Arizona; expectations regarding the ability of the Blythe Energy Center, Blythe II and Blythe III to contract with multiple utilities and others, serve multiple markets, increase generating capacity and to deliver generation to customers in CAISO and other neighbouring states; expectations regarding Pomona including future bid plans and the ability to transition to merchant market; expectations for growth in the utilities segment as a result of expansion of and investment in existing distribution systems, acquisition of new franchises, fuel switching and development of natural gas storage opportunities; expectations relating to PNG's rates and timing of final decisions to be made by BCUC; expectations that advancing energy export opportunities will provide higher netbacks to producers; expectations with respect to the development of the proposed Ridley Island Propane Export Terminal including development costs, initial shipment capacity and timing of final investment decision and commercial operations; expectations relating to the development of the northeast British Columbia Liquids Separation Facility including connection capability to rail, existing AltaGas infrastructure and the proposed Ridley Island Propane Export Terminal, facility specifications and cost and timing of final investment decision; expectations that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise; expectations relating to the San Joaquin Facilities including strengthening AltaGas' overall California market position, expected contributions to growth and impact on earnings; expectations relating to the Northwest Hydro Facilities including expected contributions to earnings and seasonality impacts; expected impact on earnings of dispositions of non-core gas assets; expectations regarding Petrogas including plans for growth and earnings, expectations regarding commodity prices and commodity hedging; expectations regarding the US dollar; expected earnings from the utilities segment including from SEMCO Gas as a result of its Main Replacement Program; and expectations with respect to the Alton Natural Gas Storage Project including expected natural gas storage capacity, timing of completion of construction and in service date, expected reduction in natural gas price volatility and expectations that the project will provide security of gas supply, enhanced reliability and delivery of natural gas for customers of Heritage Gas.*

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

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

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

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, Annual Information Form, Management Information Circular, material change reports and press releases, are also available through AltaGas' website or through 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' business strategy is underpinned by strong growth in natural gas supply and the growing demand for clean energy. More than 1,700 employees across North America are focused on executing AltaGas' strategy through three business segments:

- Gas, which transacts more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids 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). The Gas segment has significant prospects for growth in British Columbia and Alberta;
- Power, which includes generation assets located across North America with more than 2,000 MW of capacity from five fuel types, with significant opportunities to expand in California and across the United States, as well as the potential opportunity to develop new gas-fired and renewable generation in Alberta to replace coal; 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.

As at December 31, 2015, AltaGas' enterprise value exceeded $9 billion. With the physical and economic links along the energy value chain, primarily from wellhead to burner tip, together with its experienced and talented workforce and its efficient, reliable and profitable assets, market knowledge and financial discipline, AltaGas has provided strong, stable and predictable returns to its investors. AltaGas focuses on maximizing the profitability of its assets, adding services that are complementary to its existing business segments, and growing through the acquisition and development of energy infrastructure, including infrastructure required to provide access to new markets and higher netbacks to producers in the Western Canadian Sedimentary Basin (WCSB) by establishing a western energy hub in northeast British Columbia with access to export markets off the West Coast.

2015 GROWTH HIGHLIGHTS

- Completed the acquisition of three natural gas-fired electrical generation facilities in northern California totaling 523 MW (collectively, the San Joaquin Facilities), including the 330-MW Tracy, the 97-MW Hanford and the 96-MW Henrietta facilities in November 2015;
- Completed 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 January 2015;
- Began construction of the 198 Mmcf/d Townsend shallow-cut processing facility (Townsend Facility), which is on track to be in service by mid-2016. Completed construction of the 25 km gas gathering line and started work on two liquids egress lines and a truck terminal on the Alaska highway;
- Signed a sublease and related agreements with Ridley Terminals Inc. (Ridley Terminals) to develop, build, own and operate a proposed propane export terminal (the Ridley Island Propane Export Terminal), which is to be located on a portion of land leased by Ridley Terminals from the Prince Rupert Port Authority (PRPA) on Ridley Island near Prince Rupert, British Columbia;
- Continued the development of a liquids separation facility near Fort St. John, British Columbia;
- Increased the number of shipments from the Ferndale liquefied petroleum gas (LPG) terminal (the Ferndale Terminal), which is owned by Petrogas and operated by AltaGas, from 8 ships in 2014 to 13 ships in 2015;
- Achieved commercial operations at the 66-MW McLymont Creek Hydroelectric Facility (McLymont) in October 2015;
- Declared the 15-MW Cogeneration III (Cogeneration III) at the Harmattan extraction plant (Harmattan) in-service in the fourth quarter 2015; and
- Received regulatory approval of the Main Replacement Program (MRP) at SEMCO Gas resulting in increased rates.

2015 FINANCIAL HIGHLIGHTS[1]

- Normalized EBITDA was $582 million in 2015, a 7 percent increase compared to $546 million in 2014;
- Normalized funds from operations was $470 million ($3.41 per share) in 2015, compared to $472 million ($3.72 per share) in 2014;
- Net revenue was $996 million in 2015, compared to $1 billion in 2014;
- Net debt was $3.9 billion as at December 31, 2015, compared to $2.9 billion as at December 31, 2014;
- Debt-to-total capitalization ratio was 48 percent as at December 31, 2015, compared to 45 percent as at December 31, 2014;
- On April 14, 2015, issued US$125 million senior unsecured medium-term notes (MTNs). The notes carry a floating coupon rate of three month LIBOR plus 0.85 percent and mature on April 17, 2017;
- On April 30, 2015, AltaGas announced an increase in its dividend of $0.0125 per common share per month to $0.160 and on September 21, 2015, AltaGas announced an increase in its dividend of $0.005 per common share per month to $0.165, which collectively represent a 12 percent increase in the dividend over 2014;
- On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million;
- On November 23, 2015, AltaGas closed a public offering of 8,000,000 Cumulative Redeemable 5-Year Minimum Rate Reset Preferred Shares, Series I, at a price of $25.00 per Series I Preferred Share for aggregate gross proceeds of $200 million; and
- On December 4, 2015, AltaGas extended the maturity of its $1.4 billion syndicated credit facility by one year to December 15, 2019.

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

ALTAGAS' VISION AND OBJECTIVE

AltaGas' vision is to be a leading North American diversified energy infrastructure company. The Corporation's overall objective is to generate superior economic returns by investing in low-risk, long-life energy assets. The Corporation focuses on assets underpinned by contracts with strong counterparties and regulated assets, both of which provide stable utility-like returns and long-life cash flows. Diversification increases the stability of earnings and cash flows and reduces AltaGas' exposure to commodity market volatility. AltaGas' earnings are underpinned by three business segments, and within each segment there is further diversification: by customer and service type in the Gas segment; by fuel source, customer, and geography within the Power segment; and by regulatory jurisdiction in the Utilities segment. The Corporation also focuses on expanding its business through acquisitions and organic growth to further support dividend and capital growth. AltaGas believes that, in the long term, the abundant supply of natural gas in North America and the increasing global demand for clean energy will continue to provide opportunities for sustained growth across all of its business segments. Superior service, safety, and reliability are also integral to AltaGas' customer value proposition.

STRATEGY

AltaGas' strategy is to execute opportunities created by the renaissance of natural gas in North America and the increasing global demand for clean energy, by owning and operating a diversified mix of assets in gas, power, and utilities.

In the Gas segment, AltaGas' strategy is to provide a fully-integrated midstream service offering to its customers across the energy value chain. As part of this strategy, the Corporation builds and acquires gathering and processing infrastructure on behalf of, or from producers wishing to redeploy capital to exploration and production activities, rather than to non-core activities such as gas processing. The currently depressed commodity market conditions are accelerating this trend as producers seek to conserve capital and monetize non-core assets. AltaGas seeks to move natural gas and natural gas liquids (NGL or NGLs) to key markets, including Asia. AltaGas is uniquely positioned to deliver higher netbacks to producers for NGL by establishing a western energy hub in northeast British Columbia, through its ownership interest in Petrogas and the Ferndale Terminal, and through its proposed Ridley Island Propane Export Terminal currently under development. AltaGas is focused on developing and operating larger gas infrastructure projects. On February 2, 2016, AltaGas announced 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. The sale is part of a plan to focus resources on operating and optimizing AltaGas' larger plants and developing larger scale opportunities as part of the northeast British Columbia strategy.

The Power segment is focused on building, owning, and operating a diversified portfolio of clean energy assets that reduce the Corporation's carbon footprint and on meeting North America's demand for clean energy. There is a particular focus on natural gas-fired power generation, which is expected to provide critical load balancing across North America, as significant nuclear and coal-fired power generation is expected to be decommissioned over the next decade and be replaced by renewable power and natural gas-fired power generation. AltaGas is positioned to take advantage of this opportunity.

In the Utilities segment, the Corporation is focused on finding innovative ways to continue to safely and reliably deliver clean and affordable natural gas to more customers. AltaGas focuses on growing rate base through adding customers, including serving power plants within service jurisdictions, and improving and upgrading existing infrastructure to meet increased residential and commercial demand. The Corporation also seeks to execute strategic utility acquisitions and dispositions when opportunities arise.

Integral to AltaGas' strategy is maintaining financial strength and flexibility, an investment grade credit rating, and ready access to capital markets.

AltaGas strives to employ the best available practices and technologies for integrity management systems, and maintenance and operations, in order to mitigate risks to customers, the public, employees and the environment. AltaGas' number one core value is to operate in a safe and reliable manner. AltaGas has the internal capabilities and resources to safely deliver capital projects on time and on budget, in close partnership with First Nations and community stakeholders. AltaGas has significant in-house construction expertise, demonstrated by the successful completion of more than $1.7 billion in projects over the last few years, which provides a significant competitive advantage. Cost efficiency and strong operating performance are the drivers for increasing value as the Corporation continues to build out its portfolio of assets. Key initiatives continue to increase proficiency in managing costs and include changes to cost tracking systems and implementing best practice procurement strategies.

Consistent with its mandate of overseeing and directing the Corporation's strategic direction, AltaGas' Board of Directors (Board of Directors) reviews the Corporation's strategy on an annual basis. The Corporation continually assesses the macro- and micro-economic trends impacting its business and seeks opportunities to generate value for shareholders, including acquisitions, dispositions or other strategic transactions. Opportunities pursued by AltaGas must meet strategic, operating and financial criteria.

Owning and Operating Energy Infrastructure

Natural gas supply and demand fundamentals and the demand for clean energy have consistently underpinned the Corporation's strategy. In recent years, the supply and demand fundamentals have been changing. Abundant supply of natural gas in North America, driven by new technology that has improved the economics of unconventional gas plays, has been positive news for North American energy consumers and has led to renewed interest in natural gas as an economically priced, clean-burning fuel. As a result, the use of natural gas for power generation, household, and commercial and industrial uses has increased substantially, providing significant opportunities across AltaGas' Gas, Power and Utilities segments to invest in and optimize assets.

Canada produces a surplus of gas, NGL and crude oil. The U.S. has traditionally been the sole export market for this surplus, but with the U.S. now having a surplus of these products, its demand for import of these products has decreased. As a result, netbacks have been less attractive for Canadian producers. AltaGas believes that energy market diversification is critical for Canadian producers. Investing in infrastructure for export outside of North America provides an opportunity for Canadian producers to align the vast supply of NGL and natural gas reserves with the growing demand from Asia. AltaGas is uniquely positioned to provide producers with a competitive service offering across the integrated value chain, from wellhead to coast. Access to Asian markets provides market diversity to producers, especially those in the vast Montney and Duvernay basins under development in northeastern British Columbia and western Alberta. With the development of the proposed Ridley Island Propane Export Terminal, AltaGas will be in a position to provide multiple outlets for producers to deliver their products to the highest value markets. AltaGas is an experienced operator of LPG export terminals and operates the Ferndale Terminal. AltaGas has access to Asian markets through its relationship with Idemitsu Kosan Co.,Ltd. (Idemitsu) who owns 51 percent of Astomos Energy Corporation, the largest LPG importer in Japan.

There has been an increase in the demand for clean sources of power to reduce greenhouse gas emissions due to increased regulations. Such regulations necessitate significant development of natural gas-fired and renewable generation. AltaGas is positioned to take advantage of this opportunity. In California, the California Independent System Operator (CAISO) has stated that up to 13,000 MW of fast ramping flexible capacity is required to meet the needs of the current 33 percent Renewable Portfolio Standard (RPS) of California by 2020. In October 2015, the State of California amended the RPS, increasing the RPS standard to a 50 percent renewables target by 2030. The CAISO has yet to announce the anticipated additional generation required to meet the 50 percent RPS. In northern California, the Corporation is focused on owning generation assets in locally constrained areas near load pockets as local resource adequacy needs result in more opportunities for expansion and re-contracting. AltaGas is well positioned in northern California with the acquisition of the San Joaquin Facilities and Ripon in 2015. In southern California, AltaGas is well positioned at the convergence of transmission lines with multiple options available for contractual counterparties. The Blythe Energy Center along with potential expansions of Blythe II and Blythe III are in a position where generation can be delivered to customers in the CAISO, and other neighboring states such as Arizona in the Western Area Power Authority (WAPA). Further development and expansion opportunities could arise if CAISO becomes the Regional Transmission Organization incorporating Nevada and Arizona.

Within the Utilities segment, growth is expected through expansion of the existing distribution systems to acquire new customers; acquisition of new franchises when it is cost effective or strategic to do so; fuel switching as abundant natural gas provides a clean low-cost energy alternative and investment in existing distribution systems to ensure safe, reliable service for AltaGas' customers. Also, there is a natural gas storage opportunity currently under construction in Nova Scotia to increase reliability of supply to AltaGas' natural gas distribution customers in that area.

Maintain Financial Strength and Flexibility

Financial discipline and effective risk management are fundamental cornerstones of the Corporation's strategy. AltaGas seeks to optimize risk and reward, ensuring that returns are commensurate with the level of risk assumed. AltaGas' financing strategy is to ensure the Corporation has sufficient liquidity to meet its capital requirements and to do so at the lowest cost possible. As a growth-oriented energy infrastructure company, AltaGas creates value for its investors through minimizing its cost of capital and maximizing its return on invested capital, which ensures operating cash flows are maintained and growing. The Corporation develops and executes financing plans and strategies to ensure investment grade credit ratings, diversity in its funding sources, and maintain ready access to capital markets.

A key element of the Corporation's stable business model is mitigating its exposure to certain market price risks as well as volume risk. In addition to its diversification strategy, the Corporation has developed risk management processes that mitigate earnings volatility from commodity price risk and volume risk. AltaGas proactively hedges interest rates, foreign exchange rates and commodity price exposures when it is prudent to do so. As well, the continued management of counterparty credit risk remains an ongoing priority. AltaGas mitigates the foreign exchange exposure on its U.S. investments by incorporating US dollar (US$) denominated capital, both debt and preferred shares, into its financing strategy.

Continue to Develop Organizational Capability to Support the Strategy

AltaGas recognizes that to be successful in operating and constructing energy infrastructure, specific core competencies are required. To that end, the Corporation continues to focus on hiring and training the required competencies to execute its strategy, and ensuring that the performance management processes support the long-term objective of creating shareholder value. Several changes at the executive level were made in 2015 due to planned retirements. Succession plans are in place to ensure continuity and a smooth transition to position the Corporation for its next phase of growth.

STRATEGY EXECUTION

AltaGas has successfully executed its strategy to create shareholder value and to maintain financial strength and flexibility, growing from under $3 billion in assets five years ago to total assets of over $10 billion at the end of 2015. In the last five years, the Corporation has reported a 6 percent and 7 percent compound annual growth rate in normalized EBITDA and dividends per share, respectively. AltaGas delivers an effective balance between yield and growth.

AltaGas continues to drive its strategy to grow its highly contracted, clean power generation portfolio. As at December 31, 2015, approximately 62 percent and 21 percent of total generation capacity came from gas-fired and renewables sources, respectively. In 2015, AltaGas acquired 687 MW of western U.S. natural gas-fired power generation through two acquisitions: 164 MW in January through the acquisition of Ripon, Pomona and Brush II, followed by 523 MW in November through the acquisition of the San Joaquin Facilities. These acquisitions were important additions to AltaGas' business by establishing the Corporation's presence in Northern California and strengthening AltaGas' overall California market position.

The Corporation safely commissioned McLymont in the fourth quarter of 2015. Commercial operation at McLymont represented the final phase of the $1 billion Northwest Hydro Projects (the Northwest Hydro Facilities), which also include the 195-MW Forrest Kerr Hydroelectric Facility (Forrest Kerr) and the 16-MW Volcano Creek Hydroelectric Facility (Volcano), both of which were commissioned in the second half of 2014. The Corporation successfully completed the first full year of operations at Forrest Kerr, and implemented numerous operational improvements to enhance efficiency and reliability. In the fourth quarter of 2015 Cogeneration III was declared in service. Through a combination of strategic acquisitions and the completion of organic projects, AltaGas delivered over 50 percent growth in power generation capacity in 2015, providing over 80 percent of total generation capacity from clean energy sources, including hydro, wind, biomass and gas-fired. Over 90 percent of AltaGas' clean power generation portfolio is underpinned by long-term contracts.

AltaGas continues to progress its integrated northeast British Columbia strategy on several different fronts. Construction is approximately 75 percent complete at the Townsend Facility, which is underpinned by take-or-pay commitments from Painted Pony Petroleum Ltd. (Painted Pony). In addition to the Townsend Facility, AltaGas initiated two other related projects in 2015. The first is a 25 km gas gathering line, which will connect the Blair Creek field gathering area to the Townsend Facility. Painted Pony has reserved all of the firm service under a 20-year take-or-pay agreement. The second project consists of two liquids egress lines totaling approximately 30 km, and a truck terminal on the Alaska Highway. The lines will connect the Townsend Facility to the truck terminal and have a combined initial capacity of 60,000 bbls/day. Also in 2015, AltaGas began development of a liquids separation and handling facility near Fort St. John, British Columbia, which will handle liquids from both Townsend and other producers in the Montney region. The site is well connected by rail to Canada's West Coast and North American markets. Please refer to the *Growth Capital* section in this MD&A for further details regarding these projects.

AltaGas strives to meet producer needs for new markets and higher netbacks by advancing energy exports projects. AltaGas signed a sublease and related agreements with Ridley Terminals for the development of a proposed propane export terminal which is located on a portion of land leased by Ridley Terminals from the PRPA on Ridley Island near Prince Rupert, British Columbia. This proposed propane export facility is expected to ship up to 1.2 million tonnes per annum. AltaGas is working towards a final investment decision (FID) in 2016. Please refer to the *Growth Capital* section in this MD&A for further details regarding this project.

Across the five separate utility franchises throughout North America, AltaGas continues to focus on safely and reliably delivering customers clean, affordable energy. In 2015 AltaGas achieved customer growth across all utilities, and grew rate base by expanding its existing infrastructure through system upgrade programs and organic growth opportunities. SEMCO Gas also obtained approval of its MRP from the Michigan Public Service Commission (MPSC). In addition, in September 2015, the Regulatory Commission of Alaska accepted a stipulation to resolve all matters for ENSTAR's rate case, including a rate increase. ENSTAR also agreed to file a 2016 rate case with a 2015 test year.

In 2015, the Corporation enhanced its financial strength and flexibility through a combination of internally-generated cash flows, the dividend reinvestment program (DRIP), and the issuance of approximately $650 million of equity and long-term debt. During the year, AltaGas issued approximately $300 million of common shares, $200 million of preferred shares and US$125 million of medium-term notes. In addition, on December 4, 2015, AltaGas extended the maturity of its $1.4 billion syndicated credit facility by one year to December 15, 2019. AltaGas maintained sufficient liquidity and a strong balance sheet throughout the year and exited 2015 with approximately $987 million of available credit facilities, cash of $293 million, and debt-to-total capitalization of 48 percent. AltaGas entered 2016 well positioned to fund its growth capital and to take advantage of growth opportunities when they arise.

During 2015, the Board of Directors approved two dividend increases for a total increase of 12 percent from $1.77 per share to $1.98 per share on an annualized basis. The dividend increases reflect the success of AltaGas' recent asset additions across all business segments, as well as the stability and sustainability of its cash flows.

2016 OUTLOOK

AltaGas currently expects to deliver overall normalized EBITDA growth of approximately 20 percent in 2016 compared to 2015. The Power and Utilities segments are expected to report higher normalized EBITDA and operating income, while normalized EBITDA and operating income from the Gas segment are expected to remain roughly flat compared to 2015. 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 gas strategy is expected to add additional EBITDA in 2016 with a partial year contribution from the first phase of the Townsend Facility entering commercial operations mid-year. AltaGas' 2016 normalized EBITDA growth projections assume no near-term recovery in commodity prices. If commodity prices recover, AltaGas is well positioned to deliver additional normalized EBITDA growth. The Utilities segment is expected to report increased normalized EBITDA in 2016 driven by rate base and customer growth. The overall forecasted growth in normalized EBITDA includes lower commodity hedge gains compared with 2015 as well as higher operating and administrative costs due to new assets placed into service. Normalized operating income for 2016 is expected to be higher due to the factors noted above, partially offset by higher depreciation and amortization expense on new assets.

AltaGas currently expects normalized funds from operations to grow by approximately 15 percent in 2016, driven by the factors noted above for normalized EBITDA, partially offset by higher financing costs related to new assets acquired as well as new assets in service, and higher current tax expenses.

In the Power segment, increased earnings are expected to be driven by the San Joaquin Facilities and a full-year contribution from McLymont. The earnings and cash flows from the Northwest Hydro Facilities are expected to be seasonally stronger beginning in the second quarter through early in the fourth quarter, and seasonally weaker in the first quarter based on normal water flow patterns. Actual seasonal water flows will vary with rainfall and snowpack levels.

In the Utilities segment, AltaGas expects to continue to benefit from the normal seasonally strong first and fourth quarters 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 margin in 2016 as a result of a full year contribution of its MRP. The Regulatory Commission of Alaska accepted a stipulation filed by ENSTAR in 2015, which included a rate increase (annualized) of approximately US$4 million as well as an additional interim and refundable rate increase (annualized) of approximately US$2 million. 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 normalized weather, earnings at the utilities would be affected.

In the Gas segment, additional earnings are expected to be driven by a partial year contribution from the first phase of the Townsend Facility, higher earnings from Petrogas, and the absence of turnarounds at the Harmattan and Younger extraction plants and are expected to be offset by lower commodity hedge gains. AltaGas expects NGL prices to remain depressed and anticipates that the extraction of certain NGL at some of its facilities will remain uneconomic resulting in reinjection. Based on current commodity prices, AltaGas estimates an average of approximately 2,000 to 3,000 Bbls/d will be exposed to frac spread in 2016. Given weak commodity prices, AltaGas does not expect to enter into frac hedges for 2016 at this time.

On February 2, 2016, AltaGas announced 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 for total consideration of $30 million of cash and 43.7 million common shares of Tidewater Midstream and Infrastructure Ltd. The sale is part of AltaGas' strategy to focus on larger scale opportunities in the Gas segment that support the overall northeast British Columbia strategy. Subject to customary closing conditions being satisfied, the transaction is expected to close in the first quarter of 2016. These non-core gas assets represented less than 2 percent of AltaGas' expected 2016 normalized EBITDA.

If the US dollar remains strong compared with 2015, the EBITDA and operating income reported for the U.S. assets will benefit accordingly in 2016. Some of this benefit is 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.

The Alberta government announced its Climate Leadership Plan on November 22, 2015, with details of the final strategy still to be developed. The complete impact of the Climate Leadership Plan to AltaGas is yet to be determined. The key areas include: phasing out coal-generated electricity by 2030, developing more renewable energy through competitive procurement processes, a recommendation to phase out the current Specified Gas Emitters Regulation (SGER), an emissions intensity-based carbon pricing program by 2018 with a new Carbon Competitiveness Regulation (CCR), which is based on an emissions performance standard, and assessing opportunities for new gas-fired generation to support grid reliability. 2016 normalized EBITDA projections for the Power segment include no contributions from coal-fired generation.

SENSITIVITY ANALYSIS

AltaGas' financial performance is affected by factors such as changes in commodity prices, exchange rates and weather. The following table illustrates the approximate effect of these key variables on AltaGas' expected normalized EBITDA for 2016.

Factor	Increase or decrease	Impact on normalized EBITDA *($ millions)*
Alberta electricity prices	$1/Mwh	2
Natural gas liquids fractionation spread[1]	$1/Bbl	1
Degree day variance from normal — Canadian utilities[2]	5 percent	1
Degree day variance from normal — U.S. utilities[3]	5 percent	4
Change in CAD per US$ exchange rate	$0.05	14

1 *Based on no frac spread exposed NGL volumes being hedged.*

2 *Degree days – Canadian utilities relate to AUI and Heritage Gas service areas. A degree day is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not 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.*

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

GROWTH CAPITAL

Based on projects currently under review, development, or construction, AltaGas expects capital expenditures in the range of $550 to $650 million for 2016. Gas and Power maintenance capital is expected to be less than $40 million of the total expected capital expenditures. A large portion of growth capital expenditures are discretionary and AltaGas has the flexibility to adjust the pace of spending at its option. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' 2016 committed capital program is largely funded through internally-generated cash flow and DRIP, with the balance through available credit facilities.

Townsend Gas Processing Facility

The Townsend Facility is a 198 Mmcf/d shallow-cut gas processing facility located approximately 100 km north of Fort St. John and 20 km southeast of AltaGas' Blair Creek Facility. Painted Pony has reserved all of the firm capacity under a 20-year take-or-pay agreement. The estimated cost for the Facility and associated infrastructure is approximately $325 to $350 million, and includes the plant, sales gas line, improvements to site, local roads and the Alaska Highway, as well as additional compression. Construction of the Townsend Facility is progressing ahead of schedule and is approximately 75 percent complete. The facility is on track to be in service by mid-2016.

Incremental to the Townsend Facility are two other related projects. The first is a 25 km gas gathering line, which is now substantially complete and expected to cost approximately $38 million (versus $43 million original cost expectation). This pipeline connects the Blair Creek field gathering area to the Townsend Facility. Painted Pony has reserved all of the firm service under a 20-year take-or-pay agreement. The second project consists of two liquids egress lines totaling approximately 30 km, and a truck terminal on the Alaska Highway, which are estimated to cost approximately $80 to $90 million. The lines will connect the Townsend Facility to the truck terminal and are expected to have a combined initial capacity of up to 60,000 bbls/day. The pipelines have been approximately 30 percent constructed. Construction of the truck terminal is scheduled to occur in the second to third quarter of 2016. Long-lead equipment is on order, and site clearing has commenced. Painted Pony is expected to reserve all firm liquids capacity under a 20-year take-or-pay agreement.

Northeast British Columbia Liquids Separation Facility

AltaGas has begun development of a liquids separation and handling facility near Fort St. John, British Columbia, which will be connected to existing AltaGas infrastructure in the region, including the proposed Ridley Island Propane Export Terminal, and will serve producers in the Montney region. Current specifications are expected to include up to 20,000 bbls/d of liquids separation and up to 20,000 bbls/d of stabilized condensate handling. The facility is estimated to cost approximately $130 to $140 million. The site is well connected by rail to Canada's West Coast and North American markets. A front-end engineering and design (FEED) study was substantially completed in January 2016 and further capital optimization opportunities are currently being reviewed. Consultations with First Nations and key stakeholders continue, and AltaGas expects to receive permits to reach FID in 2016.

Ridley Island Propane Export Terminal

AltaGas signed a sublease and related agreements with Ridley Terminals to develop, build, own and operate the proposed Ridley Island Propane Export Terminal located near Prince Rupert, British Columbia on a portion of lands leased by Ridley Terminals from 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 up to 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 natural gas producers will be transported to the facility using the existing CN rail network.

Preliminary engineering has been completed and a FEED study is in progress. The process of engaging and consulting with First Nations, communities, government, and environmental and regulatory authorities is underway. AltaGas is working towards reaching a FID in 2016. Commercial operation to commence propane exports is targeted for 2018, subject to First Nations consultations and necessary approvals. On February 11, 2016, AltaGas filed an application with the National Energy Board (NEB) for a 25-year propane export license.

Douglas Channel Liquefied Natural Gas (DC LNG) Project

The DC LNG Consortium, comprised of AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), EDF Trading Limited (EDFT) and EXMAR NV (EXMAR), agreed in the first quarter of 2016 to halt development of the DC LNG Project due to adverse economic conditions and worsening global energy price levels.

Alton Natural Gas Storage Project

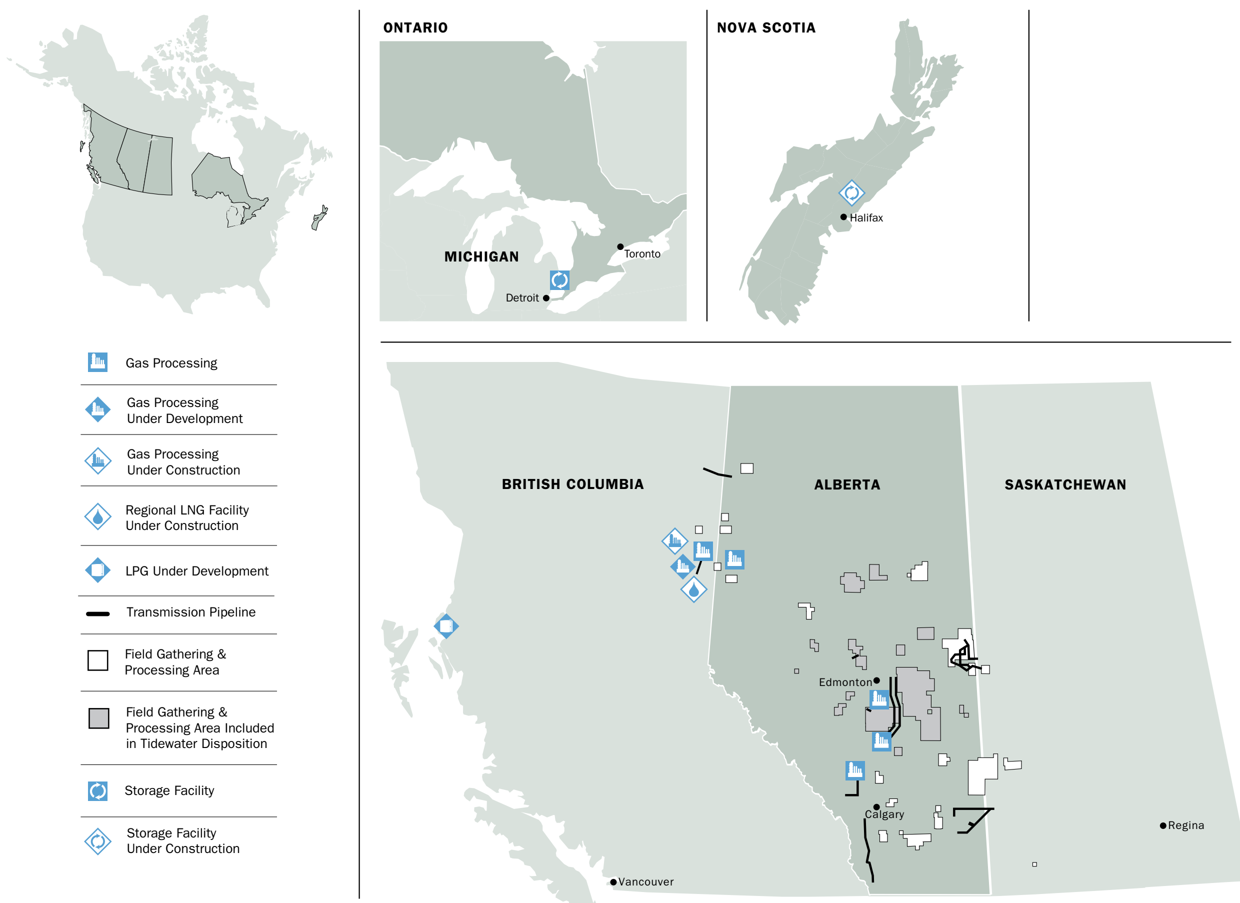
AltaGas has commenced work on the Alton Natural Gas Storage project located near Truro, Nova Scotia, which is expected to provide up to 10 Bcf of natural gas storage capacity. On January 21, 2016 the Government of Nova Scotia announced that a number of remaining permits will be issued and following receipt of such permits, construction is expected to continue in 2016 with storage service expected to commence in 2019. AltaGas has entered into a long-term storage agreement with Heritage Gas. Heritage Gas received regulatory approval from the Nova Scotia Utility and Review Board in 2015 for the recovery of the costs of the storage service and the method of recovery.

GAS

Description of Assets

AltaGas' Gas segment serves customers primarily in the WCSB and transacts more than 2 Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and separation, transmission, storage and natural gas marketing. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation. Extraction and separation facilities reprocess natural gas to extract and recover ethane and NGL. As at December 31, 2015, AltaGas owned 1.6 Bcf/d of extraction processing capacity and 1.4 Bcf/d of raw field gas processing capacity. The Gas segment also includes an equity investment in Petrogas through AIJVLP.

Transmission pipelines deliver natural gas and NGL to distribution systems, end-users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by buying and reselling natural gas; providing gas transportation, storage and gas marketing for producers; and sourcing gas supply for some of the Corporation's processing assets. The Gas segment also includes several expansion and greenfield projects under development, specifically in northeast British Columbia, and the energy export projects.



Specifically, the Gas segment includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1.6 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues. Effective January 1, 2016, AltaGas acquired the remaining 51 percent interest in Edmonton Ethane Extraction Plant (EEEP), increasing the total net licensed inlet capacity to 1.8 Bcf/d. The natural gas supply to AltaGas' extraction plants, with the exception of Harmattan and Younger extraction plants, depends on natural gas demand pull from residential, commercial and industrial usage inside and outside of western Canada, and gas liquids demand pull from the Alberta petrochemical market and propane heating. Natural gas supply to Younger extraction plant (Younger) is dependent on the amount of raw natural gas processed at the McMahon gas plant, which is based on the robust natural gas producing region of northeastern British Columbia. Harmattan's raw natural gas supply is based on producer activity in the west-central region of Alberta. Harmattan is the only deep-cut and full fractionation plant in the area, and is the third largest producer of NGL in the WCSB;
- Four natural gas transmission systems with combined transportation capacity of approximately 0.6 Bcf/d and four NGL pipelines with combined capacity of 189,300 Bbls/d. The transmission assets provide stable take-or-pay based revenues. In 2014, Nova Chemicals Corporation (Nova Chemicals) provided notice that it intends to exercise its option to purchase the Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission assets effective March 31, 2017;
- Approximately 70 gathering and processing facilities in Western Canada and a network of approximately 6,100 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets as at December 31, 2015. The field facilities provide fee-for-service revenues based on volumes processed as well as revenues based on take-or-pay contracts. A significant portion of contracts flow through operating costs to the producers. On February 2, 2016, AltaGas announced 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;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn Hub in Eastern Canada;
- The Alton Natural Gas Storage Project under construction;
- Natural gas marketing and gas transportation services to optimize the value of the infrastructure assets and meet customer needs;
- 50 percent ownership in AIJVLP, with the remaining 50 percent owned by Idemitsu;
- AIJVLP holds a two-third ownership in Petrogas, a leading North American integrated midstream company, with an extensive logistics network consisting of over 1,700 rail cars and 24 rail and truck terminals providing key infrastructure, supply logistics and marketing expertise. Petrogas also owns the Ferndale Terminal, which is operated by AltaGas;
- A 15-year strategic alliance between AltaGas and Painted Pony for the development of processing infrastructure and marketing services for natural gas and NGL. In the first phase of the strategic alliance, the 198 Mmcf/d Townsend Facility will be constructed and operated by AltaGas, where AltaGas markets Painted Pony's gas and liquids;
- Development of the proposed Ridley Island Propane Export Terminal in British Columbia; and
- Development of the liquids separation and handling facility near Fort St. John, British Columbia.

Please refer to the *Growth Capital* section in this MD&A for further details regarding the Townsend Facility, the proposed Ridley Island Propane Export Terminal, the liquids separation and handling facility near Fort St. John, British Columbia, and the Alton Natural Gas Storage Project.

Capitalize on Opportunities

AltaGas plans to grow its gas business by expanding and optimizing strategically-located assets and by adding new assets to serve customers by providing access to new markets, including Asia. New infrastructure is expected to be larger scale facilities supporting the vast reserves in the WCSB. AltaGas' strategic investment in Petrogas enhances the services provided by the Gas segment by offering integrated midstream services to AltaGas' customers and by creating long-term value for the Gas segment. While providing safe and reliable service, AltaGas pursues opportunities in the Gas segment to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Capitalize on the infrastructure growth opportunities associated with growing natural gas and liquids supply in the WCSB;
- Provide a fully-integrated midstream service offering including pipeline, liquefaction, and refrigeration facilities to its customers across the energy value chain, with higher producer netbacks resulting from export access to higher value markets, including Asia;
- Maximize profitability of existing facilities by increasing capacity, utilization and efficiency;
- Mitigate volume risk through contractual structures, redeployment of equipment and expansion of geographical reach;
- Coordinate between facilities, business segments and product lines to improve efficiencies and maximize profits;
- Expand into new natural gas infrastructure markets such as regional liquefied natural gas (LNG); and
- Maintain strong social license with local communities, First Nations, governments, and regulatory bodies.

In recent years, the WCSB has changed from a maturing basin to one capable of sustainable long-term growth via new low cost sub-plays such as the Montney basin. Despite the currently depressed commodity market conditions, AltaGas remains confident that the long-term demand for natural gas, combined with improvements in exploration, drilling and completion technology, will support the long-term viability of the WCSB. The emergence of unconventional gas plays in the WCSB such as the Montney and Duvernay, as well as increased focus on horizontal multi-fracturing technology have resulted in abundant natural gas supply and associated liquids. Market demand, including the demand generated from the potential LPG and LNG export projects on the West Coast of North America, provides significant growth opportunities in the Corporation's Gas segment in the long term. AltaGas expects to capitalize on these opportunities by increasing throughput at facilities, by increasing interests in existing plants, and by acquiring and constructing new facilities such as liquefaction, refrigeration, natural gas processing, extraction, separation, storage and transmission capacity. AltaGas' 15-year strategic alliance with Painted Pony is an example of the Corporation's ability to partner with producers to provide a fully-integrated service offering.

The currently depressed commodity market conditions are accelerating a trend of producers seeking to conserve capital and monetize non-core assets. AltaGas is well positioned to build or acquire gathering and processing infrastructure from, or on behalf of, producers. The Corporation also expects there to be opportunities to increase volumes by tying-in new wells and building or purchasing adjoining facilities and systems to create larger processing infrastructure to capture operating synergies and enhance its competitive advantage. The strategic location of some of its existing gas processing infrastructure is expected to benefit from growing natural gas production in northeastern British Columbia and western Alberta, in response to the development of unconventional sources of gas, such as the Montney and Duvernay shale gas plays. The Townsend Facility and its related infrastructure is an example of AltaGas' ability to capitalize on energy infrastructure growth opportunities while providing a fully-integrated midstream service offering to its customers. The Gordondale Gas Plant and the Blair Creek Facility are meeting liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. The Gordondale and Blair Creek facilities are underpinned by take-or-pay contracts, which provide stable cash flows. Overall, the diverse nature of AltaGas' natural gas and NGL infrastructure is expected to provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

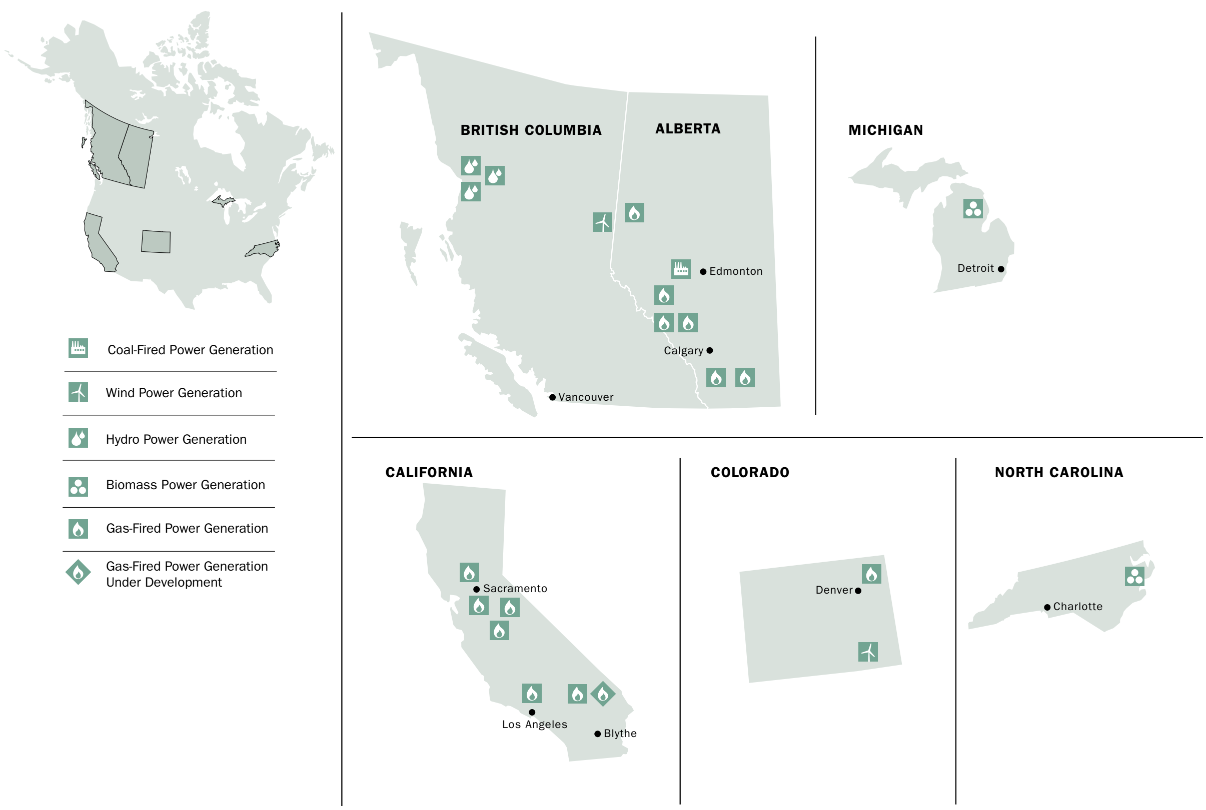
Due to the integrated nature of AltaGas' gas gathering and processing assets, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas is uniquely positioned to work with producers providing services across the integrated value chain, from wellhead to the coast. This is particularly the case with producers in the vast Montney and Duvernay basins under development in northeastern British Columbia and western Alberta. With the proposed Ridley Island Propane Export Terminal near Prince Rupert, British Columbia currently under development and the Petrogas Ferndale Terminal in the State of Washington, AltaGas can provide multiple outlets for producers to deliver their products to the highest value markets, including Asia. AltaGas also pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure based businesses. These include maintaining the cost effective flow of gas through extraction plants and increasing services provided to producers. AltaGas has significant gas and power market knowledge, which it employs across all its assets to enhance returns along the energy value chain and more effectively serve customers' needs.

POWER

Description of Assets

AltaGas' Power segment is engaged in the generation and sale of electricity and ancillary services in Western Canada and the United States, all of which are under long-term contracts with the exception of the Alberta assets and Pomona. AltaGas continues to expand its geographic footprint and to capitalize on the demand for clean energy sources, while increasing earnings, cash flow stability, and predictability.

As at December 31, 2015, the Power segment included 2,041 MW of power generation capacity from hydro, gas-fired, coal-fired, wind, and biomass assets, along with an additional 1,253 MW of assets under development.



Specifically, the Power segment includes:

- Seven natural gas-fired plants with 1,194 MW of generating capacity in the United States, including the 523-MW San Joaquin Facilities, the 507-MW Blythe Energy Center, the 50-MW Ripon and the 44-MW Pomona, all of which are located in California, and the 70-MW Brush II in Colorado. All facilities are under PPAs with creditworthy utilities except Pomona. A further 1,163 MW of gas-fired generation is under development;
- 353 MW of coal-fired generating capacity in Alberta through the Sundance B PPA until December 31, 2020. Power is sold into the Alberta spot market and AltaGas employs an economic hedging strategy to mitigate the exposure to Alberta spot power prices;

- 277 MW of operating run-of-river generation in British Columbia (the Northwest Hydro Facilities), under 60-year Electricity Purchase Agreements (EPA) fully indexed to the Consumer Price Index (CPI) with BC Hydro;
- 117 MW of wind generation, of which 102 MW is in British Columbia and 15 MW is in Colorado. All operating wind generation is sold via long-term EPAs;
- 45 MW of cogeneration and 20 MW of gas-fired peaking plants capacity in Alberta, with a further 90 MW of peaking plant capacity under development; and
- 35 MW of biomass generation in the United States. The plants have long-term PPAs with strong counterparties.

In northern California, the Corporation is focused on owning generating assets in locally constrained areas near load pockets as local resource adequacy needs result in more opportunities for expansion and re-contracting. On November 30, 2015, AltaGas acquired three northern California natural gas-fired power assets with total generating capacity of 523 MW, located in the San Joaquin Valley. All three assets are fully contracted through 2022 with Pacific Gas & Electric Company (PG&E) under PPAs which are structured as tolling arrangements for 100 percent of facility energy, capacity and ancillary services. This is in addition to Ripon acquired in early 2015, which is also contracted with PG&E until May 31, 2018. AltaGas is currently in the preliminary stages of permitting to increase generation capacity at Ripon.

In southern California, the existing 507-MW Blythe Energy Center is currently operating under a long-term PPA with Southern California Edison (SCE) until July 31, 2020, serving the CAISO market. The opportunities for growth include Blythe Energy Center's unique position to potentially serve both CAISO and the WAPA markets. Blythe Energy Center is located on an owned 76-acre site which provides a significant geographic footprint and water resource to support future expansions. The facility is directly connected to a Southern California Gas Company natural gas pipeline for its supply, and interconnects the SCE and CAISO via its 67-mile transmission line. The facility also has the capability of directly connecting to both the California and Arizona markets and is also connected to the El Paso gas supply. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth. In 2014, AltaGas acquired a fully permitted and shovel-ready site directly adjacent to the existing Blythe Energy Center, known as the Sonoran Energy Project or Blythe II, and 76 acres of land north of the current Blythe Energy Center to support further expansion opportunities (Blythe III). Both projects have the potential to contract with multiple creditworthy utilities and regional municipalities in California and adjacent states. The development of both projects could potentially more than triple AltaGas' current generating capacity in the vicinity of the Blythe Energy Center over the medium and long term. In addition, AltaGas acquired Pomona in early 2015, which is strategically located in the Los Angeles basin load pocket. As development activities advance, the PPA for Pomona was amended at the end of 2015 with no fixed capacity payments in order to facilitate the transition of this facility on an interim basis to the merchant market. AltaGas is currently in the preliminary stages of permitting the site for repowering Pomona with more efficient technology and plans to bid into a competitive solicitation process with a load serving entity.

AltaGas owns and operates the Northwest Hydro Facilities in northwest British Columbia with total generation capacity of 277 MW. The three facilities include Forrest Kerr, Volcano, and McLymont. McLymont commenced commercial operations in fourth quarter of 2015. These facilities are each underpinned by 60-year EPAs, fully indexed to CPI. Impact Benefit Agreements are in place for all three facilities, ensuring a cooperative and mutually beneficial relationship between the Tahltan Nation and AltaGas.

AltaGas also owns the 102-MW Bear Mountain Wind Park (Bear Mountain) in British Columbia, which came into service in October 2009 and has a 25-year EPA with BC Hydro, and a 50 percent interest in the Busch Ranch wind farm (Busch Ranch), a 29 MW wind farm in Colorado with a 25-year EPA with the local utility, which came into service in October 2012. AltaGas' biomass assets are a 30 percent working interest in a 37 MW wood biomass power facility in Grayling, Michigan and a 50 percent working interest in a 48 MW wood biomass power facility in Craven County, North Carolina. Both biomass facilities have long-term PPAs.

In Alberta, the Corporation employs a power hedging strategy, which is designed to balance market and operational risks related to the Alberta generation portfolio. AltaGas also sells power to Commercial and Industrial (C&I) end-users in Alberta, providing further earnings stability. Counterparties are subject to credit reviews and credit thresholds in the normal course of business. AltaGas actively markets electricity and gas directly to end-users, enabling the Corporation to secure fixed-price sales at competitive market prices while earning fees associated with the administration of the metered data and billing. These C&I sales are typically for three to five year terms. A portion of the electricity sales are used to secure long-term power sales for AltaGas' Alberta generation portfolio, offering AltaGas price certainty and a source of liquidity that has decreased in the wholesale market.

Capitalize on Opportunities

While providing safe and reliable service, AltaGas pursues opportunities in the Power segment to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Capitalize on North American demand for clean energy;
- Further grow and diversify the power generation portfolio by geography and fuel source;
- Acquire and develop power infrastructure backstopped by long-term PPAs or supported by strong power supply and demand fundamentals;
- Secure PPAs for Blythe II and III, as well as seeking to re-contract and/or extend existing PPAs for operating assets at beneficial terms;
- Execute power hedges to balance operational and market risk and explore opportunities for new natural gas-fired and renewable power generation in Alberta; and
- Maintain strong social license with local communities, First Nations, governments, and regulatory bodies.

AltaGas' strategy is to build, own and operate long-life, low-risk power infrastructure assets to deliver strong, stable returns for investors. Growth is focused on natural gas-fired and renewable sources of clean energy as the Corporation seeks to capitalize on the increasing demand for clean power while reducing its carbon footprint.

The demand for clean energy continues to be strong across North America as the industry addresses climate change legislation and utilities are faced with RPS. Although coal-fired generation is still the largest fuel source for power generation in North America, it is decreasing in market share for environmental and economic reasons. Low cost natural gas has resulted in a cost competitive option to coal as a source of fuel on a marginal cost basis in many parts of North America. The economic benefit of natural gas-fired generation is enhanced by capital cost efficiency, dispatch flexibility and the fact that it is a cleaner burning fossil fuel, thus enhancing its appeal as a source of energy.

Opportunities to develop and own additional power generation are likely to arise with the growing North American demand for cleaner energy sources such as natural gas, hydroelectric and wind. Both the Canadian federal government's stated policy to have coal-fired generators retire at the end of their useful economic lives and the Alberta government's proposed Climate Leadership Plan necessitates new natural gas-fired and renewable generation. In addition, the Once-Through Cooling Water Policy for power generating facility intake structures in California is expected to result in additional opportunities to develop clean power generation capacity. The San Joaquin Facilities, Blythe Energy Center, Bear Mountain, Busch Ranch, Grayling Generating Station, Craven County wood biomass power facility, the Northwest Hydro Facilities, Ripon, Pomona and Brush II are all examples of AltaGas' strategy in action to meet North America's growing demand for clean energy.

UTILITIES

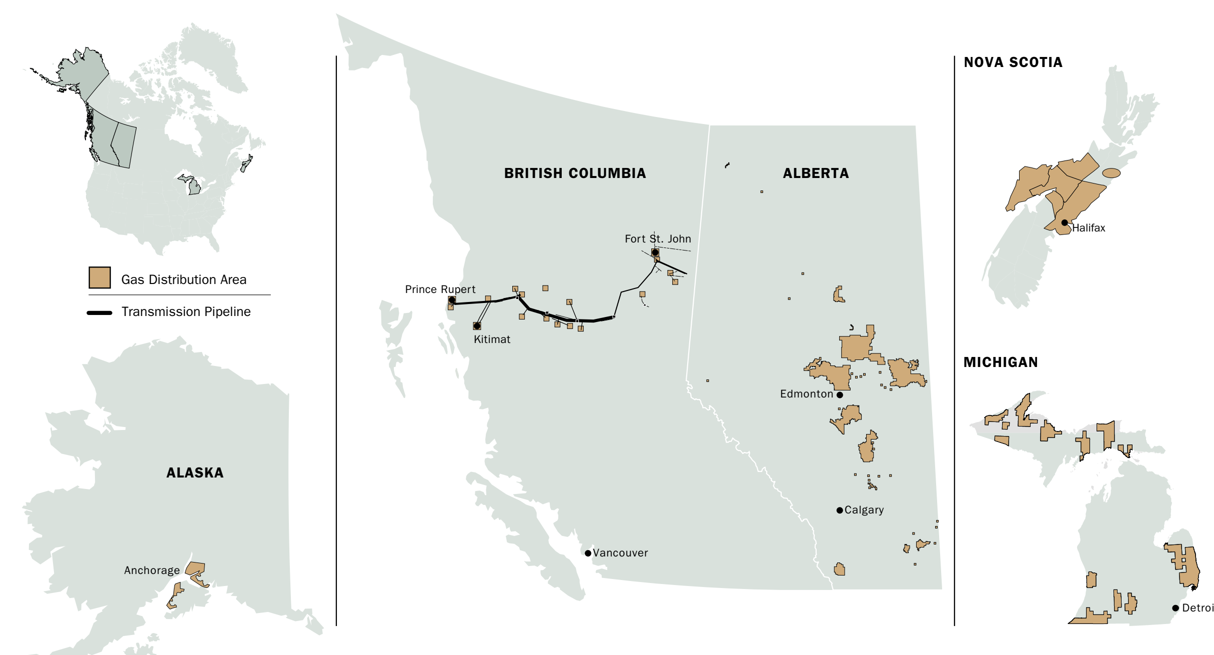
Description of Assets

AltaGas owns and operates utility assets that store and deliver natural gas to end-users in Alberta, British Columbia, Nova Scotia, Michigan and Alaska. AltaGas also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. AltaGas' utility businesses serve over 560,000 customers and have a rate base of approximately $1.9 billion.

The utilities are underpinned by regulated returns and regulatory regimes that generally provide stable earnings and cash flows. The Utilities segment enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Corporation's business profile, thus allowing the Corporation to meet its objective of generating superior economic returns by investing in regulated, long-life assets with stable earnings.

The Utilities segment includes:

- SEMCO Gas in Michigan;
- ENSTAR in Alaska;
- 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska;
- AUI in Alberta;
- PNG in British Columbia;
- Heritage Gas in Nova Scotia; and
- One-third interest in Inuvik Gas Ltd. (Inuvik Gas) and the Ikhil Joint Venture in the Northwest Territories.



All of the utilities are allowed the opportunity to earn regulated returns. This return on rate base is composed of regulator-allowed financing costs and return on equity (ROE). In a cost-of-service regime and Performance Based Regulation (PBR) regime, if actual costs are different from those recoverable through approved rates, the utility bears the risk of this difference other than for certain costs that are subject to deferral treatment. Inuvik Gas operates a natural gas distribution franchise in a regulatory environment where delivery service and natural gas pricing are market-based.

Earnings in the Utilities segment are seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. In Alberta, Nova Scotia, Michigan and Alaska, earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. Increases in the number of customers or changes in customer usage are other factors that might typically affect delivered volumes, and hence actual earned returns for the Utilities segment. PNG is authorized by the BCUC to maintain a Revenue Stabilization Adjustment Mechanism regulatory account to mitigate the effect of weather on earnings.

SEMCO Gas

SEMCO owns and operates a regulated natural gas distribution utility in Michigan under the name SEMCO Gas and has an interest in a regulated natural gas storage facility in Michigan. At the end of 2015, SEMCO Gas had approximately 300,000 customers. Of these customers, approximately 84 percent are residential. In 2015, SEMCO Gas experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favourable price of natural gas. The rate base at year end was approximately US$477 million. In 2015, the approved regulated ROE for SEMCO Gas was 10.35 percent on 50 percent equity.

SEMCO Gas is regulated by the MPSC. It operates under cost-of-service regulation and utilizes actual results from the most recently completed fiscal year along with known and measurable changes in its application for new rates.

In December 2012, SEMCO Gas filed an application with the MPSC seeking to amend the MRP effective in 2013. SEMCO Gas proposed to double the amount spent annually on the MRP from US$4 million to US$9 million; to double the miles of main replaced from 13 miles to 26 miles per year; to include vintage plastic main as eligible main, and to increase the MRP surcharge to recover the incremental capital costs associated with the MRP. On May 29, 2013, the MPSC issued an order approving SEMCO Gas' application. Revised surcharges generating incremental revenue are effective for the period June 1, 2013 through May 30, 2017.

On January 23, 2015, SEMCO Gas filed an MRP rate case. As part of the case, SEMCO Gas requested to continue the MRP program for an additional five years. The anticipated annual average capital spending over the five year period is approximately US$10 million. In June 2015, the MPSC approved this filing and the new rates became effective immediately following the approval.

In May 2015, SEMCO Gas filed its 2014 Energy Optimization (EO) reconciliation with the MPSC. As part of the filing, SEMCO Gas demonstrated that it had implemented its EO plan during 2014, and met the goals and objectives for the approved performance incentive. In September 2015, the MPSC issued an order authorizing SEMCO Gas to collect US$0.8 million as its 2014 EO plan performance incentive.

ENSTAR and CINGSA

SEMCO owns and operates a regulated natural gas distribution utility in Alaska under the name ENSTAR. SEMCO, through a subsidiary, holds a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. At the end of 2015, ENSTAR had approximately 140,000 customers including residential, commercial and transportation and of these customers, approximately 91 percent are residential. In 2015, ENSTAR experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favourable price of natural gas. The rate base at year end was approximately US$288 million for ENSTAR and US$86 million for CINGSA (SEMCO's 65 percent share).

ENSTAR and CINGSA are regulated by the Regulatory Commission of Alaska (RCA) and operate under cost-of-service regulation utilizing actual results from the most recently completed fiscal year along with known and measureable changes in their application for new rates.

ENSTAR filed a base rate case in September 2014. In July 2015, the parties to ENSTAR's rate case proceeding reached an agreement in principle to settle the case and a stipulation was filed with the RCA in August 2015, which was accepted by the RCA in September 2015. As part of the stipulation, ENSTAR agreed to a 2016 rate case to be filed by June 1, 2016, with a 2015 test year. As part of the order accepting the stipulation, the RCA indicated that it intended to fully adjudicate the new rate case. The stipulation also granted a permanent rate increase effective October 1, 2015 of approximately 2.2 percent over the 1 percent interim and refundable rate increase that went into effect on November 1, 2014. Furthermore, the parties agreed that there would not be any refunds of the interim and refundable rate increases that were previously approved, which went into effect on November 1, 2014. Finally, the stipulation granted another interim and refundable rate increase of approximately 0.8 percent to go into effect on January 1, 2016, until resolution of the 2016 rate case.

CINGSA made a filing in March 2014, updating the rates for service for the CINGSA Storage Facility to reflect its actual capital investment, permanent debt cost, and actual operating costs. In May 2014, the regulators approved CINGSA's new rates on a permanent basis to be effective for billings on or after May 12, 2014. CINGSA is also required to file a base rate case in mid-2017 based upon data from a test year ending December 31, 2016.

In November 2013, CINGSA detected higher than expected pressure during its biannual shut-in. CINGSA determined that it had encountered a pocket of gas that was at or near the initial reservoir pressure of approximately 2,200 pounds per square inch (psi). Following extensive analysis, CINGSA has determined that the pocket of found gas it discovered, totaling approximately 14.5 Bcf, is not necessary to provide pressure support for CINGSA's storage operations. In January 2015, CINGSA filed a tariff revision with the RCA to permit and account for the sale of a portion of the found gas.

In August 2015, CINGSA entered into a stipulation with most of its customers regarding the disposition of the found gas. Hearings before the RCA were held in September 2015. On December 4, 2015, the RCA issued an order that denied the stipulation, allowed CINGSA to sell up to 2 Bcf of the gas and required that approximately 87 percent of the net proceeds of any such sale be allocated to CINGSA's firm customers. On January 4, 2016, CINGSA appealed the RCA decision to the Superior Court of Alaska.

AltaGas Utilities Inc.

AUI owns and operates a regulated natural gas distribution utility in Alberta. At the end of 2015, AUI served approximately 78,000 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. Customer growth in 2015 was 2 percent and AUI's rate base at year end was approximately $261 million.

AUI is currently operating under a revenue cap per customer formula under PBR, a regulation that commenced with Alberta electric and natural gas distribution companies effective January 1, 2013, in place of the existing cost-of-service regulatory system. The PBR framework is intended to incentivize utilities to be more efficient. The initial PBR term lasts for five years (2013-2017) and the Alberta Utilities Commission (AUC) will make a determination at the end of the initial term as to how it will proceed for future years.

For 2015 and 2014, AUI's approved placeholder for regulated ROE was 8.3 percent on a prescribed capital structure of 42 percent equity and 58 percent debt. The 2016-2017 Generic Cost of Capital (GCOC) proceeding is in progress and expected to be completed in 2016. The proceeding will establish the return on equity and capital structures for all AUC-regulated utilities for 2016, 2017 and, possibly, future years. In the interim, the AUC has approved continued use of the 2013-2015 ROE of 8.3 percent as a placeholder.

Pacific Northern Gas Ltd.

PNG operates a transmission and distribution system in the west central portion of northern British Columbia (PNG West) and in the areas of Fort St. John and Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) in northeastern British Columbia (PNG(N.E.)). At the end of 2015, PNG served approximately 41,300 customers. Customer growth in 2015 was 1.5 percent, which is strong for PNG's mature network and reflective of the economic activity in this region. Approximately 87 percent of PNG's total customers are residential. PNG's rate base at year end was approximately $203 million.

PNG operates under a cost of service regulatory model whereby customer rates are set based on revenues that allow for the recovery of forecast costs plus an established rate of return on deemed common equity of PNG. For 2015, PNG did not file its annual revenue requirement application and maintained customer rates at the 2014 approved levels.

In November 2015, PNG filed its 2016 and 2017 revenue requirements application with the BCUC for all its divisions. The applications sought approvals to increase rates on an interim basis effective January 1, 2016 at the levels set forth in the applications. A written regulatory process has been established and the BCUC's final decision on new delivery rates for both 2016 and 2017 is expected in the third quarter of 2016.

On March 25, 2014, the BCUC issued its decision on the Generic Cost of Capital (GCOC) Stage 2 proceeding. The approved common equity ratio for PNG West and PNG(N.E.) TR division was set at 46.5 percent and the approved common equity ratio for PNG(N.E.) FSJ/DC division was set at 41 percent. The BCUC also established an equity risk premium of 75 basis points (bps) for PNG West and PNG(N.E.) TR division and an equity risk premium of 50 bps for PNG(N.E.) FSJ/DC division. This resulted in an allowed ROE of 9.50 percent for PNG West and PNG(N.E.) TR and 9.25 percent for PNG(N.E.) FSJ/DC effective January 1, 2013. These common equity ratios and allowed ROEs were also in effect for 2015. In October 2015, FortisBC Energy Inc., the Benchmark Utility, filed an application for its Common Equity Component and Return on Equity for 2016 with BCUC. BCUC's decision is expected in the third or fourth quarter of 2016 and will impact PNG's common equity component and allowed ROE for 2016 onwards.

On January 20, 2015, PNG received BCUC approval to assign, novate, and amend a Gas Transportation Service Agreement (GTSA) with EDFT, a member of DC LNG Consortium, that provides an option to contract for 80 Mmcf/d of the existing capacity on the Western System. On October 15, 2015, PNG also received BCUC approval on its Application for a Certificate of Public Convenience and Necessity to Construct and Operate an Interconnecting Pipeline between Kitimat and Douglas Channel to facilitate servicing the GTSA, EDFT and the DC LNG Project. In the first quarter of 2016, the DC LNG Consortium halted development of the DC LNG Project. Please refer to the *Growth Capital* section of the MD&A for more details.

Heritage Gas Limited

Heritage Gas has the exclusive rights to distribute natural gas through its distribution system to all or part of seven counties in Nova Scotia, including the Halifax Regional Municipality. At the end of 2015, Heritage Gas had approximately 6,300 customers. Customer growth in 2015 was 9 percent, reflecting Heritage Gas' relatively new presence in the Nova Scotia energy market. Heritage Gas has a relatively balanced mix of residential, small commercial, and large commercial customers. Heritage Gas' rate base at year end was approximately $277 million. For 2015 and 2014, Heritage Gas' approved regulated ROE was 11 percent with a prescribed capital structure of 45 percent equity and 55 percent debt.

Heritage Gas operates under cost-of-service regulation. Heritage Gas is regulated by the Nova Scotia Utility and Review Board (NSUARB). Heritage Gas has not applied for updated rates for 2015 and continues to assess if it will apply for a change to rates for 2016 or later.

In 2012, Heritage Gas began to develop a Compressed Natural Gas (CNG) trucking distribution system, which will allow customers who are not connected through the traditional pipeline distribution infrastructure to gain access to natural gas. Operations commenced in May 2013 and to date the business has been developed and operated as non-regulated. In December 2014, Heritage Gas received approval from the NSUARB to expand its regulated operations into Antigonish County. Heritage Gas intends to serve this new market using CNG, which would result in a portion of the CNG business being subject to rate-based regulation once the Antigonish distribution system is in operation.

Current propane and oil commodity prices have made the energy market serving small commercial customers extremely competitive with some customers choosing to adopt alternative fuels to natural gas, or implement dual fuel options. Therefore, natural gas storage service is critical to ensuring security of gas supply for Heritage Gas' customers and to reducing natural gas price volatility. In October 2014, Heritage Gas negotiated a long-term Precedent Agreement with Alton Natural Gas Storage LP (Alton), a wholly-owned subsidiary of AltaGas, which has been granted NSUARB approval to construct an underground hydrocarbon storage facility in Nova Scotia. In December 2014, Heritage Gas submitted an application to the NSUARB for approval of the natural gas storage costs and the method of recovery and allocation of those costs. On June 4, 2015 Heritage Gas received the NSUARB's Decision approving Heritage Gas' Application for the treatment, and the recovery, of natural gas storage service costs related to the proposed Alton Natural Gas Storage Facility. The Alton storage service is anticipated to provide benefits to Heritage Gas and its customers in the form of security of gas supply, enhanced reliability and delivery of natural gas during the peak heating season, as well as reduced natural gas price volatility. AltaGas currently expects storage service to commence in 2019. See *Growth Capital* section of this MD&A for further details.

In October 2014, Heritage Gas signed a Precedent Agreement with Spectra Energy on the Atlantic Bridge Project, on the Algonquin Gas Transmission (AGT) pipeline system. The contract, which is backed by a guarantee issued by AltaGas, is a 15-year commitment that provides Heritage Gas an opportunity to diversify suppliers and provide access to other supply basins. The expected in-service date is late 2017.

Inuvik Gas Ltd. & Ikhil Joint Venture

AltaGas has a one-third equity interest in Inuvik Gas and the Ikhil Joint Venture (Ikhil) natural gas reserves, which has historically supplied Inuvik Gas with natural gas for the Town of Inuvik. The Ikhil natural gas reserves have depleted more rapidly than expected. As such, a propane air mixture system producing synthetic natural gas is currently the main source of energy supply for Inuvik Gas with Ikhil serving as a back-up. Effective August 8, 2014, Inuvik Gas extended its gas distribution franchise with the town of Inuvik for a period of 10 years. AltaGas and the other shareholders in Inuvik Gas continue to pursue alternative long-term energy sources for Inuvik Gas.

Capitalize on Opportunities

While providing safe and reliable service, AltaGas pursues opportunities in the Utilities segment to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Maximize use of existing infrastructure and market penetration in order to maintain cost-effective rates;
- Invest in the safety and reliability of existing infrastructure, including delivery system upgrade programs;
- Expand infrastructure to new markets to bring the economic and environmental benefits of gas to new customers, without unduly burdening existing customers;
- Maintain strong community and regulatory relationships while ensuring fair returns to shareholders;
- Acquire new franchises when the opportunities arise; and
- Maintain strong social license with local communities, First Nations groups, governments, and regulatory bodies.

AltaGas expects to grow its existing utility infrastructure through continued investment and capital improvements in franchise areas, which will result in rate base growth and continued customer growth including the conversion of users of alternative energy sources to natural gas. After adjusting for the impact of foreign exchange translation AltaGas' utilities have averaged 6 percent rate base growth over the past three years. The growth in rate base is a direct result of prudent investments in current areas of operations, as well as the addition of new customers. The growth rate of new customers varies amongst the Corporation's utilities, with Heritage Gas seeing significant growth to date, while mature utilities such as AUI and SEMCO Gas see more moderate growth rates, which are generally tied closely to the economic growth of the respective franchise regions.

CONSOLIDATED FINANCIAL REVIEW

	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Revenue	**580**	667	**2,193**	2,406
Net revenue [1]	**216**	286	**996**	1,019
Normalized operating income [1]	**111**	105	**359**	366
Normalized EBITDA [1]	**173**	155	**582**	546
Net income (loss) applicable to common shares	**(54)**	10	**10**	96
Normalized net income [1]	**56**	48	**140**	165
Total assets	**10,100**	8,396	**10,100**	8,396
Total long-term liabilities	**4,949**	4,058	**4,949**	4,058
Net additions to property, plant and equipment	**732**	144	**1,150**	503
Dividends declared [2]	**72**	59	**260**	215
Cash flows				
Normalized funds from operations [1]	**159**	154	**470**	472

	Three Months Ended December 31		Years Ended December 31	
($ per share, except shares outstanding)	**2015**	2014	**2015**	2014
Normalized EBITDA [1]	**1.19**	1.16	**4.22**	4.31
Net income (loss) per common share — basic	**(0.37)**	0.08	**0.07**	0.75
Net income (loss) per common share — diluted	**(0.37)**	0.08	**0.07**	0.74
Normalized net income [1]	**0.38**	0.36	**1.02**	1.30
Dividends declared [2]	**0.50**	0.44	**1.89**	1.69
Cash flows				
Normalized funds from operations [1]	**1.09**	1.15	**3.41**	3.72
Shares outstanding – basic (millions)				
During the period [3]	**146**	134	**138**	127
End of period	**146**	134	**146**	134

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 and $0.165 beginning on October 26, 2015.*
3 *Weighted average.*

FOURTH QUARTER 2015

The overall results for the fourth quarter of 2015 reflect the seasonally stronger quarter for the Utilities segment, the closing of the San Joaquin Facilities acquisition on November 30, 2015, and the successful commissioning of McLymont on October 28, 2015. The fourth quarter of 2015 also reflects the benefit of the strong US dollar when compared to the same quarter in 2014. However, fourth quarter results continued to be impacted by the low commodity price environment when compared to the prior year.

Normalized EBITDA for the fourth quarter of 2015 was $173 million, compared to $155 million for the same quarter in 2014. With the commissioning of McLymont, the Northwest Hydro Facilities contributed EBITDA growth of approximately $14 million compared to the fourth quarter of 2014, while the acquisition of Ripon, Pomona and Brush II in January 2015 and the acquisition of the San Joaquin Facilities on November 30, 2015 contributed approximately $11 million of normalized EBITDA. The stronger US dollar on reported results of the U.S. assets also contributed to the increase in normalized EBITDA. These increases were partially offset by record low Alberta power prices, weak frac spreads, and warmer weather experienced at certain Utilities.

Normalized funds from operations for the fourth quarter of 2015 were $159 million ($1.09 per share), compared to $154 million ($1.15 per share) for the same quarter in 2014, driven by the same factors as normalized EBITDA, partially offset by lower cash distributions from AltaGas' equity accounted investments and higher current income tax expense.

Normalized operating income for the fourth quarter of 2015 was $111 million, compared to $105 million for the same quarter in 2014, which reflects the factors noted above for normalized EBITDA partially offset by higher depreciation and amortization expense due to new assets placed into service.

Operating and administrative expense for the fourth quarter of 2015 was $120 million, compared to $114 million for the same quarter in 2014. 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, administrative costs related to establishing AltaGas' U.S. office in Dallas, Texas, and the impact of the stronger US dollar. Depreciation and amortization expense for the fourth quarter of 2015 was $59 million, compared to $47 million for the same quarter in 2014, due to the new assets placed into service. Interest expense for the fourth quarter of 2015 was $34 million, compared to $35 million for the same quarter in 2014.

Certain asset provisions totaling $125 million before tax were recorded in the fourth quarter of 2015, including a pre-tax charge of $35 million related to AltaGas' investment in common shares of Painted Pony; a pre-tax provision of $26 million against AltaGas' investment in ASTC Power Partnership (ASTC), which holds the Sundance B PPA; a pre-tax provision of $17 million on AltaGas' investment in its joint ventures with Idemitsu including in relation to the DC LNG Project; a pre-tax provision of $7 million on the DC LNG Project related to deferred lease expense; a pre-tax provision of $17 million for certain wind development projects; a pre-tax provision of $16 million for certain gas processing assets that were held for sale; a pre-tax provision of $4 million on AltaGas' one third interest in Inuvik Gas; and a pre-tax provision of $3 million on assets in the Ikhil Joint Venture. These asset provisions compare to the $70 million provision taken in the fourth quarter of 2014 for certain non-productive gas assets.

AltaGas recorded income tax expense of $3 million for the fourth quarter of 2015, compared to a recovery of $5 million in the same quarter of 2014, mainly due to charges to income in the fourth quarter of 2015 that did not attract tax recoveries.

Normalized net income was $56 million ($0.38 per share) for the fourth quarter of 2015, compared to $48 million ($0.36 per share) reported for the same quarter in 2014. The increase in normalized net income was primarily due to the increase in normalized operating income as discussed above, partially offset by higher income tax expense.

Net loss applicable to common shares for the fourth quarter of 2015 was $54 million ($0.37 per share), compared to net income applicable to common shares of $10 million ($0.08 per share) for the same quarter in 2014. Net loss applicable to common shares for the fourth quarter of 2015 was normalized for after-tax amounts related to transaction costs related to acquisitions, development costs related to energy export projects, provisions on assets and on investments accounted for by the equity method, unrealized gain on risk management contracts, and loss on long-term investments. In the fourth quarter of 2014, net income applicable to common shares was normalized for unrealized gain on risk management contracts, loss on long-term investments, gains on asset dispositions, provisions on assets and costs associated with early redemption of medium-term notes (MTNs).

FULL YEAR 2015

Normalized EBITDA for the year ended December 31, 2015 was $582 million, compared to $546 million in 2014. Earnings from the Northwest Hydroelectric Facilities, the stronger US dollar, growth in the Utilities segment, the Ripon, Pomona and Brush II facilities acquired in January 2015, the acquisition of the San Joaquin Facilities on November 30, 2015, and improved results for Blythe Energy Center and Energy Services are some of the key contributions to higher normalized EBITDA. These increases were partially offset by the impact of lower contributions from Alberta power assets and sales of NGL, lower earnings from Petrogas, lower fee-for-service revenues, the impact of major turnarounds at Younger and Harmattan in second quarter 2015, and warmer weather at certain of the natural gas utilities.

Normalized funds from operations for the year ended December 31, 2015 were $470 million ($3.41 per share), compared to $472 million ($3.72 per share) in 2014, reflecting the same drivers as normalized EBITDA, partially offset by lower distributions from Petrogas and higher current income tax expense. AltaGas received $54 million of dividends declared by Petrogas in 2014, whereas AltaGas received $11 million in 2015, as cash was retained by Petrogas to fund its capital program.

Normalized operating income for the year ended December 31, 2015 was $359 million, compared to $366 million in 2014, driven by the same factors as normalized EBITDA, offset by higher depreciation and amortization expense.

Operating and administrative expense for the year ended December 31, 2015 was $492 million, compared to $451 million in 2014. The increase was primarily due to new assets placed into service or acquired; administrative costs related to establishing AltaGas' U.S. office in Dallas, Texas; and the impact of the stronger US dollar. Depreciation and amortization expense for the year ended December 31, 2015 increased to $212 million compared to $173 million for the same period in 2014, mainly due to new assets placed into service and the impact of the stronger US dollar.

Interest expense for the year ended December 31, 2015 was $125 million, compared to $111 million in 2014. Interest expense increased primarily due to interest no longer being capitalized on assets placed into service in the second half of 2014 and during 2015, higher interest costs incurred on US dollar denominated debt, and higher average debt outstanding as a result of the acquisition of the San Joaquin Facilities in the fourth quarter of 2015.

AltaGas recorded income tax expense of $48 million for the year ended December 31, 2015, compared to $19 million in 2014. Income tax expense increased primarily due to higher future income taxes as a result of a 2 percent increase in the Alberta corporate income tax rate that was enacted on June 29, 2015, and charges to income that did not attract tax recoveries.

Normalized net income for the year ended December 31, 2015 was $140 million ($1.02 per share), compared with $165 million ($1.30 per share) reported in 2014. The decrease was primarily due to the lower normalized operating income as discussed above, along with higher interest, and income tax expense and preferred share dividends.

Net income applicable to common shares for the year ended December 31, 2015 was $10 million ($0.07 per share), compared to $96 million ($0.75 per share) in 2014. Total normalizing adjustments in 2015 were $130 million (2014 – $69 million). Net income applicable to common shares for the year ended 2015 was normalized for unrealized gain on risk management contracts, loss on long-term investments, provisions on assets and investments accounted for by equity method, development costs incurred for energy export projects, transaction costs related to acquisitions, and statutory tax rate changes. In 2014, net income applicable to common shares was normalized for unrealized gain on risk management contracts, loss on long-term investments, provisions on assets, costs associated with early redemption of medium-term notes, development costs incurred for energy export projects and gain on asset dispositions.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for and incremental information associated with each non-GAAP measure is discussed below.

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

Net Revenue

	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Net revenue	**$ 216**	$ 286	**$ 996**	$ 1,019
Add (deduct):				
Other loss (income)	**34**	(13)	**29**	(25)
Loss (income) from equity investments	**58**	(1)	**63**	(39)
Cost of sales	**272**	395	**1,105**	1,451
Revenue (GAAP financial measure)	**$ 580**	$ 667	**$ 2,193**	$ 2,406

Management believes that net revenue, which is revenue adjusted for other income or loss, income or loss from equity investments, and the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of commodities affect both revenue and cost of sales, and equity investments are part of operating activities for the Corporation.

Normalized Operating Income

	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Normalized operating income	**$ 111**	$ 105	**$ 359**	$ 366
Add (deduct):				
Transaction costs related to acquisitions	**(2)**	(1)	**(2)**	(1)
Loss on long-term investments	**(35)**	(2)	**(34)**	(2)
Provision on assets	**(43)**	(70)	**(54)**	(119)
Provision on investments accounted for by equity method	**(47)**	—	**(47)**	—
Costs associated with early redemption of MTN	**—**	(14)	**—**	(17)
Gain on asset dispositions	**—**	27	**—**	38
Energy export development costs	**(2)**	—	**(4)**	(2)
Unrealized gain on risk management contracts	**8**	7	**9**	5
Interest expense	**(34)**	(35)	**(125)**	(111)
Foreign exchange gain	**6**	—	**6**	—
Income tax (expense) recovery	**(3)**	5	**(48)**	(19)
Net income (loss) after taxes (GAAP financial measure)	**$ (41)**	$ 22	**$ 60**	$ 138

Normalized operating income is calculated from the Consolidated Statements of Income using net income adjusted for pre-tax unrealized gain or loss on risk management contracts, interest expense, foreign exchange gain (loss), income tax expense, transaction costs related to acquisitions, gain (loss) on long-term investments, provision on assets and on investments accounted for by equity method, costs associated with early redemption of MTNs, gain (loss) on asset dispositions. Normalized operating income also includes an adjustment for the certain non-capitalizable development costs related to energy export projects. Management believes that adjusting net income for these non-operating items is a better indicator of operating performance than net income as it is more comparable between periods.

Normalized EBITDA

($ millions)	Three Months Ended December 31		Years Ended December 31	
	2015	2014	**2015**	2014
Normalized EBITDA	**$ 173**	$ 155	**$ 582**	$ 546
Add (deduct):				
Transaction costs related to acquisitions	**(2)**	(1)	**(2)**	(1)
Loss on long-term investments	**(35)**	(2)	**(34)**	(2)
Gain on asset dispositions	**—**	27	**—**	38
Energy export development costs	**(2)**	—	**(4)**	(2)
Unrealized gain on risk management contracts	**8**	7	**9**	5
Accretion expenses	**(3)**	(3)	**(11)**	(7)
Provision on assets	**(43)**	(70)	**(54)**	(119)
Provision on investments accounted for by equity method	**(47)**	—	**(47)**	—
Costs associated with early redemption of MTNs	**—**	(14)	**—**	(17)
Foreign exchange gain	**6**	—	**6**	—
EBITDA [1]	**$ 55**	$ 99	**$ 445**	$ 441
Add (deduct):				
Depreciation and amortization	**(59)**	(47)	**(212)**	(173)
Interest expense	**(34)**	(35)	**(125)**	(111)
Income tax (expense) recovery	**(3)**	5	**(48)**	(19)
Net income (loss) after taxes (GAAP financial measure)	**$ (41)**	$ 22	**$ 60**	$ 138

1 *AltaGas revised the calculation of EBITDA to earnings before interest, taxes, depreciation and amortization effective July 1, 2015. Comparative information has been restated to reflect this change. Calculation of normalized EBITDA remains unchanged.*

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 gain (loss) on risk management contracts, gain (loss) on long-term investments, transaction costs related to acquisitions, gain (loss) on asset dispositions, accretion expense, provision on assets and on investments accounted for by equity method, costs associated with early redemption of MTNs, and foreign exchange gain (loss). 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 as it is frequently used by analysts and investors in the evaluation of companies within the industry.

Normalized Net Income

($ millions)	Three Months Ended December 31 2015	2014	Years Ended December 31 2015	2014
Normalized net income	**$ 56**	$ 48	**$ 140**	$ 165
Add (deduct) after-tax:				
Transaction costs related to acquisitions	**(1)**	—	**(1)**	—
Unrealized gain on risk management contracts	**6**	4	**7**	3
Loss on long-term investments	**(34)**	(2)	**(33)**	(1)
Gain on asset dispositions	**—**	23	**—**	32
Provision on assets	**(33)**	(52)	**(39)**	(89)
Provision on investments accounted for by equity method	**(47)**	—	**(47)**	—
Energy export development costs	**(1)**	—	**(3)**	(1)
Costs associated with early redemption of MTNs	**—**	(11)	**—**	(13)
Statutory tax rate change	**—**	—	**(14)**	—
Net income (loss) applicable to common shares (GAAP financial measure)	**$ (54)**	$ 10	**$ 10**	$ 96

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gain (loss) on risk management contracts, gain (loss) on long-term investments, gain (loss) on asset dispositions, provision on assets and on investments accounted for by equity method, transaction costs related to acquisitions, costs associated with early redemption of MTNs, 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 December 31 2015	2014	Years Ended December 31 2015	2014
Normalized funds from operations	**$ 159**	$ 154	**$ 470**	$ 472
Add (deduct):				
Energy export development costs	**(1)**	—	**(1)**	—
Transaction costs related to acquisitions	**(2)**	(1)	**(2)**	(1)
Current tax expense on disposition	**(1)**	—	**(1)**	—
Funds from operations	**155**	153	**466**	471
Add (deduct):				
Net change in operating assets and liabilities	**(61)**	(53)	**39**	(11)
Asset retirement obligations settled	**(2)**	(1)	**(4)**	(2)
Cash from operations (GAAP financial measure)	**$ 92**	$ 99	**$ 501**	$ 458

Normalized funds from operations are 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, energy export development costs, and current tax expense on disposition. Funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP.

Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities and expenditures incurred to settle asset retirement obligations.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized EBITDA[1]

($ millions)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Years Ended December 31 2015	Years Ended December 31 2014
Gas	**$ 44**	$ 59	**$ 172**	$ 238
Power	**53**	30	**177**	107
Utilities	**80**	74	**257**	230
Sub-total: Operating Segments	**177**	163	**606**	575
Corporate	**(4)**	(8)	**(24)**	(29)
	$ 173	$ 155	**$ 582**	$ 546

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

Normalized Operating Income[1]

($ millions)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Years Ended December 31 2015	Years Ended December 31 2014
Gas	**$ 27**	$ 41	**$ 105**	$ 167
Power	**31**	16	**106**	65
Utilities	**60**	57	**181**	166
Sub-total: Operating Segments	**118**	114	**392**	398
Corporate	**(7)**	(9)	**(33)**	(32)
	$ 111	$ 105	**$ 359**	$ 366

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

GAS

OPERATING STATISTICS

	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Years Ended December 31 2015	Years Ended December 31 2014
Total inlet gas processed (Mmcf/d)[1]	**1,298**	1,551	**1,302**	1,512
Extraction ethane volumes (Bbls/d)[1]	**32,250**	37,811	**30,970**	34,999
Extraction NGL volumes (Bbls/d)[1]	**33,215**	38,392	**31,308**	37,777
Total extraction volumes (Bbls/d)[1, 2]	**65,465**	76,203	**62,278**	72,776
Frac spread – realized ($/Bbl)[1, 3]	**15.55**	16.29	**18.03**	18.33
Frac spread – average spot price ($/Bbl)[1, 4]	**5.06**	11.18	**5.10**	20.14

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.

Total inlet gas processed for the three and twelve months ended December 31, 2015 decreased by 253 and 210 Mmcf/d, respectively, compared to the same periods in 2014. The decreases were primarily driven by lower volumes at certain extraction plants, the shut-in by the third party operator of the Empress Gas Liquids Joint Venture (EGLJV) plant, lower processed volumes at Younger and the impact of pipeline curtailments downstream of certain AltaGas processing facilities. Significantly lower commodity prices in 2015 also made extraction of certain NGL at some of the facilities uneconomical resulting in reinjections. Turnarounds at Harmattan and Younger during the second quarter of 2015 also impacted inlet volumes.

Average ethane volumes for the three and twelve months ended December 31, 2015 decreased by 5,561 and 4,029 Bbls/d, respectively, and NGL volumes decreased by 5,177 and 6,469 Bbls/d, respectively, compared to the same periods in 2014. Lower ethane volumes were due to lower produced volumes at EGLJV and EEEP facilities. NGL volumes throughout 2015 were impacted by the lower commodity price environment resulting in reinjections. Turnarounds at Harmattan and Younger during the second quarter of 2015 also impacted ethane and NGL volumes in 2015.

Three Months Ended December 31

The Gas segment reported normalized operating income of $27 million in the fourth quarter of 2015, compared to $41 million in the same quarter of 2014. The decrease in operating income reflects the significantly lower commodity price environment, lower processed volumes and the impact of pipeline curtailments downstream of certain gas processing facilities. During the fourth quarter of 2015, AltaGas recorded equity earnings of $nil from Petrogas, compared to $5 million in the same quarter of 2014. Lower earnings from Petrogas' margin-based business and the impact of reduced activities in the upstream oil and gas sector were partially offset by increased shipments from the Ferndale Terminal. Operating earnings before interest, amortization and non-cash charges of Petrogas increased in the fourth quarter of 2015 compared with the same quarter in 2014; however, this was offset by higher amortization and interest expense and certain non-cash charges that impacted net income of Petrogas.

In the fourth quarter of 2015, AltaGas recorded a pre-tax provision of $17 million on its investment in its joint ventures with Idemitsu including in relation to the DC LNG Project; a pre-tax provision of $16 million on certain gas processing assets that were held for sale; and a pre-tax provision of $7 million on the DC LNG Project related to deferred lease expense. In the fourth quarter of 2014, a $70 million pre-tax provision was taken on certain non-productive gas processing assets.

During the fourth quarter of 2015, AltaGas hedged approximately 3,000 Bbls/d of NGL at an average price of $27/Bbl. During the fourth quarter of 2014, AltaGas hedged 6,300 Bbls/d of NGL at an average price of $26/Bbl. The average indicative spot NGL frac spread for the fourth quarter of 2015 was approximately $5/Bbl compared to $11/Bbl in the same quarter of 2014. Realized frac spread of $16/Bbl in the fourth quarter of 2015 (2014 – $16/Bbl) was consistent with the same quarter in 2014 due to gains on NGL frac hedges in the quarter.

Full Year 2015

The Gas segment reported normalized operating income of $105 million for the year ended December 31, 2015, compared to $167 million in 2014. The decrease reflects the impact of weak NGL prices; lower earnings from Petrogas; completion of two major turnarounds at Younger and Harmattan during the second quarter of 2015; and lower throughput at certain gas processing facilities caused in part by third party pipeline curtailments downstream of certain AltaGas processing facilities. Third party pipeline curtailments reduced normalized operating income by $5 million. Partially offsetting these decreases were improved results from Energy Services due to unusually high costs incurred in the first quarter of 2014 to fulfill delivery commitments from operational curtailments resulting from extremely cold weather in eastern North America.

For the year ended December 31, 2015, AltaGas recorded equity earnings of $7 million from Petrogas as compared to $29 million in 2014. The decrease in Petrogas earnings was due to lower earnings from Petrogas' margin-based business, the impact of reduced activities in the upstream oil and gas sector and higher depreciation and interest related to the Ferndale Terminal and other new assets placed into service at Petrogas, partially offset by increased shipments from the Ferndale Terminal. Market conditions were particularly favourable in the first quarter of 2014, which contributed to Petrogas' strong 2014 earnings. Petrogas' earnings in 2015 were impacted by depressed commodity market conditions as well as a planned maintenance shutdown at Ferndale in the first quarter of 2015.

During the year ended December 31, 2015, AltaGas hedged approximately 3,100 Bbls/d of NGL volumes at an average price of $27/Bbl. During the year ended December 31, 2014, AltaGas hedged 5,500 Bbls/d of NGL at an average price of $26/Bbl. The average indicative spot NGL frac spread for the year ended December 31, 2015 was approximately $5/Bbl compared to approximately $20/Bbl in 2014. Realized frac spread of $18/Bbl in 2015 was consistent with 2014.

POWER

OPERATING STATISTICS

	Three Months Ended December 31		Years Ended December 31	
	2015	2014	**2015**	2014
Volume of power sold (GWh)	**1,574**	1,457	**5,708**	5,169
Average Alberta realized power price ($/MWh)	**33.83**	48.85	**41.48**	58.62
Average price realized on the sale of power ($/MWh)[1]	**61.15**	63.77	**62.40**	65.97
Alberta Power Pool average spot price ($/MWh)	**21.19**	30.47	**33.34**	49.42

1 *Price received excludes Blythe Energy Center, Ripon, Pomona, Brush II and the San Joaquin Facilities, as these facilities earn fixed capacity payments under power purchase agreements.*

During the fourth quarter of 2015, volume of power sold increased by 117 GWh compared to the same quarter in 2014. Volumes sold during the fourth quarter of 2015 were comprised of 1,264 GWh of conventional power generation and 310 GWh of renewable power generation, compared to 1,249 GWh of conventional power generation and 208 GWh of renewable power generation in the same quarter of 2014.

For the year ended December 31, 2015, volume of power sold increased by 539 GWh compared to 2014. Volumes sold in 2015 were comprised of 4,408 GWh of conventional power generation and 1,300 GWh of renewable power generation, compared to 4,570 GWh conventional power generation and 599 GWh renewable power generation in 2014. The change in the generation composition was due to renewable volumes from Forrest Kerr, Volcano and McLymont, as well as the impact of the U.S. natural gas-fired assets acquired in 2015, which were offset by decreasing conventional volumes due to the disposition of peakers in Alberta in late 2014, and weak Alberta realized power prices with associated volume impacts.

Three Months Ended December 31

The Power segment reported normalized operating income of $31 million for the fourth quarter of 2015, compared to $16 million for the same quarter in 2014. Normalized operating income increased as a result of higher contributions from Forrest Kerr combined with a full quarter contribution from Volcano and the start of commercial operations at McLymont on October 28, the impact of the U.S. natural gas-fired assets acquired in 2015, and the stronger US dollar. These increases were partially offset by the impact of weaker Alberta realized power prices. The average Alberta power pool spot price dropped to a record low in the fourth quarter of 2015 to $21/MWh.

In the fourth quarter of 2015, AltaGas was 47 percent hedged in Alberta at an average price of $47/MWh. In the fourth quarter of 2014, AltaGas was 57 percent hedged at an average price of $61/MWh.

During the fourth quarter of 2015, the Power segment recorded $43 million of pre-tax provisions, comprised of $26 million for AltaGas' investment in ASTC, which holds the Sundance B PPA; as well as $17 million for certain wind development projects. No asset provisions were taken in the Power segment in the fourth quarter of 2014.

In the fourth quarter of 2015, AltaGas disposed of its effective 25 percent interest in the 7-MW run-of-river hydroelectric power generation facility on Scuzzy Creek near Boston Bar. In addition, AltaGas disposed of the 10-MW McNair run-of-river hydroelectric generating facility located on the Sunshine Coast of British Columbia, near Port Mellon, as well as 40 MW of small hydro development projects in British Columbia. The total gross proceeds from these disposals were approximately $9 million.

Full Year 2015

The Power segment reported normalized operating income of $106 million for the year ended December 31, 2015, compared to $65 million in 2014. Normalized operating income increased as compared to the same period in 2014 due to the contributions from Forrest Kerr and Volcano as well as the start of commercial operations at McLymont on October 28, favourable exchange rates; the impact of the six U.S. natural gas-fired assets acquired in 2015; and increased results from Blythe Energy Center due to a major planned maintenance turnaround in early 2014 and improved efficiencies at the Blythe Energy Center in 2015. This was partially offset by lower Alberta realized power prices and volumes.

For the year ended December 31, 2015, AltaGas was 50 percent hedged in Alberta at an average price of $50/MWh. AltaGas was 55 percent hedged at an average price of $64/MWh in 2014.

The Power segment recorded a total pre-tax provision of $54 million for the year ended December 31, 2015, comprised of $26 million for AltaGas' investment in ASTC and $28 million for certain wind development projects. A pre-tax provision of $11 million was recorded for the year ended December 31, 2014 related to certain small hydro power assets under development in British Columbia.

UTILITIES

OPERATING STATISTICS

	Three Months Ended December 31		Years Ended December 31	
	2015	2014	**2015**	2014
Canadian utilities				
Natural gas deliveries – end-use (PJ)[1]	**10.2**	10.6	**31.8**	32.7
Natural gas deliveries – transportation (PJ)[1]	**1.9**	1.4	**6.9**	5.6
U.S. utilities				
Natural gas deliveries – end-use (Bcf)[1]	**20.2**	23.1	**68.3**	72.3
Natural gas deliveries – transportation (Bcf)[1]	**13.5**	11.7	**47.7**	41.0
Service sites[2]	**568,751**	562,746	**568,751**	562,746
Degree day variance from normal – AUI (%)[3]	**(10.0)**	(3.6)	**(10.0)**	2.3
Degree day variance from normal – Heritage Gas (%)[3]	**(8.0)**	(8.4)	**5.6**	(0.2)
Degree day variance from normal – SEMCO Gas (%)[4]	**(20.4)**	5.1	**0.0**	16.1
Degree day variance from normal – ENSTAR (%)[4]	**(6.1)**	(10.5)	**(9.0)**	(9.0)

1 Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.
2 Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non-regulated business lines.
3 A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG, as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.
4 A degree day for U.S. utilities is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 10 years for ENSTAR.

REGULATORY METRICS

Years Ended December 31	**2015**	2014
Approved ROE (%)		
Canadian utilities (average)	**9.4**	9.7
U.S. utilities (average)	**11.8**	11.2
Approved return on debt (%)		
Canadian utilities (average)	**5.1**	5.9
U.S. utilities (average)	**6.0**	5.3
Rate base ($ millions)[1]		
Canadian utilities	**741**	692
U.S. utilities[2, 3]	**851**	838

1 Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application, which may be different from that indicated above.
2 In US dollars.
3 Reflects AltaGas' 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC.

Three Months Ended December 31

The Utilities segment reported operating income of $60 million in the fourth quarter of 2015, compared to $57 million in the same quarter of 2014. The increase was mainly due to the impact of rate base and customer growth across all Utilities, favourable foreign exchange rates, and the approval of SEMCO Gas' MRP. The increase in operating income was partially offset by warmer weather experienced in Michigan and Alberta.

During the fourth quarter, the Utilities segment recorded $4 million of pre-tax provisions related to AltaGas' one third interest in Inuvik Gas and $3 million of pre-tax provisions related to assets in the Ikhil Joint Venture. No asset provisions were taken in the Utilities segment in the fourth quarter of 2014.

Full Year 2015

The Utilities segment reported operating income of $181 million for the year ended December 31, 2015, compared to $166 million in 2014. The increase was mainly due to rate base and customer growth across all Utilities, favourable foreign exchange rates, the approval of SEMCO Gas' MRP and colder weather experienced in Nova Scotia. The increase in operating income was partially offset by warmer weather experienced in Michigan and Alberta, and higher operating costs due to increased pension, retiree medical, and severance costs.

On June 3, 2015, SEMCO Gas' MRP case was approved by the MPSC. This program was for the recovery of capital expenses projected from 2016 to 2020 combined with a reconciliation of the current program that expires in December 2015. The new rates took effect immediately, resulting in approximately US$4 million of additional operating income for the year ended December 31, 2015.

CORPORATE

Three Months Ended December 31

In the Corporate segment, normalized operating loss for the fourth quarter of 2015 was $7 million, compared to $9 million in the same quarter of 2014. The decrease was mainly due to cost saving initiatives implemented in 2015 partially offset by higher depreciation and amortization expense on major IT projects placed into service in 2015.

During the fourth quarter of 2015, a pre-tax charge of $35 million was recorded related to AltaGas' investment in common shares of Painted Pony.

Full Year 2015

Normalized operating loss for the year ended December 31, 2015 was $33 million, compared to $32 million in 2014. The increase in normalized operating loss was due to higher depreciation and amortization expense on major IT projects placed into service in 2015, partially offset by cost saving initiatives implemented in 2015.

INVESTED CAPITAL

During the fourth quarter of 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $1.1 billion, compared to $194 million in the same quarter of 2014. The net invested capital was $1.1 billion for the fourth quarter of 2015, compared to $157 million in the same quarter of 2014. The increase from 2014 was mainly as a result of the acquisition of the San Joaquin Facilities, which closed on November 30, 2015.

The invested capital in the fourth quarter of 2015 included maintenance capital of $4 million (2014 – $6 million) in the Gas segment and $2 million (2014 – $nil) in the Power segment.

Three Months Ended December 31, 2015 *($ millions)*	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Property, plant and equipment	**$ 138**	**$ 538**	**$ 61**	**$ 4**	**$ 741**
Intangible assets	**1**	**355**	**2**	**2**	**360**
Long-term investments	**1**	**—**	**—**	**—**	**1**
	140	**893**	**63**	**6**	**1,102**
Disposals:					
Property, plant and equipment	**—**	**(9)**	**—**	**—**	**(9)**
Net Invested capital	**$ 140**	**$ 884**	**$ 63**	**$ 6**	**$ 1,093**

Three Months Ended December 31, 2014 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 44	$ 58	$ 76	$ 3	$ 181
Intangible assets	—	—	2	7	9
Long-term investments	1	—	—	3	4
	45	58	78	13	194
Disposals:					
Property, plant and equipment	—	(37)	—	—	(37)
Net Invested capital	$ 45	$ 21	$ 78	$ 13	$ 157

During the year ended December 31, 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $1.6 billion, compared to $654 million in 2014. The net invested capital was approximately $1.6 billion for the year ended December 31, 2015, compared to $590 million in 2014.

During 2015, the Power segment paid $11 million (2014 – $5 million) to BC Hydro in support of the construction and operation of the Northwest Transmission Line.

The invested capital for year ended December 31, 2015 included maintenance capital of $23 million (2014 – $12 million) in the Gas segment and $4 million (2014 – $nil) in the Power segment. Gas segment maintenance capital included $8 million related to the Harmattan turnaround during the second quarter of 2015 (2014 – $nil).

Year Ended December 31, 2015 *($ millions)*	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Property, plant and equipment	**$ 263**	**$ 702**	**$ 186**	**$ 9**	**$ 1,160**
Intangible assets	**3**	**376**	**4**	**13**	**396**
Long-term investments	**10**	**—**	**—**	**—**	**10**
	276	**1,078**	**190**	**22**	**1,566**
Disposals:					
Property, plant and equipment	**—**	**(9)**	**(1)**	**—**	**(10)**
Net Invested capital	**$ 276**	**$ 1,069**	**$ 189**	**$ 22**	**$ 1,556**

Year Ended December 31, 2014 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 91	$ 285	$ 184	$ 7	$ 567
Intangible assets	—	5	2	20	27
Long-term investments	7	—	—	53	60
	98	290	186	80	654
Disposals:					
Property, plant and equipment	(27)	(37)	—	—	(64)
Net Invested capital	$ 71	$ 253	$ 186	$ 80	$ 590

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. As at December 31, 2015 and 2014, the fair values of the Corporation's derivatives were as follows:

As at December 31 *($ millions)*		**2015**		2014
Natural gas	**$**	**3.1**	$	(3.9)
Storage optimization		**2.5**		0.9
NGL frac spread		**—**		20.9
Power		**19.5**		15.9
Heat rate		**0.1**		0.4
Foreign exchange		**(0.5)**		(0.5)
	$	**24.7**	$	33.7

Commodity Price Contracts

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. The calculation of fair value of foreign exchange derivatives used quoted market rates.

AltaGas does not speculate on commodity prices and therefore does not engage in commodity transactions that create incremental exposure or are based solely on expectations of future energy market price movements. Commodity transactions are used to lock in margins, optimize underlying physical assets or reduce exposure to energy price movements. AltaGas' risk management group reviews commodity and credit risk on a daily basis, and has created and adheres to a conservative risk policy and hedging program.

Power hedges:

AltaGas executes fixed for floating power price swaps to manage its Alberta power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power segment results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0/MWh to $998/MWh in 2015 and $8/MWh to $1,000/MWh in 2014. The average Alberta spot price was approximately $33/MWh in 2015 (2014 – $49/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average realized Alberta power price was approximately $41/MWh in 2015 (2014 – $59/MWh).

NGL frac spread hedges:

The Corporation executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During 2015, the Corporation hedged approximately 3,100 Bbls/d of NGL at an average price of approximately $27/Bbl. The average indicative spot NGL frac spread for 2015 was an estimated $5/Bbl (2014 – $20/Bbl). The average NGL frac spread realized by AltaGas in 2015 was approximately $18/Bbl (2014 – $18/Bbl). Given the weak commodity prices, AltaGas does not expect to enter into frac hedges for 2016 at this time.

Foreign Exchange

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts, whereby a fixed rate is locked in against a floating rate; and option agreements, whereby an option to transact foreign currency at a future date is purchased or sold. Foreign exchange gains and losses on long-term debt denominated in US dollars are unrealized and can only be realized when the long-term debt matures or is settled.

As at December 31, 2015, management designated US$724 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2014 – US$375 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 year ended December 31, 2015, AltaGas incurred after-tax unrealized loss of $98.7 million arising from the translation of debt in other comprehensive income (December 31, 2014 – after-tax unrealized loss of $35.0 million).

The Effects of Derivative Instruments on the Consolidated Statements of Income

The following table presents the unrealized gains or losses on derivative instruments as recorded in the Corporation's consolidated statements of income:

Years Ended December 31 *($ millions)*		**2015**		2014
Natural gas	**$**	**7.2**	$	(7.9)
Storage optimization		**(0.4)**		2.1
NGL frac spread		**(3.2)**		3.2
Power		**6.3**		7.5
Heat rate		**(0.3)**		0.1
Foreign exchange		**(0.1)**		(0.3)
Embedded derivative		**(0.1)**		—
	$	**9.4**	$	4.7

Please refer to Note 19 of the 2015 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities, including a sensitivity analysis on the potential impact on pre-tax income due to changes in the fair value of risk management contracts in place as at December 31, 2015.

Corporation Risks

AltaGas manages its exposure to risks using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks
Operational	• Maintain diversification across Gas, Power and Utilities • Acquire large working interests to control and optimize operations and maximize efficiencies • Contractual provisions often provide for recovery of operating costs • Centralized procurement strategy to reduce costs • Maintain control over operational decisions, operating cost and capital expenditures by operating certain jointly-owned facilities • Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs • Purchase business interruption insurance • Fixed price operating and maintenance contracts with equipment manufacturers • Hedging strategy used to balance price and operating risk; deliveries of certain hedge contracts are suspended if there is an outage at Sundance B
Construction	• Major projects group manages and monitors significant construction projects • Strong in-house project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and schedule risks
Liquidity	• Forecast cash flow on a continuous basis to maintain adequate cash balances to fund financial obligations as they come due and to support business operations • Maintain financial flexibility and liquidity needs through a variety of sources including internally-generated cash flows, DRIP, access to credit facilities, and long-term debt and equity issuances • Execute financing plans and strategies to maintain and improve credit ratings to minimize financing costs and support ready access to capital markets
Foreign exchange	• Issue long-term debt and preferred shares in US dollars which hedge the Corporation's net investment in U.S. subsidiaries • Employ hedging practices such as entering foreign exchange forward contracts
Interest rates	• Optimize financing plans to maintain and improve credit ratings to minimize interest costs • Monitor and proactively manage the Corporation's debt maturity profile • Employ hedging practices such as entering into interest rate swaps • Maintain financial flexibility and access to multiple credit facilities and continually monitoring covenant compliance

Risks	Strategies and Organizational Capability to Mitigate Risks
Long-term natural gas volume declines	• Long-term contracts such as take-or-pay, area of mutual interest, geographic franchise with economic out • Increase market share by expanding existing facilities or acquiring or constructing new facilities • Increase geographic and customer diversity to reduce exposure to individual customer or area of the WCSB • Strategically locate facilities to provide secure access to gas supply • Capitalize on integrated aspects of AltaGas' business to increase volumes through its processing facilities
Volume of power generated	• PPAs include specified target availability levels • Diversification of fuel sources and geography • Hedging strategy to balance price and operating risk • Undertake extensive studies to support investment decisions
Commodity price	• Contracting terms, processing, storage and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions • Hedging strategy with hedge targets approved by the Board of Directors • Monitor hedge transactions through Risk Management Committee • AltaGas' Commodity Risk Policy prohibits transactions for speculative purposes • Employ hedging practices to reduce exposure to commodity prices and volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility • Employ strong systems and processes for monitoring and reporting compliance with the Commodity Risk Policy • In-depth knowledge and experience of transportation systems, natural gas, NGL and power markets where AltaGas operates • Hedge power costs • Direct marketing to end-use commercial and industrial customers • Own and operate gas-fired peaking capacity to backstop the Sundance B PPA and sell energy and ancillary services • Increase base-load natural gas-fired generating capacity where cost effective to do so • Execute long-term inflation adjusted electricity purchase arrangements with power buyers
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty creditworthiness • Establish credit thresholds using appropriate credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base • Active accounts receivable monitoring and collections processes in place • Credit terms included in contracts
Weather	• Anticipated volumes are determined based on the 20-year rolling average for weather for the Canadian utilities and 15 years for SEMCO Gas and 10 years for ENSTAR • PNG has a weather normalization account for residential and small commercial customers

Risks	Strategies and Organizational Capability to Mitigate Risks
Regulatory and First Nations	• Regulatory and commercial personnel monitor and manage regulatory issues • Proactive regulatory and government relations group, strong working relationships with First Nations, stakeholders, and regulators • Build risk mitigation into contracts where appropriate • Skilled regulatory department retained • Use of expert third parties when needed
Environment and safety	• Strong safety and environmental management systems • Continuous process improvement strategy employed • Focus on mitigating the impact of the climate change regulations
Labour relations	• Maintain access to strong labour markets to attract qualified talent • Positive employee relations to retain existing talent and maintain strong relations with unions

LIQUIDITY

Years Ended December 31 *($ millions)*	**2015**	2014
Cash from operations	**$ 501**	$ 458
Investing activities	**(1,516)**	(591)
Financing activities	**930**	456
Effect of exchange rate	**7**	4
Increase (decrease) in cash and cash equivalents	**$ (78)**	$ 327

Cash from Operations

Cash from operations increased by $43 million for the year ended December 31, 2015 compared to 2014 primarily due to higher cash contributions from new assets placed into service, the favourable US dollar exchange rate, and the U.S. natural gas-fired power assets acquired in 2015, partially offset by lower commodity prices and volumes, and lower distributions from the Corporation's equity investments. AltaGas received $11 million in dividends from Petrogas in 2015, compared with $54 million in dividends in 2014. The increase in cash from operations was also impacted by the favourable variance in net change in operating assets and liabilities. The net change in operating assets and liabilities was a net cash inflow of $39 million for the year ended December 31, 2015 compared to net cash outflow of $11 million in 2014. The higher net cash inflow is due to changes in accounts receivable, inventory, and regulatory assets, largely as a result of changes in gas commodity costs, partially offset by an increase in payments for other assets, and higher accounts receivable relating to the Northwest Hydro Facilities.

Working Capital

As at December 31 *($ millions except current ratio)*	**2015**	2014
Current assets	**$ 1,038**	$ 1,058
Current liabilities	**948**	763
Working capital	**$ 90**	$ 295
Working capital ratio	**1.09**	1.39

The decrease in working capital ratio was primarily due to the decrease in cash and cash equivalents and accounts receivable, the maturity of a $50 million short-term investment during 2015, higher accounts payable and an increase in debt maturing within one-year of December 31, 2015. This was partially offset by the reclassification of $90 million of non-current net assets to current, due to the planned sale of certain non-core gas processing assets.

Investing Activities

Cash used in investing activities for the year ended December 31, 2015 was $1.5 billion, compared to $591 million in 2014. Investing activities for the year ended December 31, 2015 primarily included expenditures of $916 million for business acquisitions, $614 million for property, plant, and equipment, and $38 million for intangible assets, partially offset by cash inflow of $50 million relating to the maturity of a short-term investment and $10 million from disposition of assets. Investing activities in 2014 primarily comprised of $520 million for property, plant, and equipment, $29 million for intangible assets, $50 million for acquisition of a short-term investment, and $53 million for acquisition of long-term investments, partially offset by proceeds of $65 million received on disposition of assets.

Financing Activities

Cash from financing activities in 2015 was $930 million, compared to $456 million in 2014. Financing activities in 2015 were primarily comprised of net proceeds from the issuance of long-term debt of $1.1 billion, common shares of $403 million, and preferred shares of $196 million and the net issuance of $47 million of short-term debt, partially offset by repayment of $476 million of long-term debt. Financing activities in 2014 were primarily comprised of net proceeds from issuance of long-term debt of $1.3 billion, net proceeds from issuance of common shares of $535 million, and issuance of preferred shares of $194 million, partially offset by repayments of long-term and short-term debt of $1.3 billion and $18 million, respectively. Total dividends paid to common and preferred shareholders in 2015 were $296 million, compared to $245 million in the same period in 2014. The increase was due to more common shares outstanding and dividend increases declared in 2015.

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 and short-term investments.

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.

As at December 31 *($ millions)*	**2015**	2014
Short-term debt	**$ 131**	$ 72
Current portion of long-term debt	**288**	214
Long-term debt[1]	**3,732**	3,032
Total debt	**4,151**	3,318
Less: cash and cash equivalents	**(293)**	(371)
Less: short-term investments	**—**	(50)
Net debt	**$ 3,858**	$ 2,897
Shareholders' equity	**4,168**	3,541
Non-controlling interests	**35**	33
Total capitalization	**$ 8,061**	$ 6,471
Debt-to-total capitalization (%)	**48**	45

1 *Net of debt issuance costs of $15 million as at December 31, 2015 (December 31, 2014 – $18 million).*

As at December 31, 2015, AltaGas' total debt primarily consisted of outstanding MTNs of $2.8 billion (December 31, 2014 – $2.8 billion), PNG debenture notes of $47 million (December 31, 2014 – $57 million), SEMCO long-term debt of $522 million (December 31, 2014 – $443 million) and $811 million drawn under the bank credit facilities (December 31, 2014 – $46 million). In addition, AltaGas had $147 million of letters of credit (December 31, 2014 – $136 million) outstanding.

As at December 31, 2015, AltaGas' total market capitalization was approximately $5.3 billion based on approximately 146 million common shares; approximately 6 million series A Preferred Shares; approximately 2 million series B Preferred Shares; 8 million series C US$ Preferred Shares; 8 million series E Preferred Shares; 8 million series G Preferred Shares; and 8 million series I Preferred Shares outstanding, and a closing trading price on December 31, 2015 of $30.87 per common share; $16.17 per series A Preferred Share; $14.05 per series B Preferred Share; $20.27 per series C US$ Preferred Share; $21.78 per series E Preferred Share; $20.99 per series G Preferred Share; and $25.05 per series I Preferred Share, respectively.

AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2015 was 1.5 times.

Credit Facilities

($ millions)	Borrowing capacity	Drawn at December 31 2015	Drawn at December 31 2014
Demand operating facilities	$ 70	**$ 4**	$ 4
Extendible revolving letter of credit facility	150	**56**	113
Letter of credit demand facility	150	**80**	—
PNG operating facility	25	**10**	14
Bilateral letter of credit facility[1]	—	**—**	13
AltaGas Ltd. revolving credit facility[2]	1,400	**690**	—
SEMCO Energy US$ unsecured credit facility[2, 3]	150	**118**	38
	$ 1,945	**$ 958**	$ 182

1 Effective September 2015, the bilateral letter of credit facility was closed.
2 Amount drawn at December 31, 2015 converted at the month-end rate of 1 US dollar = 1.3840 Canadian dollar (December 31, 2014 – 1 US dollar = 1.1601 Canadian dollar).
3 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 December 31, 2015**
Bank debt-to-capitalization[1]	not greater than 65 percent	**46.2%**
Bank EBITDA-to-interest expense[1, 2]	not less than 2.5x	**4.10**
Bank debt-to-capitalization (SEMCO)[3]	not greater than 60 percent	**46.7%**
Bank EBITDA-to-interest expense (SEMCO)[3]	not less than 2.25x	**6.61**

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 December 31, 2015, $4.5 billion remains available under the base shelf prospectus.

CONTRACTUAL OBLIGATIONS

As at December 31, 2015		Payments Due by Period			
($ millions)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Short-term debt[1]	$ **130.7**	$ **130.7**	$ **—**	$ **—**	$ **—**
Long-term debt[1]	**4,035.1**	**287.6**	**578.1**	**1,520.3**	**1,649.1**
Operating leases	**91.7**	**27.6**	**39.6**	**11.6**	**12.9**
Purchase obligations	**2,395.0**	**382.8**	**677.5**	**569.1**	**765.6**
Capital project commitments	**64.9**	**64.9**	**—**	**—**	**—**
Pension plan and retiree benefits	**20.1**	**20.1**	**—**	**—**	**—**
Long-term liabilities	**162.2**	**11.0**	**20.7**	**20.0**	**110.5**
Total contractual obligations[2]	**$ 6,899.7**	**$ 924.7**	**$ 1,315.9**	**$ 2,121.0**	**$ 2,538.1**

1 Excludes interest payments.
2 US dollar commitments have been converted to Canadian dollar using the December 31, 2015 exchange rate.

RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Refer to Note 26 of the 2015 Annual Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheets and the classification of revenue, income, and expenses in the Consolidated Statements of Income.

CREDIT RATINGS

On December 16, 2015, Standard & Poor's (S&P) revised the BBB rating to BBB with a Negative Outlook and reaffirmed the P-3 (High) rating for AltaGas.

On November 19, 2015 S&P commenced rating of the Series I Preferred Shared with a rating of P-3 (High).

On November 19, 2015 DBRS Limited (DBRS) reaffirmed the BBB rating with a stable trend for AltaGas.

On November 18, 2015 DBRS commenced rating of the Series I Preferred Shares with a rating of Pfd-3.

On November 14, 2014, DBRS Limited (DBRS) reaffirmed the BBB and Pfd-3 ratings for AltaGas.

On July 3, 2014, DBRS commenced rating of the Series G Preferred Shares with a rating of Pfd-3.

On July 2, 2014, Standard & Poor's (S&P) assigned a rating of P-3 (High) to the Series G Preferred Shares.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but the entity may be vulnerable to future events, which reduce the strength of the entity and its rated securities. "High" or "low" grades are used to indicate the relative standing within a particular rating category. A Pfd-3 rating by DBRS is the third highest of six categories granted by DBRS. According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adversities present which detract from debt protection. Pfd-3 ratings normally correspond with companies whose bonds are rated in the higher end of the BBB category. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. DBRS rates AltaGas BBB with a stable trend.

According to the S&P rating system, an obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. A P-3 rating by S&P is the third highest of eight categories granted by S&P. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories. S&P rates AltaGas BBB with a negative outlook.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

SHARE INFORMATION

On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million.

On September 30, 2015, 2,488,780 of the outstanding 8,000,000 Cumulative Redeemable Five Year Fixed Rate Reset Preferred Shares, Series A were converted into Cumulative Floating Rate Preferred Shares, Series B.

On November 23, 2015, AltaGas closed a public offering of 8,000,000 Cumulative Redeemable 5-Year Minimum Rate Reset Preferred Shares, Series I, at a price of $25.00 per Series I, Preferred Share for aggregate gross proceeds of $200 million.

	As at February 17, 2016
Issued and outstanding	
Common shares	146,920,619
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	4,559,761
Share options exercisable	2,993,946

DIVIDENDS

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

On April 30, 2015, the Board of Directors approved an increase in the monthly dividend to $0.16 per common share from $0.1475 per common share effective with the May dividend.

On September 18, 2015, the Board of Directors approved an increase in the monthly dividend to $0.165 per common share from $0.16 per common share effective with the October dividend.

On September 30, 2015, the Series A preferred shares annual fixed dividend rate was reset to 3.38 percent. The dividend rate will reset on September 30, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent.

The Series B preferred shares will pay a floating quarterly dividend for the five-year period beginning on September 30, 2015 at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill plus 2.66 percent, and will reset every quarter. The first quarterly floating rate period (being the period from September 30, 2015 to, but excluding, December 31, 2015) is 3.04 percent. Commencing December 31, 2015, the floating quarterly dividend rate is 3.10 percent for the period from December 31, 2015 to, but excluding, March 31, 2016.

Holders of the Series I preferred shares will receive the first quarterly dividend payment on March 31, 2016 of $0.46387 per Series I preferred share. The dividend rate will reset on December 31, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 4.19 percent, provided that, in any event, such rate shall not be less than 5.25 percent per annum.

The following table summarizes AltaGas' dividend declaration history:

Dividends

Years ended December 31 *($ per common share)*	**2015**	2014
First quarter	**$ 0.44250**	$ 0.38250
Second quarter	**0.46750**	0.42250
Third quarter	**0.48000**	0.44250
Fourth quarter	**0.49500**	0.44250
Total	**$ 1.88500**	$ 1.69000

Series A Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2015**	2014
First quarter	**$ 0.31250**	$ 0.31250
Second quarter	**0.31250**	0.31250
Third quarter	**0.31250**	0.31250
Fourth quarter	**0.21125**	0.31250
Total	**$ 1.14875**	$ 1.25000

Series B Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2015**	2014
Fourth quarter	**$ 0.19156**	$ —
Total	**$ 0.19156**	$ —

Series C Preferred Share Dividends

Years ended December 31 *(US$ per preferred share)*	**2015**	2014
First quarter	**$ 0.27500**	$ 0.27500
Second quarter	**0.27500**	0.27500
Third quarter	**0.27500**	0.27500
Fourth quarter	**0.27500**	0.27500
Total	**$ 1.10000**	$ 1.10000

Series E Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2015**	2014
First quarter	**$ 0.31250**	$ 0.36990
Second quarter	**0.31250**	0.31250
Third quarter	**0.31250**	0.31250
Fourth quarter	**0.31250**	0.31250
Total	**$ 1.25000**	$ 1.30740

Series G Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2015**	2014
First quarter	**$ 0.29690**	$ —
Second quarter	**0.29690**	—
Third quarter	**0.29690**	0.28960
Fourth quarter	**0.29690**	0.29690
Total	**$ 1.18760**	$ 0.58650

CRITICAL ACCOUNTING ESTIMATES

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

Fair Value of Financial Instruments

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by management. Where bid or ask prices in an active market are not available, management's judgment on valuation inputs is necessary to determine fair value. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity, interest rate and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, currency exchange and interest rate yield curves. The forward curves used to mark these derivative instruments to market are vetted against public sources. Where observable market data is not available, AltaGas uses valuation techniques which require significant judgment by management. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Depreciation and Amortization

Depreciation and amortization of property, plant, and equipment and intangible assets are based on management's judgment of the estimated useful life of the assets. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. For regulated entities, amortization rates are generally prescribed by the applicable regulatory authority. There are a number of uncertainties inherent in estimating the remaining useful life of certain assets and changes in assumptions could result in material adjustments to the amount of amortization that AltaGas recognizes from period to period.

Asset Retirement Obligations

AltaGas records liabilities relating to asset retirement obligations when there is a legal obligation. In estimating the obligations, management is required to make assumptions regarding inflation and discount rates, ultimate amounts and timing of settlements, and expected changes in environmental laws and regulation. A change in any of these estimates could have a material impact on AltaGas' Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. The determination of fair value requires management to make assumptions about future cash inflows and outflows over the life of an asset. Any changes to the assumptions used for the future cash flow could result in revisions to the evaluation of the recoverability of the long-lived assets or intangible assets and the recognition of an impairment loss in the Consolidated Financial Statements.

With respect to impairment assessment, management has made fair value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistently with prior periods.

Income Taxes

The Corporation is subject to the provisions of the Income Tax Act (Canada) for purposes of determining the amount of income that will be subject to tax in Canada and the Internal Revenue Code (U.S.) for the purposes of determining the amount of income that will be subject to tax in the United States. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

Substantial deferred income tax assets and liabilities are recognized in the Consolidated Financial Statements. The recognition of deferred tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the deferred tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of tax authorities, or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See Note 16 to the 2015 Annual Consolidated Financial Statements.

Pension Plans and Post-retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate-of-return on plan assets and the discount rate applied to pension plan obligations. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates. Notes 2 and 25 to the 2015 Annual Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

Regulatory Assets and Liabilities

SEMCO, ENSTAR and CINGSA, AUI, Heritage Gas and PNG engage in the delivery and sale of natural gas and are regulated by the following regulatory agencies: MPSC and RCA, AUC, NSUARB and BCUC, respectively.

The regulatory agencies exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the regulators, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

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

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective July 1, 2015, AltaGas early adopted Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) 2015-03 "Simplifying the Presentation of Debt Issuance Costs". Under the ASU, debt issuance costs are recorded as a direct deduction from the related debt liability rather than as an asset. Upon adoption, AltaGas reclassified debt issuance costs of $16 million and $18 million for the periods ended June 30, 2015 and December 31, 2014, respectively, from "Long-term investments and other assets" to "Long-term debt". Debt issuance costs related to line-of-credit arrangements were not reclassified pursuant to guidance from ASU 2015-15 "Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements".

Effective August 2015, AltaGas prospectively adopted FASB issued ASU No. 2015-13 "Derivatives and Hedging – Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets", which allows certain forward contracts for physical delivery of electricity in nodal energy markets to qualify for the normal purchases and normal sales scope exception, as long as the physical delivery criterion and other criteria for the normal purchases and normal sales scope exception are met. The ASU applies to forward contracts in which one of the counterparties incurs location marginal pricing charges (or credits) payable to (or receivable from) an independent system operator. The adoption of this ASU did not have an impact on AltaGas' consolidated financial statements.

Effective October 1, 2015, AltaGas early adopted FASB issued ASU No. 2015-17 "Balance Sheet Classification of Deferred Taxes" which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as non-current on the balance sheet. Upon adoption, AltaGas reclassified current deferred income tax assets of $2 million and $nil, for the periods ended September 30, 2015 and December 31, 2014, respectively, to non-current deferred income tax asset. Current deferred income tax liabilities of $nil and $2 million for the periods ended September 30, 2015 and December 31, 2014, respectively, were reclassified to non-current deferred income tax liabilities.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, FASB issued ASU 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. On July 9, 2015, FASB confirmed a one-year deferral of the new revenue standard. The new 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 February 2015, FASB issued 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 amendments in this ASU are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

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. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

AltaGas is not party to any contractual arrangement under which an unconsolidated entity or a material variable interest in an unconsolidated entity have any obligation under certain guarantee contracts; a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. AltaGas is not party to any variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services.

In May 2009, the National Energy Board (NEB) issued a decision that set out guiding principles for a mechanism that would set aside funds for pipeline abandonment. It also established a five-year action plan for all NEB-regulated companies. In May 2014, the NEB issued a decision establishing that, by January 1, 2015, all NEB-regulated companies must have a mechanism in place for the accumulation of funds to pay for future pipeline abandonment. AltaGas Holdings Inc., a wholly-owned subsidiary of AltaGas, opted to comply with the NEB decision with a surety bond supplied by a surety company regulated by the Office of the Superintendent of Financial Institutions in the amount of $30 million.

In October 2014, AltaGas issued two guarantees with an aggregate maximum liability of approximately US$92 million, guaranteeing Heritage Gas' payment obligations under a transportation agreement entered into by Heritage Gas with the third party owners of the transportation facility.

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 have 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 December 31, 2015 and concluded that as at December 31, 2015, AltaGas' DCP and ICFR were effective.

On January 1, 2015, AltaGas launched a new enterprise resource planning system, JD Edwards EnterpriseOne. The changes to the internal controls over financial reporting are included in the assessment to ensure that DCP and ICFR are designed 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, reliably reported on a timely basis, and financial statements are in accordance with U.S. GAAP.

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 2015 Annual Consolidated Financial Statements for as at, and for the year ended December 31, 2015 is as follows:

($ millions)		
Revenues	$	11
Operating income	$	6
Current assets	$	44
Non-current assets	$	979
Current liabilities	$	14
Non-current liabilities	$	91

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)	**Q4-15**	**Q3-15**	**Q2-15**	**Q1-15**	Q4-14	Q3-14	Q2-14	Q1-14
Total revenue	**580**	**452**	**416**	**744**	667	444	471	824
Net revenue[2]	**216**	**268**	**204**	**307**	285	217	220	297
Normalized operating income[2]	**111**	**69**	**54**	**125**	105	59	64	137
Net income (loss) applicable to common shares	**(54)**	**20**	**(22)**	**66**	10	17	29	40
($ per share)	**Q4-15**	**Q3-15**	**Q2-15**	**Q1-15**	Q4-14	Q3-14	Q2-14	Q1-14
Net income (loss) per common shares								
Basic	**(0.37)**	**0.15**	**(0.16)**	**0.49**	0.08	0.13	0.23	0.33
Diluted	**(0.37)**	**0.14**	**(0.16)**	**0.49**	0.08	0.13	0.23	0.32
Dividends declared	**0.50**	**0.48**	**0.47**	**0.44**	0.44	0.44	0.42	0.38

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, 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 U.S. natural gas-fired power assets in the first quarter of 2015;
- The Harmattan and Younger turnarounds in the second quarter of 2015;
- The weak NGL commodity prices during the latter part of 2014 and throughout 2015;
- The San Joaquin Facilities acquired on November 30, 2015; and
- The stronger US dollar on translated results of the U.S. assets throughout 2015.

Net income (loss) applicable to common shares are also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provision on assets and gain or loss on asset dispositions. In addition, net income (loss) applicable to common shares is also impacted by preferred shares dividend. 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 were impacted by:

- An after-tax provision of $37 million for EDS and JFP transmission pipeline assets and certain hydro power development assets recorded in the first quarter of 2014;
- Higher interest and depreciation and amortization expense since the third quarter of 2014 due to new assets placed into service and interest no longer eligible for capitalization;
- 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; and
- 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 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 and assets in the Ikhil Joint Venture.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2015**	2014	2013
Revenue	**2,193**	2,406	2,043
Net income applicable to common shares	**10**	96	182
Basic ($ per share)	**0.07**	0.75	1.56
Diluted ($ per share)	**0.07**	0.74	1.52
Total assets	**10,100**	8,396	7,284
Total long-term financial liabilities	**3,899**	3,202	2,960
Weighted average number of common shares outstanding (millions)	**138**	127	116
Dividends declared per common share ($ per share)	**1.88500**	1.69000	1.49250
Preferred share dividends declared ($ per share)			
Series A	**1.14875**	1.25000	1.25000
Series B	**0.19156**	—	—
Series C	**1.10000**	1.10000	1.10000
Series E	**1.25000**	1.30740	—
Series G	**1.18760**	0.58650	—

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S RESPONSIBILITY FOR CONSOLIDATED FINANCIAL STATEMENTS

The Consolidated Financial Statements and Management's Discussion and Analysis (MD&A) are the responsibility of the management of AltaGas Ltd. (AltaGas or the Corporation) and have been approved by the Board of Directors of the Corporation. The Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP) and include amounts that are based on management's best estimates and judgments.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting for the Corporation. Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. Management undertakes communication to employees of policies that govern ethical business conduct.

The MD&A and Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of independent non-management directors.

The Audit Committee meets with management regularly and meets independently with internal and external auditors and as a group to review any significant accounting, internal controls and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Consolidated Financial Statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed Ernst & Young LLP as independent external auditors to express an opinion as to whether the Consolidated Financial Statements present fairly, in all material respects, the Corporation's consolidated financial position, results of operations and cash flows in accordance with U.S. GAAP. The report of Ernst & Young LLP outlines the scope of its examination and its opinion on the Consolidated Financial Statements.

DAVID W. CORNHILL
Chairman and Chief Executive Officer of
AltaGas Ltd.

TIM WATSON
Executive Vice President and
Chief Financial Officer of
AltaGas Ltd.

February 24, 2016

INDEPENDENT AUDITORS' REPORT

To the Shareholders of AltaGas Ltd.

We have audited the accompanying Consolidated Financial Statements of AltaGas Ltd., which comprise the consolidated balance sheets as at December 31, 2015 and 2014, and the consolidated statements of income, comprehensive income, equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian Generally Accepted Auditing Standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of AltaGas Ltd. as at December 31, 2015 and 2014 and the results of its operations and its cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

Ernst & Young LLP

Calgary, Canada
February 24, 2016

ERNST & YOUNG LLP
Chartered Professional Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 *($ millions)*		2015		2014
ASSETS				
Current assets				
Cash and cash equivalents	$	293.4	$	371.0
Short-term investment		—		50.0
Accounts receivable, net of allowances *(note 19)*		333.3		352.4
Inventory *(note 5)*		204.0		155.3
Restricted cash holdings from customers		5.4		4.2
Regulatory assets *(note 17)*		4.3		12.8
Risk management assets *(note 19)*		50.4		70.8
Prepaid expenses and other current assets		48.3		41.9
Assets held for sale *(note 4)*		98.7		—
		1,037.8		1,058.4
Property, plant and equipment *(notes 4 and 6)*		6,597.9		5,337.0
Intangible assets *(notes 4 and 8)*		735.1		356.9
Goodwill *(note 9)*		877.3		785.1
Regulatory assets *(note 17)*		333.3		302.0
Risk management assets *(note 19)*		23.5		21.1
Deferred income taxes *(note 16)*		4.5		2.2
Restricted cash holdings from customers		12.5		12.2
Long-term investments and other assets *(note 10)*		64.3		66.8
Investments accounted for by equity method *(note 11)*		413.3		453.9
	$	10,099.5	$	8,395.6
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities *(note 19)*	$	383.1	$	343.6
Dividends payable		24.1		19.8
Short-term debt *(notes 12 and 19)*		130.7		72.4
Current portion of long-term debt *(notes 13 and 19)*		287.5		214.4
Customer deposits		41.0		34.9
Regulatory liabilities *(note 17)*		21.3		10.0
Risk management liabilities *(note 19)*		33.5		43.5
Other current liabilities *(notes 15 and 19)*		17.8		24.4
Liabilities associated with assets held for sale *(note 4)*		8.7		—
		947.7		763.0
Long-term debt *(notes 13 and 19)*		3,732.4		3,031.8
Asset retirement obligations *(notes 4 and 14)*		67.9		70.9
Deferred income taxes *(note 16)*		621.7		469.3
Regulatory liabilities *(note 17)*		167.6		136.0
Risk management liabilities *(note 19)*		15.7		14.7
Other long-term liabilities *(notes 15 and 19)*		206.7		204.5
Future employee obligations *(note 25)*		136.9		131.2
	$	5,896.6	$	4,821.4

CONSOLIDATED BALANCE SHEETS (continued)

As at December 31 *($ millions)*	2015	2014
Shareholders' equity		
Common shares, no par values, unlimited shares authorized; 2015 – 146.3 million and 2014 – 133.9 million issued and outstanding *(note 20)*	**$ 3,168.1**	$ 2,759.9
Preferred shares *(note 20)*	**985.1**	788.4
Contributed surplus	**16.7**	14.9
Accumulated deficit	**(435.4)**	(185.2)
Accumulated other comprehensive income (AOCI) *(note 18)*	**433.5**	163.1
Total shareholders' equity	**4,168.0**	3,541.1
Non-controlling interests	**34.9**	33.1
Total equity	**4,202.9**	3,574.2
	$ 10,099.5	$ 8,395.6

Commitments and contingencies (note 24).

Subsequent events (note 4 and 29).

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd.

DAVID W. CORNHILL
Director

ROBERT B. HODGINS
Director

CONSOLIDATED STATEMENTS OF INCOME

For the years ended December 31 *($ millions except per share amounts)*	2015	2014
REVENUE		
Sales	**$ 357.2**	$ 845.3
Services	**758.5**	489.1
Regulated operations	**1,066.7**	1,069.1
Other revenue (loss)	**1.0**	(2.3)
Unrealized gain on risk management contracts *(note 19)*	**9.4**	4.7
	2,192.8	2,405.9
EXPENSES		
Cost of sales, exclusive of items shown separately	**1,104.9**	1,450.9
Operating and administrative	**491.9**	450.6
Accretion expenses *(notes 14 and 15)*	**11.0**	6.9
Depreciation and amortization *(notes 6 and 8)*	**211.9**	173.4
Provision on assets *(note 7)*	**53.5**	119.1
	1,873.2	2,200.9
Income (loss) from equity investments *(note 11)*	**(63.4)**	38.6
Other income (loss) *(note 22)*	**(28.7)**	25.4
Foreign exchange gain (loss)	**6.0**	(0.4)
Interest expense		
Short-term debt	**(1.1)**	(1.4)
Long-term debt	**(124.4)**	(110.0)
Income before income taxes	**108.0**	157.2
Income tax expense *(note 16)*		
Current	**23.8**	14.0
Deferred	**24.5**	5.0
Net income after taxes	**59.7**	138.2
Net income applicable to non-controlling interests	**8.6**	8.1
Net income applicable to controlling interests	**51.1**	130.1
Preferred share dividends	**(41.2)**	(34.5)
Net income applicable to common shares	**$ 9.9**	$ 95.6
Net income per common share *(note 21)*		
Basic	**$ 0.07**	$ 0.75
Diluted	**$ 0.07**	$ 0.74
Weighted average number of common shares outstanding *(millions) (note 21)*		
Basic	**137.7**	126.7
Diluted	**138.7**	128.6

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 *($ millions)*		**2015**		2014
Net income after taxes	**$**	**59.7**	$	138.2
Other comprehensive income (loss), net of taxes				
Gain on foreign currency translation		**368.2**		147.9
Unrealized loss on net investment hedge *(note 19)*		**(98.7)**		(35.0)
Unrealized gains (losses) on cash flow hedges		**(0.2)**		23.7
Reclassification of gains on cash flow hedges to net income		**(13.1)**		—
Actuarial loss on pension plans and post-retirement benefit (PRB) plans *(note 25)*		**(0.6)**		(4.2)
Reclassification of actuarial losses and prior service costs on defined benefit and PRB plans to net income *(note 25)*		**0.6**		0.3
Unrealized loss on available-for-sale assets		**(24.3)**		(10.5)
Other than temporary impairment on available-for-sale assets *(note 10)*		**33.9**		1.5
Other comprehensive income from equity investees		**4.6**		—
Total other comprehensive income (OCI), net of taxes		**270.4**		123.7
Comprehensive income attributable to common shareholders and non-controlling interests, net of taxes	**$**	**330.1**	$	261.9
Comprehensive income attributable to:				
Non-controlling interests	**$**	**8.6**	$	8.1
Controlling interests		**321.5**		253.8
	$	**330.1**	$	261.9

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

For the years ended December 31 *($ millions)*	2015	2014
Common shares *(note 20)*		
Balance, beginning of period	**$ 2,759.9**	$ 2,211.4
Shares issued for cash on exercise of options	**20.8**	24.9
Shares issued under DRIP[1]	**96.2**	70.2
Deferred taxes on share issuance costs	**3.3**	4.2
Shares issued on public offering	**287.9**	449.2
Balance, end of period	**$ 3,168.1**	$ 2,759.9
Preferred shares *(note 20)*		
Balance, beginning of period	**$ 788.4**	$ 589.6
Series A converted to Series B	**(60.9)**	—
Series B issued	**60.9**	—
Series G issued	**—**	196.1
Series I Issued	**195.6**	—
Deferred taxes on share issuance costs	**1.1**	2.7
Balance, end of period	**$ 985.1**	$ 788.4
Contributed surplus		
Balance, beginning of period	**$ 14.9**	$ 13.4
Share options expense	**3.2**	3.7
Exercise of share options	**(1.6)**	(2.1)
Forfeiture of share options	**(0.4)**	(0.1)
Other	**0.6**	—
Balance, end of period	**$ 16.7**	$ 14.9
Accumulated deficit		
Balance, beginning of period	**$ (185.2)**	$ (62.1)
Net income applicable to controlling interests	**51.1**	130.1
Reclassification of taxes on share issuance costs	**—**	(4.2)
Common share dividends	**(260.1)**	(214.5)
Preferred share dividends	**(41.2)**	(34.5)
Balance, end of period	**$ (435.4)**	$ (185.2)
AOCI *(note 18)*		
Balance, beginning of period	**$ 163.1**	$ 39.4
Other comprehensive income	**270.4**	123.7
Balance, end of period	**433.5**	163.1
Total shareholders' equity	**$ 4,168.0**	$ 3,541.1
Non-controlling interests		
Balance, beginning of period	**$ 33.1**	$ 37.8
Net income applicable to non-controlling interests	**8.6**	8.1
Sale of interest in a subsidiary	**1.8**	—
Distribution by subsidiaries to non-controlling interests	**(8.6)**	(12.8)
Balance, end of period	**34.9**	33.1
Total equity	**$ 4,202.9**	$ 3,574.2

1 *Dividend Reinvestment and Optional Share Purchase Plan.*

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 *($ millions)*		**2015**		2014
Cash from operations				
Net income after taxes	**$**	**59.7**	$	138.2
Items not involving cash:				
Depreciation and amortization		**211.9**		173.4
Provision on assets *(note 7)*		**53.5**		119.1
Accretion expenses *(notes 14 and 15)*		**11.0**		6.9
Share-based compensation *(note 20)*		**2.8**		3.7
Deferred income tax expense *(note 16)*		**24.5**		5.0
Gain on sale of assets *(note 3)*		**(0.3)**		(38.1)
Loss (income) from equity investments *(note 11)*		**63.4**		(38.6)
Unrealized gain on risk management contracts *(note 19)*		**(9.4)**		(4.7)
Loss on long-term investments *(note 10 and 22)*		**34.2**		1.6
Losses from extinguishment of debts		**—**		16.6
Other		**8.8**		1.9
Asset retirement obligations settled *(note 14)*		**(3.6)**		(2.4)
Distributions from equity investments, net of contributions		**5.5**		86.0
Changes in operating assets and liabilities *(note 27)*		**39.2**		(10.9)
	$	**501.2**	$	457.7
Investing activities				
Business acquisitions, net of cash acquired *(note 3)*		**(916.0)**		—
Acquisition of property, plant and equipment		**(613.5)**		(519.9)
Acquisition of intangible assets		**(37.8)**		(28.7)
Proceeds from dispositions of assets		**9.8**		64.5
Contributions to equity investments		**(9.7)**		(7.7)
Acquisition of short-term investments		**—**		(50.0)
Maturity of short-term investment		**50.0**		—
Change in restricted cash holdings from customers		**(0.4)**		(1.3)
Acquisition of equity investment		**—**		5.0
Acquisition of long-term investments		**—**		(53.0)
Sale of interest in a subsidiary		**2.0**		—
	$	**(1,515.6)**	$	(591.1)
Financing activities				
Net issuance (repayment) of short-term debt		**46.5**		(17.6)
Issuance of long-term debt, net of debt issuance costs		**1,065.1**		1,348.1
Repayment of long-term debt		**(476.4)**		(1,345.7)
Dividends – common shares		**(255.8)**		(210.3)
Dividends – preferred shares		**(40.1)**		(35.0)
Distributions to non-controlling interest		**(8.6)**		(12.8)
Net proceeds from shares issued on exercise of options		**19.2**		22.8
Net proceeds from issuance of common shares		**384.1**		511.8
Net proceeds from issuance of preferred shares		**195.6**		194.4
	$	**929.6**	$	455.7
Change in cash and cash equivalents		**(84.8)**		322.3
Effect of exchange rate changes on cash and cash equivalents		**7.2**		3.9
Cash and cash equivalents, beginning of year		**371.0**		44.8
Cash and cash equivalents, end of year	**$**	**293.4**	$	371.0

See accompanying notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ORGANIZATION AND OVERVIEW OF 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 2,041 MW of generating capacity from natural gas-fired, coal-fired, wind, biomass and hydro assets in Canada and the United States, along with 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 Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP).

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 Consolidated Financial Statements of AltaGas include the accounts of the Corporation and all of its wholly-owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership. Investments in unconsolidated companies where AltaGas has significant influence over, but not control, are accounted for 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 is shown as an allocation of the consolidated net income and is 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, long-lived and intangible assets impairment assessment, fair value of financial instruments, income taxes, employee future benefits, litigation, share-based compensation, and regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas’ subsidiaries or affiliates operate, which often 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

Rate-Regulated Operations

SEMCO, AUI, PNG and Heritage Gas (collectively “Utilities”) engage in the delivery and sale of natural gas and are regulated by the Michigan Public Service Commission (MPSC) and Regulatory Commission of Alaska (RCA), Alberta Utilities Commission (AUC), British Columbia Utilities Commission (BCUC) and the Nova Scotia Utility and Review Board (NSUARB), respectively.

The MPSC, RCA, AUC, BCUC and NSUARB exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the MPSC, RCA, AUC BCUC and NSUARB, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

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

Cash and Cash Equivalents

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

Restricted Cash Holdings from Customers

Cash deposited, which is restricted and is not available for general use by AltaGas, is separately presented as restricted cash holdings in the Consolidated Balance Sheets.

Short-term Investments

Short-term investments consist of investments in money market instruments with original maturities of more than three and less than 12 months. Short-term investments are carried at fair value.

Accounts Receivable

Receivables are recorded net of the allowance for doubtful accounts in the Consolidated Balance Sheets. AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies, and natural gas, which are valued at the lower of cost or net realizable value. Cost of inventory is assigned using a weighted average cost formula. In general, commodity costs and variable transportation costs are capitalized as gas in underground storage. Fixed costs, primarily pipeline demand charges and storage charges, are expensed as incurred through the cost of gas.

Property, Plant, and Equipment (PPE), Depreciation and Amortization

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

The U.S. utilities include in depreciation expense an amount allowed for regulatory purposes to be collected in current rates for future removal and site restoration costs. The Canadian utilities that collect future removal and site restoration costs in rates defer the revenue until the costs are incurred.

Interest costs are capitalized on major additions to property, plant, and equipment until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on AltaGas' prior quarter actual borrowing long-term interest rate, unless AltaGas borrowed funds specifically for the purpose of obtaining an asset. In this case, the interest costs to be capitalized are calculated using the actual interest rate applicable to the funds obtained for that asset.

Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction (AFUDC). AFUDC is the amount that a rate regulated enterprise is allowed to recover for its cost of financing assets under construction. Capitalized overhead, administrative expenses and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers through depreciation expense, as allowed by the regulators.

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

Gas assets	3-45 years
Power generation assets	2-120 years
Utilities assets	3-80 years
Corporate assets	1-7 years

As required by the respective regulatory authorities, net additions to utility assets at Heritage Gas and PNG are not depreciated until the year after they are brought into active service and net additions to utility assets at AUI and SEMCO are depreciated commencing in the year in which the assets are brought into active service.

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

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

Intangible Assets

Intangible assets are recorded at cost and are amortized on a straight-line basis over their term or estimated useful life:

Energy services relationships	15-19 years
Electricity service agreements	2-60 years
Software	2-10 years
Land rights	5-60 years
Franchises and consents	9-25 years
Extraction and Transmission (E&T) Contracts	6-34 years

Assets Held for Sale

The Corporation classifies assets as held for sale when the carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is met when management approves and commits to a formal plan to sell the assets, the assets are available for immediate sale in their present condition, and management expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, an asset is recorded at the lower of its carrying value or the estimated fair value less cost to sell. Assets held for sale are not depreciated or amortized.

Business Acquisitions

Business acquisitions are accounted for using the acquisition method. Under the acquisition method, assets and liabilities of the acquired entity are recorded at fair value at the date of acquisition. Acquisition-related costs are expensed as incurred. Goodwill represents the excess of purchase price over the fair value of the net assets acquired.

Provision on Assets

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

Goodwill is not subject to amortization, but assessed at least annually for impairment, or more often when events or changes in circumstances indicate that goodwill may be impaired. The annual assessment of goodwill is performed at the reporting unit level, which is an operating segment or one level below. The Corporation has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the first step of the two-step impairment test is to compare the fair value of the reporting unit to its book value (including goodwill). If the carrying value of the reporting unit exceeds the fair value, goodwill is reduced to its implied fair value and an impairment loss would be recorded in the Consolidated Statements of Income.

Development Costs

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

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in which AltaGas has the ability to exercise significant influence, but does not have a controlling interest. Equity investments are initially measured at cost and are adjusted for the Corporation's proportionate share of earnings or losses. Equity investments are increased for contributions made and decreased for distributions received. To the extent an investee undertakes activities necessary to commence its planned principal operations, the Corporation will capitalize interest costs associated with its investment during such period.

An equity method investment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment might not be recoverable. When such condition is deemed other than temporary, the carrying value of the investment is written down to its fair value, and an impairment charge is recorded in the Consolidated Statements of Income.

Financial Instruments

All financial instruments are initially recorded at fair value unless they qualify for, and are designated under, a normal purchase and normal sales (NPNS) exemption. Subsequent measurement of the financial instruments is based on their classification. The financial assets are classified as "held-for-trading", "held-to-maturity", "loans and receivables", or "available-for-sale". Financial liabilities are classified as "held-for-trading" or other financial liabilities. Subsequent measurement is determined by classification.

A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to AltaGas' business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, AltaGas intends to receive physical delivery of the commodity, and AltaGas deems the counterparty creditworthy. AltaGas continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Held-for-trading financial assets and liabilities consist of swaps, options, forwards and equity securities. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value recorded in net income under "unrealized gains and losses from risk management contracts" or "other income (loss)". Loans and receivables and other financial liabilities not classified as held-for-trading are recognized at amortized cost using the effective interest method. AltaGas does not have any held-to-maturity financial assets.

The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially recorded at fair value, and changes to fair value are recorded through "Other comprehensive income" (OCI). Declines in fair value below the amortized cost basis that are other than temporary are reclassified out of OCI to earnings for the period.

Investments in equity instruments not accounted for under the equity method that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in the Consolidated Statement of Income under "Other income (loss)".

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a standalone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in income.

The fair values recorded on the Consolidated Balance Sheets reflect netting of the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement.

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred.

Transaction costs for obtaining debt financing other than line-of-credit arrangements are recognized as a direct deduction from the related debt liability on the Consolidated Balance Sheets. Transaction costs related to line-of-credit arrangements are capitalized and included under "Long-term investments and other assets" on the Consolidated Balance Sheets. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheets. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in "Interest expense" on the Consolidated Statements of Income.

Hedges

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

The effective portion of changes in cash flow hedges is recognized in OCI. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income under "unrealized gains and losses from risk management contracts". Gains or losses from cash flow hedges that have been included in accumulated other comprehensive income (AOCI) are reclassified to net income when the hedged transaction affects earnings, such as when the hedged forecasted transaction occurs. If the hedging instrument ceases to be effective, hedge accounting is discontinued and the cumulative gains or losses previously recognized will remain in AOCI until the forecast transaction affects earnings. If a hedged anticipated transaction is no longer probable or is sold or terminated early, the cumulative gains or losses in AOCI are immediately reclassified to net income.

Asset Retirement Obligations

AltaGas recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations.

Certain utility assets will have future legal obligations on retirement, but an asset retirement obligation has not been recorded due to its indeterminate life and corresponding indeterminable timing and scope of these asset retirement obligations. The U.S. Utilities recognize asset retirement obligations for some interim retirements, as expected by their regulators, whereas Canadian Utilities do not.

Revenue Recognition

Revenue from sales represents the proceeds from the commodity sales in the Gas and Power reporting segments and are recognized at the time the product is delivered.

Revenue from services represents the proceeds from operating leases in the Gas and Power reporting segments where AltaGas is the lessor, and fees from the gathering, transportation, processing, and marketing of natural gas. Revenue from services are recognized at the time the service is rendered.

The Utilities reporting segment recognizes revenue, presented as "revenue from regulated operations" in the Consolidated Statements of Income, when the product or services are delivered on the basis of regular meter readings or estimates of usage and is consistent with the underlying rate setting mechanism mandated by the applicable regulatory authority. The Utilities reporting segment bills gas distribution customers monthly, on a cycle basis and accrues revenue for service rendered to its customers but not billed at month-end. Storage customers are billed monthly for services provided in the preceding month and revenue is accrued for services rendered but not billed at month end.

Foreign Currency Translation

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

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

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

Share Options and Other Compensation Plans

Share options granted are recorded using fair value. Compensation expense is measured at the date of the grant using the Black-Scholes-Merton model and is recognized over the vesting period of the options. Consideration received by AltaGas on exercise of the share options is credited to shareholders' equity.

AltaGas has a medium-term incentive plan (MTIP) for employees and executive officers which includes two types of awards: restricted units (RUs) and performance units (PUs). 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. Compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the RUs or PUs is recognized in the period the change occurs.

Pension Plans and Post-Retirement Benefits

AltaGas maintains defined benefit pension plans, defined contribution plans, and other post-retirement benefit plans for eligible employees. Contributions made by the Corporation to the defined contribution plans are expensed in the period in which the contribution occurs.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service with a reasonable range of expected plan investment performance and management's best estimate of salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on plan assets is based on historical and projected rates of return for each asset class in the plan portfolio. The projected benefit obligation is discounted using the market interest rate on high-quality debt instruments with cash flows matching the timing and amount of benefit payments.

Pension expense for the defined benefit and post-retirement benefit plans includes the cost of pension benefits earned during the year, the interest cost on pension obligations, the excepted return on pension plan assets, the amortization of net transitional obligation, the amortization of adjustments arising from pension plan amendments, the amortization of prior service costs, and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets, which is amortized on a straight-line basis over the expected average remaining service life of active employees. The expected average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 12.6 years and 13.5 years, respectively.

AltaGas recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheets. Actuarial gains and losses related to changes in funded status are recognized in OCI.

For certain regulated Utilities, the Corporation expects to recover pension expense in future rates and therefore record actuarial gains and losses as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized. Deferred income tax assets are routinely reviewed and a valuation allowance is recorded to reduce the deferred tax assets if it is more likely than not that deferred tax assets will not be realized. The financial statement effects of an uncertain tax position are recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxing authority. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Investment tax credits are deferred and amortized over the estimated service lives of the related properties.

The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be recovered from, or paid to, customers in the future.

Net Income per Share

Basic net income per common share is computed using the weighted average number of common shares outstanding during the period. Dilutive net income per common share is calculated using the weighted average number of common shares outstanding adjusted for dilutive common shares related to the Corporation’s share-based compensation awards.

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

Emission Credits

As no active market currently exists, emission credits are carried at cost and included in “Prepaid expenses and other current assets”.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective July 1, 2015, AltaGas early adopted Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2015-03 “Simplifying the Presentation of Debt Issuance Costs”. Under the ASU, debt issuance costs are recorded as a direct deduction from the related debt liability rather than as an asset. Upon adoption, AltaGas reclassified debt issuance costs of $16.1 million and $17.8 million for the periods ended June 30, 2015 and December 31, 2014, respectively, from “Long-term investments and other assets” to “Long-term debt”. Debt issuance costs related to line-of-credit arrangements were not reclassified pursuant to guidance from ASU No. 2015-15 “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements”.

Effective August 2015, AltaGas prospectively adopted FASB issued ASU No. 2015-13 “Derivatives and Hedging – Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets”, which allows certain forward contracts for physical delivery of electricity in nodal energy markets to qualify for the normal purchases and normal sales scope exception, as long as the physical delivery criterion and other criteria for the normal purchases and normal sales scope exception are met. The ASU applies to forward contracts in which one of the counterparties incurs location marginal pricing charges (or credits) payable to (or receivable from) an independent system operator. The adoption of this ASU did not have an impact on AltaGas’ consolidated financial statements.

Effective October 1, 2015, AltaGas early adopted FASB issued ASU No. 2015-17 "Balance Sheet Classification of Deferred Taxes" which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as non-current on the balance sheet. Upon adoption, AltaGas reclassified current deferred income tax assets of $2.4 million and $nil, for the periods ended September 30, 2015 and December 31, 2014, respectively, to non-current deferred income tax asset. Current deferred income tax liabilities of $0.3 million and $2.1 million for the periods ended September 30, 2015 and December 31, 2014, respectively, were reclassified to non-current deferred income tax liabilities.

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. On July 9, 2015, FASB confirmed a one-year deferral of the new revenue standard. The new 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 June 2014, FASB issued ASU No. 2014-12, "Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period". The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2015. Early adoption is permitted. AltaGas will adopt the ASU for the financial periods beginning on January 1, 2016. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In January 2015, FASB issued ASU No. 2015-01 "Income Statement – Extraordinary and Unusual Items" to eliminate the concept of extraordinary items and alleviate uncertainty for preparers, auditors, and regulators because auditors and regulators no longer will need to evaluate whether a preparer treated an unusual and/or infrequent item appropriately. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In February 2015, FASB issued 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 amendments in this ASU are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In July 2015, FASB issued ASU No. 2015-11 "Inventory – Simplifying the Measurement of Inventory". The amendment in this ASU requires an entity to measure inventory at the lower of cost and net realizable value. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, prospectively. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In September 2015, FASB issued ASU No. 2015-16 “Business Combinations – Simplifying the Accounting for Measurement-Period Adjustments”. To simplify the accounting for adjustments made to provisional amounts recognized in a business combination, the amendments in this ASU eliminate the requirement to retrospectively account for those adjustments. Instead, an acquirer will recognize a measurement-period adjustment during the period in which the amount of the adjustment is determined. The amendments in this ASU are effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years, prospectively. AltaGas will apply this ASU prospectively to adjustments to provisional amounts that occur after the effective date of this ASU.

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. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements.

3. ACQUISITIONS AND DISPOSITIONS

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 year ended December 31, 2015, transaction costs, such as legal, accounting, valuation and other professional fees of $1.8 million before taxes were incurred and included in the Consolidated Statement of Income, within “Operating and administrative expenses”. Below is the provisional purchase price allocation, representing the consideration paid and the fair value of the net assets acquired as at November 30, 2015, using an exchange rate of 1.3333 to convert US dollars to Canadian dollars.

Cash consideration	$	882.4
Total consideration	$	882.4
Fair value of net assets acquired		
Current assets	$	31.5
Property, plant and equipment		591.2
Intangible assets		355.4
Current liabilities		(11.3)
Deferred income taxes		(84.4)
	$	882.4

These consolidated financial statements incorporate the results of operations from the San Joaquin Facilities subsequent to November 30, 2015. For the year ended December 31, 2015, the assets acquired contributed $11.1 million (US$8.1 million) of revenues and $5.9 million (US$4.3 million) of pre-tax income.

If the acquisition had occurred on January 1, 2015, revenues and pre-tax income would have increased by $110.1 million (US$86.7 million) and $88.8 million (US$69.9 million), respectively.

Other Acquisitions

On January 8, 2015 AltaGas completed the acquisition of three western U.S. natural gas-fired power assets with a total generation capacity of 164 MW for cash consideration of $33.6 million (US$28.4 million). Transaction costs, such as legal, accounting, valuation, and other professional fees of US$0.8 million before taxes were incurred and included in the Consolidated Statement of Income, within "Operating and administrative expenses". Below is the final purchase price allocation.

Cash consideration	$	33.6
Total consideration	$	33.6

Fair value of net assets acquired		
Current assets	$	4.0
Property, plant and equipment		23.2
Intangible assets		9.2
Current liabilities		(2.8)
	$	33.6

Dispositions

In the fourth quarter of 2015, AltaGas disposed of its effective 25 percent interest in Boston Bar LP, which is a 7-MW run-of-river hydroelectric power generation facility on Scuzzy Creek near Boston Bar. In the same quarter, AltaGas also disposed of the 10-MW McNair run-of-river hydroelectric generating facility located on the Sunshine Coast of British Columbia, near Port Mellon, as well as 40 MW of small hydro development projects in British Columbia. The total gross proceeds from these disposals were approximately $9.2 million. A total gain of $0.4 million was recognized in the Consolidated Statement of Income under "Other income (loss)" for the year ended December 31, 2015 from the sale of these assets.

4. ASSETS HELD FOR SALE

As at 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**

As at December 31, 2015, AltaGas committed to the sale of certain non-core natural gas gathering and processing assets in the Gas segment. These assets are located primarily in central and north central Alberta and total approximately 490 Mmcf/d of gross licensed natural gas processing capacity. Accordingly, the carrying value of the assets and liabilities were classified as held for sale, which resulted in a pre-tax provision of $10.7 million on property, plant and equipment and a pre-tax provision of $5.1 million on allocated goodwill due to the reduction of the carrying value of these assets to the fair value less costs to sell.

On February 2, 2016, AltaGas announced an agreement had been entered into with Tidewater Midstream and Infrastructure Ltd. (Tidewater) for total consideration of $30 million of cash and approximately 43.7 million common shares of Tidewater. The transaction is expected to close in the first quarter of 2016 subject to customary closing conditions being satisfied.

5. INVENTORY

As at December 31		2015		2014
Natural gas held in storage	$	**166.0**	$	136.7
Other inventory		**38.0**		18.6
	$	**204.0**	$	155.3

6. PROPERTY, PLANT AND EQUIPMENT

As at December 31	2015			2014		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Gas	**$ 2,592.1**	**$ (742.3)**	**$ 1,849.8**	$ 2,318.0	$ (681.9)	$ 1,636.1
Power	**2,913.6**	**(150.9)**	**2,762.7**	2,050.1	(98.5)	1,951.6
Utilities	**2,209.3**	**(163.2)**	**2,046.1**	1,833.5	(108.4)	1,725.1
Corporate	**58.6**	**(21.6)**	**37.0**	49.6	(25.4)	24.2
Reclassified to assets held for sale	**(222.3)**	**124.6**	**(97.7)**	—	—	—
	$ 7,551.3	**$ (953.4)**	**$ 6,597.9**	$ 6,251.2	$ (914.2)	$ 5,337.0

Interest capitalized on long-term capital construction projects for the year ended December 31, 2015 was $20.9 million (2014 – $29.9 million).

As at December 31, 2015, the Corporation had approximately $357.2 million (2014 – $440.4 million) of capital projects under construction that were not yet subject to amortization.

Depreciation expense related to property, plant and equipment (including assets under capital leases) for the year ended December 31, 2015 was $191.7 million (2014 – $162.2 million).

Net additions to Utilities assets at PNG and Heritage Gas are not amortized until the year after they are brought into active service as required by the respective regulating authorities. Net additions to SEMCO's utility assets are amortized for one half year in the year in which they are brought into active service, as required by SEMCO's regulatory authority. Utility assets not yet subject to amortization were $43.6 million as at December 31, 2015 (December 31, 2014 – $48.5 million).

7. PROVISION ON ASSETS

Years Ended December 31		2015		2014
Power	$	**28.4**	$	10.9
Gas		**22.3**		108.2
Utilities		**2.8**		—
	$	**53.5**	$	119.1

Power

In 2015, AltaGas recorded a pre-tax provision of $28.4 million related to certain development stage wind assets in Canada and the United States. In 2014, AltaGas recorded a pre-tax provision of $10.9 million related to certain hydro power assets under development in British Columbia.

Gas

In 2015, AltaGas recorded a pre-tax provision of $15.8 million on certain gas processing assets that were held for sale, and a pre-tax provision of $6.5 million on the DC LNG Project related to deferred lease expense.

In 2014, AltaGas recorded a pre-tax provision of $19.5 million on its Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets, an $18.7 million pre-tax provision for related transmission contracts, all of which will be sold to NOVA Chemicals Corporation in March 2017, in accordance with contractual requirements, and a pre-tax provision of $70.0 million related to certain non-productive gas processing assets.

Utilities

A pre-tax provision of $2.8 million was recorded on the assets in the Ikhil Joint Venture in 2015.

8. INTANGIBLE ASSETS

As at December 31	**2015**			2014		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
E&T contracts	**$ 53.7**	**$ (37.9)**	**$ 15.8**	$ 56.5	$ (38.5)	$ 18.0
Electricity service agreements	**642.6**	**(12.4)**	**630.2**	260.4	(1.8)	258.6
Energy services relationships	**10.3**	**(6.7)**	**3.6**	10.2	(6.1)	4.1
Software	**108.6**	**(33.4)**	**75.2**	84.6	(25.6)	59.0
Land rights	**11.8**	**(2.2)**	**9.6**	16.6	(1.7)	14.9
Franchises and consents	**3.6**	**(1.9)**	**1.7**	3.6	(1.3)	2.3
Reclassified to assets held for sale	**(1.1)**	**0.1**	**(1.0)**	—	—	—
	$ 829.5	**$ (94.4)**	**$ 735.1**	$ 431.9	$ (75.0)	$ 356.9

Amortization expense related to intangible assets for the year ended December 31, 2015 was $20.2 million (2014 – $11.2 million).

As at December 31, 2015, the Corporation excluded $6.6 million (2014 – $36.5 million) of assets from the asset base subject to amortization.

The following table sets forth the estimated amortization expense of intangible assets, excluding any amortization of assets not yet subject to amortization, for the years ended December 31:

2016	42.6
2017	40.8
2018	38.9
2019	37.8
2020	37.2
Thereafter	531.5

9. GOODWILL

As at December 31	**2015**	2014
Balance, beginning of period	**$ 785.1**	$ 743.1
Provision on assets *(see note 4)*	**(5.1)**	—
Foreign exchange translation	**97.3**	42.0
	$ 877.3	$ 785.1

10. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at December 31	2015	2014
Investments in publicly-traded entities	$ 23.2	$ 46.3
Debt issuance costs associated with credit facilities	4.3	4.2
Refundable deposits	35.5	15.7
Loan to employees *(see note 26)*	0.8	—
Other	0.5	0.6
	$ 64.3	$ 66.8

The following table summarizes the Corporation's available-for-sale investments in equity securities:

As at December 31	2015	2014
Amortized cost	$ 21.7	$ 57.0
Gross unrealized losses	(2.4)	(13.5)
Fair value	$ 19.3	$ 43.5

In 2015, an other-than-temporary pre-tax loss of $35.4 million was re-classified from OCI and recognized in the Consolidated Statement of Income under "Other income (loss)" (2014 – $1.8 million). The recognition of the other-than-temporary losses was the result of the length of time and extent to which the market value of the shares was less than cost.

11. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

As at December 31				
Description	**Location**	**Ownership Percentage**	**2015**	**2014**
AltaGas Idemitsu Joint Venture LP (AIJVLP)	Canada	50	$ 308.7	$ 323.3
ASTC Power Partnership (ASTC)	Canada	50	—	31.6
Boston Bar LP [(a)]	Canada	25	—	2.6
Craven County Wood Energy LP	United States	50	23.4	19.1
Eaton Rapids Gas Storage System	United States	50	29.0	24.3
Grayling Generating Station LP	United States	50	32.3	27.5
Inuvik Gas Ltd.	Canada	33.333	—	4.9
Sarnia Airport Storage Pool LP	Canada	50	19.9	20.6
			$ 413.3	$ 453.9

(a) AltaGas disposed of its interest in Boston Bar LP in the fourth quarter of 2015. See note 3.

For the year ended December 31, 2015, AltaGas recorded a pre-tax provision of $26.3 million against AltaGas' investment in ASTC, which holds the Sundance B Power Purchase Arrangement in the Power segment, a pre-tax provision of $17.0 million on AltaGas' investments in its joint ventures with Idemitsu Kosan Co.,Ltd. including related to the DC LNG Project in the Gas segment, and a pre-tax provision of $4.4 million on AltaGas' interest in Inuvik Gas Ltd. in the Utilities segment.

Summarized combined financial information showing 100 percent of the AltaGas' equity investments listed above is as follows:

For the years ended December 31	2015	2014
Revenues	$ 229.4	$ 288.0
Expenses	(286.8)	(258.8)
	$ (57.4)	$ 29.2

As at December 31		2015		2014
Current assets	$	**44.1**	$	39.0
Property, plant and equipment	$	**102.7**	$	79.4
Intangible assets	$	**67.8**	$	80.6
Long-term investments and other assets	$	**873.1**	$	875.2
Current liabilities	$	**(63.5)**	$	(33.4)
Other long-term liabilities	$	**(246.6)**	$	(252.9)

12. SHORT-TERM DEBT

As at December 31		2015		2014
Bank indebtedness [(a)]	$	**9.4**	$	26.6
US$150 million operating facility [(b)]		**117.6**		37.1
$25 million operating facility [(c)]		**3.7**		8.7
	$	**130.7**	$	72.4

(a) Bank indebtedness bears interest at the lender's prime rate or at the interest rate applicable to bankers' acceptances. The prime lending rate at December 31, 2015 was 2.7 percent (December 31, 2014 – 3.0 percent).

(b) As at December 31, 2015, SEMCO held a US$150.0 million (December 31, 2014 – US$150.0 million) unsecured revolving operating credit facility with a Canadian chartered bank with a maturity date of December 20, 2020. Draws on the facility can be by way of U.S. base-rate loans, letters of credit and LIBOR loans. Letters of credit outstanding under this facility as at December 31, 2015 were $0.9 million (December 31, 2014 – $0.8 million).

(c) As at December 31, 2015, AltaGas held a $25.0 million (December 31, 2014 – $25.0 million) bank operating facility which is available for working capital purposes, has a term of 18 months and expires on November 22, 2016. Draws on the facility are by way of prime-rate advances, bankers' acceptances or letters of credit at the bank's prime rate or for a fee. Letters of credit outstanding under this facility as at December 31, 2015 were $6.1 million (December 31, 2014 – $5.7 million).

Other Credit Facilities

As at December 31, 2015, the Corporation held a $50.0 million (December 31, 2014 – $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. Letters of credit outstanding under this facility as at December 31, 2015 were $nil (December 31, 2014 – $nil).

As at December 31, 2015, AltaGas Utility Group Inc. held a $20.0 million (December 31, 2014 – $20.0 million) unsecured uncommitted demand operating credit facility with a Canadian chartered bank. Draws on the facility can be by way of prime rate loans, U.S. base-rate loans, letters of credit, bankers' acceptances and LIBOR loans. Letters of credit outstanding under this facility as at December 31, 2015 were $3.6 million (December 31, 2014 – $3.6 million).

As at December 31, 2015, AltaGas held a $150.0 million (December 31, 2014 – $150.0 million) unsecured four-year extendible revolving letter of credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances or letters of credit. Letters of credit outstanding under this facility as at December 31, 2015 were $55.8 million (December 31, 2014 – $112.8 million).

As at December 31, 2015, AltaGas held a $150.0 million unsecured bilateral letter of credit demand facility with a Canadian chartered bank. Borrowings on the facility incur fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding under this facility as at December 31, 2015 were $80.1 million (December 31, 2014 – $nil).

In September 2015, the $125.0 million unsecured bilateral letter of credit facility was closed. Letters of credit outstanding at December 31, 2014 were $12.7 million.

13. LONG-TERM DEBT

As at December 31	Maturity date	2015	2014
Credit facilities			
$1,400 million unsecured extendible revolving [a]	15-Dec-2019	**$ 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**	300.0
$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**	299.7
US$175 million Senior unsecured – floating [b]	13-Apr-2015	**—**	203.0
US$200 million Senior unsecured – floating [c]	24-Mar-2016	**276.8**	232.1
US$125 million Senior unsecured – floating [d]	17-Apr-2017	**173.0**	—
SEMCO long-term debt			
US$300 million SEMCO Senior secured – 5.15 percent [e]	21-Apr-2020	**415.2**	348.0
US$82 million SEMCO Senior secured – 4.48 percent	2-Mar-2032	**107.0**	95.1
Debenture notes			
PNG RoyNat Debenture – 3.361 percent [f]	15-Sep-2017	**8.6**	9.8
PNG 2018 Series Debenture – 8.75 percent [f]	15-Nov-2018	**9.0**	10.0
PNG 2024 CFI Debenture – 7.39 percent [g]	1-Nov-2024	**—**	7.4
PNG 2025 Series Debenture – 9.30 percent [f]	18-Jul-2025	**14.0**	14.5
PNG 2027 Series Debenture – 6.90 percent [f]	2-Dec-2027	**15.0**	15.5
Loan from Province of Nova Scotia [h]	31-Jul-2017	**1.1**	2.1
CINGSA capital lease – 3.50 percent	1-May-2040	**0.6**	0.5
CINGSA capital lease – 4.48 percent	4-Jun-2068	**0.2**	0.2
Promissory notes	25-Oct-2015	**—**	1.0
Other long-term debt		**—**	0.1
		$ 4,035.1	$ 3,264.0
Less debt issuance costs [i]		**(15.2)**	(17.8)
		4,019.9	3,246.2
Less current portion		**(287.5)**	(214.4)
		$ 3,732.4	$ 3,031.8

(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. On December 4, 2015, AltaGas extended the maturity of the facility by one year to December 15, 2019.
(b) The notes carried a floating rate coupon of three months LIBOR plus 0.79 percent.
(c) The notes carry a floating rate coupon of three months LIBOR plus 0.72 percent.
(d) The notes carry a floating rate coupon of three months LIBOR plus 0.85 percent.
(e) Collateral for the US$ MTNs is certain SEMCO assets.
(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) On December 23, 2015, the Corpfinance International Ltd. (CFI) Debenture was assigned as part of the sale of McNair. See note 3.
(h) The loan is non-interest bearing and, if certain prescribed revenue targets are achieved, interest will immediately begin to accumulate on a prospective basis at a rate of 6 percent per annum. In July 2011, Heritage Gas elected to repay the loan in five equal installments beginning July 31, 2012. Heritage Gas may also elect to fully repay the loan at any time with no penalty.
(i) Effective July 1, 2015, AltaGas early adopted FASB issued ASU No. 2015-03. Please see note 2.

14. ASSET RETIREMENT OBLIGATIONS

As at December 31	2015	2014
Balance, beginning of year	**$ 70.9**	$ 76.1
New obligations	**—**	0.7
Obligations settled	**(3.6)**	(2.4)
Disposals	**—**	(1.3)
Revision in estimated cash flow	**2.3**	(7.5)
Accretion expense	**4.1**	4.2
Foreign exchange translation	**2.9**	1.1
Reclassified to liabilities associated with assets held for sale	**(8.7)**	—
Balance, end of year	**$ 67.9**	$ 70.9

The majority of the asset retirement obligations are associated with gas processing facilities in the Gas segment.

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2015 was $245.2 million (December 31, 2014 – $235.4 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 4.0 and 8.5 percent and are expected to be incurred between 2016 and 2164. No assets have been legally restricted for settlement of the estimated liability.

In May 2009, the National Energy Board (NEB) issued a decision that set out guiding principles for a mechanism that would set aside funds for pipeline abandonment. It also established a five-year action plan for all NEB-regulated companies. In May 2014, the NEB issued a decision establishing that, by January 1, 2015, all NEB-regulated companies must have a mechanism in place for the accumulation of funds to pay for future pipeline abandonment. AltaGas Holdings Inc., a wholly-owned subsidiary of AltaGas, opted to comply with the NEB decision with a surety bond supplied by a surety company regulated by the Office of the Superintendent of Financial Institutions in the amount of $30.3 million.

15. LONG-TERM LIABILITIES

In 2010, AltaGas entered into a 60-year CPI-indexed Electricity Purchase Agreement (EPA) and other related agreements with BC Hydro for the 195-MW Forrest Kerr run-of-river hydroelectric facility. As part of the related agreements, AltaGas agreed to pay BC Hydro annual payments of approximately $11.0 million per year, adjusted for inflation, in support of the construction and operation of the Northwest Transmission Line (NTL) until 2034.

The fair value of the firm commitment on initial recognition was measured using an estimated 2 percent inflation rate and 4.27 percent discount rate. The NTL liability has been recorded within other current liabilities for $11.0 million (December 31, 2014 – $10.6 million) and other long-term liabilities for $151.2 million (December 31, 2014 – $155.6 million) as at December 31, 2015. Accretion expense for the year ended December 31, 2015 was $6.9 million (2014 – $2.7 million). The initial consideration and the fair value of the future considerations of $258.5 million, has been recognized within the intangible assets and depreciated over 60 years, the term of the EPA with BC Hydro.

16. INCOME TAXES

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

For the years ended December 31		2015		2014
Income before income taxes – consolidated	**$**	**108.0**	$	157.2
Financial instruments – net		**(9.4)**		(4.7)
Income before financial instruments and income taxes	**$**	**98.6**	$	152.5
Income before income taxes – operating subsidiaries	**$**	**98.6**	$	152.5
Statutory income tax rate (%)		**26.00**		25.18
Expected taxes at statutory rates	**$**	**25.6**	$	38.4
Add (deduct) the tax effect of:				
Financial instruments		**2.5**		1.2
Rate adjustments to enacted Canadian rates		**(6.1)**		(5.1)
Permanent differences between accounting and tax basis of assets and liabilities		**2.0**		1.1
Non-taxable portion of capital (gains) losses on disposition of assets and investments		**4.8**		(3.8)
Non-taxable portion of recorded equity income		**(1.8)**		(7.2)
Tax benefit of state expense		**0.3**		4.0
Rate adjustment for change in the Alberta tax rate		**13.8**		—
Tax on preferred shares		**1.1**		1.2
Change in valuation allowance		**16.0**		0.9
Other		**(0.3)**		(1.9)
Deferred income tax recovery on regulated assets		**(5.0)**		(4.7)
Prior year adjustment		**(4.6)**		(5.1)
	$	**48.3**	$	19.0
Income tax provision				
Current				
Canada		**15.6**		8.2
United States		**8.2**		5.8
	$	**23.8**	$	14.0
Deferred				
Canada		**6.7**		(13.5)
United States		**17.8**		18.5
	$	**24.5**	$	5.0
Effective income tax rate (%)		**44.70**		12.09

Effective July 1, 2015, the Alberta corporate tax rate increased from 10 percent to 12 percent. As a result of the revaluation of the deferred income tax liabilities using the increased tax rate, AltaGas recognized an additional $13.8 million of deferred income tax expense for the year ended December 31, 2015 (2014 – $nil).

Net deferred income tax liabilities were composed of the following:

As at December 31		2015		2014
PPE and intangible assets	**$**	**612.6**	$	487.4
Regulatory assets		**168.6**		143.9
Deferred financing		**(12.9)**		(16.6)
Deferred compensation		**(14.3)**		(17.0)
Financial instruments		**(4.5)**		(1.7)
Non-capital losses		**(161.4)**		(131.0)
Valuation allowance		**17.7**		1.3
Other		**11.4**		0.8
	$	**617.2**	$	467.1

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

As at December 31, 2015 the Corporation had tax-affected non-capital losses of approximately $165.9 million for tax purposes, which will be available to offset future taxable income. If not used, these losses will expire between 2023 and 2035.

Uncertain Tax Positions

On an annual basis the Corporation and its subsidiaries file tax returns in Canada and various foreign jurisdictions. In Canada AltaGas' federal and provincial tax returns for the years 2008 to 2014 remain subject to examination by taxation authorities. In the United States both the federal and state tax returns filed for the years 2010 to 2014 remain subject to examination by the taxation authorities.

Management determined that the following provision was required for uncertainty on income taxes during the year:

Years ended December 31		2015		2014
Balance, beginning of year	**$**	**3.7**	$	3.3
Increases as a result of positions taken during the year		**—**		0.4
Balance, end of year	**$**	**3.7**	$	3.7

17. REGULATORY ASSETS AND LIABILITIES

AltaGas accounts for certain transactions in accordance with ASC 980, Regulated Operations. AltaGas refers to this accounting guidance for regulated entities as “regulatory accounting”. Under regulatory accounting, utilities are permitted to defer expenses and income as regulatory assets and liabilities, respectively, in the Consolidated Balance Sheets when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the Consolidated Statements of Income by a non rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statements of Income in future periods when the amounts are reflected in customer rates. Management’s assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and rate-making conventions. The relevant regulatory bodies are the AUC, BCUC and NSUARB in Canada, and MPSC and RCA in the United States.

If, for any reason, the Corporation ceases to meet the criteria for application of regulatory accounting for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be de-recognized from the Consolidated Balance Sheets and included in the Consolidated Statements of Income for the period in which the discontinuance of regulatory accounting occurs. Criteria that give rise to the discontinuance of regulatory accounting include: (i) increasing competition that restricts the ability of the Corporation to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Corporation’s review of these criteria currently supports the continued application of regulatory accounting for utilities.

The following table summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets, as well as the remaining period, as of December 31, 2015 and 2014, over which the Corporation expects to realize or settle the assets or liabilities:

		2015		2014	Recovery Period
Regulatory assets- current					
Deferred cost of gas	**$**	**3.7**	$	12.5	Less than one year
Deferred property taxes		**0.6**		0.3	Less than one year
	$	**4.3**	$	12.8	
Regulatory assets – non-current					
Deferred regulatory costs and rate stabilization adjustment mechanism	**$**	**19.0**	$	10.4	Various
Pipeline rehabilitation costs		**6.8**		6.0	10 years
Future recovery of pension and other retirement benefits (a)		**130.3**		127.3	Various
Deferred environmental costs		**22.3**		21.6	2-10 years
Deferred loss on reacquired debt		**4.3**		2.9	2-5 years
Deferred depreciation and amortization (b)		**22.9**		20.3	Various
Deferred future income taxes (c)		**96.4**		79.1	Various
Revenue deficiency account (d)		**29.3**		33.4	Various
Other		**2.0**		1.0	2-3 years
	$	**333.3**	$	302.0	
Regulatory liabilities – current					
Deferred cost of gas	**$**	**15.1**	$	3.9	Less than one year
Energy optimization costs		**3.0**		3.4	Less than one year
Interruptible storage service revenue		**1.1**		0.9	Less than one year
Refundable tax credit (f)		**2.1**		1.8	Less than one year
	$	**21.3**	$	10.0	
Regulatory liabilities – non-current					
Option fees deferral (e)	**$**	**3.7**	$	0.7	Various
Refundable tax credit (f)		**12.5**		12.2	Various
Future removal and site restoration costs (g)		**150.3**		120.7	Various
Insurance recovery of environmental costs		**0.8**		1.0	4 years
Interruptible storage service revenue		**0.3**		1.1	2 years
Other		**—**		0.3	Various
	$	**167.6**	$	136.0	

(a) Certain utilities have recovered pension costs related to regulated operations in rates, and as such the Corporation has recorded a regulatory asset for the pension funding deficiency. Depending on the method utilized by the utility the recovery period can be either the expected service life of the employees or the benefit period for employees or a specific recovery period as approved by the respective regulator.

(b) Pursuant to the NSUARB decision dated February 12, 2009, Heritage Gas was ordered to suspend amortization of property, plant and equipment and intangible assets for regulatory purposes for the fiscal periods from 2009 to 2011 inclusively. The NSUARB, in its most recent decision dated November 24, 2011, continued the order to suspend amortization for regulatory purposes for the fiscal periods from 2012 to 2013 inclusively, however amortization was to resume for regulatory purposes in 2014 at 25 percent of authorized rates; 2015 at 50 percent of authorized rates; 2016 at 75 percent of authorized rates; and 2017 at 100 percent of authorized rates. As a result of this order, the Corporation recognizes a regulatory asset equal to the amortization that would have otherwise been included in rates. The deferred regulatory asset is recovered over the remaining useful life of related assets.

(c) Remaining amortization period varies depending on the timing of underlying transactions.

(d) Heritage Gas has an approval from the NSUARB to use a revenue deficiency account (RDA) until it is fully recovered, subject to a cap of $50 million, imposed in 2010, which may be increased subject to approval by the NSUARB. The RDA is the cumulative difference between the revenue requirements and the actual amounts billed to customers.

(e) Pursuant to BCUC approved negotiated settlement agreement.

(f) On September 18, 2013, CINGSA received a US$15.0 million gas storage facility tax credit from the State of Alaska for the benefit of its firm storage service customers. CINGSA will derive no direct or indirect benefit from the tax credit. Following receipt of the tax credit, CINGSA deposited it in a separate interest-bearing account. CINGSA will act as a custodian of the tax credit and any interest earned for the benefit of CINGSA's customers. On an annual basis, covering the years 2012 through 2021, CINGSA will disburse to the customers 1/10th of the amount of the tax credit not subject to refund to the State and interest earned. The RCA has approved the disbursement methodology.

(g) This amount and timing of draw down is dependent upon the cost of removal of underlying utility property, plant and equipment and the life of property, plant and equipment.

18. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Available-for-sale	Cash flow hedges	Defined benefit pension and PRB plans	Hedge net investments	Translation foreign operations	AOCI Investee	Total
Opening balance, January 1, 2015	**$ (12.0)**	**$ 13.3**	**$ (9.6)**	**$ (70.9)**	**$ 242.3**	**$ —**	**$ 163.1**
OCI before reclassification	**(24.2)**	**(0.4)**	**(1.4)**	**(99.1)**	**368.2**	**4.6**	**247.7**
Amounts reclassified from OCI	**35.4**	**(17.5)**	**0.9**	**—**	**—**	**—**	**18.8**
Current period OCI (pre-tax)	**11.2**	**(17.9)**	**(0.5)**	**(99.1)**	**368.2**	**4.6**	**266.5**
Income tax on amounts retained in AOCI	**(0.1)**	**0.2**	**0.8**	**0.4**	**—**	**—**	**1.3**
Income tax on amounts reclassified to earnings	**(1.5)**	**4.4**	**(0.3)**	**—**	**—**	**—**	**2.6**
Net current period OCI	**9.6**	**(13.3)**	**—**	**(98.7)**	**368.2**	**4.6**	**270.4**
Ending balance, December 31, 2015	**$ (2.4)**	**$ —**	**$ (9.6)**	**$ (169.6)**	**$ 610.5**	**$ 4.6**	**$ 433.5**
Opening balance, January 1, 2014	$ (3.0)	$ (10.4)	$ (5.7)	$ (35.9)	$ 94.4	$ —	$ 39.4
OCI before reclassification	(12.0)	31.4	(5.7)	(40.1)	147.9	—	121.7
Amounts reclassified from OCI	1.8	(0.1)	0.5	—	—	—	2.2
Current period OCI (pre-tax)	(10.2)	31.5	(5.2)	(40.1)	147.9	—	123.9
Income tax on amounts retained in AOCI	1.5	(7.9)	1.5	5.1	—	—	0.2
Income tax on amounts reclassified to earnings	(0.3)	0.1	(0.2)	—	—	—	(0.4)
Net current period OCI	(9.0)	23.7	(3.9)	(35.0)	147.9	—	123.7
Ending balance, December 31, 2014	$ (12.0)	$ 13.3	$ (9.6)	$ (70.9)	$ 242.3	$ —	$ 163.1

Reclassification From Accumulated Other Comprehensive Income

Years Ended December 31

AOCI components reclassified	Income Statement line item	2015	2014
Cash flow hedges – commodity contracts			
Commodity contracts – NGL (realized effective portion)	Service revenue	**$ (7.2)**	$ —
Commodity contracts – NGL (discontinuation of hedge accounting)[(a)]	Unrealized gains on risk management contracts	**(10.3)**	(0.4)
Bond forward	Interest expense – Long-term debt	**—**	0.1
	Other income (expenses)	**—**	0.2
Available-for-sale	Other income (expenses)	**35.4**	1.8
Defined benefit pension plans	Operating and administrative expense	**0.9**	0.5
	Total before income taxes	**18.8**	2.2
Deferred income taxes	Income tax expenses – Deferred	**2.6**	(0.4)
		$ 21.4	$ 1.8

(a) In September 2015, AltaGas discontinued cash flow hedge accounting on its existing NGL frac hedges as the forecasted NGL sales were no longer expected to occur.

19. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation's financial instruments consist of cash and cash equivalents, accounts receivable, risk management contracts, 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, interest rates, and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, currency exchange, and interest rate yield curves. The forward curves used to mark-to-market these derivative instruments are vetted against public sources.

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

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

Cash and cash equivalents, Short-term investments, 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 liabilitie*s – 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 derivatives were calculated using discounted cash flow analysis based upon forward prices from published sources for the relevant period. The fair value of foreign exchange derivatives was calculated using quoted market rates.

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)] *(note 10)*	**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)] *(note 15)*	**11.0**	**—**	**11.0**	**—**	**11.0**
Other long-term liabilities [(b)] *(note 15)*	**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.

December 31, 2014	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Cash and cash equivalents	$ 371.0	$ 371.0	$ —	$ —	$ 371.0
Short-term investment	50.0	50.0	—	—	50.0
Risk management assets – current	70.8	—	70.8	—	70.8
Risk management assets – non-current	21.1	—	21.1	—	21.1
Long-term investments and other assets [(a)] *(note 10)*	46.3	46.3	—	—	46.3
	$ 559.2	$ 467.3	$ 91.9	$ —	$ 559.2
Financial liabilities					
Risk management liabilities – current	$ 43.5	$ —	$ 43.5	$ —	$ 43.5
Risk management liabilities – non-current	14.7	—	14.7	—	14.7
Current portion of long-term debt	214.4	—	214.4	—	214.4
Long-term debt	3,031.8	—	3,170.3	—	3,170.3
Other current liabilities [(b)] *(note 15)*	10.6	—	10.6	—	10.6
Other long-term liabilities [(b)] *(note 15)*	155.6	—	149.1	—	149.1
	$ 3,470.6	$ —	$ 3,602.6	$ —	$ 3,602.6

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

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

Years Ended December 31	2015	2014
Natural gas	**$ 7.2**	$ (7.9)
Storage optimization	**(0.4)**	2.1
NGL frac spread	**(3.2)**	3.2
Power	**6.3**	7.5
Heat rate	**(0.3)**	0.1
Foreign exchange	**(0.1)**	(0.3)
Embedded derivative	**(0.1)**	—
	$ 9.4	$ 4.7

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.

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**
Total	**$ 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.

December 31, 2014 Risk management assets [a]	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Net amounts presented in balance sheet
Natural gas	$ 61.0	$ 25.2	$ 35.8
Storage optimization	1.0	—	1.0
NGL frac spread	26.6	—	26.6
Power	28.0	—	28.0
Heat rate	0.5	—	0.5
	$ 117.1	$ 25.2	$ 91.9
Risk management liabilities [b]			
Natural gas	$ 64.9	$ 25.2	$ 39.7
Storage optimization	0.1	—	0.1
NGL frac spread	5.7	—	5.7
Power	12.1	—	12.1
Heat rate	0.1	—	0.1
Foreign exchange	0.5	—	0.5
	$ 83.4	$ 25.2	$ 58.2

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $70.8 million and risk management assets (non-current) balance of $21.1 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $43.5 million and risk management liabilities (non-current) balance of $14.7 million.

Risks Associated with Financial Instruments

AltaGas is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates as well as credit risk and liquidity risk.

Commodity Price Risk

AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices. The use of derivative instruments is governed under formal risk management policies and is subject to parameters set out by AltaGas' Risk Management Committee and Board of Directors. AltaGas does not make use of derivative instruments for speculative purposes.

Natural Gas

AltaGas purchases and sells natural gas to its customers. The fixed price and market price contracts for both the purchase and sale of natural gas extend to 2020. AltaGas had the following contracts and commodity swaps outstanding related to the storage optimization activities:

December 31, 2015	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**	**Fair Value ($ millions)**
Sales	**1.40 to 5.25**	**1-60**	**95,526,580**	**25.2**
Purchases	**1.37 to 5.20**	**1-60**	**81,949,419**	**(22.1)**
Swaps	**2.58 to 3.02**	**1-3**	**3,372,837**	**—**

December 31, 2014	Fixed price (per GJ)	Period (months)	Notional volume (GJ)	Fair Value ($ millions)
Sales	2.00 to 12.00	1-72	77,394,117	39.0
Purchases	2.09 to 9.08	1-72	72,262,437	(37.4)
Swaps	2.51 to 16.26	1-10	4,266,090	(5.5)

Power

Under the Sundance B Power Purchase Arrangement (PPA) AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Corporation sells the power to the Alberta Electric System Operator at market prices and uses swaps to fix the prices over time on a portion of the volumes. AltaGas' strategy is to mitigate the cash flow risk to Alberta power prices to provide predictable earnings. As at December 31, 2015, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following commodity forward contracts on electrical power, commodity swaps, and heat rate hedges outstanding:

December 31, 2015	**Fixed price (per GJ or MWh)**	**Period (months)**	**Notional volume (GJ or MWh)**	**Fair Value ($ millions)**
Power sales	**35.94 to 99.25**	**1-60**	**2,834,736**	**24.5**
Power purchases	**52.50 to 69.72**	**1-36**	**478,112**	**(8.6)**
Swap sales	**31.00 to 44.00**	**1-12**	**256,800**	**2.0**
Swap purchases	**37.00 to 56.50**	**1-48**	**490,752**	**1.6**
Heat rate electricity sales	**43.55 to 49.35**	**1**	**4,960**	**0.1**

December 31, 2014	Fixed price (per GJ or MWh)	Period (months)	Notional volume (GJ or MWh)	Fair Value ($ millions)
Power sales	43.94 to 97.55	1-72	2,808,405	22.1
Power purchases	48.50 to 88.00	1-48	1,226,496	(9.9)
Swap sales	49.10 to 63.00	1-4	229,985	2.5
Swap purchases	56.50	1-36	78,912	(0.9)
Heat rate electricity sales	61.75 to 75.35	1-4	31,190	0.4
Heat rate gas purchases	3.93	1	49,600	(0.1)

The table below provides the potential impact on pre-tax income due to changes in the fair value of risk management contracts in place as at December 31, 2015.

Factor	Increase or decrease to forward prices	Increase or decrease to income before tax *($ millions)*
Alberta power price	$1/MWh	2.1
AECO natural gas price	$0.50/GJ	4.9

Foreign Exchange Risk

AltaGas is exposed to foreign exchange risk as changes in foreign exchange rates may affect the fair value or future cash flows of the Corporation's financial instruments. AltaGas has foreign operations whereby the functional currency is the US dollar. As a result, the Corporation's earnings, cash flows, and OCI 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. AltaGas had no contracts outstanding as at December 31, 2015.

AltaGas also designates its US dollar-denominated debt as a net investment hedge of its U.S. subsidiaries. As at December 31, 2015, AltaGas designated US$723.5 million of outstanding debt as a net investment hedge (December 31, 2014 – US$375 million). For the year ended December 31, 2015, AltaGas incurred unrealized loss of $98.7 million arising from the translation of debt in OCI (Year ended December 31, 2014 – after-tax unrealized loss of $35.0 million).

Interest Rate Risk

AltaGas is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Corporation manages its interest rate risk by holding a mix of both fixed and floating interest rate debts. As at December 31, 2015, approximately 70% of AltaGas' total outstanding short-term and long-term debt was at fixed rates. In addition, from time to time, AltaGas may enter into interest rate swap agreements to fix the interest rate on a portion of its banker's acceptances issued under its credit facilities. There were no outstanding interest rate swaps as at December 31, 2015.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses that allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas provides an allowance for doubtful accounts in the normal course of its business.

AltaGas' maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. As at December 31, 2015, AltaGas had no concentration of credit risk with a single counterparty.

Accounts Receivable Past Due or Impaired

AltaGas had the following past due or impaired accounts receivable (AR):

	As at December 31, 2015	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 323.3	$ 122.7	$ 2.7	$ 187.3	$ 6.4	$ 1.2	$ 3.0
Other	12.7	—	—	12.5	0.1	—	0.1
Allowance for credit losses	(2.7)	—	(2.7)	—	—	—	—
	$ 333.3	$ 122.7	$ —	$ 199.8	$ 6.5	$ 1.2	$ 3.1

	As at December 31, 2014	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 341.4	$ 126.7	$ 2.5	$ 194.7	$ 11.1	$ 2.9	$ 3.5
Other	13.5	—	—	11.9	—	—	1.6
Allowance for credit losses	(2.5)	—	(2.5)	—	—	—	—
	$ 352.4	$ 126.7	$ —	$ 206.6	$ 11.1	$ 2.9	$ 5.1

Allowance for credit losses	December 31, 2015	December 31, 2014
Balance, beginning of year	$ 2.5	$ 3.8
Foreign exchange translation	0.3	0.1
New allowance	0.1	0.7
Recovery of allowance	—	(1.3)
Allowance applied to uncollectible customer accounts	(0.2)	(0.8)
Balance, end of year	$ 2.7	$ 2.5

Liquidity Risk

Liquidity risk is the risk that AltaGas will not be able to meet its financial obligations as they come due. AltaGas manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. AltaGas' objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required.

AltaGas had the following contractual maturities with respect to financial liabilities:

		Payments due by period			
As at December 31, 2015	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**$ 383.1**	**$ 383.1**	**$ —**	**$ —**	**$ —**
Dividends payable	**24.1**	**24.1**	**—**	**—**	**—**
Short-term debt	**130.7**	**130.7**	**—**	**—**	**—**
Other current liabilities (a)	**11.0**	**11.0**	**—**	**—**	**—**
Other long-term liabilities (a)	**151.2**	**—**	**20.7**	**20.0**	**110.5**
Risk management contract liabilities	**49.2**	**33.5**	**12.4**	**3.3**	**—**
Current portion of long-term debt (b)	**287.6**	**287.6**	**—**	**—**	**—**
Long-term debt (b)	**3,747.5**	**—**	**578.1**	**1,520.3**	**1,649.1**
	$ 4,784.4	**$ 870.0**	**$ 611.2**	**$ 1,543.6**	**$ 1,759.6**

(a) Excludes non-financial liabilities
(b) Excludes deferred financing costs

		Payments due by period			
As at December 31, 2014	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$ 343.6	$ 343.6	$ —	$ —	$ —
Dividends payable	19.8	19.8	—	—	—
Short-term debt	72.4	72.4	—	—	—
Other current liabilities (a)	10.6	10.6	—	—	—
Other long-term liabilities (a)	155.6	—	20.5	19.6	115.5
Risk management contract liabilities	58.2	43.5	13.2	1.2	0.3
Current portion of long-term debt (b)	214.4	214.4	—	—	—
Long-term debt (b)	3,049.6	—	457.4	388.1	2,204.1
	$ 3,924.2	$ 704.3	$ 491.1	$ 408.9	$ 2,319.9

(a) Excludes non-financial liabilities
(b) Excludes deferred financing costs

20. 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 September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million.

Dividend Reinvestment Plan (DRIP)

AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan for holders of common shares (the Plan).

The Plan, as may be amended from time to time, provides eligible holders of common shares with the opportunity to reinvest the cash dividends paid by AltaGas on their common shares towards the purchase of new common shares at a 5 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). The Plan also 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, 2014	122,305,293	$	2,211.4
Shares issued for cash on exercise of options	989,162		24.9
Shares issued on public offering	9,027,500		449.2
Deferred taxes on share issuance cost	—		4.2
Shares issued under DRIP	1,619,794		70.2
December 31, 2014	133,941,749		2,759.9
Shares issued on public offering	8,760,000		287.9
Shares issued for cash on exercise of options	834,268		20.8
Deferred taxes on share issuance costs	—		3.3
Shares issued under DRIP	2,745,230		96.2
Issued and outstanding at December 31, 2015	**146,281,247**	**$**	**3,168.1**

Preferred Shares

On September 30, 2015, 2,488,780 of the outstanding 8,000,000 Cumulative Redeemable Five Year Fixed Rate Reset Preferred Shares, Series A were converted into Cumulative Floating Rate Preferred Shares, Series B.

On November 23, 2015, AltaGas closed a public offering of 8,000,000 Cumulative Redeemable 5-Year Minimum Rate Reset Preferred Shares, Series I, at a price of $25.00 per Series I, Preferred Share for aggregate gross proceeds of $200 million.

Preferred Shares Series A Issued and Outstanding	Number of shares		Amount
January 1, 2014	8,000,000	$	194.1
Deferred taxes on share issuance costs	—		1.8
December 31, 2014	8,000,000		195.9
Shares converted to Series B	(2,488,780)		(60.9)
Issued and outstanding at December 31, 2015	**5,511,220**	**$**	**135.0**

Preferred Shares Series B Issued and Outstanding	Number of shares		Amount
January 1, 2014 and December 31, 2014	—	$	—
Shares issued on conversion from Series A	2,488,780		60.9
Issued and outstanding at December 31, 2015	**2,488,780**	**$**	**60.9**

Preferred Shares Series C Issued and Outstanding	Number of shares		Amount
January 1, 2014	8,000,000	$	200.6
December 31, 2014	8,000,000		200.6
Issued and outstanding at December 31, 2015	**8,000,000**	**$**	**200.6**

Preferred Shares Series E Issued and Outstanding	Number of shares		Amount
January 1, 2014	8,000,000	$	194.9
Deferred taxes on share issuance costs	—		0.9
December 31, 2014	8,000,000		195.8
Issued and outstanding at December 31, 2015	**8,000,000**	**$**	**195.8**

Preferred Shares Series G Issued and Outstanding	Number of shares		Amount
January 1, 2014	—	$	—
Shares issued on public offering	8,000,000		200.0
Share issuance costs, net of taxes	—		(3.9)
December 31, 2014	8,000,000		196.1
Issued and outstanding at December 31, 2015	**8,000,000**	**$**	**196.1**

Preferred Shares Series I Issued and Outstanding	Number of shares		Amount
January 1, 2014 and December 31, 2014	—	$	—
Shares issued	8,000,000		200.0
Share issuance costs, net of taxes	—		(3.3)
Issued and outstanding at December 31, 2015	**8,000,000**	**$**	**196.7**

The following table outlines the characteristics of the cumulative redeemable preferred shares:

	Current Yield	Annual dividend per share [a]	Redemption price per share	Redemption and conversion option date [b][c]	Right to convert into [c]
Series A [d]	3.38%	$0.845	$25	September 30, 2020	Series B
Series B [e]	Floating [e]	Floating [e]	$25	September 30, 2020	n/a
Series C [f]	4.40%	US$1.10	US$25	September 30, 2017	Series D
Series E [d]	5.00%	$1.25	$25	December 31, 2018	Series F
Series G [d]	4.75%	$1.1875	$25	September 30, 2019	Series H
Series I [g]	5.25%	$1.3125	$25	December 31, 2020	Series J

(a) The holder of Series A, C, E, G, and I is entitled to receive a cumulative quarterly fixed dividend as and when declared by the Board of Directors. The holder of Series B is entitled to receive quarterly floating dividend as and when declared by the board.

(b) AltaGas may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter.

(c) The holder will have the right, subject to certain conditions, to convert their preferred shares of a specified series into preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

(d) Holders will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent (Series A), 3.17 percent (Series E), and 3.06 percent (Series G).

(e) Holders of Series B will be entitled to receive cumulative quarterly floating dividends, which will reset each quarter thereafter at a rate equal to the sum of the then 90-day government of Canada Treasury Bill plus 2.66 percent. Each quarterly dividend is calculated as the annualized amount multiplied by the number of days in the quarter, divided by the number of days in the year. Commencing December 31, 2015, the floating quarterly dividend rate for Series B is $0.19269 per Series B preferred share for the period starting December 31, 2015 to, but excluding, March 31, 2016.

(f) Holders of Series C will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the sum of the U.S. Government Bond Yield on the applicable rate calculation date plus 3.58 percent.

(g) Holders will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the then five-year Government of Canada bond yield plus 4.19 percent, provided that, in any event, such rate shall not be less than 5.25 percent per annum.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at December 31, 2015, 10,068,864 shares were reserved for issuance under the plan. As at December 31, 2015, options granted under the plan have a term between six and 10 years until expiry and vest no longer than over a four-year period.

As at December 31, 2015, unexpensed fair value of share option compensation cost associated with future periods was $2.7 million (December 31, 2014 – $5.2 million).

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

	December 31, 2015			December 31, 2014		
Options outstanding	**Number of options**		**Exercise price [a]**	Number of options		Exercise price [a]
Share options outstanding, beginning of year	**5,123,655**	**$**	**30.28**	5,561,505	$	27.25
Granted	**470,000**		**36.94**	666,000		45.57
Exercised	**(834,268)**		**22.93**	(989,162)		23.03
Expired	**(19,125)**		**41.67**	—		—
Forfeited	**(181,001)**		**36.88**	(114,688)		34.44
Share options outstanding, end of year	**4,559,261**	**$**	**32.02**	5,123,655	$	30.28
Share options exercisable, end of year	**3,009,946**	**$**	**28.71**	3,007,280	$	25.51

(a) Weighted average.

As at December 31, 2015, the aggregate intrinsic value of the total options exercisable was $12.0 million (December 31, 2014 – $53.6 million), the total intrinsic value of options outstanding was $12.2 million (December 31, 2014 – $68.2 million) and the total intrinsic value of options exercised was $12.0 million (December 31, 2014 – $22.6 million).

The following table summarizes the employee share option plan as at December 31, 2015:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Weighted average exercise price
$14.24 to $18.00	**245,000**	**$ 15.20**	**3.31**	**245,000**	**$ 15.20**
$18.01 to $25.08	**633,750**	**21.43**	**4.35**	**633,750**	**21.43**
$25.09 to $50.89	**3,680,511**	**34.96**	**5.45**	**2,131,196**	**32.43**
	4,559,261	**$ 32.02**	**5.18**	**3,009,946**	**$ 28.71**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes-Merton option pricing model. The weighted average grant date fair value and assumptions are as follows:

Years ended December 31	2015	2014
Fair value per option ($)	**2.98**	5.86
Risk-free interest rate (%)	**1.16**	1.71
Expected life (years)	**6**	6
Expected volatility (%)	**18.84**	20.21
Annual dividend per share ($)	**1.77**	1.71
Forfeiture rate (%)	**16.00**	16.00

MTIP

AltaGas has a MTIP plan for employees and executive officers, which includes RUs and PUs with vesting periods between 36 to 44 months from the grant date.

Performance and Restricted Units

	December 31, 2015	December 31, 2014
Balance, beginning of year	**282,817**	224,713
Granted	**196,770**	207,180
Vested and paid out	**(71,883)**	(137,795)
Forfeited	**(7,133)**	(9,435)
Units in lieu of dividends	**8,466**	(1,846)
Outstanding, end of year	**409,037**	282,817

For the year ended December 31, 2015, the compensation expense recorded for the MTIP was $3.3 million (2014 – $4.6 million). As at December 31, 2015, the unrecognized compensation expense relating to the remaining vesting period was $12.6 million (December 31, 2014 – $11.7 million) and is expected to be recognized over the vesting period.

21. NET INCOME PER COMMON SHARE

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

Years Ended December 31		2015		2014
Numerator:				
Net income applicable to controlling interests	**$**	**51.1**	$	130.1
Less: Preferred share dividends		**(41.2)**		(34.5)
Net income per common share	**$**	**9.9**	$	95.6
Denominator: *(millions)*				
Weighted average number of common shares outstanding		**137.7**		126.7
Dilutive equity instruments [(a)]		**1.0**		1.9
Weighted average number of common shares outstanding – diluted		**138.7**		128.6
Basic net income per common share	**$**	**0.07**	$	0.75
Diluted net income per common share	**$**	**0.07**	$	0.74

(a) Includes all options that have a strike price lower than the market share price of AltaGas' common shares as at December 31, 2015 and 2014.

For year ended December 31, 2015, 1.6 million of share options, (year ended December 31, 2014 – 0.6 million) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

22. OTHER INCOME (LOSS)

Years Ended December 31		2015		2014
Gain from sale of assets	**$**	**0.3**	$	38.2
Interest income and other revenue		**5.2**		6.2
Losses from extinguishment of debts		**—**		(17.4)
Other than temporary impairment of available-for-sale investments		**(35.4)**		(1.8)
Unrealized gain from held-for-trading assets		**1.2**		0.2
	$	**(28.7)**	$	25.4

23. OPERATING LEASES

Certain of AltaGas' revenues are obtained through power purchase agreements or take-or-pay contracts whereby AltaGas is the lessor in these operating lease arrangements. Minimum lease payments received are amortized over the term of the lease. Contingent rentals are recorded when the condition that create the present obligation to make such payments occurs such as when actual electricity is generated and delivered. The carrying value of property, plant, and equipment associated with these leases was $3.1 billion as at December 31, 2015 (December 31, 2014 – $2.2 billion). For the year ended December 31, 2015, the total revenue earned from minimum lease payments was $111.1 million (2014 – $91.4 million) and from contingent rentals was $102.8 million (2014 – $32.6 million).

The following table sets forth the future fixed minimum revenue related to the operating leases for the years ended December 31:

2016	214.2
2017	218.7
2018	223.3
2019	227.9
2020	200.8

24. 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.

Future payments of these commitments at December 31, 2015 are estimated as follows:

	2016	2017	2018	2019	2020	2021 and beyond	Total
Gas purchase [a]	$ 369.6	$ 364.7	$ 277.8	$ 269.3	$ 265.0	$ 564.0	**$ 2,110.4**
Service agreement [b][c]	9.8	10.1	17.9	17.7	10.1	168.6	**234.2**
Storage services [d]	3.4	3.5	3.5	3.5	3.5	33.0	**50.4**
Capital projects [e]	64.9	—	—	—	—	—	**64.9**
Operating leases [f]	27.6	32.4	7.2	6.6	5.0	12.9	**91.7**
	$ 475.3	$ 410.7	$ 306.4	$ 297.1	$ 283.6	$ 778.5	**$ 2,551.6**

(a) 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.

(b) 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. The LTSA has fixed fees that will be incurred in the five years following December 31, 2014 and variable fees on a per equivalent operating hour (EOH) basis. As at December 31, 2015, the total commitment was $224.1 million payable over the next 18 years, of which $57.1 million is expected to be paid over the next five years.

(c) 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 $10.1 million over the next six years, of which $8.4 million is payable in the next five years.

(d) 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.

(e) Commitments for capital projects are related to the construction of Power and Gas assets. Estimated amounts are subject to variability depending on the actual construction costs.

(f) Operating leases include lease arrangements for office spaces, vehicles, office and other equipment.

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 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 December 31, 2015.

25. PENSION PLANS AND RETIREE BENEFITS

Defined Contribution Plan

AltaGas has a defined contribution (DC) pension plan for substantially all employees who are not members of defined benefit plans. The net pension expense recorded for the DC plan was $7.4 million for the year ended December 31, 2015 (2014 – $5.7 million).

Defined Benefit Plans

AltaGas has several defined benefit pension plans in Canada and the United States for unionized and non-unionized employees. These benefit plans are funded.

Supplemental Executive Retirement Plan (SERP)

AltaGas has non-registered, defined benefit plans that provide defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. The SERP benefits will be paid from the general revenue of the Corporation as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Post-Retirement Benefits

AltaGas has several post-retirement benefit plans for unionized and non-unionized employees in Canada and the United States. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums. These benefit plans are not funded, except for one plan. Post-retirement benefit plans in the United States provide certain medical and prescription drug benefits to eligible retired employees, their spouses and covered dependents. Benefits are based on a combination of the retiree's age and years of service at retirement. These benefit plans are funded.

The most recent actuarial valuation of the defined benefit plans for funding purposes was completed as of December 31, 2015. Information from the funding valuation was used in the actuarial valuation completed for expense calculation purposes. The next actuarial valuation for funding purposes is required to be completed as of a date no later than December 31, 2016.

The following table summarizes the details of the defined benefit plans, including the SERP and post-retirement plans in Canada and the United States:

	Canada		United States		Total	
Year ended December 31, 2015	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Accrued benefit obligation						
Balance, beginning of year	$ 130.8	$ 14.4	$ 238.7	$ 77.3	$ 369.5	$ 91.7
Actuarial loss (gain)	(4.3)	(0.6)	(15.7)	(7.9)	(20.0)	(8.5)
Current service cost	7.0	0.6	7.9	2.0	14.9	2.6
Member contributions	0.2	—	—	—	0.2	—
Interest cost	5.2	0.6	10.7	3.5	15.9	4.1
Benefits paid	(4.0)	(0.3)	(7.3)	(1.9)	(11.3)	(2.2)
Expenses paid	(0.4)	—	—	—	(0.4)	—
Plan amendments	0.6	—	—	0.4	0.6	0.4
Foreign exchange translation	—	—	45.7	14.6	45.7	14.6
Balance, end of year	$ 135.1	$ 14.7	$ 280.0	$ 88.0	$ 415.1	$ 102.7

Plan assets												
Fair value, beginning of year	**$**	**90.3**	**$**	**4.7**	**$**	**177.6**	**$**	**56.8**	**$**	**267.9**	**$**	**61.5**
Actual return on plan assets		**1.2**		**0.1**		**(0.7)**		**0.1**		**0.5**		**0.2**
Employer contributions		**6.2**		**1.2**		**10.7**		**0.4**		**16.9**		**1.6**
Member contributions		**0.2**		**—**		**—**		**—**		**0.2**		**—**
Benefits paid		**(4.0)**		**(0.3)**		**(7.3)**		**(1.9)**		**(11.3)**		**(2.2)**
Expenses paid		**(0.4)**		**—**		**—**		**—**		**(0.4)**		**—**
Foreign exchange translation		**—**		**—**		**34.5**		**10.8**		**34.5**		**10.8**
Fair value, end of year	**$**	**93.5**	**$**	**5.7**	**$**	**214.8**	**$**	**66.2**	**$**	**308.3**	**$**	**71.9**
Accrued benefit liability	**$**	**(41.6)**	**$**	**(9.0)**	**$**	**(65.2)**	**$**	**(21.8)**	**$**	**(106.8)**	**$**	**(30.8)**

	Canada				**United States**				**Total**			
Year ended December 31, 2014		Defined Benefit		Post-Retirement Benefits		Defined Benefit		Post-Retirement Benefits		Defined Benefit		Post-Retirement Benefits
Accrued benefit obligation												
Balance, beginning of year	$	108.3	$	11.9	$	182.2	$	60.8	$	290.5	$	72.7
Actuarial loss		16.2		1.7		35.1		11.6		51.3		13.3
Current service cost		5.8		0.5		5.7		1.5		11.5		2.0
Member contributions		—		0.6		—		—		—		0.6
Interest cost		5.2		—		9.8		3.3		15.0		3.3
Benefits paid		(4.7)		(0.3)		(10.6)		(1.7)		(15.3)		(2.0)
Plan amendments		—		—		—		(3.7)		—		(3.7)
Foreign exchange translation		—		—		16.5		5.5		16.5		5.5
Balance, end of year	$	130.8	$	14.4	$	238.7	$	77.3	$	369.5	$	91.7
Plan assets												
Fair value, beginning of year	$	80.0	$	3.6	$	157.2	$	50.4	$	237.2	$	54.0
Actual return on plan assets		5.7		0.3		10.0		3.3		15.7		3.6
Employer contributions		9.1		1.1		6.7		0.2		15.8		1.3
Member contributions		0.2		—		—		—		0.2		—
Benefits paid		(4.7)		(0.3)		(10.6)		(1.7)		(15.3)		(2.0)
Foreign exchange translation		—		—		14.3		4.6		14.3		4.6
Fair value, end of year	$	90.3	$	4.7	$	177.6	$	56.8	$	267.9	$	61.5
Accrued benefit liability	$	(40.5)	$	(9.7)	$	(61.1)	$	(20.5)	$	(101.6)	$	(30.2)

The following amounts were included in the Consolidated Balance Sheets:

		Defined Benefit		**Post-Retirement Benefits**		Defined Benefit		Post-Retirement Benefits
	December 31, 2015				December 31, 2014			
Accounts payable and accrued liabilities	**$**	**0.7**	**$**	**—**	$	0.6	$	—
Future employee obligations		**106.1**		**30.8**		101.0		30.2
	$	**106.8**	**$**	**30.8**	$	101.6	$	30.2

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

	Canada		United States		Total	
Year ended December 31, 2015	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service cost	**$ (0.7)**	**$ —**	**$ —**	**$ —**	**$ (0.7)**	**$ —**
Net actuarial loss	**(11.3)**	**(0.7)**	**(0.8)**	**—**	**(12.1)**	**(0.7)**
Recognized in AOCI pre-tax	**$ (12.0)**	**$ (0.7)**	**$ (0.8)**	**$ —**	**$ (12.8)**	**$ (0.7)**
Increase (decrease) by the amount included in deferred tax liabilities	**3.1**	**0.2**	**0.6**	**—**	**3.7**	**0.2**
Net amount in AOCI after-tax	**$ (8.9)**	**$ (0.5)**	**$ (0.2)**	**$ —**	**$ (9.1)**	**$ (0.5)**

	Canada		United States		Total	
Year ended December 31, 2014	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost	$ 0.1	$ —	$ —	$ —	$ 0.1	$ —
Net actuarial loss	(11.9)	(1.0)	(0.2)	—	(12.1)	(1.0)
Recognized in AOCI pre-tax	$ (11.8)	$ (1.0)	$ (0.2)	$ —	$ (12.0)	$ (1.0)
Increase (decrease) by the amount included in deferred tax liabilities	3.0	0.2	0.2	—	3.2	0.2
Net amount in AOCI after-tax	$ (8.8)	$ (0.8)	$ —	$ —	$ (8.8)	$ (0.8)

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.

Amounts to be amortized in the next fiscal year from AOCI	Defined Benefit	Post-Retirement Benefits
Past service costs	$ 0.2	$ —
Actuarial losses	0.8	—
Total	**$ 1.0**	**$ —**

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

Year ended December 31, 2015	**Canada** Defined Benefit	**Canada** Post-Retirement Benefits	**United States** Defined Benefit	**United States** Post-Retirement Benefits	**Total** Defined Benefit	**Total** Post-Retirement Benefits
Current service cost	**$ 7.0**	**$ 0.6**	**$ 7.9**	**$ 2.0**	**$ 14.9**	**$ 2.6**
Interest cost	**5.2**	**0.6**	**10.7**	**3.5**	**15.9**	**4.1**
Expected return on plan assets	**(5.1)**	**(0.2)**	**(14.8)**	**(4.6)**	**(19.9)**	**(4.8)**
Amortization of past service cost	**0.1**	**—**	**—**	**—**	**0.1**	**—**
Amortization of net actuarial loss	**0.8**	**—**	**—**	**—**	**0.8**	**—**
Amortization of regulatory asset	**1.4**	**0.1**	**6.7**	**1.2**	**8.1**	**1.3**
Net benefit cost recognized	**$ 9.4**	**$ 1.1**	**$ 10.5**	**$ 2.1**	**$ 19.9**	**$ 3.2**

Year ended December 31, 2014	Canada Defined Benefit	Canada Post-Retirement Benefits	United States Defined Benefit	United States Post-Retirement Benefits	Total Defined Benefit	Total Post-Retirement Benefits
Current service cost	$ 5.7	$ 0.5	$ 5.7	$ 1.5	$ 11.4	$ 2.0
Interest cost	5.2	0.6	9.7	3.3	14.9	3.9
Expected return on plan assets	(4.6)	(0.1)	(12.8)	(4.1)	(17.4)	(4.2)
Amortization of past service cost	—	—	—	—	—	—
Amortization of net actuarial loss	1.5	—	—	—	1.5	—
Amortization of regulatory asset	—	—	2.9	0.6	2.9	0.6
Net benefit cost recognized	$ 7.8	$ 1.0	$ 5.5	$ 1.3	$ 13.3	$ 2.3

The objective of the Corporation's investment policy is to maximize long-term total return while protecting the capital value of the fund from major market fluctuations through diversification and selection of investments.

The objective for fund returns, over three to five-year periods, is the sum of two components – a passive component, which is the benchmark index market returns for the asset mix in effect, plus the added value expected from active management. It is the Corporation's belief that the potential additional returns justify the additional risk associated with active management. The risk inherent in the investment strategy over a market cycle (a three-to five-year period) is two-fold. There is a risk that the market returns, as measured by the benchmark returns, will not be in line with expectations. The other risk is that the expected added value of active management over passive management will not be realized over the time period prescribed in each fund manager's mandate. There is also the risk of annual volatility in returns, which means that in any one year the actual return may be very different from the expected return.

Cash and money market investments may be held from time to time as short-term investment decisions at the discretion of the fund manager(s) within the constraints prescribed by their mandate(s).

The Corporation has a target asset mix for the Canadian plans of 45 percent to 55 percent fixed income assets. The target asset mix for the U.S. plans is 33 percent fixed income assets. These objectives have taken into account the nature of the liabilities and the risk-reward tolerance of the Corporation.

The collective investment mixes for the plans are as follows as at December 31, 2015:

Canada		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$**	**4.4**	$	4.4	$	—	4.4
Canadian Equities		**30.2**		30.2		—	30.5
Foreign Equities		**17.0**		17.0		—	17.1
Fixed Income		**42.0**		42.0		—	42.3
Real Estate		**5.6**		—		5.6	5.7
	$	**99.2**	$	93.6	$	5.6	100.0

United States		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$**	**0.7**	$	0.7	$	—	0.2
Foreign Equities		**187.3**		187.3		—	66.7
Fixed Income		**93.0**		93.0		—	33.1
	$	**281.0**	$	281.0	$	—	100.0

Total		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$**	**5.1**	$	5.1	$	—	1.3
Canadian Equities		**30.2**		30.2		—	8.0
Foreign Equities		**204.3**		204.3		—	53.7
Fixed Income		**135.0**		135.0		—	35.5
Real Estate		**5.6**		—		5.6	1.5
	$	**380.2**	$	374.6	$	5.6	100.0

Significant actuarial assumptions used in measuring net benefit plan costs	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Year ended December 31		**2015**		2014
Discount rate (%)	**3.40-4.10**	**4.10**	4.70-5.00	4.70-4.95
Expected long-term rate of return on plan assets (%)[a]	**0.00-7.50**	**3.10-7.50**	0.00-7.50	3.05-7.50
Rate of compensation increase (%)	**3.00-4.00**	**3.50**	3.00-4.00	3.50-4.00
Average remaining service life of active employees (years)	**12.6**	**13.5**	12.5	11.7

(a) Only applicable for funded plans

Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
As at December 31		**2015**		2014
Discount rate (%)	**2.70-4.50**	**4.20-4.60**	2.95-4.10	4.10
Rate of compensation increase (%)	**2.75-4.00**	**3.25**	3.00-4.00	3.50

The expected rate of return on assets is based on the current level of expected returns on risk free investments, the historical level of risk premium associated with other asset classes in which the portfolio is invested, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected rate of return on assets assumption for the portfolio.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated timing and amount of expected benefit payments.

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rates used to measure the expected cost of benefits range between 7 and 7.5 percent and the ultimate trend rate between 4.5 and 5 percent, which is expected to be achieved by 2029.

The assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one percentage point change in the assumed health care trend rates would have the following effects for 2015:

	Increase	Decrease
Service and interest costs	2.3	(1.6)
Accrued benefit obligation	25.9	(18.7)

The following table shows the expected cash flows for defined benefit pension and other-post retirement plans:

	Defined Benefit	Post-Retirement Benefits
Expected employer contributions:		
2016	19.8	0.3
Expected benefit payments:		
2016	16.0	2.9
2017	16.3	3.2
2018	17.4	3.4
2019	18.9	3.7
2020	20.1	4.0
2021-2025	114.8	23.8

26. RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Amounts due to or from related parties on the Consolidated Balance Sheets were measured at the exchange amount and were as follows:

As at December 31		2015		2014
Due from related parties				
Accounts receivable [(a)]	**$**	**0.6**	$	2.2
Long-term investments and other assets [(b)]		**0.8**		—
Prepaid expenses and other current assets [(b)]		**—**		0.8
	$	**1.4**	$	3.0
Due to related parties				
Accounts payable [(c)]		**6.2**		17.6
Long-term debt [(d)]		**—**		0.1
	$	**6.2**	$	17.7

(a) Receivable from joint ventures and an affiliate.
(b) AltaGas and one of its managers agreed on a loan in the principal amount of $0.8 million, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2021 (December 31, 2014 – May 31, 2015).
(c) Payables to joint ventures.
(d) Due to an affiliate of the Corporation.

Years ended December 31		2015		2014
Revenue [(a)]	**$**	**31.3**	$	94.8
Cost of sales [(b)]	**$**	**(4.7)**	$	(3.8)
Operating and administrative expenses [(c)]	**$**	**(8.1)**	$	(10.7)
Other income (loss) [(d)]	**$**	**0.5**	$	0.4
Interest expense on long-term debt	**$**	**—**	$	(0.2)

(a) In the ordinary course of business, AltaGas sold natural gas to an affiliate.
(b) In the ordinary course of business, AltaGas purchased natural gas from two of its joint ventures.
(c) Administrative costs recovered from joint ventures.
(d) Interest income from an affiliate.

27. SUPPLEMENTAL CASH FLOW INFORMATION

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

Years Ended December 31		2015		2014
Accounts receivable	**$**	**68.7**	$	29.0
Inventory		**(7.7)**		(21.0)
Other current assets		**(2.0)**		(9.3)
Regulatory assets (current)		**11.4**		(5.9)
Accounts payable and accrued liabilities		**(15.1)**		(11.5)
Customer deposits		**1.4**		(2.3)
Regulatory liabilities (current)		**9.2**		7.7
Other current liabilities		**(5.3)**		(1.1)
Other operating assets and liabilities		**(21.4)**		3.5
	$	**39.2**	$	(10.9)

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

Years Ended December 31	2015	2014
Interest paid (net of capitalized interest)	$ 126.5	$ 97.0
Income taxes paid	$ 20.1	$ 17.4

28. SEGMENTED INFORMATION

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

Gas	• NGL processing and extraction plants; • transmission pipelines to transport natural gas and NGL; • natural gas gathering lines and field processing facilities; • purchase and sale of natural gas, including to commercial and industrial users; • natural gas storage facilities; • liquefied petroleum gas (LPG) development projects; and • equity investments 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; • coal-fired generation purchased under the Sundance B power purchase arrangement; and • sale of power to commercial and industrial users in Alberta.
Utilities	• rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and • rate-regulated natural gas storage in Michigan and Alaska.
Corporate	• the cost of providing corporate services, financing and general corporate overhead, investments in public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts.

Geographic Information

Years ended December 31	2015	2014
Revenue [(a)]		
Canada	$ 1,279.0	$ 1,574.9
United States	904.4	826.3
Total	$ 2,183.4	$ 2,401.2

(a) Operating revenue from external customers, excluding unrealized gain on risk management contracts.

As at December 31	2015	2014
Property, plant and equipment		
Canada	$ 3,914.0	$ 3,642.9
United States	2,683.9	1,694.1
Total	$ 6,597.9	$ 5,337.0

The following tables show the composition by segment:

Year ended December 31, 2015	**Gas**	**Power**	**Utilities**	**Corporate**	**Intersegment Elimination** [a]	**Total**
Revenue	**$ 845.5**	**$ 476.2**	**$ 1,076.5**	**$ 1.1**	**$ (215.9)**	**$ 2,183.4**
Unrealized gain on risk management	**—**	**—**	**—**	**9.4**	**—**	**9.4**
Cost of sales	**(503.2)**	**(214.4)**	**(595.8)**	**—**	**208.5**	**(1,104.9)**
Operating and administrative	**(175.4)**	**(68.7)**	**(228.3)**	**(26.5)**	**7.0**	**(491.9)**
Accretion expenses	**(3.7)**	**(7.2)**	**(0.1)**	**—**	**—**	**(11.0)**
Depreciation and amortization	**(62.7)**	**(63.8)**	**(76.1)**	**(10.2)**	**0.9**	**(211.9)**
Provision on assets *(note 7)*	**(22.3)**	**(28.4)**	**(2.8)**	**—**	**—**	**(53.5)**
Income (loss) from equity investments *(note 11)*	**(17.0)**	**(44.0)**	**(2.4)**	**—**	**—**	**(63.4)**
Other income (loss) *(note 22)*	**—**	**0.5**	**2.7**	**(31.4)**	**(0.5)**	**(28.7)**
Foreign exchange gain	**—**	**—**	**—**	**6.0**	**—**	**6.0**
Interest expense	**—**	**—**	**—**	**(125.5)**	**—**	**(125.5)**
Income (loss) before income taxes	**$ 61.2**	**$ 50.2**	**$ 173.7**	**$ (177.1)**	**$ —**	**$ 108.0**
Net additions (reductions) to:						
Property, plant and equipment [b]	**$ 262.6**	**$ 693.0**	**$ 185.6**	**$ 8.7**	**$ —**	**$ 1,149.9**
Intangible assets	**$ 2.8**	**$ 375.6**	**$ 3.9**	**$ 13.4**	**$ —**	**$ 395.7**

(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.

Year ended December 31, 2014	Gas	Power	Utilities	Corporate	Intersegment Elimination [a]	Total
Revenue	$ 1,178.8	$ 388.0	$ 1,076.9	$ —	$ (242.5)	$ 2,401.2
Unrealized loss on risk management	—	—	—	4.7	—	4.7
Cost of sales	(789.6)	(244.4)	(651.6)	—	234.7	(1,450.9)
Operating and administrative	(177.1)	(52.1)	(199.3)	(29.9)	7.8	(450.6)
Accretion expenses	(3.7)	(3.1)	(0.1)	—	—	(6.9)
Depreciation and amortization	(66.8)	(38.9)	(64.3)	(3.4)	—	(173.4)
Provision on assets	(108.2)	(10.9)	—	—	—	(119.1)
Income from equity investments	23.6	13.8	1.2	—	—	38.6
Other income (loss)	12.0	27.0	3.2	(16.8)	—	25.4
Foreign exchange loss	—	—	—	(0.4)	—	(0.4)
Interest expense	—	—	—	(111.4)	—	(111.4)
Income (loss) before income taxes	$ 69.0	$ 79.4	$ 166.0	$ (157.2)	$ —	$ 157.2
Net additions (reductions) to:						
Property, plant and equipment [b]	$ 63.8	$ 247.6	$ 183.7	$ 6.5	$ —	$ 501.6
Intangible assets	$ 0.3	$ 5.3	$ 2.3	$ 19.9	$ —	$ 27.8

(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.

The following table shows goodwill and total assets by segment:

As at December 31, 2015	Gas	Power	Utilities	Corporate	Total
Goodwill	**$ 156.3**	**$ —**	**$ 721.0**	**$ —**	**$ 877.3**
Segmented assets	**$ 2,449.0**	**$ 3,579.9**	**$ 3,576.7**	**$ 493.9**	**$ 10,099.5**
As at December 31, 2014					
Goodwill	$ 161.4	$ —	$ 623.7	$ —	$ 785.1
Segmented assets	$ 2,284.3	$ 2,338.1	$ 3,142.5	$ 630.7	$ 8,395.6

29. SUBSEQUENT EVENTS

Subsequent events have been reviewed through February 24, 2016, the date these consolidated financial statements were issued, and no subsequent events requiring disclosure were noted except for the agreement entered into with Tidewater on February 2, 2016 as discussed under note 4.

SHAREHOLDER INFORMATION

2015

Ex-Dividend Date	Record Date	Payment Date	**Amount**
January 22, 2015	January 26, 2015	February 17, 2015	$0.1475
February 23, 2015	February 25, 2015	March 16, 2015	$0.1475
March 23, 2015	March 25, 2015	April 15, 2015	$0.1475
April 23, 2015	April 27, 2015	May 15, 2015	$0.1475
May 21, 2015	May 25, 2015	June 15, 2015	$0.1600
June 23, 2015	June 25, 2015	July 15, 2015	$0.1600
July 23, 2015	July 27, 2015	August 17, 2015	$0.1600
August 21, 2015	August 25, 2015	September 15, 2015	$0.1600
September 23, 2015	September 25, 2015	October 15, 2015	$0.1600
October 22, 2015	October 26, 2015	November 16, 2015	$0.1650
November 23, 2015	November 25, 2015	December 15, 2015	$0.1650
December 23, 2015	December 29, 2015	January 15, 2016	$0.1650
Total 2015 Dividends:			**$1.885**

Dividend Reinvestment and Optional Common Share Purchase Plan of AltaGas Ltd. for Holders of Common Shares

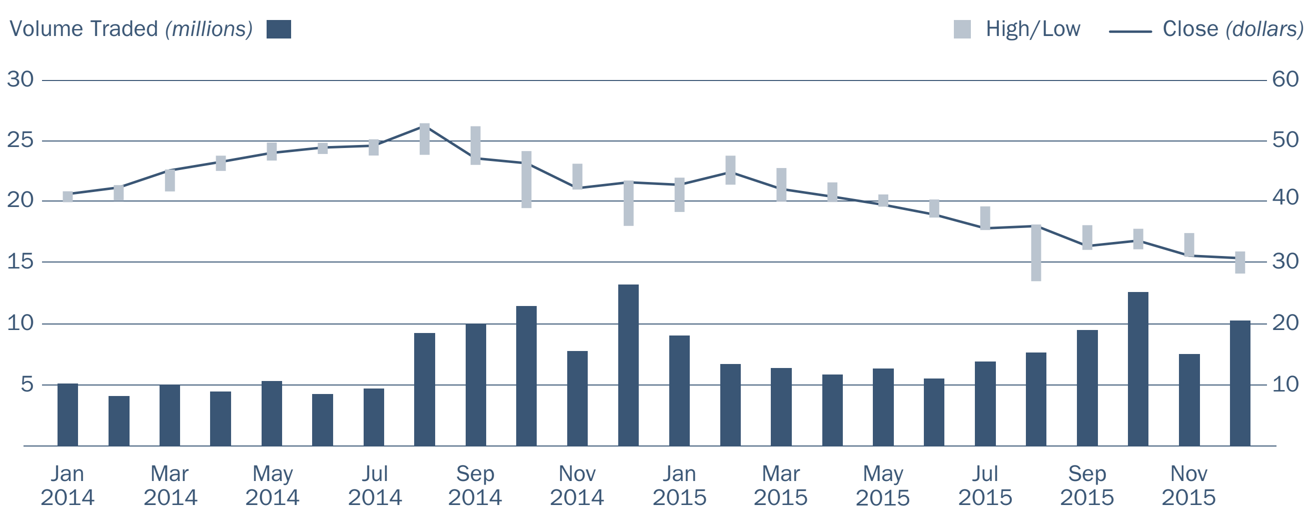
AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan ("Plan") for holders of common shares of AltaGas Ltd.

The Plan provides shareholders with a convenient and economical way to maximize their investment in AltaGas. The Plan enables eligible shareholders to direct cash dividends paid by AltaGas in respect of their existing shares be reinvested at 95 percent of the average market price (as defined in the Plan) of a share. Shareholders resident outside of Canada are not entitled to participate in the Plan. Eligible shareholders can also make optional share purchases at the weighted average market price subject to Plan limits.

If you wish to participate in the Plan, eligible registered shareholders must enroll directly with Computershare Trust Company of Canada, while beneficial shareholders should simply contact their broker, investment dealer, financial institution or other nominee through which shares are held, as they must enroll on your behalf.

Complete details on the DRIP are available on the AltaGas website at **www.altagas.ca**.

AltaGas Share Price and Volume (ALA)



CORPORATE INFORMATION

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on renewable energy sources.

For more information visit: www.altagas.ca.

Management Team

David Cornhill
Chairman and Chief Executive Officer

David Harris
President and Chief Operating Officer

Tim Watson
Executive Vice President and
Chief Financial Officer

John O'Brien
President AltaGas Services U.S.

Deborah Stein
Executive Vice President

John Lowe
Executive Vice President

Brad Grant
Vice President and General Counsel

Kent Stout
Vice President Corporate Resources

Auditors

Ernst & Young LLP
Calgary, Alberta, Canada

Transfer Agent

Computershare Trust Company
of Canada
Calgary, Alberta, Canada
Toll free: 1-800-564-6253
Email: service@computershare.com

Investors are encouraged to contact Computershare for information concerning their security holdings.

Stock Exchange Listing

Toronto Stock Exchange:
ALA, ALA.PR.A, ALA.PR.B, ALA.PR.U,
ALA.PR.E, ALA.PR.G, ALA.PR.I

Annual Meeting

The annual meeting will be held at 3:30 p.m. MDT on Wednesday, April 20, 2016 at The Calgary Petroleum Club,
Devonian Room
319-5 Avenue SW
Calgary, Alberta

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
EBITDA	earnings before interest, taxes, depreciation, and amortization
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

Forward-looking Information

This annual report may contain certain statements that are forward looking and are subject to risks and uncertainties. The words "may", "would", "could", "should", "will", "intend", "plan", "anticipate", "expect", "believe", "aim", "seek", "propose", "estimate", "project", "target", "outlook", "forecast" or other similar words are used to identify such forward-looking statements. Forward-looking statements in this annual report are intended to provide securityholders and potential investors with information regarding AltaGas and its subsidiaries, including management's assessment of AltaGas' and its subsidiaries' future financial and operations plans and outlook. Forward looking information in this annual report may include, among others, statements regarding business objectives, anticipated business prospects and growth and expansion opportunities, projects under construction and in development (including expected costs, design, location, capacity, construction schedule and anticipated operation and final investment decision dates), financial and operational performance, expectations for cash flow and access to capital, expectations or projections about the future (including, industry, market and economic conditions), and strategies and goals for growth and expansion. All forward-looking statements reflect AltaGas' beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of AltaGas to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of AltaGas' assets, the construction and completion of projects, costs of labour, equipment and materials, access to capital markets, interest and currency exchange rates, the price, generation and availability of commodities and hedging, regulatory, First Nations and other stakeholder processes and decisions, changes in environmental and other laws and regulations, competitive factors in the natural gas and power energy sectors, performance and credit risk of counterparties, weather, and economic conditions. This list should not be considered to be exhaustive. By its nature, forward-looking statements are subject to various risks and uncertainties, which could cause AltaGas' actual results and experience to differ materially from the anticipated results or expectations expressed in such forward-looking statements. Additional information on these and other factors is available in the reports filed by AltaGas with Canadian securities regulators, including in the MD&A forming part of this annual report, and available on SEDAR at www.sedar.com. Readers are cautioned to not place undue reliance on such forward-looking information that is given as of the date it is expressed in this annual report or other document in which it is contained and which is expressly qualified by cautionary statements contained in this annual report or other document in which such forward looking information is contained. Readers are also cautioned not to use future-oriented information or financial outlooks for anything other than their intended purpose. AltaGas undertakes no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

TSX: **ALA**

Investor Relations

AltaGas trades on the Toronto Stock Exchange
TSX: **ALA, ALA.PR.A, ALA.PR.B, ALA.PR.U, ALA.PR.E, ALA.PR.G, ALA.PR.I**

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AltaGas

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