AltaGas

2014 Annual Report

Clean Energy Global Opportunities Competitive Advantage

Vision:

To be a leading North American diversified energy infrastructure company.

Strategy:

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.

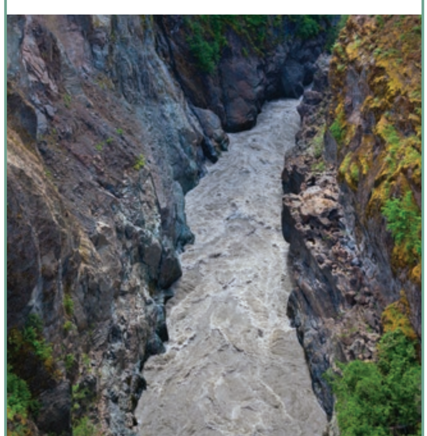
Gas

We invest in assets that process and move clean natural gas to key markets, including Asia. We provide a fully integrated service offering to customers across the natural gas energy value chain.

In 2014, we became a global exporter and delivered our first shipment of liquefied petroleum gas to Asia. We also signed a contract with a Montney producer to connect Canada's natural gas from wellhead to export markets.

Power

We are focused on building, owning, and operating a diversified portfolio of clean energy assets that reduce our carbon footprint.



In 2014, we successfully completed the largest project in our history, the 195-MW Forrest Kerr Hydroelectric Facility. We also completed the 16-MW Volcano Creek Hydroelectric Facility. With these two facilities, we added 211 MW of clean, hydroelectric generation to our power portfolio, increasing our total generation by nearly 20 percent and renewable generation by over 130 percent.

Utilities

We continue to find innovative ways to deliver clean and affordable natural gas to more end-users.

In 2014, we invested $186 million to support customer and rate base growth across our Utilities and increased our total rate base by 8 percent.

Clean Energy

We are poised to double our assets over the next five years and to expand our capabilities to provide clean and affordable energy to more customers for years to come.

We have significantly increased our clean energy footprint by executing opportunities driven by the natural gas renaissance in North America and the demand for clean energy. We have executed more than $4 billion in growth opportunities over the last five years alone, becoming the $8 billion company we are today.

It is estimated that there is more than 3,000 Tcf of gas in the world-class Montney and Duvernay gas plays in Canada. By investing in natural gas processing and export infrastructure, we are pursuing opportunities to unlock the value of western Canada's vast natural gas reserves. AltaGas' gas business is uniquely positioned to serve producers in these plays and to supply Asian markets with clean energy.

The abundance of natural gas in North America provides a clean, low-cost energy alternative for home and business owners. AltaGas' utilities deliver clean-burning natural gas to end-users in geographically diverse areas of North America. We continue to maximize existing infrastructure to maintain cost-effective rates, and to invest in upgrades to provide safe and reliable operations. AltaGas expects to grow its existing utility infrastructure through the expansion of existing distribution systems, the acquisition of new franchises when it is cost effective or strategic, and through fuel switching as end-users realize the benefit of choosing a clean, low-cost energy alternative.

AltaGas' power assets are strategically located in key markets, and our teams have operational expertise and an understanding of the various regulatory environments. In Alberta, it is forecasted that over 3,500 MW of coal-fired power generation will be retired through 2030. This, coupled with increasing demand over the same period, results in the potential need for approximately 8,000 MW of new generation. In the U.S., particularly in California, approximately 15,000 MW of new generation will be required by 2030 as new environmental regulations are implemented. AltaGas is positioned in these markets, as well as others, to capitalize on opportunities to develop and own additional power generation assets to meet the growing North American demand for cleaner energy.

Last year we added more than 200 MW of clean, hydroelectric power generation to our asset base. In August 2014, the 195-MW Forrest Kerr Hydroelectric Facility – the largest project in AltaGas' history – commenced operations. Four months later, the 16-MW Volcano Creek Hydroelectric Facility also achieved commercial operations – two years ahead of schedule. Our employees and contractors, the Government of British Columbia, BC Hydro, and the Tahltan First Nation all played key roles in the success of these projects and we look forward to working with them closely as we provide clean energy to British Columbia for decades to come.

In August 2014, the Forrest Kerr Hydroelectric Facility started delivering clean energy to British Columbia through BC Hydro's 287-kV Northwest Transmission Line. The project was completed on time and on budget.

Forrest Kerr from Start to Finish at a Glance

July 2008
Acquired project.

July 2010
Construction begins.

November 2012
Iskut River diverted to build in-river weir.

Spring 2013
Tunnelling and weir completed. Turbine installation begins.

December 2013
Inlet structure and inlet gate bridge completed.

March 2014
Tunnel breakthrough to Iskut River.

April 2014
Start of water flow at Forrest Kerr.

June 2014
Construction completed.

August 2014
Commercial operations begin.

October 2014
Delivers Commercial Operations Date certificate.

Northwest Projects by the Numbers

95,000

homes can be powered
by all three projects

1 million cubic metres

of rock was excavated
at Forrest Kerr – enough to fill
400 Olympic-size swimming pools

$1 BILLION

financed on balance sheet
to construct the three projects

550 milliseconds

is the amount of time it takes for
information to transfer from AltaGas' offices
in Calgary to the Northwest Projects site
using our satellite system

300

temporary jobs were created
during peak construction

79

local contractors were
hired during construction

Global Opportunities

In 2014 we started exporting liquefied petroleum gas (LPG) to Asia. By opening the doors to international markets, we now provide a highly competitive and integrated service offering to producers.

Our energy export initiative first gained momentum in early 2013 when AltaGas announced a strategic partnership with Idemitsu Kosan Co.,Ltd, to pursue opportunities to export energy from Canada to Asian markets. By first quarter 2014, the AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) completed the acquisition of a two-thirds strategic interest in Petrogas Energy Corp., which owns and operates midstream facilities and an extensive logistics network. This strategic alignment added key infrastructure and marketing expertise needed to develop our LPG export business. Subsequently, Petrogas acquired the Ferndale LPG storage and distribution facility in Ferndale, Washington. The acquisition was a strong fit for AltaGas, providing us with LPG export capability two years ahead of our original schedule. In August 2014, the first shipment of approximately 500,000 barrels of LPG arrived in Chiba, Japan. We expect to increase volumes up to 30,000 Bbls/d at this facility over the next few years. We are also evaluating an additional 30,000 Bbls/d of LPG exports off Canada's West Coast.

We have also made significant strides towards becoming an early exporter of liquefied natural gas (LNG) off Canada's west coast. AIJVLP worked diligently throughout 2014 to advance the Douglas Channel LNG project through the Companies' Creditors Arrangement Act proceeding. By early 2015, AIJVLP and two other consortium members gained ownership and control of the project, which has a nameplate capacity of 0.55 million tonnes per annum. The consortium is targeting LNG exports by 2018.

Two Years

sooner than originally planned, we are exporting LPG to Asia off the U.S. west coast.

60,000 Bbls/d

Our target for LPG exports off of the west coast of Canada and the U.S.

Over the next several years,
LPG shipments from the Ferndale Terminal
are expected to increase to 30,000 Bbls/d.

Competitive Advantage

Significant competitive advantages across our diversified energy infrastructure business position us well for sustained future growth.

Gas

We have a competitive service offering from wellhead to export markets across the energy value chain. Our unique access to international markets creates significant opportunities for AltaGas to meet producer needs for new markets and higher netbacks.

Power

Our power assets supply clean electricity to various communities in North America. We have significant construction and operational expertise to continue to grow our generation portfolio. Strategically located assets in Alberta and California provide significant opportunities to support the shift to cleaner sources of power.

Utilities

We deliver clean and affordable energy to end-users in Canada and the U.S. Our utilities are located in areas where there are supportive regulatory regimes, and they are operated by knowledgable teams with strong regulatory expertise.

Approximately 90 percent of our earnings come from contracted or regulated assets, ensuring solid, stable earnings and cash flow through economic cycles.

Our Gas segment serves producers in the Western Canadian Sedimentary Basin. We own and operate a significant portfolio of energy infrastructure assets that includes natural gas gathering and processing, natural gas liquids extraction and fractionation, transmission, storage, and marketing. The Gas segment also includes a 50 percent ownership in AltaGas Idemitsu Joint Venture Limited Partnership and a one third interest in Petrogas Energy Corp.

- More than 2 Bcf of natural gas transacted per day
- Approximately 70 gathering and processing facilities in western Canada and a network of 6,100 km of gathering and sales lines
- Six extraction plants in Alberta and British Columbia
- Significant NGL logistics network and access to LPG exports through one-third interest in Petrogas Energy Corp.
- Joint venture with Idemitsu Kosan Co.,Ltd. to develop energy export infrastructure

We own and operate 1,449 MW of highly contracted, long-life power assets across North America. Our power generation is diversified across five fuel sources, including gas-fired, coal-fired, wind, biomass, and run-of-river assets. More than 75 percent of total generation capacity is from clean energy sources.

- Generation capacity in Canada and the U.S.
- 25 percent of generation capacity from renewable sources
- More than 2,300 MW under development or evaluation

We own and operate natural gas distribution utilities that serve more than 560,000 customers across Canada and the U.S. Our Utilities segment includes AltaGas Utilities Inc. in Alberta, Pacific Northern Gas in British Columbia, Heritage Gas Limited in Nova Scotia, SEMCO Energy Gas Company in Michigan and Enstar Natural Gas Company in Alaska.

- Delivered approximately 150 Bcf of natural gas in 2014
- $1.5 billion total rate base
- Opportunities to grow rate base

A Leading North American Infrastructure Company

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 northern and western United States.

Forrest Kerr

We safely commissioned the largest project in our history.
We completed it on time and on budget.

Volcano Creek

We completed this project two years ahead of schedule.
We have significant engineering, procurement and construction expertise.

Townsend

We are building gas processing infrastructure to support producers. We are helping to unlock northeast British Columbia's vast gas resources with the 198 Mmcf/d Townsend shallow-cut natural gas processing facility.

Douglas Channel LNG

With the consortium of credible and experienced partners, we are confident this small scale project is well-positioned to be an early exporter of LNG from Canada's west coast.

Ferndale Terminal

We are exporting LPG to Asia and have access to international markets.
We see opportunities to expand the capabilities of this facility.

Blythe

We have significantly grown our clean power presence in California.
We see many opportunities to expand our generating capacity.

Gas

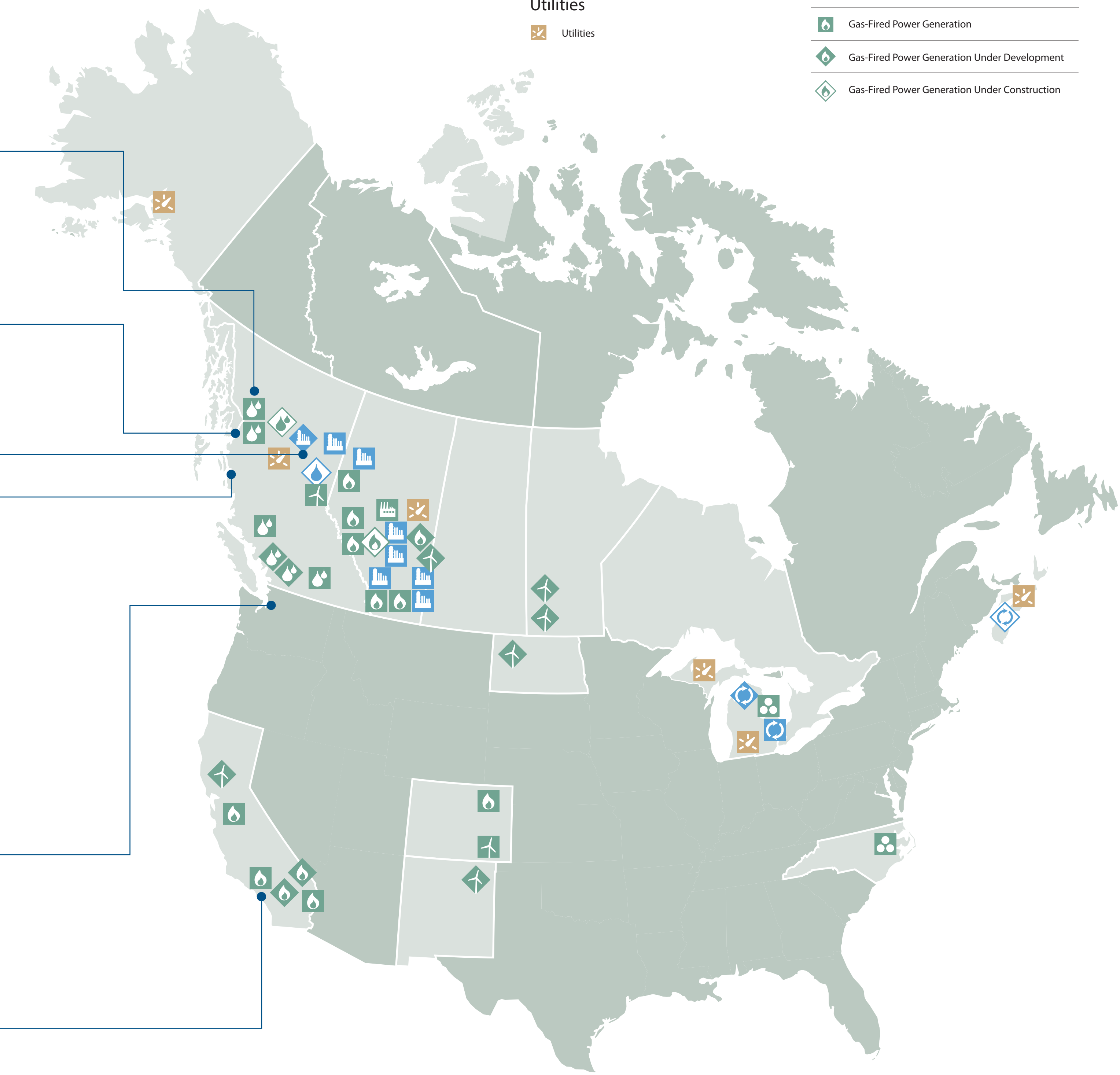
- Gas Processing
- Gas Processing Under Development
- Regional LNG Facility Under Construction
- Storage Facility
- Storage Facility Under Development
- Storage Facility Under Construction

Utilities

- Utilities

Power

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

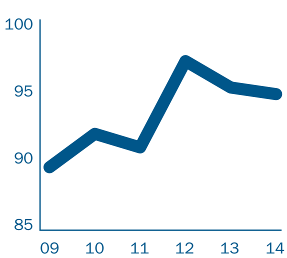


Safety

Above all else, safety is AltaGas' priority. We remain committed to protecting employees, the public, and the environment as we embark on exciting projects in new as well as familiar regions. At AltaGas, we believe all incidents are preventable and safety is everyone's responsibility.

AltaGas commits that employees and contractors performing work at our operations will conduct their work in accordance with the health and safety laws of any jurisdiction in which they are working. They also abide by the policies prescribed by the AltaGas Environmental, Occupational Health & Safety Management System. Anyone performing work for AltaGas has Stop Work Authority. This means everyone – employee or contractor – has the right and responsibility to stop any work that they see being done in an unsafe manner without fear of repercussion. In 2014, AltaGas' health and safety audit score for our gas operations was once again in the high nineties. Vehicle accident rates have been trending downward. The frequency rates for first aid, medical aid, lost-time, and recordable injuries for both our Gas and Utilities segments are also trending downward.

Health & Safety Audit Scoring
(%)



It is AltaGas policy to:

- Consciously and systematically assess and mitigate hazards in the workplace.
- Perform our work safely by using the right equipment and protective apparel.
- Ensure all workers are properly trained to perform their work competently and safely.
- Respond quickly and carefully to help others in the event of an incident.
- Report and thoroughly investigate all work-related incidents, near-misses, injuries, occupational illnesses, and non-conformances.

These are key to maintaining a safe, reliable and productive workplace.

Environment

Natural gas supply and demand fundamentals, and the demand for clean energy in North America, have consistently underpinned AltaGas' strategy. As we continue to grow, we are focused on building, owning, and operating a diversified portfolio of clean energy assets that reduces our carbon footprint.

The protection of the environment is one of AltaGas' core values. By following sound sustainability practices, AltaGas helps preserve a healthy environment for future generations. We are committed to reducing our environmental footprint by reducing the amount of waste we produce, by reducing the emissions from our facilities, and by using energy more efficiently. Through energy efficiency programs at our Harmattan liquids extraction facility and our CO_2 and H_2S injection process at our Bantry and Turin gas processing facilities, it is estimated that AltaGas reduced greenhouse gas emissions by approximately 120,000 tonnes in Alberta for the calendar year 2014.

Electricity generated by AltaGas run-of-river hydroelectric and wind facilities:

- **360,000 MWhs in 2014**
- **1,070,000 MWhs since 2009**

Electricity generated by AltaGas clean burning natural gas facilities:

- **1,900,000 MWhs in 2014**
- **3,600,000 MWhs since 2010**

In 2014, AltaGas' environmental management system audit scores for our gas and power operations improved relative to the 2013 scores.

- Gas segment: **82.68 percent*** (81.61 percent in 2013)
- Power segment: **79.82 percent*** (78.39 percent in 2013)
- In 2014, AltaGas received its highest climate change disclosure score since we started reporting in 2007. Disclosure scores are an assessment of the quality and completeness of responses and are expressed as a number out of 100. When a company's disclosure score is 50 or more, the response is also assessed and ranked in a performance band. The performance score is expressed as a band (A, A-, B, C, D, E).
- 2014 score:
  Disclosure score: **78** (69 in 2013)
  Performance band: **C** (D in 2013)

* Preliminary Scores

Community

In 2014, AltaGas celebrated its 20th anniversary. As part of the year-long celebration, employees were encouraged to participate in a number of volunteer opportunities. Employees spent over 74 days giving back to the community by helping with activities such as preparing lunches at a homeless shelter, sorting and packing gifts for isolated seniors, and building pathways and performing spring clean-up at a camp dedicated to helping children who are battling cancer.

Additionally, an employee-driven initiative during the 2014 Sochi Winter Olympics raised $20,000 for Cross Country Canada athletes, earning AltaGas the Sponsor of the Year Award for 2014. We also supported the Special Olympics Canada Summer Games, with a $50,000 contribution to help bring the sport of basketball to the games for the first time. In all, AltaGas and its subsidiaries contributed nearly $2 million to 483 organizations.

AltaGas' objective is to develop long-term relationships and to provide sustainable benefits to the communities in which we operate. In 2014, we launched a new partnership with the Indian Business Corporation (IBC). Together, AltaGas and IBC developed the AltaGas First Nations Development Fund to support the creation and growth of sources of revenue for First Nations businesses in Alberta. AltaGas agreed to an interest-free $500,000 loan to IBC that will be paid in installments over the next five years. The funding arrangement will boost IBC's capacity to finance viable First Nations entrepreneurs in Alberta as demand for IBC's lending services outstrips its capital. IBC typically receives funding from Aboriginal Business Canada, which makes this funding arrangement unique.

Established in 1987, IBC provides financing for First Nations peoples in western Canada. IBC believes access to capital for First Nations peoples provides opportunities for success and development.

Since 1987 IBC has been able to provide $70 million in financing to First Nations business initiatives.

At AltaGas, we recognize that volunteering reduces stress, improves health, and most importantly builds communities.

Letter to Shareholders

David W. Cornhill
Chairman and Chief Executive Officer

Over the past two decades, we have built AltaGas on strong economic fundamentals, operational excellence and disciplined financing. The result is a business that is resilient and promising as we continue to grow our portfolio of energy infrastructure assets underpinned by long-life, low-risk cash flows. Our growth in earnings and cash flow, as well as our potential to add over $7 billion in new assets over the next five years, positions us extremely well to continue to deliver strong growth in dividends and capital appreciation for our shareholders. We are a company driven by our core values, which keep us focused on delivering not only strong shareholder value, but also strong social value. By building a corporate culture based on trust and respect, and supporting the communities in which we operate, we believe we will achieve our vision of being a leading energy infrastructure company in North America.

3,000,000 working hours

were spent constructing and energizing Forrest Kerr safely.

With our 2014 accomplishments, we have grown our base business to over $8 billion in total assets and we continue to strengthen our portfolio of long-life, diversified and contracted infrastructure across North America. We have the strength and stability to weather economic cycles, such as the declining commodity price environment we are currently experiencing. Two-thirds of AltaGas' business consists of regulated utilities and highly contracted power generation. The other third is AltaGas' gas business which is also highly contracted. This means our base business is approximately 90 percent regulated or under long-term contracts, helping ensure that our infrastructure assets can continue to deliver solid earnings and cash flow even throughout a prolonged downturn.

I am very proud of what we achieved in 2014. After four years of hard work, AltaGas' landmark 195-megawatt (MW) Forrest Kerr Hydroelectric Facility was successfully brought online, on time and on budget. Forrest Kerr is the largest construction project in our history. It is also one of the most remote, making it an impressive feat of engineering, procurement and construction. More than three million working hours were spent constructing and energizing Forrest Kerr safely. Employees and contractors called our project site home for various lengths of time. Some spent long periods away from their families so that the project could stay on track. Due to their outstanding contributions, our construction team was also able to complete the 16-MW Volcano Creek Hydroelectric Facility – two full years ahead of schedule, and on budget. These facilities will provide British Columbians with clean power for decades to come, and they will deliver reliable cash flow and value to AltaGas' shareholders. The remarkable success of these projects is to be shared by our dedicated employees and contractors, the Tahltan First Nation, BC Hydro and the Government of British Columbia.

I am equally as proud of the accomplishments in our gas business. Over the last five years we strategically positioned ourselves to reach international markets and to work with producers to unlock the value of Canada's vast natural gas reserves. In 2014, we made great strides. Through our interest in Petrogas Energy Corp., we started exporting liquefied petroleum gas (LPG) off the U.S. west coast at the Ferndale Terminal, two years sooner than originally planned. Our first shipment of LPG arrived in Chiba, Japan, on August 17, 2014 aboard the Crystal Marine Very Large Gas Carrier.

We also made significant progress on our plans to export liquefied natural gas (LNG) off of Canada's west coast. Through the successful restructuring of the Douglas Channel LNG project and the consortium established with Exmar and EDF Trading, we could potentially commence exports as early as 2018. Through our subsidiary, Pacific Northern Gas Ltd., we have the only natural gas pipeline with gas flowing to Kitimat and Prince Rupert. With a smaller scale, floating barge, and capable business partners, our project is well positioned to be an early exporter of LNG from Canada's west coast.

> “
> **We have significant balance sheet strength and ample sources of cash available to continue pursuing our numerous growth opportunities. Over the next five years we have over $7 billion of opportunities across all three of our business segments.**

From a strategic standpoint, our accomplishments on the LPG and LNG front have established our significant competitive advantage to provide an integrated solution and higher netbacks to producers. We offer access to the full value chain from wellhead to export markets, for both their natural gas and natural gas liquids. Our 15-year strategic alliance with Painted Pony Petroleum Ltd. is just one example of our successful strategy execution. The 198-Mmcf/d Townsend shallow cut natural gas processing facility is our first step in unlocking northeast British Columbia’s vast resource. We are working hard to build further alliances with other producers.

Financially, we delivered a record year of cash flow. On a normalized basis, we achieved record EBITDA of $546 million and funds from operations of $472 million or $3.72 per share, a 17 percent increase over 2013. While Alberta power prices fell nearly 40 percent compared to 2013, we saw strong operational performance from our Gas and Utilities segments, and we brought Forrest Kerr into service. As a result, in 2014 we increased our dividend by 16 percent. With a payout ratio of 45 percent of funds from operations – one of the lowest payout ratios among our peers – we remain well positioned to see further dividend growth. We also achieved significant success on the financing side. We raised approximately $2 billion in medium-term notes, common equity and preferred shares during the year. This was the most AltaGas has ever raised in a single year. Furthermore, 2014 was the first year we issued 30-year medium-term notes. We ended the year with a very manageable debt maturity profile, $420 million in cash, $1.7 billion in available credit, and 45 percent debt-to-total capitalization. This gives us significant financial flexibility as we enter 2015 to fund our growth capital and to take advantage of growth opportunities especially in turbulent times when being nimble and financially strong are competitive advantages.

We have significant balance sheet strength and ample sources of cash available to continue pursuing our numerous growth opportunities. Over the next five years we have over $7 billion in opportunities across all three of our business segments. Approximately $3.5 billion of these opportunities are in advanced stages of development and construction, and most importantly, these projects are fully financed over the next five years and are either regulated or highly contracted.

In Power, we continue to build a portfolio of highly contracted, long-life assets that provide stable cash flows. By mid-2015 we expect to complete the 66-MW McLymont Creek Project. Like the other two Northwest hydroelectric facilities, upon completion the McLymont facility will deliver stable cash flows for decades to come. California’s growing demand for clean energy is also expected to create significant opportunities for us. We have strategically positioned ourselves to potentially triple our Blythe facility.

Our utilities continue to have strong growth opportunities through improving and upgrading existing infrastructure. Over the next five years, we see investment opportunities of over $1 billion and the ability to deliver clean and affordable natural gas to an increasing customer base.

Finally, in Gas there are significant opportunities to strengthen and grow our competitive service offering to producers. The lack of processing infrastructure in northeast British Columbia presents opportunities for AltaGas to establish a new hub for natural gas and natural gas liquids that is ideally situated with connections to export facilities and markets. We are actively working on building out processing capacity in this area and exploring opportunities for fractionation to further unlock value for producers. To the extent that these opportunities are delayed as a result of the current economic environment, we would look to redeploy growth capital to other attractive opportunities in our Power and Utilities segments.

We also continue to work diligently on the expansion of our energy export business. This creates another $3 billion in potential growth opportunities. Through our ownership of Petrogas, we see the opportunity to expand LPG exports up to 30,000 Bbls/d over the next few years at the Ferndale facility in Washington. We are also working on securing a site on Canada's west coast to export an additional 30,000 Bbls/d.

On LNG, Douglas Channel provides us with a site to develop our Triton LNG project. Given the current pricing environment we will focus our efforts on Douglas Channel in 2015, but we will continue to evaluate Triton over the next couple of years.

The growth opportunities in front of us are larger than ever before. We have the financial strength and flexibility to execute on them. We also have established world class teams, as well as the systems and processes to be successful.

As we continue to grow we will also continue to focus on balancing the needs of our customers and the communities in which we operate. Delivering value to communities, our employees, and to our shareholders is the ultimate measure of success for AltaGas. In 2014 we formed or maintained key partnerships. In May, AltaGas and the Indian Business Corporation (IBC) launched the AltaGas First Nations Development Fund. Through this fund, AltaGas agreed to an interest-free $500,000 loan to boost IBC's capacity to finance viable First Nations entrepreneurs.

We also maintained our strong partnerships with Cross Country Canada, STARS and the United Way. I am proud of the long-term relationships we have built with First Nations and other Aboriginal communities and of the relationships we have, and are continuing to build, in the growing number of communities in which we operate.

AltaGas has achieved an excellent safety and environmental record due to our talented and committed employees who continue to deliver significant results, without losing focus on safety, environmental stewardship, and reliable, efficient operations. Last year, AltaGas was once again recognized with several top employer awards. As we grow, we will continue to do our best to support our employees and to make a difference in our communities. We are dedicated to delivering sustainable benefits and building social value.

As we embark on the significant opportunities in front of us, we continue to be committed to growing profitably while delivering meaningful social and shareholder value. We are poised once again to double our assets. We have the financial strength to support our growth and to provide dividend growth along the way. Most importantly, we have a proven track record for putting our strategy into action and providing value to shareholders, communities and employees.

I would like to thank our employees, the Board of Directors, investors, customers, business partners, communities, and our service providers for helping us deliver another successful year.

Sincerely,

David W. Cornhill
Chairman and Chief Executive Officer

Corporate Governance

Myron F. Kanik
Lead Director

Independent director;
Chair of the GC and
Member of the HRCC

The members of the Board of Directors of AltaGas are elected by the shareholders to manage, or supervise the management of, its business and affairs. It is our responsibility 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. We regularly review AltaGas' activities, with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that shareholders expect. We are 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 www.altagas.ca.

The annual meeting will be held at 3:00 p.m. MDT
on Thursday, April 30, 2015
at The Fairmont Palliser, Alberta Ballroom
133 - 9th Avenue S.W., Calgary, Alberta

On behalf of the Board of Directors,

Myron F. Kanik
Lead Director

David W. Cornhill
Chairman and Chief
Executive Officer

Catherine M. Best
Director

Independent Director;
Member of the AC
Member of the EOHSC

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

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

David F. Mackie
Director

Independent Director;
Member of the GC
and HRCC

Neil McCrank
Director

Independent Director;
Member of the GC
and EOHSC

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.**

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 also a member of management and considered not to be independent.

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 and HRCC are composed exclusively of non-management, independent directors. The EOHSC includes a majority of independent, non-management directors. Each of the committees has a mandate that prescribes its composition and responsibilities 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.

Audit Committee

The AC consists of four 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 being a steward of the environment and to the health and safety of its employees.

The Chair of the EOHSC is 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 share options.

AltaGas is committed to operating its businesses in an ethical manner. In 2006, we adopted 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.

Financial Strategy

Financial discipline and effective risk management are fundamental to our strategy. 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.

While growing from over $2 billion in assets five years ago to over $8 billion in assets at the end of 2014, AltaGas has successfully created shareholder value, maintained financial strength and flexibility, and delivered an effective balance between yield and growth.

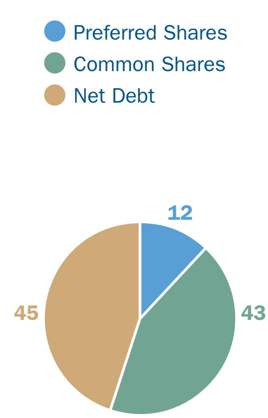
Long-life, stable assets with strong contractual or regulated underpinnings

- Predictable and stable cash flows
- Approximately 90 percent of earnings come from contracted or regulated assets

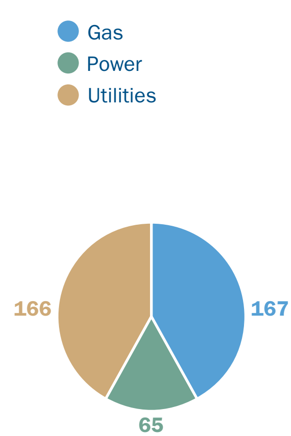
Financial strength & flexibility

- Competitive cost of capital
- Ample liquidity, diversified funding sources, and strong access to capital markets
- Balance sheet strength and flexibility
- Investment grade credit ratings

Capital Structure
(%)



2014 Operating Income*
($ millions)



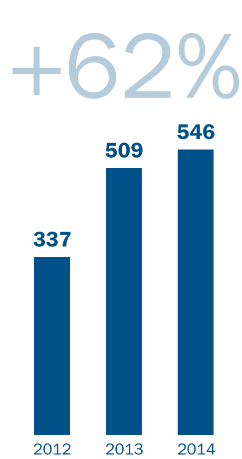
* Normalized

Five-Year Financial Highlights

($ millions except as indicated)	**2014**	2013	2012	2011	2010
				(Restated)	(Restated)
Revenue	**2,406**	2,043	1,450	1,280	1,219
Net revenue [1]	**1,019**	960	665	513	505
EBITDA [1]	**563**	539	320	257	235
Normalized EBITDA [1]	**546**	509	337	266	240
Operating income	**264**	360	214	175	152
Net income applicable to common shares	**96**	182	102	83	117
Normalized net income [1]	**165**	176	110	90	101
Total assets	**8,413**	7,284	5,932	3,556	2,743
Total long-term liabilities	**4,074**	3,727	3,357	1,638	1,225
Net additions to property, plant and equipment	**605**	1,145	1,532	643	212
Dividends declared	**215**	174	133	112	54
Distributions declared	**–**	–	–	–	87
Cash flows					
Normalized funds from operations [1]	**472**	402	281	219	193
Funds from operations [1]	**471**	400	255	213	192
Cash from operations	**458**	366	146	185	190
($ per basic share, except shares outstanding)					
EBITDA [1]	**4.45**	4.64	3.36	3.06	2.88
Normalized EBITDA [1]	**4.31**	4.38	3.55	3.16	2.95
Net income – basic	**0.75**	1.56	1.07	0.98	1.43
Net income – diluted	**0.74**	1.52	1.06	0.97	1.43
Normalized net income [1]	**1.30**	1.51	1.15	1.07	1.24
Dividends declared	**1.69**	1.50	1.40	1.34	0.66
Distributions declared per share	**–**	–	–	–	1.08
Cash flows					
Normalized funds from operations [1]	**3.72**	3.47	2.96	2.61	2.36
Cash from operations	**3.61**	3.16	1.54	2.21	2.34
Shares outstanding – basic (millions)					
During the period [2]	**127**	116	95	84	82
End of period	**134**	122	105	89	83

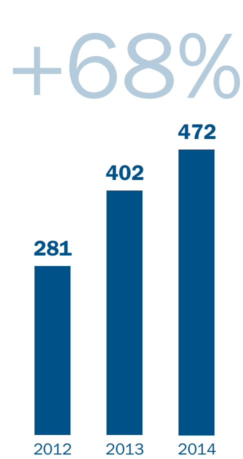
1 Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of the MD&A.
2 Weighted average.

EBITDA*
($ millions)



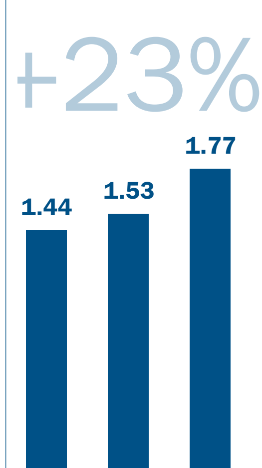
* Normalized

Funds from Operations*
($ millions)



* Normalized

Annual Dividend
($ per common share)



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, 2014, compared to the year ended December 31, 2013. This MD&A dated February 25, 2015, 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, 2014.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or any affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects, opportunities and financial results. Specifically, such forward-looking statements are set forth under: "2015 Outlook" and "Growth Capital".

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. Factors which could cause results or events to differ from current expectations are discussed in the "Risk Management" section of the MD&A and may also include: capital resources and liquidity risk, market risk, commodity price risk, operational risk, volume declines, weather, construction, counterparty risk, environmental risk, regulatory risk and labour relations. 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 annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular and Proxy Statement, material change reports and press releases, are also available through AltaGas' website or directly through the SEDAR system at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by AltaGas, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., and AltaGas Services (U.S.) Inc.

OVERVIEW OF THE BUSINESS

AltaGas is a diversified energy business with a focus on investing in and operating infrastructure to provide clean and affordable energy to its customers in North America and Asia. AltaGas' business strategy is underpinned by strong growth in natural gas supply and the growing demand for clean energy. AltaGas executes its strategy through three business segments: Gas, which includes natural gas processing, transportation, storage, and natural gas marketing; Power, which includes power generation assets, power purchase agreements for power supply, and sale of power to Commercial and Industrial (C&I) customers; and Utilities, which include regulated natural gas distribution utilities across North America and a regulated natural gas storage utility in the United States. AltaGas has an enterprise value of over $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 support the export of liquefied natural gas (LNG) and liquefied petroleum gas (LPG) from North America.

Gas

AltaGas' Gas segment serves producers in the Western Canadian Sedimentary Basin (WCSB) and transacts more than 2 Bcf/d of natural gas. It includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing. The Gas segment also includes the Corporation's 50 percent investment in AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) which in turn owns the Corporation's one-third interest in Petrogas Energy Corp. (Petrogas).

Gas gathering systems move natural gas from producing wells to processing facilities. The gas is then compressed for transportation. The extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and NGL. The transmission pipelines deliver natural gas and NGL to distribution systems, end-users or other downstream pipelines. AltaGas buys and resells energy; provides gas transportation, storage and gas marketing for producers; and sources gas supply to some of its processing assets.

AIJVLP is pursuing energy export opportunities, including long-term supply and sales arrangements to meet the growing demand for LNG and LPG in Asia. Idemitsu Kosan Co.,Ltd. (Idemitsu), AltaGas' partner in AIJVLP, is a global leader in the supply of energy, petroleum, lubricants and petrochemical products and services to Japan. Petrogas is a leading North American integrated midstream company with an extensive logistics network consisting of over 1,500 rail cars and 24 rail and truck terminals, which provides key infrastructure, supply logistics and marketing expertise required to pursue LPG export opportunities. Together, AltaGas, Idemitsu and Petrogas bring key infrastructure assets and marketing expertise along with energy supply and access to markets in Asia to pursue LPG export opportunities.

Through AIJVLP, AltaGas and Idemitsu formed the Douglas Channel LNG Consortium (Consortium), which includes EDF Trading Limited (EDFT) and EXMAR NV (EXMAR), to support the plan of arrangement under the Companies' Creditors Arrangement Act (CCAA) proceedings for the Douglas Channel LNG project. The Douglas Channel LNG project is a proposed barge-based LNG export facility on the west bank of the Douglas Channel in Kitimat, British Columbia with a nameplate capacity of 0.55 million tonnes of LNG per annum. On January 28, 2015, the Consortium announced that it had obtained full ownership and control of the Douglas Channel LNG project as a result of the statutory plan of arrangement completed under the CCAA proceedings. The Consortium has executed long-term lease agreements with the Haisla Nation regarding land and water tenure and with Pacific Northern Gas Ltd. (PNG) for long-term pipeline capacity to supply gas to the project. AltaGas will act as the project manager of the Douglas Channel LNG project. The Consortium is targeting a final investment decision (FID) by the end of 2015 and commercial operation in 2018.

Power

As at December 31, 2014, the Power segment includes 1,285 MW of power generation capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets, along with an additional 81 MW of assets under construction. On January 8, 2015 AltaGas completed the acquisition of three western U.S. gas-fired power assets with a total generation capacity of 164 MW. As a result, AltaGas entered 2015 with 1,449 MW of total power generation capacity.

In 2014, the 195-MW Forrest Kerr Hydroelectric Facility (Forrest Kerr) and 16-MW Volcano Creek Hydroelectric Facility (Volcano Creek) were commissioned. The 66-MW McLymont Creek Hydroelectric Facility (McLymont Creek) will be the third and final Northwest Hydro Project to come online, with commissioning expected in mid-2015. The 277-MW Northwest Projects are contracted with 60-year Electricity Purchase Agreements (EPAs) with BC Hydro that are fully indexed to the Consumer Price Index (CPI). Impact Benefit Agreements are in place for all three facilities, ensuring a cooperative and mutually beneficial relationship between the Tahltan First Nation and AltaGas.

AltaGas owns Blythe Energy Inc. (Blythe), which owns Blythe Energy Center, a 507 MW natural gas-fired power plant, associated major spare parts and a related 230 kV 67-mile electric transmission line in southern California. Blythe is fully contracted under a power purchase agreement (PPA) with Southern California Edison Company (SCE) until July 31, 2020, at which point the facility is uniquely positioned to potentially serve both the California Independent System Operator (CAISO) and the Desert Southwest (DSW) markets. In 2014, AltaGas acquired a fully permitted and shovel-ready site directly adjacent to the existing Blythe facility, known as the Sonoran Energy Project or Blythe II. Also in 2014, AltaGas acquired an additional 76 acres of land north of the current Blythe facility to provide further opportunities to expand the Blythe Energy Center (Blythe III). The development of both projects could potentially more than triple AltaGas' current generating capacity in California over the medium and long term.

AltaGas is also expanding its cogeneration fleet at the Harmattan Complex (Harmattan) from 30 MW to 45 MW. AltaGas is in the final stages of construction of the additional 15 MW of cogeneration capacity (Cogeneration III), which is being constructed to meet the increased power demand at Harmattan and to increase sales to the Alberta power market. Cogeneration III is expected to be in service in the first half of 2015.

AltaGas owns 50 percent of the Sundance B PPA, giving it the rights to 353 MW of power output and ancillary services from coal-fired base-load generation until December 31, 2020.

AltaGas owns 117 MW of wind power generation capacity as well as 35 MW of biomass generation capacity from which all power generation is sold via long-term contracts.

Utilities

The Utilities segment is composed of natural gas distribution utilities that serve more than 560,000 customers in Canada and the United States. The Utilities segment in Canada is composed of AltaGas Utilities Inc. (AUI) in Alberta, PNG in British Columbia, Heritage Gas Limited (Heritage Gas) in Nova Scotia, as well as a one-third equity interest in Inuvik Gas Ltd. (Inuvik Gas) in the Northwest Territories. The Utilities segment in the United States is comprised of SEMCO Energy Gas Company (SEMCO Gas) in Michigan, ENSTAR Natural Gas Company (ENSTAR) in Alaska and a 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA), also in Alaska. 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.

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. Our 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 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 its business segments.

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 focused on investing in assets that process and move natural gas to key markets, including Asia, to provide a fully integrated midstream service offering to its customers across the energy value chain. AltaGas is uniquely positioned to deliver higher netbacks to producers for natural gas and NGL through its ownership interest in Petrogas and the Ferndale Terminal as well as through AltaGas' role in the Douglas Channel LNG project.

The Power segment is focused on building, owning, and operating a diversified portfolio of clean energy assets that reduces the Corporation's carbon footprint and on meeting North America's demand for clean energy.

In the Utilities segment, the Corporation is focused on finding innovative ways to continue to deliver clean and affordable natural gas to more customers, safely and reliably.

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

AltaGas operates in a safe, reliable manner with ongoing development of organizational capability to execute its strategy. AltaGas has the ability to safely deliver capital projects on time and on budget, in close partnership with First Nations and community stakeholders.

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.

Investing in 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 and household, commercial and industrial uses is expected to increase substantially, providing significant opportunities across AltaGas' Gas, Power and Utilities segments to invest in and optimize assets.

The abundant supply and relatively low natural gas prices in North America stand in sharp contrast to the higher prices in Asia. Investing in export infrastructure represents a compelling opportunity to unlock the value of western Canada's vast natural gas reserves. AltaGas is uniquely positioned to provide producers a competitive service offering across the integrated value chain, from wellhead to tidewater. Access to Asian markets provides the opportunity for attractive netbacks to producers, especially those in the vast Montney and Duvernay basins under development in northeastern British Columbia and western Alberta. Through AltaGas' ownership of the only natural gas pipeline to Kitimat and Prince Rupert (through its wholly-owned subsidiary PNG) and its investment in Petrogas, with its logistics network of rail cars, terminals and storage facilities, including the Ferndale LPG export terminal in the State of Washington acquired in 2014, AltaGas can provide multiple outlets for producers to deliver their natural gas and NGL products to the highest value markets. In partnership with Idemitsu, AltaGas is actively pursuing multiple LNG and LPG export opportunities.

AltaGas expects that economic growth and increased demand for clean sources of power to reduce greenhouse gas emissions will require significant development in gas-fired and renewable generation. Within the Power segment, growth is planned through the completion of projects currently under construction, the expansion of existing assets, and through the development of its portfolio of clean energy generation in North America. AltaGas' strategic acquisition of the Blythe facility in California provides significant opportunities to grow that facility to meet the growing demand for power in California and surrounding regions.

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. There are also natural gas storage opportunities currently under development in Nova Scotia to increase reliability of supply to AltaGas' natural gas distribution customers in that area.

AltaGas is an industry leading operator of energy infrastructure serving customers since 1994. AltaGas strives to employ the best available practices and technologies for integrity management systems and maintenance and operations in order to mitigate risks to the public, employees and the environment. Cost efficiency and 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. Superior service, safety and reliability are also integral to AltaGas' customer value proposition. AltaGas has approximately 1,700 employees building long-term relationships and sustainable benefits in the communities in which AltaGas operates.

Maintain Financial Strength and Flexibility

Financial discipline and effective risk management are fundamental cornerstones of the Corporation's strategy. 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 maintain and improve its credit ratings, diversify 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. As well, the continued management of counterparty credit risk remains an ongoing priority. AltaGas mitigates the foreign exchange exposure on its United States investments by incorporating U.S. dollar (US dollar or US$) denominated capital, both debt and preferred shares, into its financing strategy.

AltaGas seeks to optimize risk and reward, ensuring that returns are commensurate with the level of risk assumed.

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 training and hiring the required competencies for executing its strategy and ensuring that the performance management processes support the long-term objective of creating shareholder value.

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 $8 billion at the end of 2014. In the last three years, the Corporation has reported 6 percent and 10 percent compound annual growth rate in earnings and dividends per share, respectively. AltaGas delivers an effective balance between yield and growth.

2014 was a significant year for AltaGas. The Corporation safely commissioned Forrest Kerr, the largest construction project in its 20-year history, on time and on budget and completed Volcano Creek two years ahead of schedule. Adding these high quality renewable generation assets, which deliver long-term stable cash flows supported by 60-year EPAs, demonstrates the successful execution of AltaGas' strategy. AltaGas continues to make good progress at McLymont Creek, which is expected to be in service in mid-2015. In addition, AltaGas optimized its power portfolio in 2014 by divesting the ownership of 25 MW of peaking capacity exposed to the merchant Alberta power market, and entered into a purchase and sale agreement for 164 MW of contracted gas-fired assets located in the western United States. The transaction closed on January 8, 2015 and increased AltaGas' presence in the U.S. and overall contracted position to further support stable cash flows. AltaGas delivered growth in its Power segment generation of 32 percent in 2014, providing over 75 percent of total generation from clean energy sources, including hydro, wind, biomass and gas-fired.

AltaGas also opened the doors to international markets in 2014 and built a competitive service offering for producers. The Corporation enhanced its logistics capabilities by increasing its investment in Petrogas in early 2014, bringing its ownership interest to one-third. Petrogas subsequently acquired the Ferndale LPG export terminal, which completed shipments to Asia off the U.S. west coast in 2014. In addition, AltaGas made significant progress on executing its strategy to export LNG off Canada's west coast. The Douglas Channel LNG export initiative was granted creditor approval in 2014, enabling AltaGas and its partners to proceed with the project. Gaining access to Asian markets and building competencies from wellhead to tidewater has positioned AltaGas as a preferred partner for producers. This was validated by a 15-year strategic alliance with Montney producer Painted Pony Petroleum Ltd. (Painted Pony), which was executed in 2014. AltaGas has established a competitive advantage of providing an integrated service offering for producers to earn higher netbacks through the successful execution of its strategy in 2014.

In 2014, AltaGas initiated further growth in all business lines with projects such as the acquisition of the Blythe II development project and the land acquisition for Blythe III, completing commercial agreements for a 198 Mmcf/d shallow-cut gas processing facility (Townsend Facility), and beginning groundwork on AltaGas' first regional LNG facility in Dawson Creek, British Columbia. Construction of Cogeneration III is advancing and the project remains on schedule with completion expected in the first half of 2015. In fourth quarter 2014, AltaGas completed the construction of the second part of the Cold Lake Pipeline Expansion. Across the utilities, AltaGas continued to focus on customer and rate base growth by expanding its existing infrastructure through system upgrade programs and organic growth opportunities.

In 2014, the Corporation enhanced its financial strength and flexibility through a combination of internally-generated cash flows, the Corporation's dividend reinvestment program (DRIP), and the issuance of $1.8 billion of equity and long-term debt. The Corporation extended its debt maturity profile and lowered its cost of debt with the early redemption of $500 million of medium-term notes (MTNs) and the issuance of $1.1 billion of MTNs, including the $400 million 30-year issuance. During the year, AltaGas completed a $460 million Common Share issuance and a $200 million Preferred Share issuance (Series G Shares). AltaGas maintained sufficient liquidity and a strong balance sheet throughout the year and exited 2014 with approximately $1.7 billion of available credit facilities, cash and short-term investments of $421 million, and debt-to-total capitalization of 45 percent. AltaGas entered 2015 exceptionally well-positioned to fund its growth capital and to take advantage of growth opportunities when they arise.

In May 2014, the Board of Directors approved a 16 percent dividend increase from $1.53 per share to $1.77 per share on an annualized basis. The dividend increase reflects the success of AltaGas' asset additions across all business segments and the strength and stability of its cash flows.

2014 GROWTH HIGHLIGHTS

- Increased AltaGas' effective ownership of Petrogas to one-third. Petrogas is a privately-held leading North American integrated midstream company;
- Acquired the remaining 50 percent ownership interest in Alton Natural Gas Storage LP, making it a wholly-owned subsidiary;
- Through Triton LNG Limited Partnership (Triton LNG), a wholly-owned subsidiary of AIJVLP, received National Energy Board (NEB) approval to export up to 2.3 million tonnes per year of LNG;
- Acquired Blythe II, a shovel-ready gas-fired generation development site, located adjacent to the Blythe facility already owned by AltaGas. An additional 76 acres of land was also purchased north of the current Blythe facility that provides the potential for further expansion of the Blythe Energy Center;
- Completed Forrest Kerr, the largest project in the Corporation's history, on time and on budget;
- Entered into a 15-year strategic alliance with Painted Pony for the development of processing infrastructure and marketing services for natural gas and NGL;
- Completed commercial agreements for the 198 Mmcf/d Townsend natural gas processing facility;
- Completed the 16 MW Volcano Creek project two years ahead of schedule;
- Completed construction on the second Cold Lake Pipeline Expansion project;
- Invested $186 million in the Utilities segment to support customer and rate base growth; and
- Obtained approval for the CCAA Plan of Arrangement for the Douglas Channel LNG project.

2014 FINANCIAL HIGHLIGHTS

- Normalized EBITDA[1] of $546 million in 2014, compared to $509 million in 2013;
- Normalized funds from operations[1] of $472 million ($3.72 per share) in 2014, compared to $402 million ($3.47 per share) in 2013;
- Normalized net income[1] of $165 million ($1.30 per share) in 2014, compared to $176 million ($1.51 per share) in 2013;
- Net income applicable to common shares of $96 million ($0.75 per share) in 2014, compared to $182 million ($1.56 per share) in 2013;
- Dividend payout as a percentage of normalized funds from operations(1) of 45 percent in 2014, compared to 43 percent in 2013;
- Net debt as at December 31, 2014 of $2,915 million, compared to $3,201 million as at December 31, 2013;
- Debt-to-total capitalization ratio as at December 31, 2014 of 45 percent, compared to 53 percent as at December 31, 2013;
- On January 13, 2014, issued $200 million of senior unsecured medium-term notes (MTNs) with a coupon rate of 4.40 percent, maturing on March 15, 2024, and $100 million senior unsecured MTNs with a coupon rate of 5.16 percent, maturing on January 13, 2044;

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

- Redeemed $200 million of senior unsecured MTNs early on February 14, 2014. The notes had a coupon rate of 7.42 percent and a maturity of April 29, 2014;
- Issued US$200 million senior unsecured MTNs on March 24, 2014. The notes carry a floating coupon rate of three-month LIBOR plus 0.72 percent and mature on March 24, 2016;
- On April 30, 2014, increased dividends per share by 16 percent to $1.77 on an annualized basis from $1.53;
- On July 3, 2014, issued 8,000,000 five-year rate-reset Series G Preferred Shares at a price of $25 per Series G Preferred Share for aggregate gross proceeds of $200 million, including 2,000,000 Series G Preferred Shares pursuant to the exercise in full of an underwriters' option;
- On August 15, 2014, issued $300 million of 30-year senior unsecured MTNs. The notes carry a coupon rate of 4.50 percent and mature on August 15, 2044;
- On August 28, 2014, issued 9,027,500 Common Shares at a price of $51 per Common Share for aggregate gross proceeds of $460 million, including 1,177,500 Common Shares pursuant to the exercise in full of an underwriters' option;
- On November 10, 2014, issued $300 million of senior unsecured MTNs with a coupon rate of 3.84 percent and a maturity of January 15, 2025;
- Redeemed $100 million of senior unsecured MTNs on December 4, 2014. The notes had a coupon rate of 6.94 percent and a maturity of June 29, 2016;
- Redeemed $200 million of senior unsecured MTNs on December 8, 2014. The notes had a coupon rate of 4.10 percent and a maturity of March 24, 2016;
- On December 15, 2014, AltaGas extended the maturity of the SEMCO US$150 million credit facility to December 20, 2019; and
- On December 17, 2014, AltaGas extended the maturity of its $1.4 billion syndicate credit facility and its $150 million extendible revolving letter of credit facility to December 15, 2018.

2015 OUTLOOK

AltaGas' diversified portfolio of energy infrastructure assets is well positioned to weather commodity and economic cycles. Two-thirds of AltaGas' business consists of regulated utilities and highly contracted power generation. The other third is AltaGas' Gas business which is also highly contracted with take-or-pay and cost-of-service contracts. The Power and Utilities segments are expected to report higher earnings and the Gas segment is expected to remain nearly flat to 2014 after adjusting for the impact of the turnarounds at Harmattan and the Younger Extraction Plant (Younger) and assuming frac spreads recover in the latter half of 2015.

AltaGas expects to deliver earnings and cash flow growth in 2015 compared to 2014 as a result of the contribution from the Northwest Projects, the investment in Petrogas, growth in rate base and customers at the utilities, several other growth projects coming into service, and a weaker Canadian dollar. These increases are expected to offset the impact of lower power prices in Alberta as well as lower frac spreads if the lower commodity price environment should persist for all of 2015. Based on the current price environment, AltaGas expects that over 90 percent of overall EBITDA will be driven by its portfolio of long-life assets underpinned by long-term, take-or-pay and cost-of-service contracts and regulated earnings. 13 percent of overall EBITDA is underpinned by volumes processed in the Gas business. In 2015 AltaGas expects to report higher financing costs related to new assets in service, higher income taxes and the impact of turnarounds at Younger and Harmattan.

First quarter 2015 earnings are expected to be lower than same period 2014. While there is an uplift from the impact of the weaker Canadian dollar on our U.S. business results, our first quarter 2015 is also expected to be impacted by normal seasonality of the utilities and the Northwest Projects, and a planned turnaround at Forrest Kerr, as well as lower frac and Alberta power prices. Normalized funds from operations are expected to be roughly flat to first quarter 2014.

Activity in AltaGas' Gas business is expected to be driven by the continued development in the Montney basin as well as the abundant supply and relatively low natural gas price environment in North America. Given the near term momentum of development in the world class Montney play, AltaGas expects growing demand for processing infrastructure in the area as natural gas supply increases. Surplus natural gas and NGL in western Canada will necessitate energy exports to potentially mitigate the low regional price environment. AltaGas is uniquely positioned to deliver higher netbacks to producers by providing a competitive service offering across the energy value chain and by connecting producers to the highest value markets, including Asia.

While the current pace of development in the Montney is strong, if the significantly decreased oil and regional NGL prices experienced in late 2014 and early 2015 are sustained, growth opportunities for processing infrastructure could be delayed. To the extent there are delays, AltaGas has the potential to redeploy its growth capital into additional attractive investment opportunities across its diversified Power and Utility businesses.

Management estimates an average of 6,500 Bbls/d will be exposed to frac spread in 2015. For 2015, AltaGas has hedged approximately 50 percent of the estimated 6,500 Bbls/d exposed to frac spread at an average price of approximately $27/Bbl before deducting extraction premiums.

In the Power segment, earnings are expected to be driven by the full year contribution from Forrest Kerr and Volcano Creek, the partial year contribution from McLymont Creek, optimization of power assets including increased volumes generated at Sundance, and higher contribution from the U.S. power business due to continued growth and development opportunities. The earnings and cash flows from Forrest Kerr and Volcano Creek 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. AltaGas expects to mitigate the impact of downward pressure on Alberta power prices in 2015 through its hedging strategy.

AltaGas has hedged approximately 55 percent of volumes exposed to Alberta power prices for first quarter 2015 at an average price of approximately $59/MWh. Overall for 2015, AltaGas has hedged approximately 25 percent of volumes exposed to Alberta power prices at an average price of approximately $59/MWh. AltaGas expects to continue to hedge its exposure to Alberta power prices throughout 2015 at prices lower than 2014 hedged prices if current forward curves persist throughout 2015.

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 are expected to report increased earnings in 2015 driven by increased customer and rate base growth. Earnings at all of the utilities except PNG are affected by the weather in their franchise areas with colder weather generally benefitting earnings. If the weather varies from the previous year, earnings at the utilities would be affected. If the US dollar continues to appreciate, the earnings from the U.S. utilities will benefit accordingly in 2015. Some of this benefit is offset by higher US dollar-denominated interest.

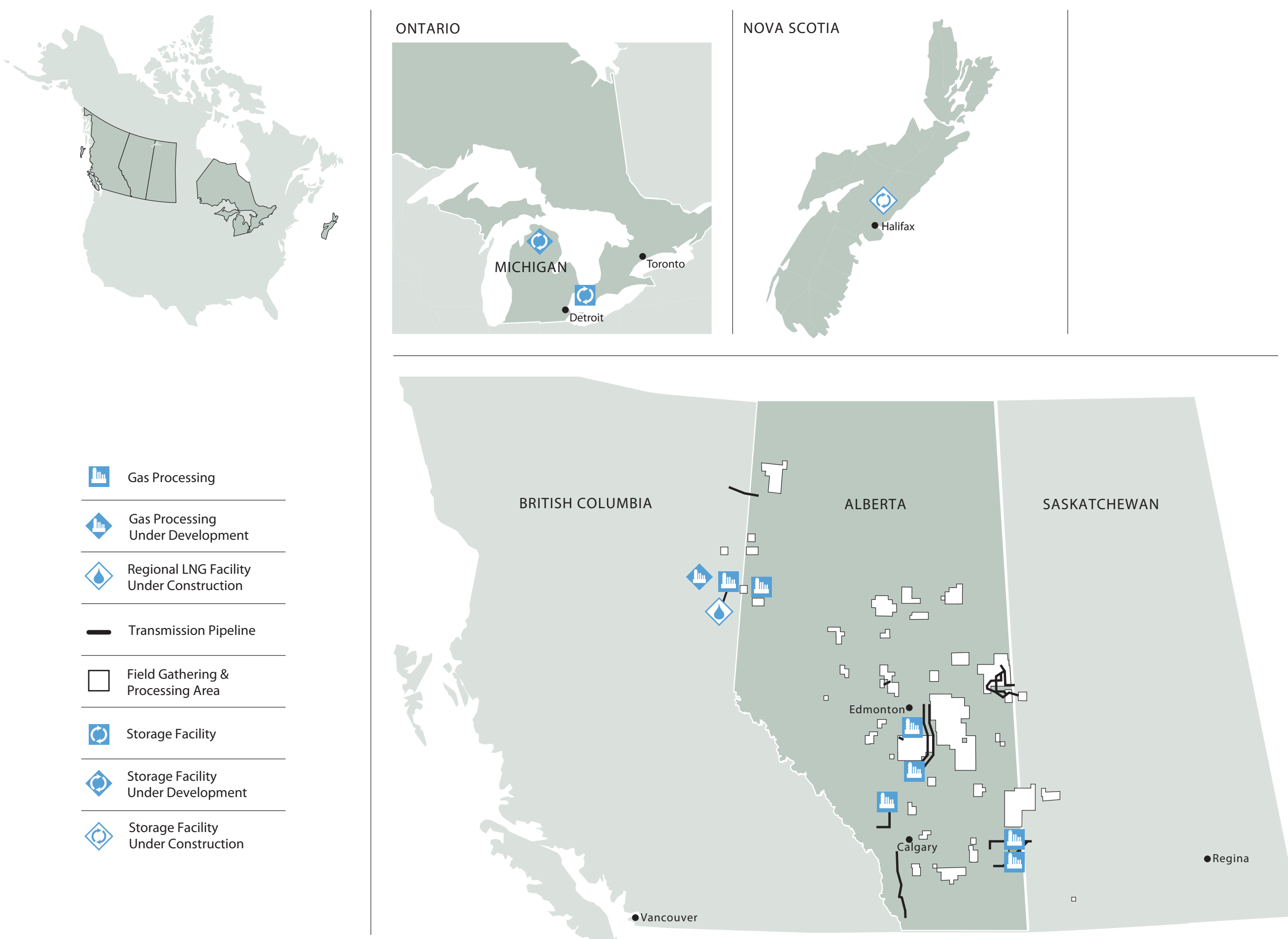
GAS

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 fractionation, 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 field fractionation facilities reprocess natural gas to extract and recover ethane and NGL. AltaGas owns 1.6 Bcf/d of extraction processing capacity and 1.4 Bcf/d of raw field gas processing capacity. The Gas segment also includes equity investments in Petrogas and 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, including its energy export projects through AIJVLP.

On January 29, 2013, AltaGas signed an agreement with Idemitsu to form AIJVLP. AltaGas and Idemitsu each own a 50 percent interest in AIJVLP. AIJVLP is pursuing opportunities to develop liquefaction infrastructure and long term natural gas supply and sales arrangements to meet the growing demand for natural gas in Asia. AIJVLP is also pursuing opportunities to develop a Canadian LPG export business, including logistics, plant refrigeration and storage facilities.



On October 1, 2013, AltaGas completed the acquisition of a 25 percent interest in Petrogas, a privately-held leading integrated midstream company. Petrogas' extensive logistics network, consisting of over 1,500 rail cars and 24 rail and truck terminals, provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities. Effective March 1, 2014, AltaGas increased its effective ownership of Petrogas to one-third, which it holds through its 50 percent interest in AIJVLP.

On August 19, 2014 AltaGas and Painted Pony signed an agreement to enter into a 15-year strategic alliance for the development of processing infrastructure and marketing services for natural gas and NGL. This strategic alliance is expected to further expand AltaGas' fully integrated midstream business by providing Painted Pony with essential gas processing infrastructure for their Montney reserves as well as access to global energy markets, including Asia. In the first phase of the strategic alliance, the Townsend Facility, a 198-Mmcf/d shallow-cut gas processing facility, will be constructed and operated by AltaGas.

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;
- 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 pipelines 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. 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 producers;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn Hub in Eastern Canada;
- Natural gas storage projects under construction in Nova Scotia and under development in Michigan;
- Natural gas marketing and gas transportation services to optimize the value of the infrastructure assets and meet customer needs;
- 50 percent ownership of AIJVLP which is developing LNG and LPG export opportunities from the west coast of Canada to Asia;
- One-third ownership in Petrogas, a leading North American integrated midstream company, including the LPG export facility at Ferndale, Washington; and
- 15-year strategic alliance with Painted Pony for the development of processing infrastructure and marketing services for natural gas and NGL.

The Gas segment provides safe and reliable natural gas and liquids gathering, processing, extraction, transportation and storage services to its customers. The strategic focus is to increase profitability of the existing infrastructure, expand and add new infrastructure, and redeploy assets in areas with increased exploration and drilling activities in the WCSB. AltaGas also focuses on long-term, fixed-fee, take-or-pay and cost-of-service contracts with strong counterparties to mitigate the impact of volume risk and increase stability of earnings.

The Corporation employs a frac hedging strategy that is designed to reduce commodity price exposure. This hedging strategy is integrated with the Power segment's hedging strategy with respect to AltaGas' combined exposure to commodities.

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, primarily Asia. New infrastructure is expected to be larger scale facilities supporting the vast reserves in the WCSB as well as the strong producer activity in liquids-rich areas. AltaGas' strategic investment in Petrogas enhances the services provided by the Gas segment by offering integrated midstream services to AltaGas' customers and 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 supply in the WCSB;
- Provide a fully integrated midstream service offering including pipeline and liquefaction 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;
- Expand into new natural gas infrastructure markets such as regional LNG;
- Coordinate between facilities, business segments and product lines to improve efficiencies and maximize profits; 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 with significant growth potential. 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 Montney, Horn River, Duvernay and Glauconite, as well as increased focus on horizontal multi-fracturing technology have resulted in abundant natural gas supply. AltaGas expects growing demand for processing infrastructure in the WCSB as natural gas supply increases. Continued producer focus on liquids-rich natural gas and oil is thereby increasing the demand for processing capacity that allows producers to earn higher netbacks on liquids-rich gas and associated gas from increasing oil production.

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. 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, natural gas processing, extraction, fractionation, 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 from wellhead to tidewater.

AltaGas is pursuing a regional LNG business to supply LNG to remote industries and communities for power generation, space heating and industrial use in northeastern British Columbia and Northern Canada.

The natural gas supply to AltaGas' extraction plants, with the exception of Harmattan and Younger, 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 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. There has been significant demand for gas processing capacity at Harmattan as a result of the high volume of liquids-rich gas being produced in the area.

AltaGas also expects to see increased opportunities to 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. The Corporation 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 198-Mmcf/d Townsend Facility 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 expansion of 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 contractual underpinning of the Gordondale and Blair Creek facilities provides 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.

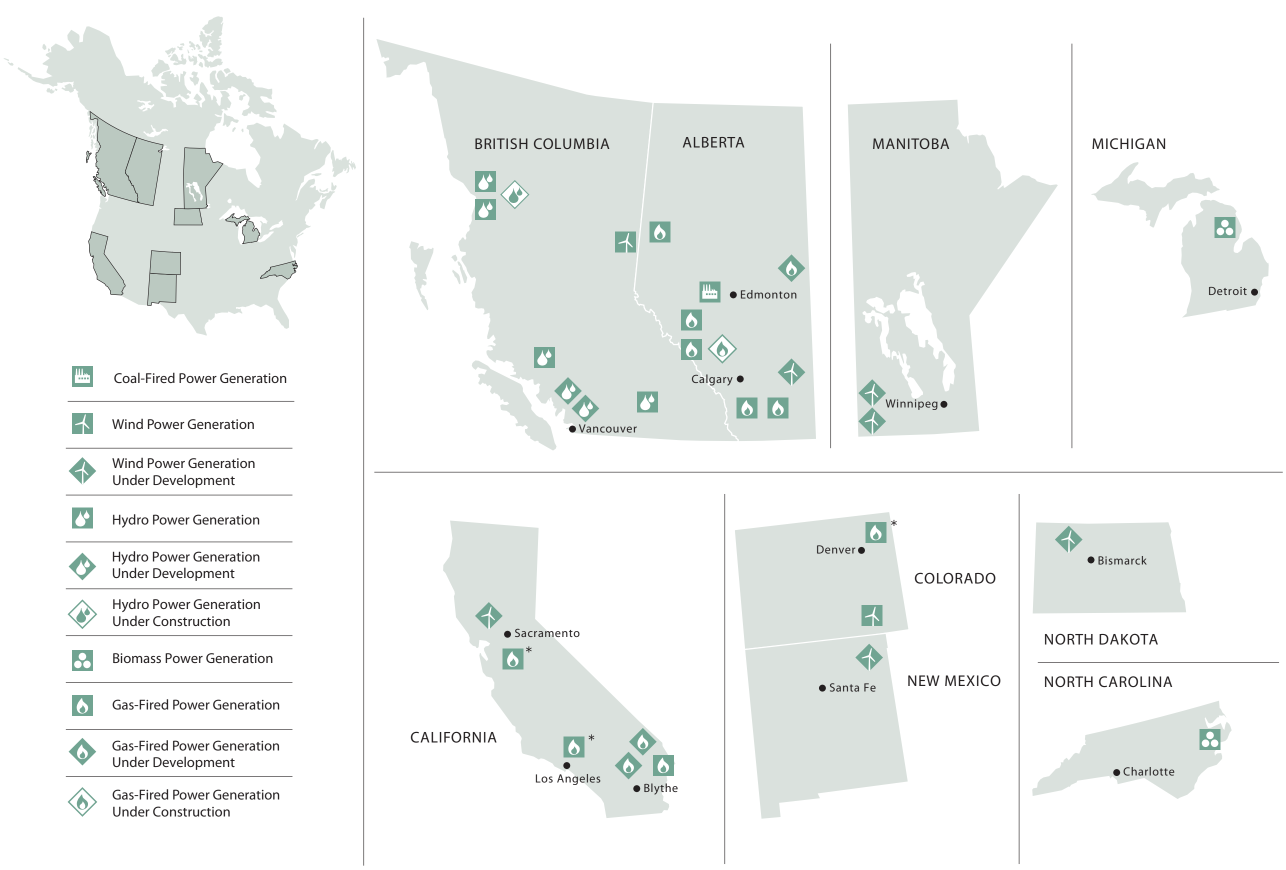
Due to the integrated nature of AltaGas' gas gathering and processing assets, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is required to meet producer and end-user demands. This integrated service model has been further enhanced with the ownership interest in Petrogas. Petrogas provides logistics and market services which can be offered as additional value to AltaGas' customers. 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

As at December 31, 2014, the Power segment includes 1,285 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. Further power generation of 81 MW is in construction, which includes 66 MW for the McLymont Creek run-of-river project and 15 MW of cogeneration at Harmattan. In addition, there is 2,360 MW of power generation in various stages of development. On January 8, 2015 AltaGas completed the acquisition of three gas-fired power assets in the western U.S. As a result, AltaGas entered 2015 with 1,449 MW of total power generation capacity.

AltaGas continues to expand its geographic footprint and at the end of 2014 owned 557 MW of generating capacity in the United States. On May 16, 2013, AltaGas acquired the 507 MW Blythe Energy Center. The gas-fired generation capacity at Blythe is currently operating under a long-term PPA with SCE and serves the CAISO market. Due to the structure of the long-term PPA, the majority of the facility's revenues are derived from capacity payments, thereby providing stable cash flows. The current capacity is contracted until July 31, 2020, at which time the facility is uniquely positioned to potentially serve both the CAISO and DSW markets. The 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 with SCE and the CAISO via its 67-mile transmission line. The facility also has the capability of directly reconnecting to the DSW market and 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 entered into a long-term agreement with Siemens Energy, Inc. (Siemens) for the maintenance of the two existing combustion turbines. Also in 2014, AltaGas acquired a fully permitted and shovel-ready site directly adjacent to the existing Blythe facility, known as the Sonoran Energy Project or Blythe II. In addition, AltaGas acquired 76 acres of land north of the current Blythe facility to support further expansion opportunities.



AltaGas owns a 50 percent interest in the Busch Ranch wind farm (Busch Ranch), a 29 MW wind farm in Colorado with a 25-year PPA with the local utility, which came into service in October 2012. AltaGas' biomass assets are a 30 percent working interest in the 37 MW wood biomass power facility in Grayling, Michigan and a 50 percent working interest in the 48 MW wood biomass power facility in Craven County, North Carolina. Both biomass facilities have long-term PPAs.

On December 1, 2014 AltaGas sold four gas-fired peaking plants located in Southern Alberta with a total of 25 MW of generation that was exposed to the merchant Alberta power market. AltaGas re-invested these proceeds by acquiring three gas-fired power assets in the western U.S. All three assets are currently contracted under PPAs with local creditworthy utilities, and generate stable cash flows.

The Power segment includes:

- 507 MW of gas-fired generating capacity in California at Blythe Energy Center with a further 1,163 MW under development;
- 353 MW of coal-fired generating capacity in Alberta through the Sundance B PPA. AltaGas employs an economic hedging strategy to mitigate the exposure to Alberta spot power prices;
- 117 MW of wind generation, of which 102 MW is in British Columbia and 15 MW is in Colorado, with a further 1,087 MW in various stages of development. All operating wind generation is sold via long-term EPAs;
- 35 MW of biomass generation in the United States. The plants have long-term PPAs with strong counterparties;
- 30 MW of cogeneration capacity in Alberta and a further 15 MW under construction;
- 223 MW of operating run-of-river generation, with 66 MW under construction and 20 MW under development. All Northwest Projects have 60-year EPAs fully indexed to CPI;
- 20 MW of gas-fired peaking plants in Alberta with a further 90 MW under development;
- C&I power sales in Alberta which provide further opportunities to hedge a portion of the Alberta generation for periods of one to five years; and
- 164 MW of gas-fired generation capacity in the United States acquired on January 8, 2015. The plants are supported by PPAs with creditworthy counterparties.

The Corporation employs a power hedging strategy which is designed to balance market and operational risk related to the Sundance B PPA, thereby reducing the exposure to Alberta spot power prices and providing earnings stability in the Power segment. AltaGas also sells power to 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. This hedging strategy is integrated with the Gas segment's hedging strategy with respect to AltaGas' combined exposure to commodities.

Growth in the Power segment aligns with AltaGas' strategy of generating clean energy and increasing earnings and cash flow stability and predictability. AltaGas' most significant undertaking to date is the construction of the three Northwest Projects with total generation capacity of 277 MW. In 2014, AltaGas completed the construction and commissioning of the 195-MW Forrest Kerr facility, which is the largest project in AltaGas' 20-year history. Start-up was also achieved for the 16-MW Volcano Creek facility, with construction and commissioning completed two years ahead of schedule. Construction continues to progress well on the 66-MW McLymont Creek project, which is expected to be in service by mid-2015. The aggregate 277-MW Northwest Projects, estimated to cost approximately $1.0 billion, are underpinned by 60-year EPAs, fully indexed to CPI. Impact Benefit Agreements are in place for all three projects, ensuring a cooperative and mutually beneficial relationship between the Tahltan First Nation and AltaGas. Also operating in British Columbia is the 102-MW Bear Mountain Wind Park (Bear Mountain); McNair, a wholly-owned 10 MW run-of-river power generation facility; and Boston Bar, a 25 percent effective interest in a 7 MW run-of-river facility. These projects are also underpinned by EPAs with BC Hydro.

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;
- Execute power hedges to balance operational and market risk and to increase earnings stability from its Alberta power assets; 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 gas-fired and renewable sources of clean energy as the Corporation seeks to capitalize on 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 renewable portfolio standards. Although coal-fired generation is still the dominant fuel source for power generation in North America, it is decreasing in market share for environmental and economic reasons. Low natural gas costs have 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 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.

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. C&I customers are also supplied through long-term power purchases from third parties. Currently, AltaGas has approximately 120 MW of fixed price sales to C&I customers for 2015, 85 MW for 2016, 74 MW for 2017, 18 MW for 2018, 6 MW for 2019 and 4 MW for 2020, with average prices in the high $50s per MWh, excluding retail fees.

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 Once-Through Cooling Water Policy for power generating facility intake structures in California may prompt additional opportunities to develop new clean power generation capacity. The Blythe Energy Center, Bear Mountain, Busch Ranch, Grayling Generating Station, Craven County wood biomass power facility, the Northwest Projects and the U.S. power assets acquisition are all examples of AltaGas' strategy in action to meet North America's growing demand for clean energy.

AltaGas has approximately 2,360 MW of renewable and gas-fired power under development, including 1,087 MW of wind power, 1,253 MW of gas-fired generation, and 20 MW of run-of-river hydroelectric developments. The wind projects are geographically dispersed in western North America, with 612 MW in Canada and 475 MW in the northern and western regions of the United States, while the run-of-river projects are located in British Columbia. AltaGas has 66 MW of run-of-river hydroelectric and 15 MW of gas-fired generation under construction.

In 2014, there was continued progress made in the natural gas industry in developing LNG projects in western Canada. The potential addition of LNG export facilities is expected to require additional power generation to support the LNG facilities and the increased economic and industrial activity expected to occur in the region. The strategic location of AltaGas' assets and operational expertise, along with a track record of collaborating with First Nations in British Columbia, provide AltaGas with a significant competitive advantage to capitalize on opportunities to increase its power generation portfolio to support LNG activities as they materialize.

UTILITIES

Description of Assets

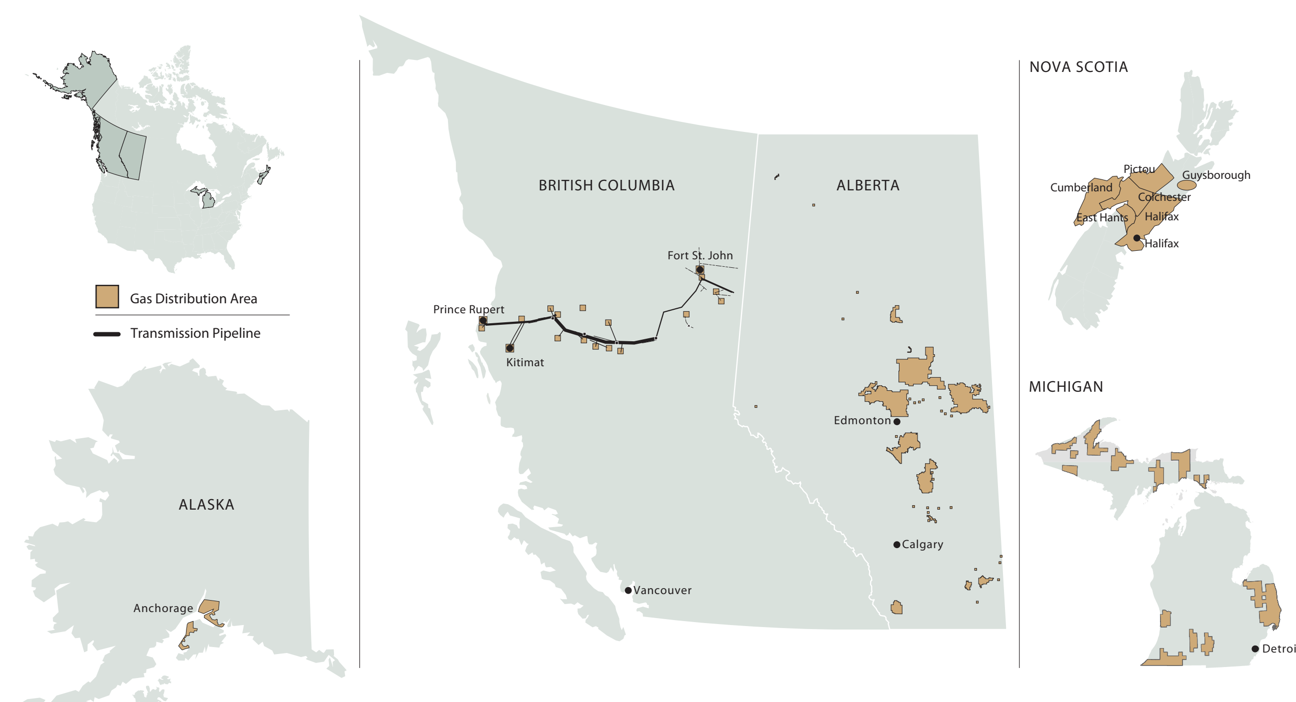
AltaGas owns and operates utility assets that store and deliver natural gas to end-users in Alberta, British Columbia, Nova Scotia, Michigan and Alaska. AltaGas also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. AltaGas' utility businesses serve over 560,000 customers and have a rate base of approximately $1.5 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:

- AUI in Alberta;
- PNG in British Columbia;
- Heritage Gas in Nova Scotia;
- SEMCO Gas in Michigan;
- ENSTAR and CINGSA in Alaska; and
- One-third interest in 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 British Columbia Utilities Commission (BCUC) to maintain a Revenue Stabilization Adjustment Mechanism regulatory account to mitigate the effect of weather on deliveries to certain customers and the impact on earnings.

SEMCO Gas

SEMCO Gas owns and operates a regulated natural gas distribution utility in Michigan and an interest in a regulated natural gas storage facility in Michigan. At the end of 2014, SEMCO Gas had approximately 300,000 customers. Of these customers, approximately 90 percent are residential. In 2014, 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$490 million. In 2014, the approved regulated ROE for SEMCO Gas was 10.35 percent on 50 percent equity.

SEMCO Gas is regulated by the Michigan Public Service Commission (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 Main Replacement Program (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; 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 contested rate case. The regulatory proceedings on the MRP case are expected to take between six to 12 months. As part of the case, SEMCO Gas is requesting 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.

ENSTAR and CINGSA

ENSTAR owns and operates a regulated natural gas distribution utility in Alaska and a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. At the end of 2014, ENSTAR had approximately 140,000 customers including regulated, transportation and non-regulated business lines. Of these customers, approximately 90 percent are residential. In 2014, ENSTAR experienced customer growth of approximately 2 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$230 million for ENSTAR and US$100 million for CINGSA (AltaGas' 65 percent share).

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

ENSTAR filed a new base rate case in September 2014. In the filing, ENSTAR requested an increase of approximately US$15 million in base rate revenue on a normalized annual basis. These rates reflect the addition of approximately US$115 million in gross rate base that ENSTAR has invested since its 2009 rate case to ensure the ongoing safe and reliable delivery of natural gas. ENSTAR proposed to increase its rates in two steps: (i) an interim and refundable rate increase of 1.0 percent of total revenues, which was approved by its regulators and became effective for billings on or after November 1, 2014; and (ii) an additional 4.06 percent increase upon final approval or acceptance, bringing a permanent rate increase of 5.06 percent of total normalized annual revenues. The second increase is not expected to be approved and implemented until fourth quarter 2015.

CINGSA made a filing in March 2014, updating the rates for service from the CINGSA Storage Facility to reflect its actual capital investment, permanent debt cost and actual operating costs. The calculation of rate base, levelized revenue requirement and rates has been adjusted to reflect a final capital cost of approximately US$160 million for the CINGSA Storage Facility. 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.

AltaGas Utilities Inc. (AUI)

AUI owns and operates a regulated natural gas distribution utility in Alberta. At the end of 2014, AUI served approximately 76,000 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. Customer growth in 2014 was 2 percent, reflecting the continued strong growth of the Alberta market. AUI's rate base at year end was approximately $215 million.

For 2013 and 2014, AUI's approved placeholder for regulated ROE was 8.75 percent on a prescribed capital structure of 43 percent equity and 57 percent debt. In 2013, the Alberta Utilities Commission (AUC) commenced a Generic Cost of Capital (GCOC) proceeding which will establish the ROE and capital structures for all AUC regulated utilities for 2013, 2014 and, possibly, future years. The decision is pending and is expected in early March 2015.

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 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 2014 interim rates were approximately 4 percent higher than those approved for 2013 with a decision on final rates from the AUC expected in the second quarter of 2015. The initial PBR term lasts for five years (2013-2017) and the AUC will make a determination at the end of the initial term as to how it will proceed for future years.

In addition to capital spend for new business, normal-course system betterment and general plant maintenance, AUI spent approximately $20 million in 2014 on its multi-year system rejuvenation program. This program is being undertaken to maintain public and worker safety and to ensure reliable and efficient long-term operation of AUI's gas delivery systems, many of which are in their fifth and sixth decade of service. Capital investment under the rejuvenation program has been allowed by the regulator as an adjustment factor to the PBR rate resulting in AUI earning its regulated rate of return on the capital.

Pacific Northern Gas Ltd. (PNG)

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 2014, PNG served approximately 41,000 customers. Customer growth in 2014 was 1 percent, which is strong for PNG's mature network and reflective of the economic activity in this region. PNG's residential customers comprised approximately 85 percent of its total customers. PNG's rate base at year end was approximately $200 million.

PNG is regulated by the BCUC. On March 25, 2014, the BCUC issued its decision on the GCOC Stage 2 proceeding established during 2012 of which PNG was a participant. The approved common equity ratio for PNG West and (PNG(N.E.)) TR division was set at 46.5 percent compared to the previously approved ratios of 45 percent and 40 percent, respectively. The approved common equity ratio for (PNG(N.E.)) FSJ/DC division was set at 41 percent compared to the previously approved ratio of 40 percent. The BCUC also set the Benchmark Utility ROE at 9.50 percent and 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 10.15 percent for PNG West and (PNG(N.E.)) TR and 9.90 percent for (PNG(N.E.)) FSJ/DC effective January 1, 2013. These common equity ratios and allowed ROEs were in effect for 2014 and will remain the same for 2015.

PNG operates under a cost-of-service regulation and filed its annual revenue requirement for (PNG(N.E.)) FSJ/DC in November 2014. The application sought approval to increase its 2015 approved rates on an interim basis effective January 1, 2015 pending the BCUC's review of the application. For PNG West and (PNG(N.E.)) TR, PNG filed a letter application requesting that the 2014 rates remain in effect for 2015 and any potential increases or decreases in its cost-of-service be addressed through a deferral account to be amortized during 2016. The Commission approved PNG's applications on an interim basis effective January 1, 2015 at the levels set forth in the applications. A negotiated settlement process (NSP) is expected to be conducted with respect to PNG's applications during the second quarter of 2015. The 2014 rates were approved under a NSP.

On January 20, 2015, PNG received BCUC approval to assign, novate and amend a Gas Transportation Service Agreement (GTSA) with EDFT that provides an option to contract for 80 Mmcf/d of the existing capacity in the Western System. If EDFT's project receives FID, it is expected to use the firm gas transportation service to deliver natural gas to a small scale LNG facility to be located in the Douglas Channel near Kitimat, British Columbia. Under the amended GTSA, PNG will receive additional option fees in excess of $2 million to hold this capacity until the commencement of service.

Heritage Gas Limited

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 2014, Heritage Gas had approximately 5,800 customers. Customer growth in 2014 was 14 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 $265 million. For 2014 and 2013, Heritage Gas' approved regulated ROE was 11 percent and debt recovery rate was 7.25 percent on 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. Heritage Gas invested approximately $1 million into the CNG business in 2014 (2013 – $9 million).

In response to a November 6, 2013 application by Heritage Gas, on February 20, 2014, the NSUARB issued a Decision ruling that prudently incurred costs of natural gas storage may be included within Heritage's cost-of-service. 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. Natural gas storage service is critical to ensuring security of gas supply for Heritage Gas' customers. The service will also provide benefits to Heritage Gas and its customers in the form of enhanced reliability and delivery of natural gas during the peak heating season, as well as reduced natural gas price volatility. 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. Heritage Gas expects a decision on the application in the first half of 2015.

After evaluating a number of alternative upstream transportation options, 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 fall of 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 including LNG through a developing regional LNG supply chain.

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 safety and the reliability of existing infrastructure;
- 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 return to shareholders;
- Develop rate-regulated infrastructure supporting the growth of LNG exports to Asia;
- Acquire new franchises when the opportunities arise; and
- Maintain strong social license with local communities, First Nations, governments, and regulatory bodies.

AltaGas expects to grow its existing utility infrastructure with customer growth in the franchise areas and through the conversion of users of alternative energy sources to natural gas. The growth rate of new customers varies amongst the Corporation's utilities with Heritage Gas seeing significant growth as it penetrates its market 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 region.

Some of AltaGas' utilities have delivery system upgrade programs underway. SEMCO Gas has the MRP program which is replacing 26 miles per year of vintage plastic main. AUI has a multi-year system rejuvenation program which is replacing certain infrastructure, much of which is in its fifth and sixth decade of service.

AltaGas' wholly-owned subsidiary PNG is pursuing an expansion of its transmission line. The expansion would be part of PNG's regulated asset base and would provide transportation infrastructure for the export of LNG from the west coast of Canada.

CONSOLIDATED FINANCIAL REVIEW

Years ended December 31 *($ millions)*	**2014**	2013	2012
Revenue	**2,406**	2,043	1,450
Net revenue [1]	**1,019**	960	665
Normalized operating income [1]	**366**	353	235
Normalized EBITDA [1]	**546**	509	337
Net income applicable to common shares	**96**	182	102
Normalized net income [1]	**165**	176	110
Total assets	**8,413**	7,284	5,932
Total long-term liabilities	**4,074**	3,727	3,357
Net additions to property, plant and equipment	**605**	1,145	1,532
Dividends declared [2]	**215**	174	133
Cash flows			
Normalized funds from operations [1]	**472**	402	281

($ per share, except shares outstanding)	**2014**	2013	2012
Normalized EBITDA [1]	**4.31**	4.38	3.55
Net income – basic	**0.75**	1.56	1.07
Net income – diluted	**0.74**	1.52	1.06
Normalized net income [1]	**1.30**	1.51	1.15
Dividends declared [2]	**1.69**	1.50	1.40
Cash flows			
Normalized funds from operations [1]	**3.72**	3.47	2.96
Shares outstanding – basic (millions)			
During the year [3]	**127**	116	95
End of year	**134**	122	105

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 of $0.12 beginning September 10, 2012, $0.125 beginning April 24, 2013, $0.1275 beginning July 31, 2013 and $0.1475 beginning May 26, 2014.*

3 *Weighted average.*

FULL YEAR 2014 CONSOLIDATED FINANCIAL REVIEW

Normalized net income was $165 million ($1.30 per share) for 2014 compared to $176 million ($1.51 per share) reported for 2013. Normalized net income decreased compared to 2013 primarily due to lower contribution from Alberta power assets, higher compensation costs, preferred share dividends, interest costs, and lower contribution from Energy Services.

Two of the Northwest Projects were brought into service in second half of 2014 resulting in a negative impact to earnings as a result of full depreciation and interest costs recorded during the ramp up period of the facilities. Partially offsetting the significant decline in contributions from power assets were the higher contributions from gas assets due to increased volumes at some key processing facilities and higher NGL sales, the earnings contributions from Petrogas and Blythe, favourable foreign exchange rates on U.S. business results, and continued rate base and customer growth and colder weather at the utilities.

Net income applicable to common shares for 2014 was $96 million ($0.75 per share) compared to $182 million ($1.56 per share) for 2013. Net income applicable to common shares for 2014 was normalized for after tax amounts related to provisions taken for certain assets, impact from the sale of non core assets, unrealized gain or loss on mark to market adjustments, realized and unrealized losses on long term investments, costs associated with the early redemption of MTNs, transaction costs related to acquisitions and development costs incurred for the energy export projects. Net income applicable to common shares for 2013 was normalized for similar extraordinary items as in 2014, excluding the costs associated with the early redemption of MTNs. Results in 2013 were also normalized for the impact of statutory tax rate changes.

Normalized funds from operations for 2014 increased 17 percent to $472 million ($3.72 per share), compared to $402 million ($3.47 per share) for 2013. Normalized EBITDA for 2014 increased 7 percent to $546 million compared to $509 million for 2013. The increase in cash flow was a result of higher contributions from the Gas and Utilities segments, and the addition of Forrest Kerr, partially offset by lower results from Alberta power assets.

Normalized operating income for 2014 was $366 million, compared to $353 million for 2013. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest expense, preferred share dividends and income taxes.

Operating and administrative expense for 2014 was $451 million, compared to $431 million for 2013. The increase was primarily due to asset growth of the Corporation as well as increased activity to support growth initiatives. Amortization expense for 2014 was $173 million compared to $152 million for 2013 mainly due to asset growth of the Corporation. Amortization and accretion expenses of $9 million were recorded for the Northwest Projects in 2014. In 2014, $119 million of pre-tax provisions for long-lived assets were recorded, compared to $23 million in 2013. Of these provisions, $70 million were taken for certain non-productive gas processing assets and $38 million for transmission pipeline assets as a result of a purchase option to be exercised by the customer in 2017.

Interest expense for 2014 was $111 million compared to $102 million for 2013. Interest expense increased due to a higher average debt balance of $3,262 million for 2014, compared to $2,966 million for 2013 as a result of the growth of the Corporation, as well as slightly lower capitalized interest of $30 million in 2014, compared to $31 million in 2013. The increase in interest expense was partially offset by a lower average borrowing rate of 4.3 percent in 2014 (2013 – 4.5 percent). In 2014, interest expense no longer being capitalized related to the Northwest Projects was $14 million.

AltaGas recorded income tax expense of $19 million for 2014 compared to $40 million for 2013. Income tax expense decreased due to lower taxable earnings in the year driven by provisions taken for long-lived assets and tax on a capital gain realized in 2013. The decrease in income tax expense was partially offset by unrealized gains on financial instruments in the year and the impact of adjustments in deferred tax estimates recorded in 2013.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $550 million to $650 million for 2015. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' committed capital program is fully funded through internally-generated cash flow, the DRIP, and available bank lines. As at December 31, 2014, the Corporation had approximately $1.7 billion available on its credit facilities as well as cash on hand and short-term investments of $421 million primarily from the equity issuance and MTN offering completed in third quarter 2014.

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwestern British Columbia: 195-MW Forrest Kerr, 16-MW Volcano Creek and 66-MW McLymont Creek. The 277-MW Northwest Projects are contracted with 60-year EPAs with BC Hydro fully indexed to the CPI, as well as Impact Benefit Agreements with the Tahltan First Nation. The Forrest Kerr and Volcano Creek projects both entered service in 2014.

McLymont Creek

At the 66-MW McLymont Creek project, construction of the seven kilometre intake access road is complete and intake construction is underway. Excavation of the McLymont power tunnel has been completed. Construction of the powerhouse is advancing ahead of schedule and installation of the turbines is underway. The project is expected to be in service in mid-2015.

Townsend Gas Processing Facility

On August 19, 2014 AltaGas and Painted Pony entered into a 15 year strategic alliance for the development of processing infrastructure and marketing services for natural gas and NGL. In the first phase of the strategic alliance, a 198 Mmcf/d shallow cut gas processing facility, known as the Townsend Facility, will be constructed and operated by AltaGas, of which Painted Pony will reserve the right to a minimum of 150 Mmcf/d of firm capacity. The Townsend Facility will be located approximately 100 kilometers north of Fort St. John and 20 kilometers southeast of AltaGas' Blair Creek facility and is estimated to cost $325 to $350 million. Subject to regulatory approvals, construction of the Townsend facility is expected to commence in 2015 and is expected to be available by mid 2016, in advance of Painted Pony's production requirements.

Alton Natural Gas Storage Project

AltaGas has commenced work on the Alton Natural Gas Storage project, with up to 10 Bcf of natural gas storage located near Truro, Nova Scotia. Drilling of the wells and construction at the cavern and river sites are complete. AltaGas has entered into a long-term storage agreement with Heritage Gas for the first phase, which is subject to regulatory approval by the Nova Scotia Utility and Review Board. The issuance of permits by the Nova Scotia Government's Department of Environment to commence brining has been delayed. AltaGas continues to work with the regulatory agencies to obtain the remaining permits, expected in 2015.

AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP)

On January 29, 2013, AltaGas signed an agreement with Idemitsu Kosan Co.,Ltd. (Idemitsu) to form AIJVLP. AltaGas and Idemitsu each own, through subsidiaries, a 50 percent interest in AIJVLP. AIJVLP is pursuing opportunities to develop liquefaction infrastructure to meet the growing demand for natural gas in Asia. AIJVLP is also pursuing opportunities to develop a Canadian LPG export business, including logistics, plant refrigeration and storage facilities.

LPG Export Business

On March 1, 2014, AIJVLP completed the acquisition of two-thirds of Petrogas. Petrogas is a privately-held leading North American integrated midstream company. Petrogas' extensive logistics network provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities.

On May 1, 2014 Petrogas acquired the Ferndale LPG export terminal located in the State of Washington. The facility is expected to increase the number of LPG shipments resulting in a ramp up over the next several years to approximately 30,000 Bbls/d. Tank inspections were completed in late 2014. The facility has been re-configured to handle propane. First propane shipments are expected in first half 2015.

Through AIJVLP, AltaGas is also developing a greenfield LPG terminal on the west coast of Canada and is currently conducting site evaluation studies, which are expected to be completed in 2015. Terminal sites and refrigeration technology are being evaluated. AIJVLP is currently in discussions with key stakeholders to determine project timing, and with market participants to develop sales and logistics agreements.

LNG Export Business

In addition to pursuing LPG export initiatives through AIJVLP, AltaGas and Idemitsu formed the Douglas Channel LNG Consortium, which includes EDFT and EXMAR, to support the plan of arrangement under the CCAA proceedings for the Douglas Channel LNG project. The Douglas Channel LNG project, is a proposed barge based LNG export facility on the west bank of the Douglas Channel in Kitimat, British Columbia with a nameplate capacity of 0.55 million tonnes of LNG per annum. On January 28, 2015, the Consortium announced that it had obtained full ownership and control of the Douglas Channel LNG project as a result of the statutory plan of arrangement completed under the CCAA proceedings. All of the useful assets of the former project have been transferred to the Consortium and all creditor claims have been settled. The Consortium has executed long-term lease agreements with the Haisla Nation regarding land and water tenure and with PNG for long-term pipeline capacity to supply gas to the project. The Consortium is targeting FID by the end of 2015 and commercial operation in 2018.

In addition, AIJVLP continues to evaluate the development of a second LNG export facility. On April 16, 2014, Triton LNG, a wholly owned subsidiary of AIJVLP, received NEB approval to export up to 2.3 million tonnes per annum of LNG. The LNG export projects are subject to further consultations and regulatory approvals, FIDs and facility constructions.

PNG Pipeline Looping Project (PLP)

PNG continues to proceed with the development of the potential expansion on its natural gas transmission line. PNG has signed Transportation Reservation Agreements (TRAs) with two parties to support the PNG expansion project. The TRAs provide for cost recovery of development costs related to the PLP and are backstopped by letters of credit provided by the counterparties. On July 24, 2013, the British Columbia Environmental Assessment Office (BCEAO) issued an order accepting the project into the environmental assessment process following PNG's filing of its project description.

On March 31, 2014, the BCEAO issued the approved Application Information Requirements (AIR), which specifies the required information in an application for environmental assessment certificate. Under the approved environmental assessment process, PNG has up to three years to provide the required information. PNG is continuing its consultation activities while undertaking the field studies necessary to address the AIR.

Sonoran Energy Project (Blythe II) and Blythe III

In second quarter 2014, AltaGas paid US$9 million to acquire the shovel ready Blythe II project, adjacent to the existing AltaGas Blythe facility located near the California Arizona border. In fourth quarter 2014, AltaGas commenced the preliminary engineering of the project and began early discussions with major equipment suppliers. AltaGas also acquired 76 acres of land north of the current Blythe facility for the development of a second expansion (Blythe III). The development of both projects could potentially triple AltaGas' current generating capacity in California over the long term.

Harmattan Cogeneration III

AltaGas is expanding its cogeneration fleet at Harmattan to 45 MW. In first quarter 2014, AltaGas began engineering and procured the combustion turbine for the new 15 MW Cogeneration III to meet the increased power demand at Harmattan and increase sales to the Alberta power market. Construction is well underway. Pilings and major foundations are complete and the combustion turbine and heat recovery steam generator have been installed. Cogeneration III is on schedule and budget and is expected to be in service in first half 2015 with a total project cost estimated at $40 million.

Regional LNG

AltaGas is developing a small scale LNG production facility in Dawson Creek, British Columbia. Capital cost of the Regional LNG project is estimated to be approximately $35 million. In fourth quarter 2014, permitting, engineering work and preliminary ground work commenced and the purchase orders for major equipment were completed. This LNG production facility is expected to displace diesel fuel in both the commercial and residential markets in the area. As market demand for LNG to displace diesel fuel further develops, expansion of the business may occur in British Columbia and other regions.

U.S. Power Assets Acquisition

On January 8, 2015 AltaGas completed the acquisition of three gas-fired power assets in the western U.S. with a total generation capacity of 164 MW. All three assets are currently contracted under PPAs with local creditworthy utilities and generate stable cash flows. The acquisition is consistent with AltaGas' strategy of capitalizing on the demand for clean energy sources such as natural gas; growing and diversifying the power portfolio by increasing AltaGas' presence in the California and Colorado power markets; providing low-risk, fully contracted cash flows; and providing the potential for future organic growth opportunities via repowering of the sites.

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

Years ended December 31 *($ millions)*	2014	2013	2012
Net revenue	**1,019**	960	665
Add (deduct):			
Other income (expenses)	**(25)**	(41)	(1)
Income from equity investments	**(39)**	(112)	(67)
Cost of sales	**1,451**	1,236	853
Revenue (GAAP financial measure)	**2,406**	2,043	1,450

Management believes that net revenue, which is revenue plus other income (expenses) plus income from equity investments not held-for-trading, less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of commodities affect both revenue and cost of sales, and equity investments are part of the operating activities for the Corporation.

Normalized Operating Income

Years ended December 31 *($ millions)*	2014	2013	2012
Normalized operating income	**366**	353	235
Add (deduct):			
Transaction costs related to acquisitions	**(1)**	(2)	(6)
Realized/unrealized losses on long-term investments	**(2)**	(5)	–
Gain on asset dispositions	**38**	41	–
Provision for long-lived assets	**(119)**	(23)	(3)
Joint venture development costs	**(1)**	(4)	–
Sundance force majeure arbitration decision	**–**	–	(11)
Costs associated with early redemption of MTNs	**(17)**	–	–
Operating income	**264**	360	215
Add (deduct):			
Unrealized gain (loss) on mark-to-market adjustments	**5**	(9)	22
Interest expense	**(111)**	(102)	(61)
Foreign exchange loss	**–**	–	(9)
Income tax expense	**(19)**	(40)	(46)
Net income applicable to non-controlling interests	**(8)**	(7)	(4)
Preferred share dividends	**(35)**	(20)	(15)
Net income applicable to common shares (GAAP financial measure)	**96**	182	102

Operating income is a measure of AltaGas' profitability from its principal operating activities prior to how these activities are financed, how the results are taxed, or the impact of unrealized mark-to-market adjustments. The measure is used to assess operating performance since management believes that it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gain (loss) on mark-to-market adjustments, interest expense, foreign exchange loss, income tax expense, net income applicable to non-controlling interests and preferred share dividends.

Normalized operating income represents operating income adjusted for non-operating related expenses such as transaction costs related to acquisitions, realized and unrealized losses on long-term investments, gain on asset dispositions, provision for long-lived assets, arbitration decisions, and costs associated with early redemption of MTNs. Normalized operating income also includes an adjustment for the development costs incurred by AIJVLP.

Normalized EBITDA

Years ended December 31 *($ millions)*	**2014**	2013	2012
Normalized EBITDA	**546**	509	337
Add (deduct):			
Transaction costs related to acquisitions	**(1)**	(2)	(6)
Realized/unrealized losses on long-term investments	**(2)**	(5)	–
Gain on asset dispositions	**38**	41	–
Joint venture development costs	**(1)**	(4)	–
Sundance force majeure arbitration decision	**–**	–	(11)
Costs associated with early redemption of MTNs	**(17)**	–	–
EBITDA	**563**	539	320
Add (deduct):			
Unrealized gain (loss) on mark-to-market adjustments	**5**	(9)	22
Depreciation, depletion and amortization	**(173)**	(152)	(99)
Provision for long-lived assets	**(119)**	(23)	(3)
Accretion expense	**(7)**	(4)	(3)
Interest expense	**(111)**	(102)	(61)
Foreign exchange loss	**–**	–	(9)
Income tax expense	**(19)**	(40)	(46)
Net income applicable to non-controlling interests	**(8)**	(7)	(4)
Preferred share dividends	**(35)**	(20)	(15)
Net income applicable to common shares (GAAP financial measure)	**96**	182	102

EBITDA is a measure of AltaGas' operating profitability without the impact of mark-to-market adjustments and prior to how business activities are financed, assets are amortized or earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk on a significant portion of the volumes subject to commodity price fluctuations, and therefore evaluates company performance excluding unrealized gains or losses from risk management contracts. EBITDA is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gain (loss) on mark-to-market adjustments; depreciation, depletion and amortization; provision for long-lived assets; accretion expense; interest expense; foreign exchange loss; income tax expense; net income applicable to non-controlling interests; and preferred share dividends.

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as transaction costs related to acquisitions, realized and unrealized loss on long-term investments, gain on asset dispositions, arbitration decisions, and costs associated with early redemption of MTNs. Normalized EBITDA also includes an adjustment for the development costs incurred by AIJVLP.

Normalized Net Income

Years ended December 31 *($ millions)*	**2014**	2013	2012
Normalized net income	**165**	176	110
Add (deduct) after-tax:			
Unrealized gain (loss) on mark-to-market adjustments	**3**	(7)	16
Realized/unrealized losses on long-term investments	**(1)**	(4)	–
Transaction costs and foreign exchange loss related to acquisitions	**–**	(1)	(13)
Gain on asset dispositions	**32**	36	–
Provision for long-lived assets	**(89)**	(17)	(2)
Joint venture development costs	**(1)**	(3)	–
Sundance force majeure arbitration decision	**–**	–	(8)
Costs associated with early redemption of MTNs	**(13)**	–	–
Statutory tax rate change	**–**	2	(1)
Net income applicable to common shares (GAAP financial measure)	**96**	182	102

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as transaction costs related to acquisitions, gain on asset dispositions, provision for long-lived assets, arbitration decisions, costs associated with early redemption of MTNs, and statutory tax rate changes. Normalized net income also includes an adjustment for the development costs incurred by AIJVLP.

Normalized Funds from Operations

Years ended December 31 *($ millions)*	2014	2013	2012
Normalized funds from operations	**472**	402	281
Add (deduct):			
Transaction costs and foreign exchange loss related to acquisitions	**(1)**	(2)	(15)
Sundance force majeure arbitration decision	**–**	–	(11)
Funds from operations	**471**	400	255
Add (deduct):			
Net change in operating assets and liabilities	**(11)**	(32)	(106)
Asset retirement obligations settled	**(2)**	(2)	(3)
Cash from operations (GAAP financial measure)	**458**	366	146

Normalized funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in operating assets and liabilities in the period and non-operating related one-time expenses such as transaction costs related to acquisitions and arbitration decisions. 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 Operating Income

Years ended December 31 *($ millions)*	2014	2013
Gas	**167**	113
Power	**65**	123
Utilities	**166**	150
Sub-total: Operating Segments	**398**	386
Corporate	**(32)**	(33)
	366	353

GAS

OPERATING STATISTICS

Years ended December 31	2014	2013
Total inlet gas processed *(Mmcf/d)* [1]	**1,512**	1,361
Extraction ethane volumes *(Bbls/d)* [1, 2]	**34,999**	32,695
Extraction NGL volumes *(Bbls/d)* [1, 2]	**37,777**	31,086
Total extraction volumes *(Bbls/d)* [1, 2]	**72,776**	63,781
Frac spread – realized *($/Bbl)* [1, 3]	**22.83**	24.96
Frac spread – average spot price *($/Bbl)* [1, 4]	**24.64**	27.15

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, are 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.*

In 2014, total inlet gas processed increased by 151 Mmcf/d, average ethane volumes produced increased by 2,304 Bbls/d and NGL volumes produced increased by 6,691 Bbls/d, compared to 2013. The higher total inlet was primarily driven by higher Harmattan Co-stream volumes; higher Younger volumes primarily from increased inlet volumes on the Septimus line; higher Gordondale and Blair Creek volumes from increased producer drilling; and higher volumes processed at Empress. The increase in total inlet gas processed was partially offset by the sale of Ante Creek and declines in dry gas areas. Higher ethane volumes were due to increased volumes at Harmattan Co-stream and Empress. Higher NGL volumes were due to increased inlet volumes at Younger, Harmattan Co-stream, and Gordondale.

Full Year Results 2014

The Gas segment reported a 48 percent increase in normalized operating income to $167 million for 2014, compared to $113 million in 2013. The increase was primarily a result of the contribution from increased volumes processed at Harmattan, Gordondale, Blair Creek, and Younger, combined with higher contribution from sales of NGL, in addition to the earnings contribution from Petrogas. The increase was partially offset by higher costs to fulfill firm delivery commitments from operational curtailments of natural gas storage, higher pipeline rebalancing costs, lower C&I customers, higher operating expenses related to turnarounds at various gas facilities and lower earnings contribution from transportation volumes.

The Gas segment reported operating income of $69 million for 2014, compared to $96 million in 2013. Results for 2014 included the impact of a $70 million pre-tax provision taken for certain non-productive gas processing assets and a $38 million pre-tax provision taken for Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets, partially offset by the pre-tax gain from the sale of the Ante Creek facility. Also included in 2014 are $2 million of AIJVLP development costs. Results for 2013 included the $16 million provision taken for certain non-core assets, the $4 million pre-tax gain from the sale of ECNG Energy L.P. (ECNG), $3 million of AIJVLP development costs, and $1 million of transaction costs related to acquisitions.

For the year ended December 31, 2014, AltaGas hedged 68 percent of frac exposed production at an average price of approximately $26/Bbl before deducting extraction premiums. For the year ended December 31, 2013, AltaGas hedged 70 percent of frac exposed production at an average price of approximately $27/Bbl before deducting extraction premiums. The average indicative spot NGL frac spread in 2014 was approximately $25/Bbl compared to approximately $27/Bbl in 2013.

POWER

OPERATING STATISTICS

Years ended December 31	2014	2013
Volume of power sold *(GWh)* [1]	**5,169**	4,458
Average price realized on the sale of power *($/MWh)* [2]	**65.97**	76.82
Alberta Power Pool average spot price ($/MWh)	**49.42**	80.19

1 Power sold from Sundance B is disclosed as volumes based on target availability and not volumes delivered.

2 Price received excludes Blythe as it earns fixed capacity payments under its power purchase tolling agreement with Southern California Edison Company (SCE).

For the year ended December 31, 2014, volume of power sold increased by 711 GWh compared to 2013. Volumes sold during 2014 included 4,570 GWh conventional power generation and 599 GWh renewable power generation, compared to 4,004 GWh conventional power generation and 454 GWh renewable power generation in 2013. The increase in power generated was primarily due to the Blythe acquisition in May 2013 and the contribution from Forrest Kerr coming into service in August 2014. For the year ended December 31, 2014, Blythe and Forrest Kerr generated 1,663 and 152 GWh of power, respectively. In 2014, delivered volumes were lower than actual availability at the Sundance B units.

Full Year Results 2014

For the year ended December 31, 2014, the Power segment reported normalized operating income of $65 million compared to $123 million for same period 2013. Normalized operating income decreased primarily as a result of a 38 percent decrease in Alberta Power Pool spot prices, lower generation from Alberta power assets, and increased administrative expenses. The decrease was partially offset by the contribution from Forrest Kerr, despite delays in the Northwest Transmission Line (NTL), and unforeseen weather and river conditions causing a slower ramp up of the facility during the second half of 2014. The decrease was also offset by the contribution from Blythe, despite a planned major turnaround from March 1 to April 15, 2014 and the impact of favourable foreign exchange on U.S. business results.

Operating income in the Power segment was $80 million in 2014, compared to $117 million in 2013. Operating income for 2014 includes the impact of a $27 million pre tax gain on the sale of power assets and an $11 million pre tax provision taken for a number of small hydro power development projects in British Columbia. Also included in 2014 are $1 million of transaction costs related to acquisitions. Results for 2013 included a $3 million pre tax provision taken for a number of small wind power development projects and $2 million of transaction costs related to acquisitions.

For the year ended December 31, 2014, AltaGas was 55 percent hedged in Alberta at an average price of $64/MWh. In 2013, AltaGas was 62 percent hedged at an average price of $66/MWh.

UTILITIES

OPERATING STATISTICS

Years ended December 31	2014	2013
Canadian utilities		
Natural gas deliveries – end-use *(PJ)* [1]	**32.7**	30.4
Natural gas deliveries – transportation *(PJ)* [1]	**5.6**	5.8
U.S. utilities		
Natural gas deliveries – end-use *(Bcf)* [1]	**72.3**	70.1
Natural gas deliveries – transportation *(Bcf)* [1]	**41.0**	41.4
Service sites [2]	**562,746**	555,198
Degree day variance from normal – AUI *(%)* [3]	**2.3**	0.5
Degree day variance from normal – Heritage Gas *(%)* [3]	**(0.2)**	1.3
Degree day variance from normal – SEMCO Gas *(%)* [4]	**16.1**	9.0
Degree day variance from normal – ENSTAR *(%)* [4]	**(9.0)**	(1.0)

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	2014	2013
Approved ROE *(%)*		
Canadian utilities *(average)*	**9.7**	10.0
U.S. utilities *(average)*	**11.2**	11.3
Approved return on debt *(%)*		
Canadian utilities *(average)*	**5.9**	6.1
U.S. utilities *(average)*	**5.3**	5.6
Rate base *($ millions)* [1]		
Canadian utilities	**677**	605
U.S. utilities [2, 3]	**818**	773

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. The rate base excludes Gas in Storage for ENSTAR. Currently ENSTAR is compensated for its Gas in Storage of $51 million (2013 – $53 million) through a carry cost component. ENSTAR has filed to incorporate the Gas in Storage as part of its rate base in the current Rate Case before the RCA. It has yet to be determined if ENSTAR will prevail in its request to include Gas in Storage in base rates. The decision on the Rate Case is expected in fourth quarter 2015.

Full Year Results 2014

For the year ended December 31, 2014, the Utilities segment reported an 11 percent increase in normalized operating income to $166 million compared to $150 million for 2013. The increase was mainly due to customer and rate base growth, favourable foreign exchange on the U.S. business results, and colder weather.

The Utilities segment reported operating income of $166 million for the year ended December 31, 2014 compared to $184 million for 2013. Results were due to the items described above as well as the $38 million pre-tax gain on the sale of Pacific Trail Pipelines Limited Partnership (PTP), partially offset by the $3 million provision taken for assets in Inuvik, both recorded in third quarter 2013.

CORPORATE

Full Year Results 2014

Normalized operating loss for the year ended December 31, 2014 was $32 million, compared to $33 million in 2013. The lower normalized operating loss was primarily due to higher interest income and lower Corporate depreciation. The decrease in normalized operating income was partially offset by higher administrative expenses due to increased compensation costs.

The operating loss in the Corporate segment was $50 million for the year ended December 31, 2014, compared to $38 million for 2013. The increase in loss was mainly due to the costs associated with the early redemption of MTNs in 2014, partially offset by the unrealized mark-to-market adjustments.

INVESTED CAPITAL

Invested Capital – Investment Type

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**

Invested Capital – Investment Type

Year ended December 31, 2013 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	37	878	149	5	1,069
Intangible assets	4	–	6	12	22
Long-term investments	338	–	–	–	338
	379	878	155	17	1,429
Disposals:					
Property, plant and equipment	(15)	–	–	–	(15)
Net invested capital	364	878	155	17	1,414

The invested capital for Gas included $12 million of maintenance capital. The invested capital for Power also included $13 million related to the turnaround at Blythe, which is amortized over four to eight years to align with the timing of major turnarounds at the facility.

RISK MANAGEMENT

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During 2014, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 18 of the Consolidated Financial Statements:

Commodity Forward Contracts

The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price.

The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The calculation of fair value of interest rate and foreign exchange derivatives used quoted market rates.

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

Commodity Swap Contracts

Power hedges

AltaGas executes fixed for floating power price swaps to manage its power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power 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 $7.88/MWh to $999.99/MWh in 2014 and $0.00/MWh to $1000.00/MWh in 2013. The average Alberta spot price was $49.42/MWh in 2014 (2013 – $80.19/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average price realized for power by AltaGas was $65.97/MWh in 2014 (2013 – $76.82/MWh). For 2015, 25 percent of volumes exposed to Alberta power prices have been hedged at an average price of approximately $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 2014, the Corporation had NGL frac spread hedges for an average of approximately 5,500 Bbls/d at an average price of approximately $26/Bbl. The average indicative spot NGL frac spread for 2014 was an estimated $25/Bbl (2013 – $27/Bbl). The average NGL frac spread realized by AltaGas in 2014 was $23/Bbl (2013 – $25/Bbl). Management estimates an average of approximately 6,500 Bbls/d will be exposed to frac spread in 2015. For 2015, approximately 50 percent of estimated volumes exposed to frac spread have been hedged at an average price of approximately $27/Bbl before deducting extraction premiums.

Interest Rate Forward Contracts

From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. At December 31, 2014, the Corporation had no interest rate swaps outstanding. At December 31, 2014, the Corporation had fixed the interest rate on 86 percent of its debt including MTNs (December 31, 2013 – 73 percent).

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 a long-term debt matures or is settled. As at December 31, 2014, management designated US$375 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2013 – US$570 million). US dollar denominated long-term debt has 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.

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	• 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 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 • Backstop Sundance B PPA operations by adding new power generation capacity
Construction	• Major projects group manages and monitors significant construction projects • Strong 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
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 wind and hydrology studies to support investment decisions

Risks	Strategies and Organizational Capability to Mitigate Risks
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
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, other 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 Specified Gas Emitters 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

Cash Flows

Years ended December 31 *($ millions)*	2014	2013
Cash from operations	**458**	366
Investing activities	**(591)**	(1,265)
Financing activities	**456**	931
Change in cash	**323**	32

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $458 million in 2014 compared to $366 million in 2013. Cash from operations increased primarily as a result of stronger cash flow generation in the Gas segment driven largely by higher volumes processed and higher frac exposed volumes, as well as distributions from Petrogas, partially offset by a lower cash flow contribution from Power due mainly to lower Alberta Power Pool spot prices and lower Alberta power generation.

Working Capital

As at December 31 *($ millions except current ratio)*	2014	2013
Current assets	**1,058**	621
Current liabilities	**765**	727
Working capital	**293**	(106)
Current ratio	**1.4**	0.9

Working capital was in a surplus position of $293 million as at December 31, 2014, compared to a working capital deficit of $106 million as at December 31, 2013. The working capital ratio was 1.4 at the end of 2014, compared to 0.9 at the end of 2013. The working capital ratio increased due to higher cash and short-term investment balances primarily due to cash on hand as a result of debt and equity financings completed in the second half of 2014.

Investing Activities

Cash used for investing activities in 2014 was $591 million compared to $1.3 billion in 2013. Investing activities in 2014 included expenditures of $520 million for property, plant and equipment, $29 million for intangible assets, $50 million for acquisition of short-term investments, and $53 million for acquisition of long-term investments, partially offset by proceeds of $65 million received on disposition of assets. Investing activities in 2013 primarily included $537 million related to the Blythe acquisition; $501 million related to investments in property, plant and equipment; $231 million related to the investment of Petrogas; and $47 million related to intangible assets.

Financing Activities

Cash received from financing activities was $456 million in 2014 compared to $931 million in 2013. Financing activities in 2014 were primarily composed of net proceeds from issuance of long-term debt of $1.3 billion, net proceeds from issuance of common shares of $512 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. Financing activities in 2013 were primarily composed of net proceeds from issuance of $2.1 billion of long-term debt, issuance of common shares of $448 million, issuance of preferred shares of $194 million, and $15 million issuance of short-term debt, partially offset by a $1.6 billion repayment of long-term debt. Total dividends paid in 2014 were $245 million, compared to $190 million in 2013. The increase was due to higher share count and dividend increases.

CAPITAL RESOURCES

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

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments.

As at December 31, 2014, AltaGas had $2.8 billion in MTNs outstanding, PNG debenture notes of $57 million, SEMCO long-term debt of $443 million and $182 million drawn from bank credit facilities. As at December 31, 2014, AltaGas' current portion of long-term debt was $214 million.

AltaGas' earnings coverage ratio, which is defined as the consolidated net income before interest and income taxes divided by total interest expense for the rolling twelve months ended December 31, 2014 was 1.90 times.

AltaGas' debt-to-total capitalization ratio as at December 31, 2014 was 45 percent (December 31, 2013 – 53 percent).

($ millions)	**December 31, 2014**	December 31, 2013
Debt		
Short-term debt	**72**	84
Current portion of long-term debt	**214**	209
Long-term debt	**3,050**	2,953
Less: cash and cash equivalents	**(371)**	(45)
Less: short-term investments	**(50)**	–
Net debt	**2,915**	3,201
Shareholders' equity	**3,541**	2,792
Non-controlling interests	**33**	38
Total capitalization	**6,489**	6,031
Debt-to-total capitalization ratio *(%)*	**44.9**	53.1

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities. The following table summarizes the Corporation's debt covenants for all credit facilities as at December 31, 2014:

Ratios	Debt covenant requirements
Debt-to-capitalization	not greater than 65 percent
EBITDA-to-interest expense	not less than 2.5x
EBITDA-to-interest expense (SEMCO)	not less than 2.25x
Debt-to-capitalization (SEMCO)	not greater than 60 percent
Debt-to-capitalization (PNG)	not greater than 65 percent

On August 23, 2013, a $4 billion base shelf prospectus valid for 25 months was filed. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance. As at December 31, 2014, $2.0 billion remains available on the base shelf prospectus.

Credit Facilities

($ millions)	Borrowing capacity	Drawn at December 31, 2014	Drawn at December 31, 2013
Demand operating facilities	70	**4**	11
Extendible revolving letter of credit facility	150	**113**	68
PNG operating facility	25	**14**	15
Bilateral letter of credit facility	125	**13**	68
AltaGas Ltd. revolving credit facility	1,400	**–**	598
SEMCO Energy US$ unsecured credit facility [1, 2]	150	**38**	64
	1,920	**182**	824

1 *Amount drawn at December 31, 2014 converted at December 2014 month-end rate of 1 US dollar = 1.1601 Canadian dollar (Amount drawn at December 31, 2013 converted at December 2013 month-end rate of 1 US dollar = 1.0636 Canadian dollar).*

2 *Borrowing capacity assumed at par.*

CONTRACTUAL OBLIGATIONS

December 31, 2014	Payments Due by Period				
($ millions)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	**3,263**	**214**	**457**	**388**	**2,204**
Interest on long-term debt	**1,273**	**139**	**244**	**202**	**688**
Operating leases	**133**	**25**	**36**	**18**	**54**
Purchase obligations	**1,330**	**336**	**615**	**191**	**188**
Capital project commitments	**29**	**29**	**–**	**–**	**–**
Pension plan and retiree benefits	**216**	**31**	**33**	**37**	**115**
Long-term liabilities	**204**	**–**	**79**	**19**	**106**
Total contractual obligations	**6,448**	**774**	**1,464**	**855**	**3,355**

AltaGas has long-term operating lease agreements for gas storage, office space, office equipment and automotive equipment.

RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Refer to Note 24 of the Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheet and the classification of revenue, income and expenses in the Consolidated Statements of Income.

CREDIT RATINGS

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.

On December 20, 2013, S&P reaffirmed the BBB and P-3 High (H) ratings for AltaGas.

On December 4, 2013, DBRS commenced rating of the Series E Preferred Shares with a rating of Pfd-3.

On December 10, 2013, S&P commenced rating of the Series E Preferred Shares with a rating of P-3 (H).

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.

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”or “low” grades which indicate relative standing within the major rating categories.

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

As at December 31, 2014, AltaGas had outstanding 134 million common shares, 8 million series A Preferred Shares, 8 million series C US$ Preferred Shares, 8 million series E Preferred Shares, and 8 million series G Preferred Shares with a combined market capitalization of approximately $6.6 billion based on a closing trading price on December 31, 2014 of $43.34 per common share, $24.99 per series A Preferred Share, $25.15 per series C US$ Preferred Share, $26.00 per series E Preferred Share and $25.70 per series G Preferred Share, respectively.

As at December 31, 2014, there were 5.1 million options outstanding and 3.0 million options exercisable under the terms of the share option plan.

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, capital expenditures, and debt repayment requirements of AltaGas.

On September 10, 2012, the Board of Directors approved an increase in the monthly dividend to $0.12 per common share from $0.115 per common share effective with the September dividend.

On April 24, 2013, the Board of Directors approved an increase in the monthly dividend to $0.125 per common share from $0.12 per common share effective with the May dividend.

On July 31, 2013, the Board of Directors approved an increase in the monthly dividend to $0.1275 per common share from $0.125 per common share effective with the August dividend.

On April 30, 2014, the Board of Directors approved an increase in the monthly dividend to $0.1475 per common share from $0.1275 per common share effective with the May dividend.

The following table summarizes AltaGas' dividend declaration history:

Dividends

Years ended December 31 *($ per common share)*	**2014**	2013	2012
First quarter	**0.3825**	0.3600	0.3450
Second quarter	**0.4225**	0.3700	0.3450
Third quarter	**0.4425**	0.3800	0.3500
Fourth quarter	**0.4425**	0.3825	0.3600
Total	**1.6900**	1.4925	1.4000

Series A Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2014**	2013	2012
First quarter	**0.3125**	0.3125	0.3125
Second quarter	**0.3125**	0.3125	0.3125
Third quarter	**0.3125**	0.3125	0.3125
Fourth quarter	**0.3125**	0.3125	0.3125
Total	**1.2500**	1.2500	1.2500

Series C Preferred Share Dividends

Years ended December 31 *(US$ per preferred share)*	**2014**	2013	2012
First quarter	**0.2750**	0.2750	–
Second quarter	**0.2750**	0.2750	–
Third quarter	**0.2750**	0.2750	0.3473
Fourth quarter	**0.2750**	0.2750	0.2750
Total	**1.1000**	1.1000	0.6223

Series E Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2014**	2013	2012
First quarter	**0.3699**	–	–
Second quarter	**0.3125**	–	–
Third quarter	**0.3125**	–	–
Fourth quarter	**0.3125**	–	–
Total	**1.3074**	–	–

Series G Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2014**	2013	2012
First quarter	**–**	–	–
Second quarter	**–**	–	–
Third quarter	**0.2896**	–	–
Fourth quarter	**0.2969**	–	–
Total	**0.5865**	–	–

CRITICAL ACCOUNTING ESTIMATES

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

AltaGas' critical accounting estimates continue to be financial instruments: depreciation, depletion and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessment, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities.

Financial Instruments and Hedge Accounting

All financial instruments on the balance sheet are initially measured at fair value. The financial assets are classified as held-for-trading, held-to-maturity, loans and receivables, or available-for-sale. Financial liabilities are classified as held-for-trading or other financial liabilities. Subsequent measurement of a financial instrument depends on its classification. AltaGas does not have any held-to-maturity financial instruments.

Held-for-trading financial assets and liabilities consist of swaps, options, forwards and equity investments. These financial instruments are initially accounted for at their fair value, and changes to fair value are recorded in income. Loans and receivables are accounted for at their amortized cost using the effective interest method. The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially accounted for at their fair value, and changes to fair value are recorded through other comprehensive income. Declines in fair value below the amortized cost basis that are other-than-temporary are reclassified out of Other Comprehensive Income (OCI) to earnings for the period. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in other revenue. Other financial liabilities not classified as held-for-trading are accounted for at their amortized cost, using the effective interest method.

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

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.

AltaGas applies hedge accounting to its arrangements that qualify for hedge accounting treatment for cash flow hedges. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while any ineffective portion is recognized in income. Gains and losses on derivatives are reclassified to net income from accumulated other comprehensive income when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer expected to occur.

AltaGas designates certain derivatives as hedges at the inception of the hedging contract. The effectiveness of hedges is assessed on a regular basis and any changes in the fair value resulting from hedge ineffectiveness is immediately recognized as income.

Depreciation, Depletion and Amortization

AltaGas performs assessments of amortization of property, plant and equipment, and intangible 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. Amortization is a critical accounting estimate because:

- 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 and Other Environmental Costs

AltaGas records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs are critical accounting estimates because:

- The majority of the asset retirement costs will not be incurred for a number of years (estimated between 2016 and 2164), requiring AltaGas to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- 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. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing impairment may be material to AltaGas' 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 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 23 to the 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 US 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.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) No. 2014-09, "Revenue from Contracts with Customers". The core principle of the amendments in this Update 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. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. Early adoption is not permitted. AltaGas will adopt the new standard effective on January 1, 2017. In June 2014, AltaGas commenced a process for the adoption of the Update.

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 to provide adequate funds to pay for 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 $41 million.

In October 2014, AltaGas issued a US$92 million guarantee related to all payment obligations under a transportation agreement entered into by Heritage Gas Ltd., a wholly-owned subsidiary of AltaGas. The transportation agreement is contracted with a third party owner of the transportation facility.

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

AltaGas' management 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.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of AltaGas' employees:

- DCP to provide reasonable assurance that material information relating to AltaGas' business is made known to them particularly during the period in which AltaGas' annual filings are being prepared and information required to be disclosed by AltaGas in its annual filings, interim filings or other reports filed or submitted under securities legislation is processed, summarized and reported within the time periods specified in securities legislation; and
- ICFR to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US 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 (COSO) of the Treadway Commission.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR and concluded that AltaGas' DCP and ICFR were effective at December 31, 2014. All internal control systems, regardless of how well designed, have inherent limitations. As a result, even those systems determined to be effective can provide only reasonable assurance.

During 2014, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

FOURTH QUARTER HIGHLIGHTS

Normalized Operating Income [1]

Three months ended December 31 *($ millions)*	2014	2013
Gas	**41**	39
Power	**16**	30
Utilities	**57**	55
Sub-total: Operating Segments	**114**	124
Corporate	**(9)**	(12)
	105	112

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

Normalized net income was $48 million ($0.36 per share) for fourth quarter 2014, compared to $60 million ($0.49 per share) reported for same quarter 2013. Fourth quarter results reflect the challenging conditions faced in the Power segment as well as increased financing costs related to new assets in service and prefunding initiatives in the second half of the year.

The decrease in normalized net income was primarily a result of lower contribution from Alberta power assets, higher interest expense and preferred share dividends, and lower contribution from Blythe. Forrest Kerr entered service in August 2014 resulting in a negative impact to fourth quarter earnings as a result of full depreciation and interest costs recorded during the ramp up period. The decrease was partially offset by the contributions from the Gas, Utilities, and Corporate segments.

Net income applicable to common shares for fourth quarter 2014 was $10 million ($0.08 per share) compared to $53 million ($0.44 per share) for same quarter 2013. Net income applicable to common shares for fourth quarter 2014 was normalized for after-tax amounts related to provisions taken for certain assets, the impact from the sale of non-core assets, unrealized gain on mark-to-market adjustments, realized and unrealized losses on long-term investments, transaction costs related to acquisitions, costs associated with the early redemption of MTNs, and development costs incurred for the energy export projects. Results in fourth quarter 2013 were normalized for similar extraordinary items as in fourth quarter 2014, excluding the costs associated with the early redemption of MTNs.

Normalized funds from operations for fourth quarter 2014 increased 27 percent to $156 million ($1.17 per share), compared to $123 million ($1.01 per share) for same quarter 2013. Normalized EBITDA for fourth quarter 2014 was $155 million, compared to $153 million for same quarter 2013. Cash flow increased primarily as a result of the growth in the Gas and Utilities segments, distributions from Petrogas, as well as lower administrative expenses, which together were able to more than offset the lower contribution from the Alberta power assets and the higher interest expense.

Normalized operating income for fourth quarter 2014 was $105 million, compared to $112 million for same quarter 2013. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest expense, preferred share dividends and income taxes.

Operating and administrative expense for fourth quarter 2014 was $114 million, compared to $118 million for same quarter 2013. Amortization expense for fourth quarter 2014 increased to $47 million, compared to $40 million for same quarter 2013, mainly due to the asset growth of the Corporation. A $70 million provision was taken in fourth quarter 2014 for certain non-productive gas processing assets, compared to a provision of $3 million related to certain power assets under development that was recorded in same quarter 2013.

Interest expense for fourth quarter 2014 was $35 million, compared to $27 million for same quarter 2013. Interest expense in fourth quarter 2014 increased due to a higher average debt balance of $3,374 million (fourth quarter 2013 – $3,331 million) as a result of the Corporation's growth, lower capitalized interest of $3 million (fourth quarter 2013 – $9 million) due to Forrest Kerr and Volcano coming into service, and an increase in the average borrowing rate to 4.4 percent, compared to 4.3 percent in same quarter 2013.

AltaGas recorded an income tax recovery of $5 million for fourth quarter 2014, compared to income tax expense of $15 million for same quarter 2013. Income tax expense decreased primarily due to lower taxable earnings driven by the provisions recorded in 2014 for long-lived assets. The decrease in income tax expense was partially offset by the tax expense adjustment associated with the 2013 adjustments to deferred tax liabilities, effect of capital gains on asset dispositions, and the higher tax expense related to financial instruments.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2015 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per share
Alberta electricity prices [1]	$1/Mwh	$0.01
Natural gas liquids fractionation spread [2]	$1/Bbl	$0.01
Degree day variance from normal – Canadian utilities [3]	5 percent	$0.01
Degree day variance from normal – U.S. utilities [4]	5 percent	$0.02
Change in CAD per US$ exchange rate	$0.05	$0.03

1 *Based on approximately two-thirds of Sundance PPA volumes being hedged.*

2 *Based on approximately one-half of frac spread exposed NGL volumes being hedged.*

3 *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 BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.*

4 *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.*

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

($ millions)	Q4-14	Q3-14	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13	Q1-13
Total revenue	**667**	**444**	**471**	**824**	581	390	459	614
Net revenue [1]	**285**	**217**	**220**	**297**	265	247	212	237
Normalized operating income [1]	**105**	**59**	**65**	**137**	112	64	68	109
Net income before taxes	**17**	**30**	**44**	**66**	75	57	40	76
Net income applicable to common shares	**10**	**17**	**29**	**40**	53	43	36	49

($ per share)	Q4-14	Q3-14	Q2-14	Q1-14	Q4-13	Q3-13	Q2-13	Q1-13
Net income applicable to common shares								
Basic	**0.08**	**0.13**	**0.23**	**0.33**	0.44	0.36	0.31	0.46
Diluted	**0.08**	**0.13**	**0.23**	**0.32**	0.43	0.35	0.30	0.45
Dividends declared	**0.44**	**0.44**	**0.42**	**0.38**	0.38	0.38	0.37	0.36

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

Significant items that impacted individual quarterly earnings were as follows:

- In second quarter 2013, AltaGas completed the acquisition of Blythe for total consideration of US$515 million; AltaGas recorded $2 million in pre-tax transaction costs;
- In second quarter 2013, AltaGas recorded an adjustment of $2 million to its deferred tax liability and an income tax recovery resulting from the enactment of a Canadian tax amendment that increased the deduction arising from the tax on dividends paid on preferred shares;
- In third quarter 2013, AltaGas reported a $38 million pre-tax gain on the sale of PTP by PNG;
- In third quarter 2013, AltaGas recorded provisions of $19 million related to the planned sale of certain non-core gas and utility assets;
- In fourth quarter 2013, AltaGas sold ECNG. AltaGas recorded a pre-tax gain of $4 million and transaction costs of $1 million related to this transaction;
- In fourth quarter 2013, AltaGas acquired a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. AltaGas paid for the initial 25 percent interest with 3 million shares priced at $35.69 per share and $231 million of cash;
- In fourth quarter 2013, AltaGas reclassified an other-than-temporary pre-tax loss of $4 million on its investment in Alterra from OCI to income for the period;
- In fourth quarter 2013, AltaGas recorded pre-tax provisions of $3 million related to six wind projects under development;
- In first quarter 2014, AltaGas completed sale of Ante Creek, a gas processing facility located near Sturgeon Lake, northwestern Alberta. The transaction closed on February 12, 2014, with a realized pre-tax gain from the sale of the asset of $12 million;
- In first quarter 2014, AltaGas early redeemed $200 million of senior unsecured MTNs, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014. The early redemption resulted in total pre-tax cost of $2 million;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $38 million for EDS and JFP transmission pipeline assets that will be sold to NOVA Chemicals in March 2017;
- In first quarter 2014, AltaGas recorded a pre-tax provision of $11 million for certain hydro power development projects in British Columbia;
- In third quarter 2014, Forrest Kerr was brought into service but did not contribute significantly to quarterly results due to limited power generation during the initial ramp up period;
- In fourth quarter 2014, AltaGas early redeemed $300 million of senior unsecured MTNs resulting in total pre-tax cost of $15 million; and
- In fourth quarter 2014, AltaGas recorded a pre-tax provision of $70 million for certain non-productive gas processing assets.

Consolidated Financial Statements

MANAGEMENT'S RESPONSIBILITY FOR 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 (US GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Corporation's financial results. It compares the Corporation's financial and operating performance in 2014 to that in 2013. The MD&A should be read in conjunction with the Consolidated Financial Statements and accompanying notes.

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.

Under the supervision and with the participation of the Chairman and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of internal controls over financial reporting. Management concluded, based on its evaluation, that internal controls over financial reporting are effective as of December 31, 2014, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

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 directors who are not officers or employees.

The Audit Committee meets with management at least five times a year 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 US 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.

Deborah S. Stein
Senior Vice President Finance and Chief Financial Officer of
AltaGas Ltd.

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, 2014 and 2013, and the consolidated statements of income, comprehensive income and accumulated other comprehensive income (loss), 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 auditor considers 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, 2014 and 2013 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 25, 2015

Ernst & Young LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at *($ millions)*	December 31 2014	December 31 2013
ASSETS		
Current assets		
Cash and cash equivalents	**371.0**	44.8
Short-term investment	**50.0**	–
Accounts receivable *(note 18)*	**352.4**	371.2
Inventory *(note 6)*	**155.3**	123.4
Restricted cash holdings from customers	**4.2**	2.7
Regulatory assets *(note 17)*	**12.8**	6.0
Risk management assets *(note 18)*	**70.8**	35.0
Prepaid expenses and other current assets	**41.9**	33.2
Deferred income taxes *(note 16)*	**–**	5.0
	1,058.4	621.3
Property, plant and equipment *(note 7)*	**5,337.0**	4,952.5
Intangible assets *(note 9)*	**356.9**	195.3
Goodwill *(note 10)*	**785.1**	743.1
Regulatory assets *(note 17)*	**302.0**	241.2
Risk management assets *(note 18)*	**21.1**	12.3
Deferred income taxes *(note 16)*	**2.2**	0.8
Restricted cash holdings from customers	**12.2**	12.8
Long-term investments and other assets *(notes 11 and 18)*	**84.6**	25.9
Investments accounted for by equity method *(note 12)*	**453.9**	479.1
	8,413.4	7,284.3
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 18)*	**343.6**	321.8
Dividends payable	**19.8**	15.6
Short-term debt *(note 13)*	**72.4**	84.4
Current portion of long-term debt *(notes 14 and 18)*	**214.4**	209.1
Customer deposits	**34.9**	35.0
Regulatory liabilities *(note 17)*	**10.0**	1.8
Risk management liabilities *(note 18)*	**43.5**	44.7
Deferred income taxes *(note 16)*	**2.1**	0.5
Other current liabilities *(note 19)*	**24.4**	14.5
	765.1	727.4
Long-term debt *(notes 14 and 18)*	**3,049.6**	2,952.7
Asset retirement obligations *(note 15)*	**70.9**	76.1
Deferred income taxes *(note 16)*	**467.2**	442.8
Regulatory liabilities *(note 17)*	**136.0**	124.3
Risk management liabilities *(note 18)*	**14.7**	7.1
Other long-term liabilities *(notes 18 and 19)*	**204.5**	52.6
Future employee obligations *(note 23)*	**131.2**	71.8
	4,839.2	4,454.8

CONSOLIDATED BALANCE SHEETS (continued)

As at *($ millions)*	December 31 2014	December 31 2013
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 133.9 million issued and outstanding *(note 20)*	**2,759.9**	2,211.4
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**195.9**	194.1
Preferred shares Series C cumulative redeemable five-year; par value US$25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**200.6**	200.6
Preferred shares Series E cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**195.8**	194.9
Preferred shares Series G cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**196.1**	–
Contributed surplus	**14.9**	13.4
Accumulated deficit	**(185.2)**	(62.1)
Accumulated other comprehensive income	**163.1**	39.4
Total shareholders' equity	**3,541.1**	2,791.7
Non-controlling interests	**33.1**	37.8
Total equity	**3,574.2**	2,829.5
	8,413.4	7,284.3

Commitments and guarantees *(note 22)*

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd.

David W. Cornhill
Director

Robert B. Hodgins

Robert B. Hodgins
Director

CONSOLIDATED STATEMENTS OF INCOME

For the years ended December 31 *($ millions except per share amounts)*	2014	2013
REVENUE		
Sales	**845.3**	747.5
Services	**489.1**	416.9
Regulated operations	**1,069.1**	888.9
Other loss	**(2.3)**	(1.1)
Unrealized gain (loss) on risk management contracts *(note 18)*	**4.7**	(9.2)
	2,405.9	2,043.0
EXPENSES		
Cost of sales, exclusive of items shown separately	**1,450.9**	1,236.2
Operating and administrative	**450.6**	430.5
Accretion of obligations *(notes 15 and 19)*	**6.9**	3.7
Depreciation, depletion and amortization *(notes 7 and 9)*	**173.4**	152.5
Provision on long-lived assets *(note 4)*	**119.1**	22.6
	2,200.9	1,845.5
Income from equity investments *(note 12)*	**38.6**	112.2
Other income (expenses) *(notes 5 and 11)*	**25.4**	41.2
Foreign exchange loss	**(0.4)**	(0.3)
Interest expense		
Short-term debt	**1.4**	2.3
Long-term debt	**110.0**	99.8
Income before income taxes	**157.2**	248.5
Income tax expense *(note 16)*		
Current	**14.0**	19.8
Deferred	**5.0**	20.3
Net income after taxes	**138.2**	208.4
Net income applicable to non-controlling interests	**8.1**	7.3
Net income applicable to controlling interests	**130.1**	201.1
Preferred share dividends	**34.5**	19.6
Net income applicable to common shares	**95.6**	181.5
Net income per common share *(note 21)*		
Basic	**0.75**	1.56
Diluted	**0.74**	1.52
Weighted average number of common shares outstanding *(notes 22 and 23)*		
Basic	**126.7**	116.1
Diluted	**128.6**	119.5

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 *($ millions)*	2014	2013
Net income after taxes	**138.2**	208.4
Total other comprehensive income (net of taxes)	**123.7**	54.8
Comprehensive income attributable to common shareholders and non-controlling interests (net of tax)	**261.9**	263.2
Comprehensive income attributable to:		
Non-controlling interests	**$8.1**	$7.3
Controlling interests	**253.8**	255.9
	261.9	263.2

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)[1]

($ millions)	Available-for-sale	Cash flow hedges	Defined benefit pension plans	Hedge net investments	Translation foreign operations	Total
Opening balance, January 1, 2014	(3.0)	(10.4)	(5.7)	(35.9)	94.4	39.4
Other comprehensive income (loss) before reclassification	(10.5)	23.7	(4.2)	(35.0)	147.9	121.9
Amounts reclassified from other comprehensive income *(note 3)*	1.5	–	0.3	–	–	1.8
Net current period other comprehensive income (loss)	(9.0)	23.7	(3.9)	(35.0)	147.9	123.7
Ending balance, December 31, 2014 [2,3,4,5]	**(12.0)**	**13.3**	**(9.6)**	**(70.9)**	**242.3**	**163.1**
Opening balance, January 1, 2013	(5.8)	(1.0)	(10.2)	(2.2)	3.8	(15.4)
Other comprehensive income (loss) before reclassification	(0.9)	(10.1)	3.9	(33.7)	90.6	49.8
Amounts reclassified from other comprehensive income *(note 3)*	3.7	0.7	0.6	–	–	5.0
Net current period other comprehensive income (loss)	2.8	(9.4)	4.5	(33.7)	90.6	54.8
Ending balance, December 31, 2013 [2,3,4,5]	(3.0)	(10.4)	(5.7)	(35.9)	94.4	39.4

1 All amounts are net of tax where applicable. Amounts in parenthesis indicate debits.

2 Available-for-sale – net of tax recovery $1.7 million (December 31, 2013 – tax recovery $0.4 million).

3 Cash flow hedges – net of tax expense $4.6 million (December 31, 2013 – $3.4 million).

4 Defined benefit pension plans – net of tax recovery $3.3 million (December 31, 2013 – tax recovery $1.0 million).

5 Hedge net investment – net of tax recovery $10.2 million (December 31, 2013 – tax recovery $5.2 million).

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

For the years ended December 31 *($ millions)*	2014	2013
Common shares *(note 20)*		
Balance, beginning of year	**2,211.4**	1,639.9
Shares issued for cash on exercise of options	**24.9**	18.9
Shares issued under DRIP [1]	**70.2**	60.3
Shares issued on private issuance	**–**	100.0
Deferred taxes on share issuance costs	**4.2**	–
Shares issued on public offering	**449.2**	392.3
Balance, end of year	**2,759.9**	2,211.4
Preferred shares *(note 20)*		
Balance, beginning of year	**589.6**	394.7
Series A deferred taxes on share issuance costs	**1.8**	–
Series E issued and share issuance costs, net of taxes	**0.9**	194.9
Series G issued and share issuance costs, net of taxes	**196.1**	–
Balance, end of year	**788.4**	589.6
Contributed surplus		
Balance, beginning of year	**13.4**	10.6
Share options expense	**3.7**	4.6
Exercise of share options	**(2.1)**	(1.4)
Forfeiture of share options	**(0.1)**	(0.4)
Balance, end of year	**14.9**	13.4
Accumulated deficit		
Balance, beginning of year	**(62.1)**	(70.0)
Net income applicable to controlling interests	**130.1**	201.1
Reclassification of taxes on share issuance costs	**(4.2)**	–
Common share dividends	**(214.5)**	(173.6)
Preferred share dividends	**(34.5)**	(19.6)
Balance, end of year	**(185.2)**	(62.1)
Accumulated other comprehensive income (loss)		
Balance, beginning of year	**39.4**	(15.4)
Other comprehensive income	**123.7**	54.8
Balance, end of year	**163.1**	39.4
Total shareholders' equity	**3,541.1**	2,791.7
Non-controlling interests		
Balance, beginning of year	**37.8**	40.0
Net income applicable to non-controlling interests	**8.1**	7.3
Distribution by subsidiaries to non-controlling interests	**(12.8)**	(9.5)
Balance, end of year	**33.1**	37.8
Total equity	**3,574.2**	2,829.5

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)*	2014	2013
Cash from operations		
Net income after taxes	**138.2**	208.4
Items not involving cash:		
Depreciation, depletion and amortization	**173.4**	152.5
Provision on long-lived assets	**119.1**	22.6
Accretion of obligations	**6.9**	3.7
Share-based compensation	**3.7**	4.2
Deferred income tax expense	**5.0**	20.3
Gain on sale of assets	**(38.1)**	(41.5)
Income from equity investments	**(38.6)**	(112.2)
Unrealized (gain)/loss on risk management contracts	**(4.7)**	9.2
Realized/unrealized losses on long-term investments	**1.6**	5.4
Losses from extinguishment of debts	**16.6**	–
Other	**1.9**	5.3
Asset retirement obligations settled	**(2.4)**	(1.9)
Distributions from equity investments	**86.0**	122.4
Changes in operating assets and liabilities:		
Accounts receivable	**29.0**	28.0
Inventory	**(21.0)**	(18.8)
Prepaid expenses and other current assets	**(9.3)**	(9.0)
Regulatory assets (current)	**(5.9)**	(1.5)
Accounts payable and accrued liabilities	**(11.5)**	(48.6)
Customer deposits	**(2.3)**	(8.3)
Regulatory liabilities (current)	**7.7**	(0.4)
Other current liabilities	**(1.1)**	2.7
Other operating assets and liabilities	**3.5**	23.7
	457.7	366.2
Investing activities		
Change in restricted cash holdings from customers	**(1.3)**	6.1
Acquisition of property, plant and equipment	**(519.9)**	(501.1)
Acquisition of intangible assets	**(28.7)**	(46.5)
Proceeds from dispositions of assets	**64.5**	51.0
Contributions to equity investments	**(7.7)**	(6.8)
Business acquisitions, net of cash acquired	**–**	(536.8)
Acquisition of short-term investments	**(50.0)**	–
Acquisition of equity investment	**5.0**	(230.5)
Acquisition of long-term investments	**(53.0)**	–
	(591.1)	(1,264.6)

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

For the years ended December 31 *($ millions)*	2014	2013
Financing activities		
Net issuance of short-term debt	**(17.6)**	14.6
Issuance of long-term debt, net of debt issuance costs	**1,348.1**	2,091.7
Repayment of long-term debt	**(1,345.7)**	(1,637.5)
Dividends – common shares	**(210.3)**	(170.7)
Dividends – preferred shares	**(35.0)**	(19.2)
Distributions to non-controlling interest	**(12.8)**	(9.5)
Net proceeds from shares issued on exercise of options	**22.8**	18.9
Net proceeds from issuance of common shares	**511.8**	447.6
Net proceeds from issuance of preferred shares	**194.4**	194.9
	455.7	930.8
Effect of exchange rate changes on cash and cash equivalents	**3.9**	0.6
Change in cash and cash equivalents	**322.3**	32.4
Cash and cash equivalents, beginning of year	**44.8**	11.8
Cash and cash equivalents, end of year	**371.0**	44.8

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

For the years ended December 31 *($ millions)*	2014	2013
Interest paid (net of capitalized interest)	**97.0**	98.9
Income taxes paid	**17.4**	5.2

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 the Corporation, AltaGas Holding Partnership, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), AltaGas Utility Holdings (Pacific) Inc., and AltaGas Services (U.S.) Inc.

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities. 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 fractionation, transmission, storage and natural gas marketing, and the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas). AIJVLP also manages the liquefied natural gas (LNG) and the liquefied petroleum gas (LPG) export development projects.

The Power segment includes 1,285 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets in Canada and the United States, along with an additional 81 MW of assets under construction and 2,360 MW of power generation in various stages of 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 (US GAAP).

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), US GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with US GAAP.

The exemption will terminate on or after the earlier of January 1, 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.

These Consolidated Financial Statements 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.

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 US 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".

SIGNIFICANT ACCOUNTING POLICIES

Business Acquisitions

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

Rate-Regulated Operations

SEMCO Energy Inc. (SEMCO), AltaGas Utilities Inc. (AUI), Pacific Northern Gas Ltd. (PNG) and Heritage Gas Limited (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 US 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.

Short-term Investments

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

Inventory

Inventory consists of materials, supplies and 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.

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 Sheet.

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	1-45 years
Power generation assets	5-120 years
Utilities assets	3-80 years
Corporate assets	1-5 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 agreement	60 years
Software	2-5 years
Land rights	25-60 years
Franchises and consents	9-25 years

Goodwill

Goodwill represents that portion of the consideration on acquisitions which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but assessed at least annually for impairment, or more often when impairment indicators exist. If an impairment test of goodwill shows that the carrying amount of the goodwill is in excess of the fair value, a corresponding impairment loss would be recorded in the Consolidated Statement of Income.

Impairment of Long-Lived Assets

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

Financial Instruments

Financial instruments are recorded using the mark-to-market method of accounting for transactions under derivative contracts for which AltaGas is not permitted, or does not elect, to apply the normal purchase/normal sale exemption, rate regulated accounting for financial instruments, or hedge accounting in order to match the earnings impact of those activities to the greatest extent permissible. Under the mark-to-market method of accounting, the fair value of these contracts is recorded as derivative assets and liabilities at the time of contract execution.

The financial assets are classified as "held-for-trading", "held-to-maturity", "loans and receivables", or "available-for-sale". Financial liabilities are classified as "held-for-trading" or other financial liabilities. Subsequent measurement is determined by classification.

Held-for-trading financial assets and liabilities consist of swaps, options, forwards and equity securities. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value recorded in net income.

AltaGas does not have any held-to-maturity financial assets.

Loans and receivables are recognized at amortized cost using the effective interest method.

The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially recorded at fair value and changes to fair value are recorded through "Other comprehensive income" (OCI). 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 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 (expenses)".

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

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a 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.

All derivatives, other than those that meet the normal purchase and normal sale (NPNS) exemption, are carried on the Consolidated Balance Sheet at fair value. 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 credit worthy. 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.

Offsetting of Derivative Assets and Derivative Liabilities

Offsetting of fair value amounts is generally not applied except where a right of set off exists. A right of set off exists only if and when AltaGas and its counterparty in the financial instrument owe a determinable amount, the two parties agreed to set off the amounts due, AltaGas intends to set off, and the right of set off is enforceable by law.

Hedges

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

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

AltaGas designated some of its US dollar denominated long-term debt as a foreign currency hedge of 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.

Long-Term Investments and Other Assets

Long-term investments are recorded at cost or designated as available-for-sale or held-for-trading. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost.

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in joint ventures and affiliates in which AltaGas has the ability to exercise significant influence, but not control.

Under this method, the assets and liabilities of the joint ventures and affiliates are not consolidated. The investments in net assets of the equity investments are recorded in the Consolidated Balance Sheet in "Investments accounted for by equity method". The gain or loss from operations of the joint ventures and affiliates is reported on a net basis in the income statement under the caption "Income from equity method investments".

Development Costs

AltaGas expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria 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.

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 utilities in Canada 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 delivered.

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.

Realized gains and losses from risk management activities related to commodity prices are recognized when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheet items “Risk management assets” or “Risk management liabilities”.

Unrealized gains and losses in respect of fair value changes to AltaGas’ risk management activities, which do not meet the criteria as effective hedges, are recorded as revenue based on the related mark-to-market calculation at the end of the reporting period in the Corporate reporting segment.

Transaction Costs Related to Financial Instruments

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

Transaction costs for obtaining debt financing are capitalized and included under “Long-term investments and other assets” on the Consolidated Balance Sheet. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheet. 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 Statement of Income.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency for domestic entities are converted at 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 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. The exchange rate used to convert a US dollar to a Canadian dollar as at December 31, 2014 was 1.1601 (December 31, 2013 – 1.0636).

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. The average exchange rate used to convert a US dollar to a Canadian dollar for the year ended December 31, 2014 was 1.1048 (December 31, 2013 – 1.0301).

Share-Based Compensation Plans

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

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

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

Pension Plans and Post-Retirement Benefits

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

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service 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. The current service cost is the sum of the individual current service costs, and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 12.5 years and 11.7 years, respectively.

Unamortized actuarial gains (losses) and transitional obligations for non-utility plans are initially recognized in the other comprehensive income (losses) and amortized on a straight-line basis over the average remaining service life of active employees for the respective plan through the income statement. Utilities recognize unamortized actuarial gains (losses) and transitional obligations for pension plans and post-retirement benefits under regulatory and other liabilities.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of tax accounting. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax bases of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized.

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 and diluted net income applicable to common shares are computed using the weighted average number of common shares and the weighted average number of common shares that could potentially dilute earnings during a reporting period (share-based compensation awards). Net income applicable to common shares is the difference between the net income applicable to controlling interests less preferred share dividends.

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

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

Emission Credits

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

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period.

Key areas where management has made complex or subjective judgments, when matters are inherently uncertain include, but are not limited to, depreciation, depletion and amortization expense, asset retirement obligations, long-lived and intangible assets impairment assessment, financial instruments, income taxes, employee future benefits, litigation, share-based compensation and regulatory assets and liabilities.

Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate, which often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

RECENTLY ADOPTED ACCOUNTING PRINCIPLES

In April 2014, FASB issued Accounting Standards Update (ASU) No. 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity". The amendments in this Update improve the definition of discontinued operations by limiting the discontinued operations to the disposals of components of an entity that represent a strategic shift that have (or will have) a major effect on an entity's operations and financial results. AltaGas adopted the Update effective July 7, 2014. The amendments of this Update are applied to the disposals (or classifications as held-for-sale) of components occurring after the adoption date.

In November 2014, FASB issued ASU No. 2014-17, "Business Combinations-Pushdown Accounting". The amendments in this Update provide an acquired entity with an option to apply pushdown accounting when an acquirer obtains control of the acquired entity. The amendments in this Update were effective on November 18, 2014.

FUTURE CHANGES IN ACCOUNTING POLICIES

In January 2014, FASB issued ASU No. 2014-05, "Service Concession Arrangements". The amendments in this Update provide guidance for accounting for service concession arrangements, previously not covered by US GAAP. A service concession arrangement is an arrangement between a public sector entity grantor and an operating entity under which the operating entity operates the grantor's infrastructure. The amendments in this Update should be applied on a modified retrospective basis to service concession arrangements that exist at the beginning of an entity's fiscal year of adoption with a cumulative effect recognized as an adjustment to the opening retained earnings balance for the annual period of adoption. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2014. AltaGas will adopt the Update for the financial periods beginning on January 1, 2015. The adoption of this Update does not have any impact on the preparation and presentation of AltaGas' Consolidated Financial Statements.

In May 2014, FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers". The core principle of the amendments in this Update 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. The amendments are effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. Early adoption is not permitted. AltaGas commenced a process for the adoption of the Update. The impacts in the recognition, measurement and presentation of revenue from contracts with customers in accordance with the Update are under assessment for AltaGas' Consolidated Financial Statements.

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 Update for the financial periods beginning on January 1, 2016. AltaGas does not expect any material impact in the preparation and presentation of its Consolidated Financial Statements.

3. RECLASSIFICATION FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (AOCI)

AOCI components reclassified	Income statement line item	Year ended December 31, 2014	Year ended December 31, 2013
Cash flow hedges			
Commodity contracts – NGL (ineffective hedge)	Unrealized gains on risk management contracts	(0.4)	–
Commodity contracts – Bond forward	Interest expense – Long-term debt	0.1	0.7
	Other income (expenses)	0.2	–
Available-for-sale	Other income (expenses)	1.8	4.2
Defined benefit pension plans	Operating and administrative expense	0.5	1.3
	Total before income taxes	2.2	6.2
Deferred income taxes	Income tax expenses – Deferred	(0.4)	(1.2)
		1.8	5.0

4. PROVISION ON LONG-LIVED ASSETS

	2014	2013
Gas [(a)]	108.2	15.9
Power	10.9	3.7
Utilities	–	3.0
	119.1	22.6

(a) Provision for 2014 includes $19.5 million for Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission pipeline assets and $18.7 million for related transmission contracts, all of which will be sold to NOVA Chemicals Corporation in March 2017, in accordance with contractual requirements. The provision also includes $56.0 million related to assets assessed as no longer in use and $14.0 million for gas processing assets reclassified as "held for sale".

5. OTHER INCOME (EXPENSES)

	Year ended December 31, 2014	Year ended December 31, 2013
Gain from sale of assets [(a)]	38.2	41.5
Interest income and other revenue	6.2	5.1
Losses from extinguishment of debts	(17.4)	–
Other than temporary impairment available for sale *(note 11)*	(1.8)	(4.3)
Unrealized gain (loss) from held-for-trading assets	0.2	(1.1)
	25.4	41.2

(a) On March 2, 2011, Pacific Northern Gas Ltd. (PNG) sold its 50 percent interest in Pacific Trail Pipelines Limited Partnership (PTP), subject to a contingent reversionary right at the end of 2013. The purchase price of $50 million was to be paid in two tranches. The first tranche of $30 million was paid to PNG on closing in March 2011 while the remaining $20 million was to be paid upon the buyers' advising PNG that they had issued a notice to proceed with respect to the construction of the Kitimat LNG project. On May 23, 2013 PNG and the buyers amended the acquisition agreement by increasing the second payment from $20 million to $38 million and removing the contingent reversionary right. During third quarter 2013, PNG received regulatory approval for the amendment, received payment of the consideration from the buyers and recognized a $37.5 million pre-tax gain on the transaction.

6. INVENTORY

As at December 31	2014	2013
Natural gas held in storage	**136.7**	106.7
Other inventory	**18.6**	16.7
	155.3	123.4

7. PROPERTY, PLANT AND EQUIPMENT

As at December 31	2014			2013		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas	**2,318.0**	**(681.9)**	**1,636.1**	2,269.8	(545.9)	1,723.9
Power	**2,050.1**	**(98.5)**	**1,951.6**	1,759.5	(50.9)	1,708.6
Utilities	**1,833.5**	**(108.4)**	**1,725.1**	1,569.0	(65.9)	1,503.1
Corporate	**49.6**	**(25.4)**	**24.2**	25.2	(8.3)	16.9
	6,251.2	**(914.2)**	**5,337.0**	5,623.5	(671.0)	4,952.5

Interest capitalized on long-term capital construction projects for the year ended December 31, 2014 was $29.9 million (2013 – $30.6 million).

As at December 31, 2014, the Corporation had spent approximately $440.4 million (2013 – $943.3 million) on 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, 2014 was $162.2 million (2013 – $142.3 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 $48.5 million as at December 31, 2014 (December 31, 2013 – $42.9 million).

8. OPERATING LEASES

AltaGas is the lessor in several operating lease arrangements. The carrying value of property, plant, and equipment associated with these leases was $2,159.4 million as at December 31, 2014 (2013 – $1,113.8 million). The total revenue earned from these operating leases was $124.0 million as at December 31, 2014 (2013 – $68.9 million).

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

2015	90.3
2016	92.1
2017	93.9
2018	95.7
2019	97.5

9. INTANGIBLE ASSETS

As at December 31	2014			2013		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
E&T contracts	**56.5**	**(38.5)**	**18.0**	57.3	(18.9)	38.4
Electricity service agreement	**260.4**	**(1.8)**	**258.6**	90.0	–	90.0
Energy services relationships	**10.2**	**(6.1)**	**4.1**	10.2	(5.3)	4.9
Software	**84.6**	**(25.6)**	**59.0**	73.5	(29.8)	43.7
Land rights	**16.6**	**(1.7)**	**14.9**	17.3	(1.6)	15.7
Franchises and consents	**3.6**	**(1.3)**	**2.3**	3.6	(1.0)	2.6
	431.9	**(75.0)**	**356.9**	251.9	(56.6)	195.3

Amortization expense related to intangible assets for the year ended December 31, 2014 was $11.2 million (2013 – $10.2 million).

As at December 31, 2014, the Corporation had capitalized approximately $36.5 million in software costs (2013 – $11.5 million) not yet 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:

2015	11.7
2016	13.1
2017	11.4
2018	11.1
2019	11.0
Thereafter	262.2

10. GOODWILL

As at December 31	2014	2013
Balance, beginning of year	**743.1**	714.9
Other changes	**–**	(1.7)
Foreign exchange translation	**42.0**	29.9
	785.1	743.1

11. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at December 31	2014	2013
Investments in publicly-traded entities (a)	**46.3**	5.0
Debt financing costs	**22.0**	17.0
Refundable deposits	**15.7**	–
Loan to employees	**–**	0.8
Other	**0.6**	3.1
	84.6	25.9

(a) *Investments in publicly traded entities include common shares issued by Canadian entities that are classified as available for sale for $43.5 million (December 31, 2013 – $2.4 million) and held for trading for $2.8 million (December 31, 2013 – $2.6 million). Pursuant to the terms of a private placement in 2014, $38.5 million of common shares classified as available-for-sale are subject to a one-year hold period restriction, expiring in August 2015.*

In 2014, an other-than-temporary pre-tax loss of $1.8 million was re-classified from OCI and recognized in the Consolidated Statement of Income under "Other income (expenses)" (2013 – $4.2 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.

Summary of After-tax Unrealized Gains (Losses) on Available-for-sale Recognized in AOCI

For the years ended December 31	2014	2013
Changes in fair value	(10.5)	(0.9)
Other-than-temporary loss	1.5	3.7
	(9.0)	2.8

12. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

As at December 31	2014	2013
Affiliates	2.6	338.8
Joint ventures	451.3	140.3
	453.9	479.1

PETROGAS

On October 1, 2013, AltaGas completed the acquisition of a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company. Petrogas is engaged in the marketing, storage, and distribution of natural gas liquids, drilling fluids, fracing fluids, crude oil and condensate diluents. Petrogas and its subsidiaries own underground storage facilities, own and lease surface storage, and own and operate processing plants, trucks and transportation equipment, loading and terminaling facilities and crude oil blending facilities. AltaGas paid for the acquisition with approximately 2.8 million common shares priced at $35.69 per share and $230.5 million of cash. The investment was accounted for using the equity method.

On October 24, 2013, AltaGas announced it planned to increase its effective ownership of Petrogas to 33 1/3 percent, exercising a call option included in the share purchase agreement with the vendor.

On March 1, 2014, AltaGas transferred its 25 percent ownership interest to AIJVLP. On March 1, 2014, AIJVLP acquired an additional 41 2/3 percent interest in Petrogas for $300.8 million cash consideration and a $250.0 million note payable to the vendor. As a result of the transaction, Petrogas is effectively owned one-third by each of AltaGas, Idemitsu Kosan Co.,Ltd. (Idemitsu), and its former majority shareholder.

The table below is a list of joint ventures and affiliates as at December 31, 2014.

Description	Location	Ownership Percentage	Accounting Method
AltaGas Idemitsu Joint Venture LP	Canada	50	Equity
AltaGas Idemitsu Management Inc.	Canada	50	Equity
ASTC Power Partnership	Canada	50	Equity
Boston Bar LP	Canada	25	Equity
Busch Ranch Wind Project	United States	50	Proportionate
Craven County Wood Energy GP	United States	50	Equity
Craven County Wood Energy LP	United States	50	Equity
Eaton Rapids Gas Storage System	United States	50	Equity
Edmonton Ethane Extraction Plant (EEEP)	Canada	48.667	Proportionate
Empress ATCO (EGLJV)	Canada	7.20	Proportionate
Empress Provident (PEEP)	Canada	11.25	Proportionate
Gilby Midstream	Canada	50	Proportionate
Grayling Generating Station GP	United States	50	Equity
Grayling Generating Station LP	United States	50	Equity
Ikhil Joint Venture	Canada	33.334	Proportionate
Inuvik Gas Ltd.	Canada	33.333	Equity
Sarnia Airport Storage Pool LP	Canada	50	Equity
Sarnia Airport Storage Pool Management Inc.	Canada	50	Equity
Younger	Canada	56.667	Proportionate

The tables below represent 100 percent of the most significant investees' financial information as at December 31, 2014 and 2013.

For the year ended December 31, 2014	Proportionate Consolidation Method	Equity Method	Total
Revenues	**279.4**	**288.0**	**567.4**
Expenses	**212.4**	**258.8**	**471.2**
	67.0	**29.2**	**96.2**
As at December 31, 2014			
Current assets	**51.0**	**39.0**	**90.0**
Property, plant and equipment	**279.3**	**79.4**	**358.7**
Intangible assets	**20.0**	**80.6**	**100.6**
Long-term investments and other assets	**3.1**	**875.2**	**878.3**
Current liabilities	**15.3**	**33.4**	**48.7**
Other long-term liabilities	**42.7**	**252.9**	**295.6**

For the year ended December 31, 2013	Proportionate Consolidation Method	Equity Method	Total
Revenues	194.9	716.4	911.3
Expenses	148.4	284.2	432.6
	46.5	432.2	478.7
As at December 31, 2013			
Current assets	57.6	677.4	735.0
Property, plant and equipment	313.2	363.3	676.5
Intangible assets	20.0	85.8	105.8
Long-term investments and other assets	1.2	12.5	13.7
Current liabilities	4.2	406.4	410.6
Other long-term liabilities	41.9	65.9	107.8

13. SHORT-TERM DEBT

As at December 31	2014	2013
Bank indebtedness	**26.6**	3.4
$50 million demand operating facility	**–**	7.2
US$150 million operating facility	**37.1**	62.8
$25 million operating facility	**8.7**	11.0
	72.4	84.4

Bank Indebtedness

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, 2014 was 3.0 percent (December 31, 2013 – 3.0 percent).

Revolving Operating Credit Facilities

As at December 31, 2014, the Corporation held a $50.0 million (December 31, 2013 – $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 at December 31, 2014 were nil (December 31, 2013 – $0.02 million).

As at December 31, 2014, SEMCO held a US$150.0 million (December 31, 2013 – US$150.0 million) unsecured revolving operating credit facility with a Canadian chartered bank with a maturity date of December 20, 2019. Draws on the facility can be by way of U.S. base-rate loans, letters of credit and LIBOR loans. Letters of credit outstanding at December 31, 2014 were $0.8 million (December 31, 2013 – $1.0 million).

As at December 31, 2014, AltaGas held a $25.0 million (December 31, 2013 – $25.0 million) bank operating facility which is available for working capital purposes, has a term of 18 months and expires on May 22, 2015. The operating facility was acquired through the acquisition of PNG. 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 at December 31, 2014 were $5.7 million (December 31, 2013 – $4.2 million).

Other Credit Facilities

As at December 31, 2014, the Utilities segment held a $20.0 million (December 31, 2013 – $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 at December 31, 2014 were $3.6 million (December 31, 2013 – $3.6 million).

As at December 31, 2014, AltaGas held a $150.0 million (December 31, 2013 – $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 at December 31, 2014 were $112.8 million (December 31, 2013 – $67.5 million).

As at December 31, 2014, AltaGas held a $125.0 million (December 31, 2013 – $125.0 million) unsecured bilateral letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding at December 31, 2014 were $12.7 million (December 31, 2013 – $67.6 million).

14. LONG-TERM DEBT

As at December 31	Maturity date	2014	2013
Credit facilities			
$1,400 million unsecured extendible revolving [a]	15-Dec-2018	–	578.6
Medium-term notes			
$200 million Senior unsecured – 7.42 percent [b]	29-Apr-2014	–	200.0
$200 million Senior unsecured – 4.10 percent [c]	24-Mar-2016	–	200.0
$100 million Senior unsecured – 6.94 percent [d]	29-Jun-2016	–	100.0
$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	01-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**	–
$300 million Senior unsecured – 3.84 percent	15-Jan-2025	**300.0**	–
$100 million Senior unsecured – 5.16 percent	13-Jan-2044	**100.0**	–
$300 million Senior unsecured – 4.50 percent	15-Aug-2044	**299.7**	–
US$175 million Senior unsecured – floating [e]	13-Apr-2015	**203.0**	186.1
US$200 million Senior unsecured – floating [f]	24-Mar-2016	**232.1**	–
SEMCO long-term debt			
US$90 million CINGSA secured construction and term loan [g]	14-Nov-2015	–	86.3
US$300 million SEMCO Senior secured – 5.15 percent [h]	21-Apr-2020	**348.0**	319.1
US$82 million SEMCO Senior secured – 4.48 percent	2-Mar-2032	**95.1**	–
Debenture notes			
PNG RoyNat Debenture – 3.79 percent [i]	15-Sep-2017	**9.8**	11.0
PNG 2018 Series Debenture – 8.75 percent [i]	15-Nov-2018	**10.0**	11.0
PNG 2024 CFI Debenture – 7.39 percent [j]	01-Nov-2024	**7.4**	7.9
PNG 2025 Series Debenture – 9.30 percent [i]	18-Jul-2025	**14.5**	15.0
PNG 2027 Series Debenture – 6.90 percent [i]	02-Dec-2027	**15.5**	16.0
Loan from Province of Nova Scotia [k]	31-Jul-2017	**2.1**	3.1
CINGSA capital lease – 3.50 percent	1-May-2040	**0.5**	0.5
CINGSA capital lease – 4.48 percent	4-Jun-2068	**0.2**	–
Promissory notes	25-Oct-2015	**1.0**	1.9
Other long-term debt		**0.1**	0.3
		3,264.0	3,161.8
Less current portion		**214.4**	209.1
		3,049.6	2,952.7

(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. Letters of credit outstanding as at December 31, 2014 were nil (December 31, 2013 – $19.0 million).

(b) The notes were early redeemed on February 14, 2014.

(c) The notes were early redeemed on December 8, 2014.

(d) The notes were early redeemed on December 4, 2014.

(e) The notes carry a floating rate coupon of three months LIBOR plus 0.79 percent.

(f) The notes carry a floating rate coupon of three months LIBOR plus 0.72 percent.

(g) Borrowings on the facility can be by way of LIBOR loans or alternative base rate loans. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. The facility is non-recourse to the Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) subsidiary.

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

(i) 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.

(j) Collateral for the Corpfinance International Ltd. (CFI) Debenture consists of first fixed specific and floating charges and a security interest over all the assets and undertakings of McNair Creek, a first security interest over all the interests of PNG in partnership interests and shares of McNair Creek.

(k) 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.

15. ASSET RETIREMENT OBLIGATIONS

	2014	2013
Balance, beginning of year	**76.1**	56.6
New obligations	**0.7**	0.3
Obligations settled	**(3.7)**	(1.8)
Revision in estimated cash flow	**(7.5)**	15.0
Accretion expense	**4.2**	3.7
Business acquisitions	**–**	2.2
Foreign exchange translation	**1.1**	0.1
Balance, end of year	**70.9**	76.1

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, 2014 was $235.4 million (December 31, 2013 – $244.7 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 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 that provides adequate funds to pay for 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 $40.8 million.

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	2014	2013
Income before income taxes – consolidated	**157.2**	248.5
Financial instruments – net	**(4.7)**	9.2
Income before financial instruments and income taxes	**152.5**	257.7
Income before income taxes – operating subsidiaries	**152.5**	257.7
Statutory income tax rate *(%)*	**25.18**	25.18
Expected taxes at statutory rates	**38.4**	64.9
Add (deduct) the tax effect of:		
Financial instruments	**1.2**	(2.3)
Rate adjustments to enacted Canadian rates	**(5.1)**	1.0
Permanent differences between accounting and tax basis of assets and liabilities	**1.1**	1.2
Non-taxable portion of capital (gains) losses on disposition of assets and investments	**(3.8)**	(9.4)
Non-taxable portion of recorded equity income	**(7.2)**	(1.4)
Tax benefit of state expense	**4.0**	3.5
Rate adjustment	**–**	0.6
Tax on preferred shares	**1.2**	1.0
Change in enacted rates on preferred shares	**–**	(3.1)
Other	**(1.0)**	(1.0)
Deferred income tax recovery on regulated assets	**(4.7)**	(4.4)
Prior year adjustment	**(5.1)**	(10.5)
	19.0	40.1
Income tax provision		
Current		
Canada	**8.2**	11.0
United States	**5.8**	8.8
	14.0	19.8
Deferred		
Canada	**(13.5)**	3.9
United States	**18.5**	16.4
	5.0	20.3
Effective income tax rate *(%)*	**12.09**	16.14

In 2013, $22.7 million of deferred income tax liabilities were assumed on the acquisition of Blythe. In 2014, there were no deferred income tax liabilities assumed on acquisitions.

Deferred income tax liabilities were composed of the following:

As at December 31	2014	2013
PPE and intangible assets	**487.4**	450.1
Regulatory assets	**143.9**	124.6
Deferred financing	**(16.6)**	(8.8)
Deferred compensation	**(17.0)**	(6.1)
Financial instruments	**(1.7)**	(1.2)
Non-capital losses	**(131.0)**	(122.7)
Other	**2.1**	1.6
	467.1	437.5

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, 2014 the Corporation had tax-affected non-capital losses of approximately $193.8 million for tax purposes, which will be available to offset future taxable income. If not used, these losses will expire between 2015 and 2034.

Uncertain Tax Positions

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

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 2007 to 2013 remain subject to examination by taxation authorities. In the United States both the federal and state tax returns filed for the years 2009 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	2014	2013
Balance, beginning of year	**3.3**	3.3
Increases as a result of positions taken during the year	**0.4**	–
Balance, end of year	**3.7**	3.3

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, 2014 and 2013, over which the Corporation expects to realize or settle the assets or liabilities:

	December 31, 2014	December 31, 2013	Recovery Period
Regulatory assets – current			
Deferred cost of gas	**12.5**	6.0	Less than one year
Deferred property taxes	**0.3**	–	Less than one year
	12.8	6.0	
Regulatory assets – non-current			
Deferred regulatory costs and rate stabilization adjustment mechanism	**10.4**	11.0	Various
Pipeline rehabilitation costs	**6.0**	6.6	1-5 years
Future recovery of pension and other retirement benefits [(a)]	**127.3**	70.4	Various
Deferred environmental costs	**21.6**	21.5	2-10 years
Deferred loss on reacquired debt	**2.9**	3.2	2-5 years
Deferred depreciation and amortization [(b)]	**20.3**	17.0	Various
Deferred future income taxes [(c)]	**79.1**	71.2	Various
Revenue deficiency account [(d)]	**33.4**	40.0	Various
Other	**1.0**	0.3	2-3 years
	302.0	241.2	
Regulatory liabilities – current			
Deferred cost of gas	**3.9**	1.4	Less than one year
Deferred property taxes	**–**	0.3	Less than one year
Deferred regulatory costs	**–**	0.1	Less than one year
Energy optimization costs	**3.4**	–	Less than one year
Interruptible storage service revenue	**0.9**	–	Less than one year
Refundable tax credit	**1.8**	–	Less than one year
	10.0	1.8	
Regulatory liabilities – non-current			
Option fees deferral	**0.7**	1.6	Various
Refundable tax credit [(e)]	**12.2**	12.8	Various
Future removal and site restoration costs [(f)]	**120.7**	107.5	Various
Load balancing	**–**	1.3	Various
Insurance recovery of environmental costs	**1.0**	1.1	4 years
Interruptible storage service revenue	**1.1**	–	2 years
Other	**0.3**	–	Various
	136.0	124.3	

(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; amortization resumed for regulatory purposes in 2014 at 25 percent of authorized rates. Amortization will be phased in over the next three years at the following 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 expected to be recovered over the remaining useful life of related assets, which commenced in 2014.

(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) 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.

(f) 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. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation purchases and sells natural gas, NGL, and power and issues short-and long-term debt. The Corporation uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Corporation does not make use of derivative instruments for speculative purposes.

Fair Values of Financial Instruments

The fair value of power, natural gas and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. The fair value of interest rate and foreign exchange derivatives was calculated using quoted market rates.

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

Short-term investments, accounts receivable, accounts payable, short-term debt and dividends payable – the carrying amount approximates fair value because of the short maturity of these instruments.

Current portion of long-term debt, long-term debt, and other long-term liabilities – the fair value of current portion of long-term debt, long-term debt, and other long-term liabilities have been estimated based on discounted future interest and principal payments using estimated interest rates.

Summary of Fair Values	December 31 2014	December 31 2013
Current portion of long-term debt		
Carrying amount	**214.4**	209.1
Fair value	**214.4**	212.4

Summary of Fair Values	December 31 2014	December 31 2013
Long-term debt		
Carrying amount	**3,049.6**	2,952.7
Fair value	**3,170.3**	3,062.6

Summary of Fair Values	December 31 2014	December 31 2013
Long-term liabilities [(a)]		
Carrying amount	**155.6**	–
Fair value	**149.1**	–

(a) Excludes non-financial 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 inputs other than quoted prices that are observable for the asset or liability. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity 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.

December 31, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Financial assets				
Cash and cash equivalents	**371.0**	**–**	**–**	**371.0**
Short-term investment	**50.0**	**–**	**–**	**50.0**
Risk management assets – current	**–**	**70.8**	**–**	**70.8**
Risk management assets – non-current	**–**	**21.1**	**–**	**21.1**
Long-term investments and other assets [(a)]	**46.3**	**–**	**–**	**46.3**
Financial liabilities				
Risk management liabilities – current	**–**	**43.5**	**–**	**43.5**
Risk management liabilities – non-current	**–**	**14.7**	**–**	**14.7**
Current portion of long-term debt	**–**	**214.4**	**–**	**214.4**
Long-term debt	**–**	**3,170.3**	**–**	**3,170.3**
Other long-term liabilities [(b)]	**–**	**149.1**	**–**	**149.1**

December 31, 2013	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	44.8	–	–	44.8
Risk management assets – current	–	35.0	–	35.0
Risk management assets – non-current	–	12.3	–	12.3
Long-term investments and other assets [(a)]	5.4	–	–	5.4
Financial liabilities				
Risk management liabilities – current	–	44.7	–	44.7
Risk management liabilities – non-current	–	7.1	–	7.1
Current portion of long-term debt	–	212.4	–	212.4
Long-term debt	–	3,062.6	–	3,062.6
Other long-term liabilities [(b)]	–	–	–	–

(a) Excludes non-financial assets and financial assets carried at cost.
(b) Excludes non-financial liabilities.

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

For the years ended December 31	2014	2013
Natural gas	(7.9)	(0.8)
Storage optimization	2.1	(1.4)
NGL Frac Spread	3.2	(3.9)
Power	7.5	(2.3)
Heat rate	0.1	0.2
Foreign exchange	(0.3)	(0.5)
Embedded derivative	–	(0.5)
	4.7	(9.2)

Summary of Unrealized Gains (Losses) and Tax Recovery (Expense) on Cash Flow Hedges Recognized in AOCI

	Unrealized gains	Tax expense	Year ended December 31 2014	Unrealized Losses	Tax Recovery	Year Ended December 31 2013
Bond forward	–	–	–	(0.3)	–	(0.3)
NGL Frac Spread	17.8	(4.5)	13.3	(13.5)	3.4	(10.1)
AOCI	17.8	(4.5)	13.3	(13.8)	$3.4	(10.4)

Offsetting of Derivative Assets and Derivative Liabilities

As at 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
	62.0	25.2	36.8
Risk management liabilities [b]			
Natural gas	64.9	25.2	39.7
Storage optimization	0.1	–	0.1
Total	65.0	25.2	39.8

(a) Net amount of risk management assets on the Consolidated Balance Sheets is composed of risk management assets (current) balance of $25.2 million and risk management assets (non-current) balance of $11.6 million.

(b) Net amount of risk management liabilities on the Consolidated Balance Sheets is composed of risk management liabilities (current) balance of $30.1 million and risk management liabilities (non-current) balance of $9.7 million.

As at December 31, 2013

Risk management assets [a]	Gross amounts of recognized assets/liabilities	Gross amounts offset in Balance Sheet	Net amounts presented in Balance Sheet
Natural gas	88.2	57.5	30.7
Storage optimization	1.9	1.2	0.7
	90.1	58.7	31.4
Risk management liabilities [b]			
Natural gas	84.1	57.5	26.6
Storage optimization	3.1	1.2	1.9
	87.2	58.7	28.5

(a) Net amount of risk management assets on the Consolidated Balance Sheets is composed of risk management assets (current) balance of $27.2 million and risk management assets (non-current) balance of $4.3 million.

(b) Net amount of risk management liabilities on the Consolidated Balance Sheets is composed of risk management liabilities (current) balance of $25.4 million and risk management liabilities (non-current) balance of $3.2 million.

Market Risk on Financial Instruments

AltaGas is exposed to market risk and potential loss from changes in the values of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates.

Commodity Price Risk Management

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, 2014	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**	**Fair value**
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)**

December 31, 2013	Fixed price (per GJ)	Period (months)	Notional volume (GJ)	Fair value
Sales	3.05 to 11.20	1-58	72,722,907	3.3
Purchases	3.06 to 11.80	1-58	69,128,935	0.7
Swaps	4.19 to 4.41	1-3	1,314,593	–

NGL Frac Spread

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread and propane sales. AltaGas had the following contracts outstanding:

December 31, 2014	**Fixed price**	**Period (months)**	**Notional volume**	**Fair value**
Propane swaps	**1.0900 to 1.1560 CAD/gal**	**1-12**	**810,316 gallons**	**19.3**
Butane swaps	**1.2450 to 1.4000 CAD/gal**	**1-12**	**197,104 gallons**	**4.1**
WTI swaps	**101.2 to 104.4 CAD/bbl**	**1-12**	**87,600 Bbl**	**3.2**
Natural gas swaps	**3.5975 to 4.045/GJ**	**1-12**	**4,566,150 GJ**	**(5.7)**

December 31, 2013	Fixed price	Period (months)	Notional volume	Fair value
Propane swaps	0.7895 to 1.0464 US/gallon	1-12	56,107,800 gallons	(14.0)
Butane swaps	1.15 to 1.3017 US/gallon	1-12	14,103,600 gallons	(1.4)
WTI swaps	91.68 to 96.80 US/Bbl	1-12	153,300 Bbl	(0.4)
US$ swaps	1.03	1-12	34.7	(0.6)
Natural gas swaps	3.145 to 3.49/GJ	1-12	7,040,580 GJ	2.9

Power

Under the Sundance B 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. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2014, 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, 2014	**Fixed price (per GJ or MWh)**	**Period (months)**	**Notional volume (GJ or MWh)**	**Fair value**
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)**

December 31, 2013	Fixed price (per GJ or MWh)	Period (months)	Notional volume (GJ or MWh)	Fair value
Power sales	43.94 to 94.10	1-48	1,631,338	7.9
Power purchases	48.50 to 105.50	1-60	1,825,960	(1.3)
Swap sales	58.75 to 66.00	1-12	111,360	0.2
Swap purchases	56.50	1-48	105,192	(0.5)
Heat rate electricity sales	66.00 to 86.63	2	28,800	0.2
Heat rate gas purchases	3.085 to 3.7875	2	122,400	0.1

Interest Rate Risk Management

To hedge against the effects of future interest rate movements, AltaGas, from time to time, enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities.

AltaGas had no interest rate swaps outstanding as at December 31, 2014 and 2013.

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, AltaGas enters into foreign exchange forwards, swaps and options for US dollars.

AltaGas had no contracts outstanding as at December 31, 2014 and 2013.

Hedge Net Investments

Foreign exchange gains and losses on long-term debt denominated in US dollars are unrealized and can only be realized when a long-term debt matures or is settled. As at December 31, 2014, management designated US$375 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2013 – US$570 million). US dollar denominated long-term debt has 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.

Sensitivity Analysis

The sensitivity analysis is estimated based on the notional volumes of each commodity contract and equity security outstanding, taking into consideration the future income tax impact.

The following table illustrates potential effects of changes in relevant risk variables on AltaGas' net income and OCI for contracts in place at December 31, 2014:

Factor Share	Increase or decrease [1]	Increase or decrease in net income	Increase or decrease in OCI
Alberta electricity average pool prices	1/MWh	1.8	–
Natural gas spot price (AECO)	0.50/GJ	0.3	–
NGL frac spread:			
Propane	1/Bbl	–	0.6
Butane	1/Bbl	–	0.1
WTI	1/Bbl	0.1	–
Natural gas to replace heat value of NGL	0.50/GJ	–	1.7
Change in CAD per US$ exchange rate	1 percent	0.2	–
Equity risk	1 percent	–	0.4

1 *Estimated increase or decrease to forward prices or curves*

Credit Risk on Financial Instruments

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, 2014, 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, 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	As at December 31, 2014
Allowance for credit losses, beginning of year	3.8
Foreign exchange translation	0.1
New allowance	0.7
Recovery of allowance	(1.3)
Allowance applied to uncollectible customer accounts	(0.8)
Allowance for credit losses, end of year	2.5

	As at December 31, 2013	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	373.4	171.9	3.8	174.7	14.1	4.7	4.2
Other receivable	1.6	–	–	–	–	–	1.6
Allowance for credit losses	(3.8)	–	(3.8)	–	–	–	–
	371.2	171.9	–	174.7	14.1	4.7	5.8

Allowance for credit losses	As at December 31, 2013
Allowance for credit losses, beginning of year	3.6
Foreign exchange translation	0.1
New allowance	1.5
Allowance applied to uncollectible customer accounts	(1.4)
Allowance for credit losses, end of year	3.8

Liquidity Risk on Financial Instruments

Liquidity risk is the risk that AltaGas will not be able to meet its financial obligations as they fall 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 non-derivative financial liabilities:

				Payments due by period			
As at December 31, 2014	**Total**	**Payable accruals**	**Sub total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**343.6**	**142.2**	**201.4**	**201.4**	**–**	**–**	**–**
Dividends payable	**19.8**	**–**	**19.8**	**19.8**	**–**	**–**	**–**
Short-term debt	**72.4**	**–**	**72.4**	**72.4**	**–**	**–**	**–**
Other current liabilities	**24.4**	**8.3**	**16.1**	**16.1**	**–**	**–**	**–**
Long-term liabilities	**204.5**	**–**	**204.5**	**–**	**79.3**	**19.2**	**106.0**
Current portion of long-term debt	**214.4**	**–**	**214.4**	**214.4**	**–**	**–**	**–**
Long-term debt	**3,049.6**	**–**	**3,049.6**	**–**	**457.4**	**388.1**	**2,204.1**
	3,928.7	**150.5**	**3,778.2**	**524.1**	**536.7**	**407.3**	**2,310.1**

				Payments due by period			
As at December 31, 2013	Total	Payable accruals	Sub total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	321.8	146.3	175.5	175.5	–	–	–
Dividends payable	15.6	–	15.6	15.6	–	–	–
Short-term debt	84.4	–	84.4	84.4	–	–	–
Other current liabilities	14.5	10.1	4.4	4.4	–	–	–
Long-term liabilities	52.6	–	52.6	–	52.6	–	–
Current portion of long-term debt	209.1	–	209.1	209.1	–	–	–
Long-term debt	2,952.7	–	2,952.7	–	579.9	972.2	1,400.6
	3,650.7	156.4	3,494.3	489.0	632.5	972.2	1,400.6

19. LONG-TERM LIABILITIES

In 2010, AltaGas entered into a 60-year CPI indexed EPA and other related agreements with BC Hydro for its 195 MW Forrest Kerr run-of-river project. As at December 31, 2013, AltaGas paid an initial consideration of $90.0 million in support of the construction and operation of the Northwest Transmission Line (NTL). On July 29, 2014, AltaGas paid $5.3 million to BC Hydro, and thereafter future consideration is expected to be approximately $9.8 million per year, adjusted for inflation.

The NTL came into service on July 12, 2014, an event that triggered AltaGas' firm commitment with BC Hydro.

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.

This fair value of the NTL liability has been recorded within other current liabilities for $10.6 million and other long-term liabilities for $155.6 million. Accretion expenses for the year ended December 31, 2014 were $2.7 million (December 31, 2013 – nil).

The initial consideration and the fair value of the future considerations, for a total amount of $258.5 million, has been recognized within the intangible assets and shall be depreciated over 60 years, the term of the EPA with BC Hydro.

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 April 4, 2013, AltaGas issued 11,615,000 common shares at a price of $34.90 per common share for aggregate gross proceeds of approximately $405 million, including 1,515,000 common shares pursuant to the exercise in full of an underwriters' option.

On October 1, 2013, AltaGas issued 2,801,905 common shares priced at $35.69 per common share as part of the acquisition of a 25 percent interest in Petrogas.

On August 28, 2014, AltaGas issued 9,027,500 common shares at a price of $51.00 per common share for aggregate gross proceeds of approximately $460 million, including 1,177,500 common shares pursuant to the exercise in full of an underwriters' option.

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.

Preferred Shares

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

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

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

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

Holders of the Series E Preferred Shares are entitled to receive a cumulative quarterly fixed dividend for the initial period ending on, but excluding, December 31, 2018 at an annual rate of 5.0 percent, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first dividend payment of $0.3699 per Series E Preferred Share was paid on March 31, 2014. The dividend rate will reset on December 31, 2018 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada Bond Yield plus 3.17 percent. The Series E Preferred Shares are redeemable by AltaGas, at its option, on December 31, 2018 and on December 31 of every fifth year thereafter.

Holders of the Series E Preferred Shares have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, the Series F Preferred Shares, subject to certain conditions, on December 31, 2018, and on December 31 of every fifth year thereafter. Holders of Series F Preferred Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 3.17 percent, as and when declared by the Board of Directors of AltaGas.

Holders of the Series G Preferred Shares are entitled to receive a cumulative quarterly fixed dividend for the initial period ending on, but excluding, September 30, 2019 at an annual rate of 4.75 percent, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first dividend payment of $0.2896 per Series G Preferred Share was paid on September 30, 2014. The dividend rate will reset on September 30 2019 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada Bond Yield plus 3.06 percent. The Series G Preferred Shares are redeemable by AltaGas, at its option, on September 30, 2019 and on September 30 of every fifth year thereafter.

Holders of the Series G Preferred Shares have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, the Series H Preferred Shares, subject to certain conditions, on September 30, 2019 and on September 30 of every fifth year thereafter. Holders of Series H Preferred Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 3.06 percent, as and when declared by the Board of Directors of AltaGas.

Common Shares Issued and Outstanding	Number of shares	Amount
January 1, 2013	105,336,884	1,639.9
Shares issued for cash on exercise of options	806,093	18.9
Shares issued under DRIP	1,745,411	60.3
Shares issued on private issuance	2,801,905	100.0
Shares issued on public offering	11,615,000	392.3
December 31, 2013	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 costs	–	4.2
Shares issued under DRIP	1,619,794	70.2
Issued and outstanding at December 31, 2014	**133,941,749**	**2,759.9**

Preferred Shares Series A Issued and Outstanding	Number of shares	Amount
January 1, 2013	8,000,000	194.1
December 31, 2013	8,000,000	194.1
January 1, 2014	8,000,000	194.1
Deferred taxes on share issuance costs	–	1.8
Issued and outstanding at December 31, 2014	**8,000,000**	**195.9**

Preferred Shares Series C Issued and Outstanding	Number of shares	Amount
January 1, 2012	–	–
January 1, 2013	8,000,000	200.6
December 31, 2013	8,000,000	200.6
Issued and outstanding at December 31, 2014	**8,000,000**	**200.6**

Preferred Shares Series E Issued and Outstanding	Number of shares	Amount
January 1, 2013	–	–
Shares issued on public offering	8,000,000	194.9
January 1, 2014	8,000,000	194.9
Deferred taxes on share issuance costs	–	0.9
Issued and outstanding at December 31, 2014	**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)
Issued and outstanding at December 31, 2014	**8,000,000**	**196.1**

Weighted Average Shares Outstanding	2014	2013
Number of shares – basic	**126,660,704**	116,068,088
Dilutive equity instruments [(a)]	**1,904,208**	3,440,922
Number of shares – diluted	**128,564,912**	119,509,010

(a) Includes all options that have a strike price lower than the market share price of AltaGas' common shares at December 31, 2014 and 2013, respectively.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at December 31, 2014, 8,270,519 shares were reserved for issuance under the plan. As at December 31, 2014, options granted under the plan generally have a term of six to 10 years until expiry and vest no longer than over a four-year period.

As at December 31, 2014, the unexpensed fair value of share option compensation cost associated with future periods was $5.2 million (December 31, 2013 – $6.2 million). As at December 31, 2014, the compensation expense recorded for share options was $3.7 million (December 31, 2013 – $4.2 million).

The following table summarizes the Corporation's share options:

	Options outstanding			
	2014		2013	
	Number of options	**Exercise price** [1]	Number of options	Exercise price [1]
Share options outstanding, beginning of year	**5,561,505**	**27.25**	5,846,460	25.01
Granted	**666,000**	**45.57**	801,500	37.72
Exercised	**(989,162)**	**23.03**	(806,093)	21.75
Forfeited	**(114,688)**	**34.44**	(280,362)	26.38
Share options outstanding, end of year	**5,123,655**	**30.28**	5,561,505	27.25
Share options exercisable, end of year	**3,007,280**	**25.51**	2,917,955	23.28

1 *Weighted average.*

The following table summarizes the employee share option plan as at December 31, 2014:

	Options outstanding			**Options exercisable**	
	Number outstanding	**Weighted average exercise price**	**Weighted average remaining contractual life**	**Number exercisable**	**Exercise price**
$9.48 to $18.00	**307,970**	**15.34**	**4.36**	**307,970**	**15.34**
$18.01 to $25.08	**1,160,800**	**20.89**	**5.14**	**1,146,550**	**20.84**
$25.09 to $50.89	**3,654,885**	**34.53**	**6.41**	**1,552,760**	**30.97**
	5,123,655	**30.28**	**6.00**	**3,007,280**	**25.51**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes-Merton option pricing model with assumptions for grants as follows:

Years ended December 31	2014	2013
Risk-free interest rate *(%)*	**1.71**	1.41
Expected life *(years)*	**6**	6
Expected volatility *(%)*	**20.21**	23.59
Annual dividend per share *($)*	**1.71**	1.53
Forfeiture rate *(%)*	**16.00**	15.00

Equity-based Compensation Plan

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. Beginning in 2008, all employees were eligible to receive phantom shares. The phantom shares are valued based on dividends declared and the trading price of the Corporation's common shares. The shares vest on a graded vesting schedule over a 36 to 44 month period. For the year ended December 31, 2014, the compensation expense recorded was $4.6 million (2013 – $3.3 million).

As at December 31, 2014, the unexpensed fair value of equity-based compensation cost associated with future periods was $11.7 million (December 31, 2013 – $9.2 million).

21. NET INCOME APPLICABLE TO COMMON SHARES

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

Years ended December 31	2014	2013
Numerator:		
Net income applicable to controlling interests	**130.1**	201.1
Less: Preferred share dividends	**34.5**	19.6
Net income applicable to common shares	**95.6**	181.5
Denominator (millions of shares):		
Weighted average number of common shares outstanding	**126.7**	116.1
Dilutive equity instruments [(a)]	**1.9**	3.4
Weighted average number of common shares outstanding – diluted	**128.6**	119.5
Basic net income applicable per common share	**0.75**	1.56
Diluted net income applicable per common share	**0.74**	1.52

(a) Includes all options that have a strike price lower than the market share price of AltaGas' common shares at December 31, 2014 and 2013, respectively.

For year ended December 31, 2014, 642,000 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (year ended December 31, 2013 – 805,500 options).

22. COMMITMENTS AND GUARANTEES

Commitments

AltaGas has long-term natural gas purchase arrangements, service and storage agreements, long-term commitments for capital projects, and operating leases, all of which are transacted at market prices and in the normal course of business.

Future payments of these commitments at December 31, 2014 are estimated as follows:

	2015	2016	2017	2018	2019	2020 and beyond	Total
Gas purchase [(a)]	324.6	293.4	297.4	152.7	1.3	1.3	**1,070.7**
Service agreement [(b)]	7.9	8.4	8.6	15.1	15.0	150.1	**205.1**
Storage services	3.4	3.4	3.4	3.5	3.5	36.2	**53.4**
Capital projects [(c)]	29.3	–	–	–	–	–	**29.3**
Operating leases [(d)]	24.7	24.0	11.6	11.6	6.3	54.4	**132.6**
	389.9	329.2	321.0	182.9	26.1	242.0	**1,491.1**

(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 2015 to 2022, 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 December 2014, AltaGas' Blythe facility entered into a Long Term Service Agreement (LTSA) 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, in exchange for $194.1 million payable over the next 19 years, of which $47.2 million is expected to be paid over the next five years. 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.

(c) 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.

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

Guarantees

On October 2014, Heritage Gas Ltd., a wholly-owned subsidiary of AltaGas, entered into a throughput contract with a third party owner 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. The contract is subject to customary regulatory approval. AltaGas issued a US $91.7 million guarantee to stand by all payment obligations under the transportation agreement.

Contingencies

AltaGas is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators. On January 20, 2015, the AUC released the AUC Loss Hearings for 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, 2014.

23. 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 $5.7 million for the year ended December 31, 2014 (year ended December 2013 – $4.8 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. 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.

The most recent actuarial valuation of the defined benefit plans for funding purposes was completed as of December 31, 2014. 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, 2015.

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, 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**	**–**	**0.2**	**9.1**	**1.3**
Member contributions	**0.2**	**–**	**6.7**	**–**	**6.9**	**–**
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)**

	Canada		United States		Total	
Year ended December 31, 2013	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Accrued benefit obligation						
Balance, beginning of year	109.2	13.8	181.6	53.1	290.8	66.9
Actuarial (gain) loss	(7.6)	(2.8)	(19.2)	2.4	(26.8)	(0.4)
Current service cost	6.3	0.6	6.2	1.3	12.5	1.9
Member contributions	–	0.1	–	–	–	0.1
Interest cost	4.6	0.5	7.8	2.3	12.4	2.8
Benefits paid	(4.2)	(0.3)	(6.7)	(2.0)	(10.9)	(2.3)
Foreign exchange translation	–	–	12.5	3.7	12.5	3.7
Balance, end of year	108.3	11.9	182.2	60.8	290.5	72.7
Plan assets						
Fair value, beginning of year	67.2	2.3	119.0	40.3	186.2	42.6
Actual return on plan assets	7.5	0.1	25.0	8.3	32.5	8.4
Employer contributions	9.4	1.5	11.7	0.5	21.1	2.0
Member contributions	0.1	–	–	–	0.1	–
Benefits paid	(4.2)	(0.3)	(6.7)	(1.5)	(10.9)	(1.8)
Foreign exchange translation	–	–	8.2	2.8	8.2	2.8
Fair value, end of year	80.0	3.6	157.2	50.4	237.2	54.0
Accrued benefit liability	(28.3)	(8.3)	(25.0)	(10.4)	(53.3)	(18.7)

The following amounts were included in the Consolidated Balance Sheets:

	Defined Benefit 2014	Post-Retirement Benefits 2014	Defined Benefit 2013	Post-Retirement Benefits 2013
Prepaid expenses and other current assets	–	–	(0.4)	–
Other current liabilities	0.6	–	0.6	–
Future employee obligations	101.0	30.2	53.1	18.7
	101.6	30.2	53.3	18.7

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, 2014	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Amounts included in accumulated other comprehensive income (loss)						
Amortization actuarial loss	0.5	–	–	–	0.5	–
Past service cost	0.1	–	–	–	0.1	–
Net actuarial loss	(12.4)	(1.0)	(0.2)	–	(12.6)	(1.0)
Total accumulated other comprehensive loss on a pre-tax basis	(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 accumulated other comprehensive loss after-tax	(8.8)	(0.8)	–	–	(8.8)	(0.8)

	Canada		United States		Total	
Year ended December 31, 2013	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Amounts included in accumulated other comprehensive income (Loss)						
Transitional obligation	0.1	–	(0.2)	–	(0.1)	–
Past service cost	(0.3)	–	–	–	(0.3)	–
Net actuarial loss	(7.1)	(0.3)	–	–	(7.1)	(0.3)
Total accumulated other comprehensive loss on a pre-tax basis	(7.3)	(0.3)	(0.2)	–	(7.5)	(0.3)
Increase (decrease) by the amount included in deferred tax liabilities	1.8	–	0.2	0.1	2.0	0.1
Net amount in accumulated other comprehensive loss after-tax	(5.5)	(0.3)	–	0.1	(5.5)	(0.2)

Amounts to be amortized in the next fiscal year	Defined Benefit	Post-Retirement Benefits
Actuarial losses	1.7	0.1
Past service losses	0.1	–
Total	**1.8**	**0.1**

The following are the benefit cost components:

Year ended December 31, 2014	**Canada**		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Net benefit plan expense for the year:						
Current service cost and expenses	**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 actuarial loss on accrued benefit obligation	**1.5**	**–**	**2.9**	**0.6**	**4.4**	**0.6**
Costs arising in the year	**7.8**	**1.0**	**5.5**	**1.3**	**13.3**	**2.3**

Year ended December 31, 2013	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Net benefit plan expense for the year:						
Current service cost and expenses	6.2	0.6	6.2	1.3	12.4	1.9
Interest cost	4.6	0.6	7.8	2.3	12.4	2.9
Expected return on plan assets	(3.9)	–	(10.4)	(3.4)	(14.3)	(3.4)
Amortization of actuarial loss on accrued benefit obligation	2.5	0.3	4.4	0.3	6.9	0.6
Costs arising in the year	9.4	1.5	8.0	0.5	17.4	2.0

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, 2014:

Canada	Fair value	Level 1	Level 2	Percentage of Plan Assets *(%)*
Cash and short-term equivalents	3.5	3.5	–	3.69
Canadian Equities	30.9	30.9	–	32.45
Foreign Equities	17.2	17.2	–	18.11
Fixed Income	38.2	38.2	–	40.17
Real Estate	5.0	–	5.0	5.32
Other	0.2	0.2	–	0.08
	95.0	90.0	5.0	100.00

United States	Fair value	Level 1	Level 2	Percentage of Plan Assets *(%)*
Cash and short-term equivalents	0.6	0.6	–	0.26
Foreign Equities	158.4	158.4	–	67.56
Fixed Income	75.4	75.4	–	32.18
	234.4	234.4	–	100.00

Total	Fair value	Level 1	Level 2	Percentage of Plan Assets *(%)*
Cash and short-term equivalents	4.1	4.1	–	1.25
Canadian Equities	30.9	30.9	–	9.36
Foreign Equities	175.6	175.6	–	53.29
Fixed Income	113.6	113.6	–	34.49
Real Estate	5.0	–	5.0	1.54
Other	0.2	0.2	–	0.08
	329.4	324.4	5.0	100.00

	Defined Benefit 2014	Post-Retirement Benefits 2014	Defined Benefit 2013	Post-Retirement Benefits 2013
Significant actuarial assumptions used as at December 31				
Discount rate *(%)*	3.80-4.90	4.10-4.90	3.20-5.00	0.00-5.00
Expected long-term rate of return on plan assets *(%)*	0.00-7.50	0.00-7.50	0.00-8.00	0.00-8.00
Rate of compensation increase *(%)*	2.75-4.00	0.00-3.50	0.00-4.00	0.00-3.50
Average remaining service life of active employees (years)	12.5	11.7	12.70	12.95

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 4 and 10 percent and the ultimate trend rate between 4 and 5 percent, which is expected to be achieved by 2027.

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 2014:

	Increase	Decrease
Service and interest costs	20.1	(13.3)
Accrued benefit obligation	89.3	(55.7)

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:		
2015	14.2	3.2
Expected benefit payments:		
2015	10.9	2.3
2016	14.0	2.4
2017	13.9	2.7
2018	14.8	2.9
2019	16.0	3.1
2020-2024	96.1	19.1

24. 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 Sheet were measured at the exchange amount and were as follows:

As at December 31	**2014**	2013
Due from related parties		
Accounts receivable [(a)]	**2.2**	1.1
Long-term investments and other assets [(b)]	**–**	0.8
Prepaid expenses and other current assets [(b)]	**0.8**	–
	3.0	1.9
Due to related parties		
Accounts payable [(c)]	**17.6**	20.6
Long-term debt [(d)]	**0.1**	0.3
	17.7	20.9

(a) Receivable from joint ventures and an affiliate.

(b) AltaGas and one of its managers agreed on a loan in the principal amount of $750,000, to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and May 31, 2015.

(c) Payables to joint ventures.

(d) Due to an affiliate of the Corporation.

Year ended December 31,	2014	2013
Revenue [a]	94.8	24.1
Cost of sales [b]	3.8	12.5
Operating and administrative expenses [c]	10.7	1.3
Other income (expenses) [d]	0.4	–
Interest expense on long-term debt	0.2	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.

25. COMPARATIVE FIGURES

Certain comparative figures related to income tax liabilities for the year ended December 31, 2013 have been reclassified to conform to the presentation adopted in the current year.

26. 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 and electricity; • natural gas storage facilities; • LNG and LPG development projects; and • equity investment in a North American entity engaged in the marketing, storage, and distribution of NGL, drilling fluids, crude oil, and condensate diluents.
Power	• coal-fired, gas-fired, wind, biomass and run-of-river power output under power purchase agreements, both operational and under construction; 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	2014	2013
Revenue [(a)]		
Canada	1,574.9	1,376.0
United States	826.3	676.2
Total	2,401.2	2,052.2

As at December 31	2014	2013
Property, plant and equipment		
Canada	3,642.9	3,418.9
United States	1,694.1	1,533.6
Total	5,337.0	4,952.5

(a) Operating revenue from external customers.

The following tables show the composition by segment:

Year ended December 31, 2014	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	1,178.8	388.0	1,076.9	–	(242.5)	2,401.2
Unrealized gain 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 of obligations	(3.7)	(3.1)	(0.1)	–	–	(6.9)
Depreciation, depletion and amortization	(66.8)	(38.9)	(64.3)	(3.4)	–	(173.4)
Provision on long-lived assets	(108.2)	(10.9)	–	–	–	(119.1)
Income from equity investments	23.6	13.8	1.2	–	–	38.6
Other income (expenses)	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 [(a)]	48.1	306.2	239.9	10.9	–	605.1
Intangible assets	0.6	171.6	3.5	16.8	–	192.5
As at December 31, 2014:						
Goodwill	161.4	–	623.7	–	–	785.1
Segmented assets	2,284.3	2,338.1	3,148.2	642.8	–	8,413.4

(a) Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.

Year ended December 31, 2013	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	1,019.9	300.4	894.4	–	(162.5)	2,052.2
Unrealized loss on risk management	–	–	–	(9.2)	–	(9.2)
Cost of sales	(658.1)	(231.8)	(502.5)	–	156.2	(1,236.2)
Operating and administrative	(184.7)	(33.1)	(190.2)	(28.8)	6.3	(430.5)
Accretion of obligations	(3.6)	(0.1)	–	–	–	(3.7)
Depreciation, depletion and amortization	(68.5)	(22.8)	(57.3)	(3.9)	–	(152.5)
Provision on long-lived assets	(15.9)	(3.7)	(3.0)	–	–	(22.6)
Income from equity investments	1.6	108.1	2.5	–	–	112.2
Other income (expenses)	5.6	0.3	40.2	(4.9)	–	41.2
Foreign exchange loss	–	–	–	(0.3)	–	(0.3)
Interest expense	–	–	–	(102.1)	–	(102.1)
Income (loss) before income taxes	96.3	117.3	184.1	(149.2)	–	248.5
Net additions (reductions) to:						
Property, plant and equipment [(a)]	42.1	333.8	765.4	3.3	–	1,144.6
Intangible assets	(7.0)	(0.2)	6.5	9.2	–	8.5
As at December 31, 2013:						
Goodwill	161.4	–	581.7	–	–	743.1
Segmented assets	2,454.8	1,924.5	2,765.9	139.1	–	7,284.3

(a) Net additions to property, plant and equipment and long-term investments and other assets may not agree to changes reflected in Consolidated Balance Sheets due to classification of business acquisition and foreign exchange changes on U.S. assets.

Ten-Year Review of Financial Information

($ millions unless otherwise indicated)	2014	2013	2012
Financial Highlights [1]			
Income Statement			
Revenue	**2,406**	2,043	1,450
Net revenue [2]	**1,019**	960	665
EBITDA [2]	**563**	539	320
Operating Income [2]			
Gas	**69**	96	94
Power	**80**	117	77
Utility	**166**	184	81
Corporate	**(50)**	(38)	(37)
	264	360	214
Net income	**96**	182	102
Net income per basic share	**0.75**	1.56	1.07
EBITDA per basic share [2]	**4.45**	4.64	3.36
Cash Flow			
Funds from operations [2]	**471**	400	255
Funds from operations per basic share [2]	**3.72**	3.45	2.68
Dividends/distributions per share declared	**1.69**	1.50	1.40
Balance Sheet			
Property, plant and equipment	**5,337**	4,953	3,949
Intangible assets	**357**	195	190
Total assets	**8,413**	7,281	5,932
Short-term debt	**72**	84	67
Long-term debt	**3,050**	2,953	2,626
Shareholders' equity	**3,541**	2,792	1,960
Share Data *(millions)*			
Shares outstanding at year end	**133.9**	122.3	105.3
Weighted average shares outstanding for the year *(basic)*	**126.7**	116.1	95.0
Ratios *(%)*			
Return on average equity	**3.9**	9.4	7.8
Return on average invested capital	**5.0**	8.5	7.7
Debt as a percentage of total capitalization	**44.9**	53.1	57.4

1 Financial results 2010 and 2011 were restated to comply with US GAAP.

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

2011	2010	2009	2008	2007	2006	2005
(restated)	*(restated)*					
1,280	1,192	1,268	1,817	1,428	1,363	1,502
513	505	457	477	324	319	297
257	235	248	245	245	173	157
105	95	103	104	59	63	60
87	76	88	118	95	91	49
24	25	7	–	–	–	6
(41)	(44)	(28)	(43)	(27)	(28)	(7)
175	152	171	178	125	127	108
83	117	141	164	109	115	90
0.98	1.43	1.80	2.38	1.90	2.06	1.67
3.06	2.88	3.16	3.57	4.28	3.10	2.90
213	192	202	217	163	162	129
2.54	2.35	2.58	3.15	2.84	2.92	2.39
1.34	1.74	2.16	2.13	2.065	1.995	1.85
2,486	1,924	1,857	1,437	682	678	645
178	80	129	139	96	103	111
3,556	2,743	2,629	2,132	1,173	1,110	1,068
17	10	15	5	4	–	3
1,214	903	1,000	561	217	266	266
1,355	1,210	1,049	957	585	529	479
89.2	82.5	80.3	71.9	58.1	56.4	54.6
84.0	81.5	78.5	68.8	57.4	55.5	54.0
8.0	9.4	13.6	19.6	19.8	22.7	18.4
8.5	8.2	10.0	13.6	16.2	16.3	13.0
49.5	42.8	49.2	37.8	27.4	33.4	36.0

Ten-Year Review of Operating Information

	2014	2013	2012
Operating Statistics			
Gas			
Total inlet gas processed *(Mmcf/d)* [1]	**1,512**	1,361	1,261
Extraction ethane volumes *(Bbls/d)* [1]	**34,999**	32,695	25,499
Extraction NGL volumes *(Bbls/d)* [1]	**37,777**	31,086	14,593
Total extraction volumes *(Bbls/d)* [1,2]	**72,776**	63,781	40,092
Frac spread – realized *($/Bbl)* [1,3]	**22.83**	24.96	30.83
Frac spread – average spot price *($/Bbl)* [1,4]	**24.64**	27.15	29.22
Power			
Volume of power sold *(GWh)*	**5,168**	4,458	3,317
Price received on the sale of power *($/MWh)* [6]	**65.97**	76.82	69.42
Alberta Power Pool price *($/MWh)*	**49.42**	80.19	64.32
Canadian utilities			
Natural gas deliveries – end-use *(PJ)* [7]	**32.7**	30.4	28.5
Natural gas deliveries – transportation *(PJ)* [7]	**5.6**	5.8	6.8
U.S. utilities [8]			
Natural gas deliveries – end-use *(Bcf)* [7]	**72.3**	70.1	26.0
Natural gas deliveries – transportation *(Bcf)* [7]	**41.0**	41.4	13.9
Service sites [9]	**562,746**	555,198	547,977
Degree day variance from normal *(%)*			
AUI [10]	**2.3**	0.5	(0.7)
Heritage Gas [10]	**(0.2)**	1.3	(9.1)
SEMCO Gas [8,11]	**16.1**	9.0	(0.2)
ENSTAR [8,11]	**(9.0)**	(1.0)	9.6

1 *Average for the period.*
2 *Excludes 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, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, divided by the respective frac exposed volumes for the period.*
5 *Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.*
6 *Price received excludes Blythe as it earns fixed capacity payments under its power purchase arrangement with Southern California Edison.*
7 *Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.*

2011	2010	2009	2008	2007	2006	2005
1,274	1,221	1,294	1,342	963	956	948
26,565	25,453	26,817	24,795	13,355	13,132	13,155
14,513	12,654	13,236	12,242	6,752	6,564	6,202
41,078	38,107	40,053	37,037	20,108	19,696	19,357
33.67	27.27	23.46	26.97	21.38	18.47	9.31
42.88	31.95	19.51	28.79	22.48	18.47	9.31
3,003	2,828	2,726	2,623	2,661	2,878	3,466
75.94	66.79	68.97	84.51	68.59	69.26	54.59
76.22	50.76	47.84	89.95	66.84	80.48	70.19
21.8	19.90	6.62	–	–	–	10.5
4.6	5.30	0.55	–	–	–	9.5
–	–	–	–	–	–	–
–	–	–	–	–	–	–
115,011	74,664	72,717	–	–	–	61,447
–	(1.60)	9.90	–	–	–	(1.4)
(12.7)	(13.20)	(1.00)	–	–	–	(5.7)
–	–	–	–	–	–	–
–	–	–	–	–	–	–

8 *Results for U.S. utilities are from August 30, 2012.*

9 *Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non-regulated business lines.*

10 *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.*

11 *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.*

Shareholder Information

2014 Dividend Declaration History

Ex-Dividend Date	Record Date	Payment Date	Amount
January 23, 2014	January 27, 2014	February 18, 2014	$0.1275
February 21, 2014	February 25, 2014	March 17, 2014	$0.1275
March 21, 2014	March 25, 2014	April 15, 2014	$0.1275
April 23, 2014	April 25, 2014	May 15, 2014	$0.1275
May 22, 2014	May 26, 2014	June 16, 2014	$0.1475
June 23, 2014	June 25, 2014	July 15, 2014	$0.1475
July 23, 2014	July 25, 2014	August 15, 2014	$0.1475
August 21, 2014	August 25, 2014	September 15, 2014	$0.1475
September 23, 2014	September 25, 2014	October 15, 2014	$0.1475
October 23, 2014	October 27, 2014	November 17, 2014	$0.1475
November 21, 2014	November 25, 2014	December 15, 2014	$0.1475
December 23, 2014	December 29, 2014	January 15, 2015	$0.1475
Total 2014 Dividends			$1.6900

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

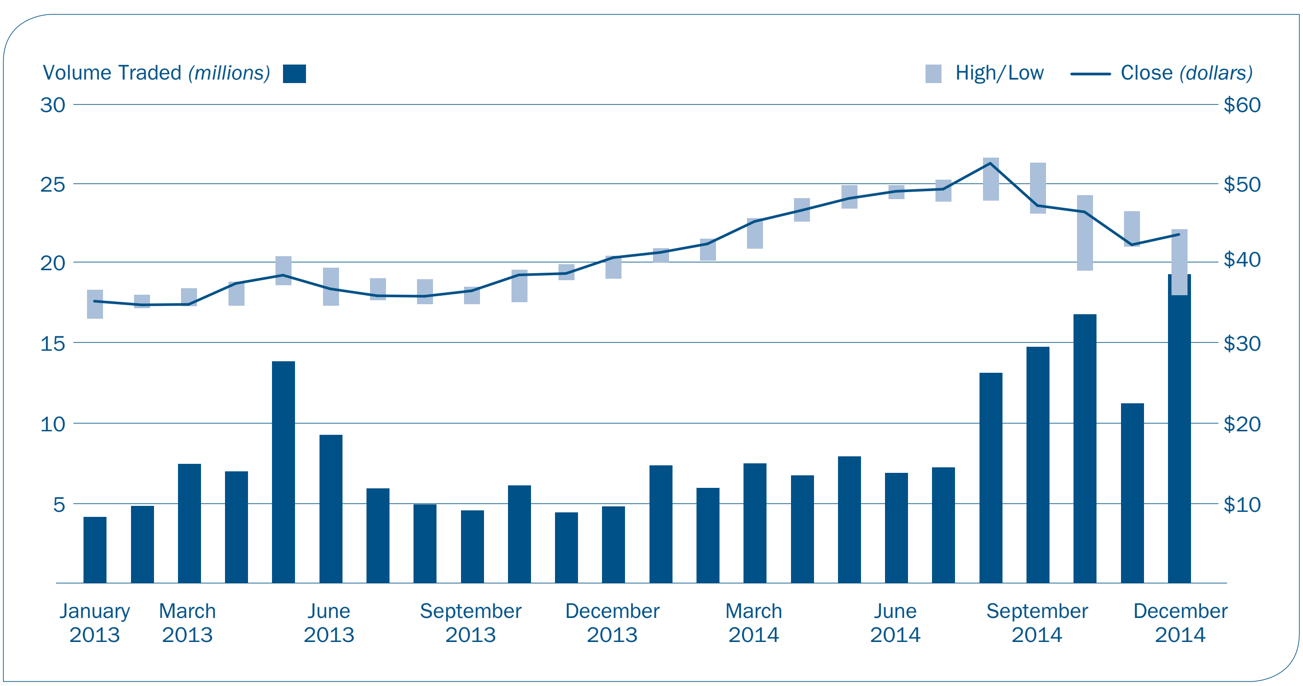
AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan ("Plan") for holders of common shares of AltaGas Ltd.

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 per cent 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 a leading North American diversified energy infrastructure company. AltaGas owns or operates a diversified mix of assets in gas, power, and utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources.

For more information visit **www.altagas.ca.**

Management Team

David W. Cornhill
Chairman and Chief Executive Officer

David M. Harris
President and Chief Operating Officer

Deborah S. Stein
Senior Vice President Finance
and Chief Financial Officer

John E. Lowe
Executive Vice President

Dennis A. Dawson
Corporate Secretary

Kent E. Stout
Vice President Corporate Resources

Auditors
Ernst & Young LLP
Calgary, Alberta, Canada

Transfer Agent
Computershare Trust Company of Canada
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Toll-free: 1-800-564-6253
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Investors are encouraged to contact Computershare for information concerning their security holdings.

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

Annual Meeting
The annual meeting will be held
at 3:00 p.m. MDT on
Thursday, April 30, 2015 at
The Fairmont Palliser, Alberta Ballroom
133 - 9th Avenue S.W.
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
kV	kilovolt
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
PJ	petajoule
MMBTU	million British thermal unit

Printed on recycled paper.

Forward-looking Information
This annual report may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "may", "would", "could", "should", "will", "intend", "plan", "anticipate", "expect", "believe", "seek", "propose", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this annual report are intended to provide AltaGas security holders 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 statements in this annual report may include, among others, statements regarding business objectives and anticipated business prospects, projects and financial performance of AltaGas and its subsidiaries, expectations or projections about the future, 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 price of energy commodities, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the natural gas and power energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, weather, economic conditions in North America. This list should not be considered to be exhaustive. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause AltaGas' actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by AltaGas with Canadian securities regulators and available through the SEDAR system at www.sedar.com. Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this annual report or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. AltaGas undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

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Investor Relations

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

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AltaGas

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