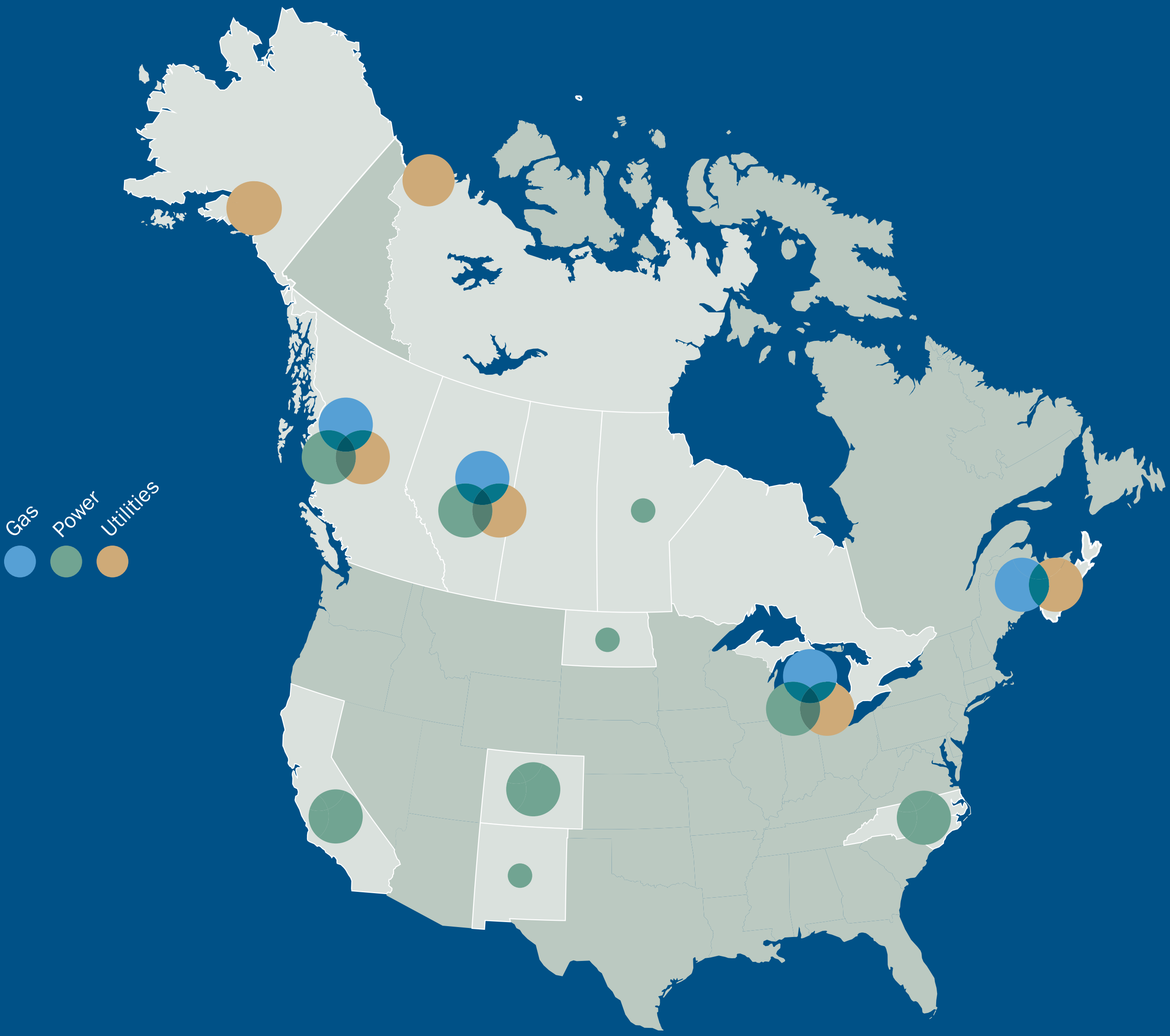
Think AltaGas

20 YEARS

2013 Annual Report

AltaGas is a leading North American energy infrastructure company.

We have a 20-year history of delivering safe and reliable service, and exceptional shareholder value. We invest in and operate energy infrastructure to serve producers and to provide clean and affordable energy to our customers.



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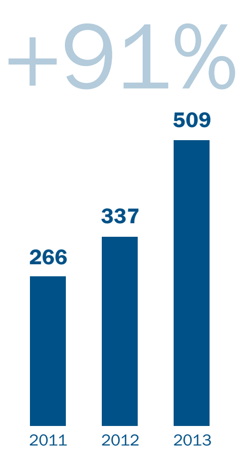
Think**Results**

We execute on our strategy and deliver results.

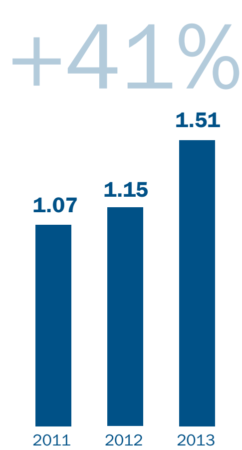
The demand for clean energy and the renaissance of natural gas in North America continue to drive AltaGas' strategy. We are focused on investing in and operating infrastructure to serve producers and to provide clean and affordable energy to our customers. By growing and diversifying our assets, maintaining financial strength and flexibility, and continuing to evolve our organizational capability, we have become a $9 billion enterprise. For the last two decades, we have delivered superior economic returns to investors, and 2013 was no exception.

Our track record speaks for itself...

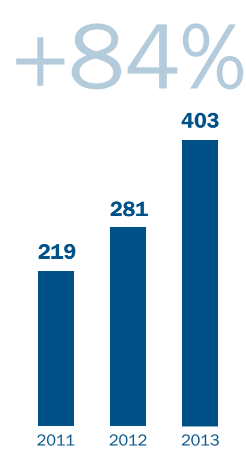
EBITDA [1]
($ millions)



Earnings per Share [1]
($ per share)



Funds from Operations [1]
($ millions)



1 *Normalized non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of the MD&A.*

Think**Value**

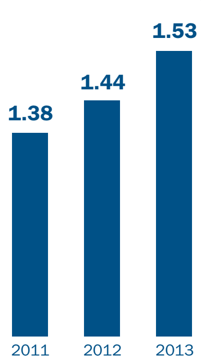
We deliver long-term value for our shareholders.

Our disciplined and proven strategy continues to create long-term value for shareholders. Since our initial public offering in 1999 we have delivered more than 934 percent in total shareholder return. We have also delivered growth and security in our dividend. We are proud of the value we have provided to shareholders and we have achieved this through changing environments over the last two decades. As our business continues to evolve we will balance yield and growth, maintain financial strength, and remain disciplined in allocating capital to provide future value for our shareholders.

Our achievements reflect the consistent execution of our strategy...

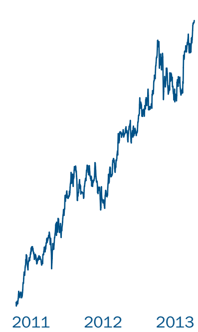
Annual Dividend
($ per common share)

+11%



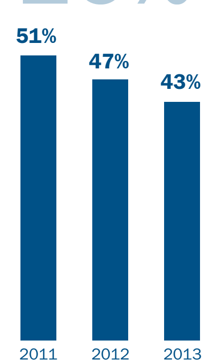
Total Shareholder Return*

+117%



Payout Ratio
(percentage of normalized funds from operations)

-16%



* Based on a $100 investment made on Dec. 31, 2010 ending on Dec. 31, 2013 and assuming the reinvestment of dividends.

AltaGas serves producers in the Western Canadian Sedimentary Basin and transacts more than 2 Bcf/d of natural gas.

Think**Growth**

We see many opportunities to grow our business.

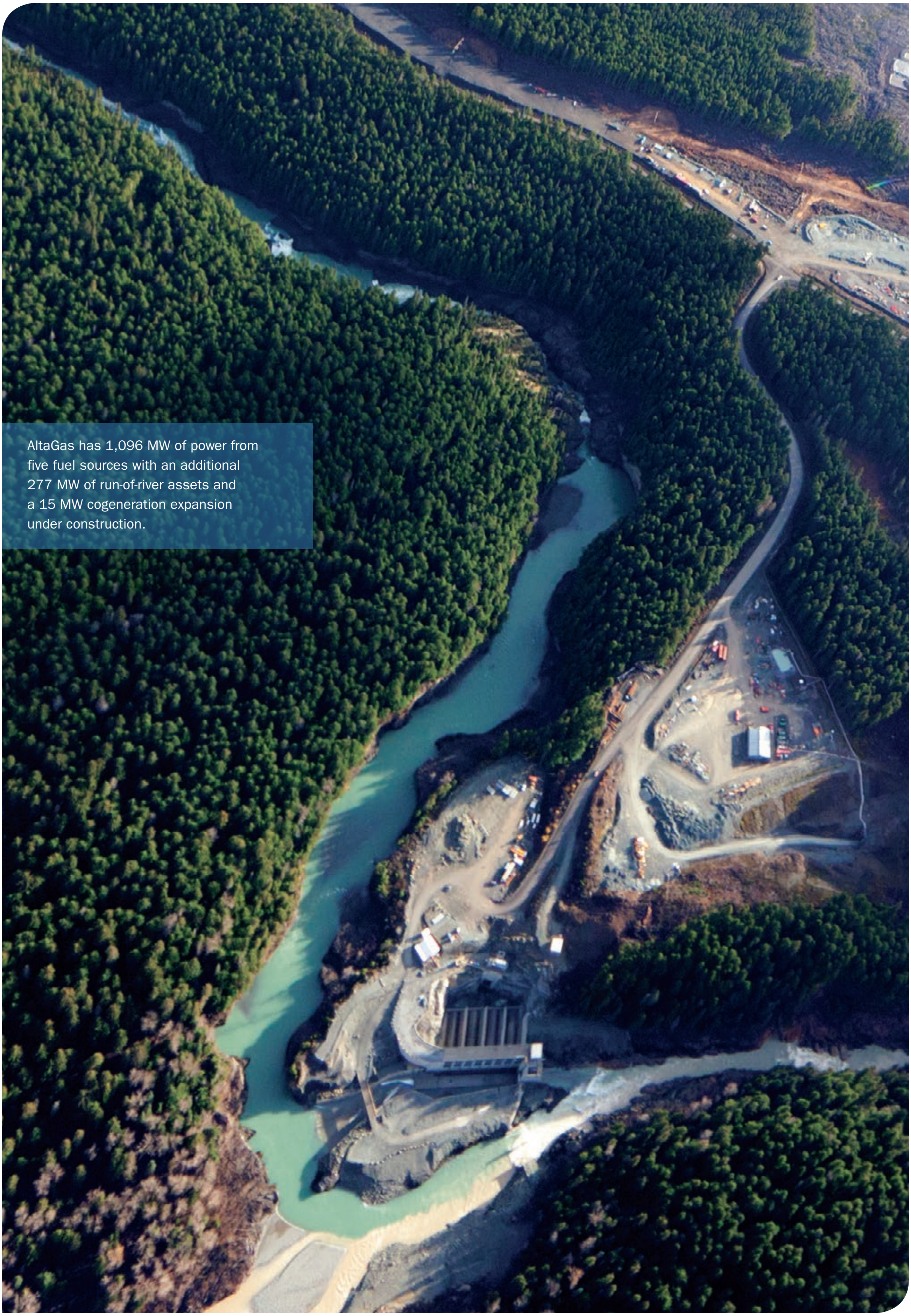
We have taken many strategic steps to become a leading North American energy infrastructure company. The demand for clean energy, and the abundance of natural gas in North America, provide significant opportunities to continue to grow our existing business, and explore new opportunities like LPG and LNG exports. We have $2.5 billion in growth opportunities across our Gas, Power and Utilities segments over the next five years – almost half of which are already secured. We have also positioned ourselves to capitalize on $2 billion to $5 billion in energy export investment opportunities. We have the financial strength and flexibility, and the experience and expertise, to deliver major projects to create significant shareholder value.

Our best is yet to come...

Total new opportunities

*$4.5 to 7.5 billion

* $2.5 billion in growth opportunities in Gas, Power and Utilities
* $2 billion to $5 billion in LPG and LNG export opportunities



AltaGas has 1,096 MW of power from five fuel sources with an additional 277 MW of run-of-river assets and a 15 MW cogeneration expansion under construction.

ThinkRelationships

We measure our success by the social value we create and the legacy we leave.

We are a trusted partner in the communities where we work and live. Whether we are working with customers, interacting at an open house in a First Nation or Aboriginal community, or at an investor meeting, we build relationships through open, honest communication and mutual respect. We see great value in continuing to strengthen our relationships and in building new ones. As we grow our company and meet significant project and financial milestones, we take tremendous pride in helping communities, customers and shareholders succeed.

Our commitments don't end here...

More than

420

organizations across North America supported by AltaGas in 2013

AltaGas is dedicated to building social value by supporting diverse organizations and partnering with communities.

ThinkSafety &Environment

We promote a safe and healthy environment.

We are committed to protecting employees, the public and the environment. Safety is a top priority at AltaGas and is paramount to how we do business. Each year we strive for continuous improvement, and we have strong management processes and a dedicated Board of Directors who oversee all aspects of safety and environment. We are pleased to report that our safety and audit scores for our gas operations are once again in the high nineties and we have been independently recognized for our safe, responsible and sustainable operations. Stewardship of the environment is critical to AltaGas' success. In 2013, we significantly reduced the emission intensity of our power generation portfolio through the acquisition of Blythe Energy Center in California. This facility adds 507 MW of clean-burning, gas-fired generation to our existing power portfolio. We will further reduce emission intensity when our 277 MW run-of-river Northwest Projects come online.

Our company continues to grow and evolve and so do our safety and environmental practices...

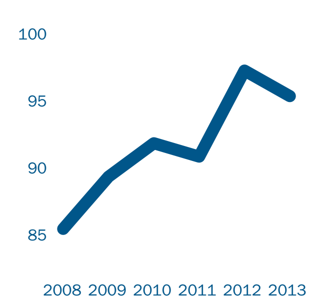
1.5 million tonnes

The quantity of greenhouse gas emissions AltaGas has reduced since 2008

1,100,000 MWh

The quantity of clean electricity produced by AltaGas-owned facilities since 2009

Health & Safety Audit Scoring
(%)



AltaGas has five natural gas distribution utilities that serve more then 550,000 customers in Canada and the U.S.

Think AltaGas

"As I reflect upon the last 20 years, we started in the midstream business and we have grown and expanded in the gas, power and utilities sectors from an initial seed capital investment of $37,000, to assets of more than $7 billion.

David W. Cornhill
Chairman and Chief Executive Officer

Our vision has always been to become a leading energy infrastructure company. Over our short 20-year history we have been executing our strategy with that goal in mind. We have taken steps to build a business that is strong and a future that is even more promising.

We continue to focus on providing infrastructure for clean and affordable energy. As I reflect upon the last 20 years, we started in the midstream business and we have grown and expanded in the gas, power and utilities sectors from an initial

20 YEARS

Harmattan

Forrest Kerr

SEMCO

seed capital investment of $37,000, to assets of more than $7 billion. 20 years ago the first shares we offered to outside investors were $0.60 a share. If those shareholders reinvested the dividends, that $0.60 was worth $166 at the end of 2013.

As important as creating shareholder value is, I believe that it is equally important to create social value. At AltaGas, we are ensuring that as we grow we are also adding value in the communities where we work, that our employees are engaged and seeing their careers flourish, and that we are safeguarding our planet for future generations. We also continue to work closely with First Nations and other Aboriginal communities to develop opportunities to create long-term, sustainable community value. Their success is our success. Today we are better positioned than ever before to chart our course for the next 20 years as we continue to realize our vision of being a leading North American energy infrastructure company.

In 2013, we had another year of exceptional accomplishments. We added more than $1 billion in new assets and two new key partnerships. We are excited to work with Idemitsu and Petrogas to provide new markets that are critical to our customers for their propane. With Idemitsu, we are also focused on providing a new market for Canada's natural gas producers. We believe that smaller export projects like ours have an important role to play in supporting producers in the Western Canadian Sedimentary Basin (WCSB). In addition to our new partnerships, the work that was completed at our Northwest run-of-river projects was nothing short of phenomenal. The team working in northern B.C. has been able to deliver the $725 million Forrest Kerr project ahead of schedule and on budget. The strong team we have built has been focused and was able to advance the schedule for the Volcano Creek project by two years. And finally, we also took our first big step into the U.S. power market by acquiring the 507 MW Blythe Energy Center in California. This natural gas-fired plant gave us a significant footprint that we can build on to meet the growing demand for clean energy in the region.

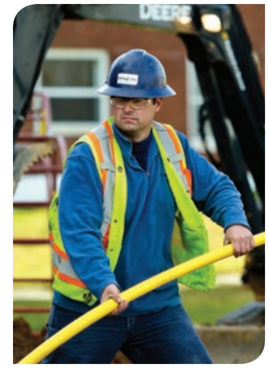
Financially, we increased normalized earnings per share by more than 31 percent and cash flow per share by over 17 percent. We also achieved an all-time record high of $509 million in normalized EBITDA. These significant results

> "The renaissance of natural gas and growing demand for clean energy are providing future growth opportunities across all areas of our business. We have opportunities to invest in new natural gas processing capacity and to provide our customers with access to new markets.

supported our ability to raise our dividend by just over 6 percent while maintaining a very conservative payout ratio – the second lowest of all our peers. AltaGas is in a good place to see further dividend growth. In 2014, two of our Northwest Projects will come online and the third in 2015. These projects provide significant room to grow our dividend. Throughout all of this growth we have maintained financial strength and flexibility. We have great access to capital. In fact, in early 2014 we issued our first ever 30-year medium-term notes – quite an accomplishment for a company that is only 20 years old.

The renaissance of natural gas and growing demand for clean energy are providing future growth opportunities across all areas of our business. We have opportunities to invest in new natural gas processing capacity and to provide our customers with access to new markets. In the WCSB we are positioned to build new infrastructure to support significant drilling activity in liquids-rich plays that currently lack the required infrastructure to get the gas to market. With the addition of our strategic interest in Petrogas in 2013, we increased our energy logistics capabilities and now have a wider geographical reach to provide our customers access to additional NGL markets and to deliver LPG to the West Coast for export. Our Power business is also expected to benefit from abundant and affordable natural gas and the demand for clean energy. We believe natural gas will continue to play an important role in power generation. Abundant, affordable, clean natural gas is also creating opportunities to grow our natural gas utilities. Customers are seeking to benefit from this clean-burning, low-cost energy source and AltaGas is well positioned to continue increasing both our customers and our rate base through infill, fuel switching and greenfield expansion of services. These opportunities of about $2.5 billion, provide a strong platform for growth of our gas, power and utilities segments, which we believe we can fund from our internally-generated cash flow.

Asia presents new energy market opportunities for Canada and we believe that AltaGas can be instrumental in supporting the effort to find new markets for Canada's natural gas supply. Our energy export projects represent an additional $2 billion to $5 billion in growth opportunities. With Petrogas, we expect to get LPG to the West Coast as early as 2016. Through our partnership with Idemitsu we can provide access to an



attractive global LNG market for gas producers in the WCSB. Building on our 2011 acquisition of Pacific Northern Gas, we have the opportunity to expand our natural gas pipeline and deliver gas to the West Coast. We expect to see LNG exports as early as 2017.

AltaGas' success has been achieved through strong relationships. We continue to strengthen our relationship with First Nations and other Aboriginal communities. We are partners with them and we create value together. We are keenly aware of the role we play to make a difference in the areas of health and social services, education, and the arts. 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 also achieved an excellent safety and environmental record. This would not be possible without our talented and dedicated employees who are committed to delivering significant results year after year 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 make a difference in communities. From supporting local theatre companies, sports teams and hospitals, to partnering with organizations like Cross Country Canada, STARS and The United Way, we are dedicated to delivering sustainable benefits and building social value.

I would like to thank our employees, the Board of Directors, investors, customers, business partners and our service providers for helping us deliver another successful year in our 20-year history. We have proven time and again that together, we can accomplish great things and there is more to come.

Sincerely,

David W. Cornhill

Chairman and Chief Executive Officer

Corporate Governance

David W. Cornhill
Chairman and Chief
Executive Officer

Member of the EOHSC

Catherine M. Best
Director

Independent director;
Member of the AC

Allan L. Edgeworth
Director

Independent director;
Chair of the EOHSC
Member of the AC

Hugh A. Fergusson
Director

Independent director;
Member of the AC
and HRCC

Daryl H. Gilbert
Director

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

Robert B. Hodgins
Director

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

David F. Mackie
Director

Independent director;
Member of the GC
and HRCC

Neil McCrank
Director

Independent director;
Member of the GC
and EOHSC

Myron F. Kanik
Lead Director

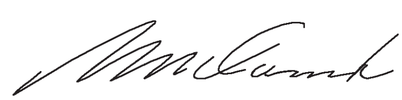
Independent director;
Chair of the GC and
Member of the HRCC

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 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 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 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 3:30 p.m. MDT on Thursday, May 1, 2014 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

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 (GC); Audit (AC); Environment, Occupational Health and Safety (EOHSC); and Human Resources and Compensation (HRCC). The GC, AC and HRCC are composed exclusively of non-management, independent directors. The EOHSC includes a majority of independent, non-management directors, as well as the Chairman and Chief Executive Officer of AltaGas. 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, former President of the Canadian Energy Pipeline Association, and former 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 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, former Treasurer of Canadian Pacific Limited and former 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 and the communities where we operate.

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 any grants of share-based compensation.

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.

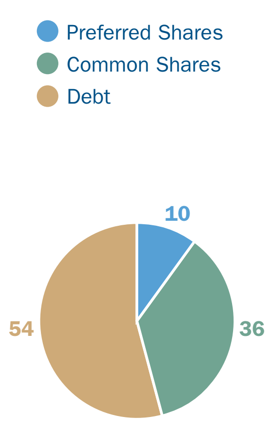
The Chair of the HRCC is Daryl H. Gilbert, a Managing Director with JOG Capital Inc. and prior to that Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., consultants in reserves evaluation.

Five-Year Financial Highlights

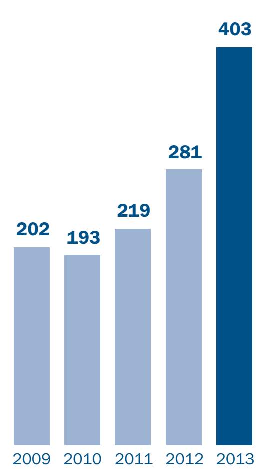
($ millions)	**2013**	2012	2011 [1]	2010 [1,2]	2009 [2]
Revenue	**2,042.9**	1,449.7	1,280.0	1,219.2	1,268.3
Net revenue [3]	**960.2**	664.4	513.1	504.8	456.6
Normalized operating income [3]	**352.7**	234.6	184.3	157.4	164.9
Normalized EBITDA [3]	**508.9**	336.9	265.8	240.2	242.0
Net income applicable to common shares	**181.5**	101.8	82.7	117.0	141.3
Normalized net income [3]	**175.8**	109.5	90.2	101.4	132.8
Total assets	**7,281.3**	5,932.4	3,556.2	2,743.1	2,628.9
Total long-term liabilities	**3,727.4**	3,357.4	1,637.6	1,225.4	719.1
Net additions to property, plant and equipment	**1,144.6**	1,532.1	642.6	211.7	486.4
Dividends declared	**173.6**	132.8	112.2	54.1	–
Distributions declared [2]	**–**	–	–	87.0	170.2
Normalized funds from operations [3]	**402.7**	281.0	219.0	192.7	202.3
($ per basic share, except shares outstanding)					
Normalized EBITDA [3]	**4.38**	3.55	3.16	2.95	3.08
Net income – basic	**1.56**	1.07	0.98	1.43	1.80
Net income – diluted	**1.52**	1.06	0.97	1.43	1.79
Normalized net income [3]	**1.51**	1.15	1.07	1.24	1.69
Dividends declared	**1.50**	1.40	1.34	0.66	–
Distributions declared per unit	**–**	–	–	1.08	2.16
Normalized funds from operations [3]	**3.47**	2.96	2.61	2.36	2.58
Shares outstanding – basic *(millions)*					
During the year [4]	**116.1**	95.0	84.0	81.5	78.5
End of year	**122.3**	105.3	89.2	82.5	80.3

1 Results were restated to comply with US GAAP.
2 On July 1, 2010, AltaGas converted from a Trust to a Corporation.
3 Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures section of the MD&A.
4 Weighted average.

Capital Structure
(%)

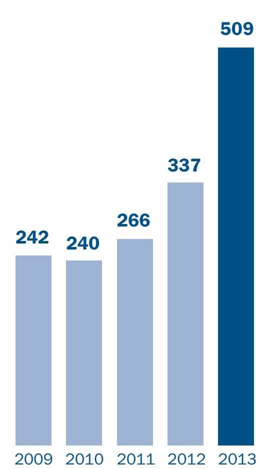


Funds from Operations*
($ millions)



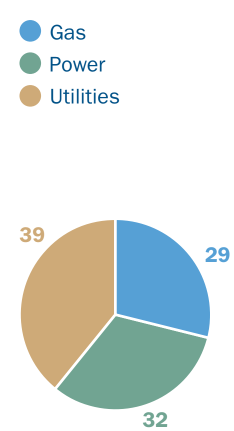
* Normalized

EBITDA*
($ millions)



* Normalized

Operating Income*
(%)



* Normalized

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, 2013, compared to the year ended December 31, 2012. This MD&A dated February 26, 2014, 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, 2013. Effective January 1, 2012, AltaGas follows United States Generally Accepted Accounting Principles (US GAAP). Information derived from the Consolidated Statements of Income and Consolidated Balance Sheets for the year ended and as at December 31, 2011, along with other selected financial information for 2011 have been restated to comply with US GAAP. All prior comparative information that has been restated to US GAAP is labeled "restated".

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or any affiliate of AltaGas, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects, opportunities and financial results. Specifically, such forward-looking statements are set forth under: "2014 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.

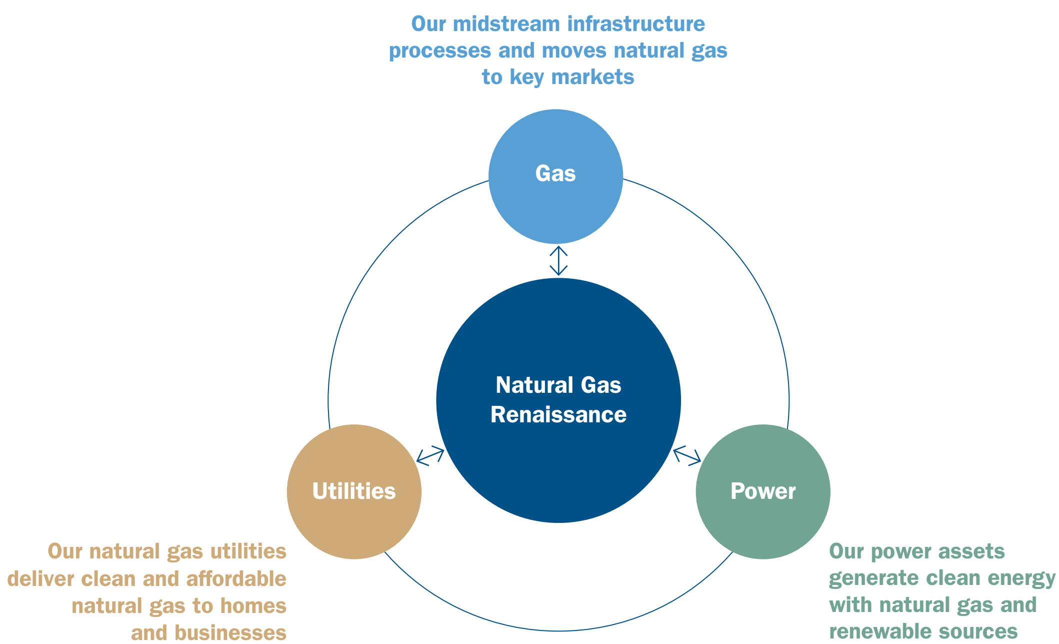
Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas, including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular and Proxy Statement, material change reports and press releases, are also available through AltaGas' website or directly through the SEDAR system at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas 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., SEMCO Energy, Inc. (SEMCO) and AltaGas Power Holdings (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. It does so through three business segments: Gas, which includes natural gas processing and transportation; Power, which includes power generation assets and power purchase arrangements (PPAs) for power supply; and Utilities, which include five regulated utilities across North America. AltaGas has an enterprise value of approximately $9 billion. With the physical and economic links along the energy value chain, primarily from well head 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.



Gas

AltaGas' Gas segment serves producers in the Western Canadian Sedimentary Basin (WCSB) and transacts more than 2 Bcf/d of natural gas and 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) along with the Corporation's 25 percent ownership interest in Petrogas Energy Corp. (Petrogas).

AIJVLP is pursuing energy export opportunities, including long-term supply and sales arrangements to meet the growing demand for liquefied natural gas (LNG) and liquefied petroleum gas (LPG or propane) in Asia. 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. 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. 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.

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.

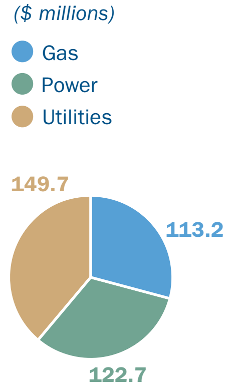
Power

The Power segment includes 1,096 MW of power generation capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets, along with an additional 277 MW of run-of-river assets under construction. AltaGas owns 50 percent of the Sundance B PPA, giving it the rights to power output and ancillary services from coal-fired base-load generation until December 31, 2020.

In 2013, AltaGas acquired 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 Energy Center is fully contracted under a PPA with Southern California Edison (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) market. Blythe Energy Center is located on a 76-acre site owned by AltaGas. 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 the 67-mile transmission line. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth.

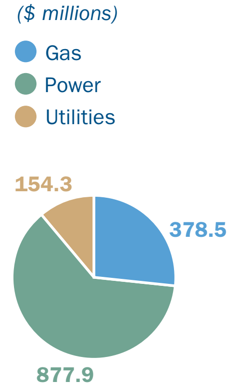
Further generation projects are in various stages of construction, including the Northwest run-of-river hydro projects (Northwest Projects), which consist of the 195 MW Forrest Kerr project (Forrest Kerr), the 66 MW McLymont Creek project (McLymont Creek), and the 16 MW Volcano Creek project (Volcano Creek). The 277 MW Northwest Projects are contracted with 60-year Energy Purchase Arrangements (EPAs) with BC Hydro, which are fully indexed to the Consumer Price Index (CPI), as well as Impact Benefit Agreements with the Tahltan First Nation. Forrest Kerr and Volcano Creek are expected to be in service in mid-2014 and late 2014, respectively, contingent on the availability of the Northwest Transmission Line (NTL). McLymont Creek is expected to be in service in mid-2015. AltaGas is also expanding its cogeneration fleet at the Harmattan complex (Harmattan) to 45 MW. AltaGas began engineering and procured the combustion turbine for the new 15 MW cogeneration facility (Cogeneration III) 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 first half 2015.

Operating Income*
($ millions)

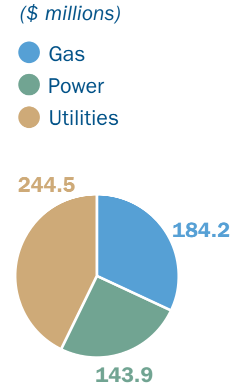


* Normalized

Invested Capital
($ millions)



EBITDA
($ millions)



Utilities

The Utilities segment is comprised of natural gas distribution utilities which serve more than 550,000 customers in Canada and the United States. The Utilities segment in Canada is comprised of AltaGas Utilities Inc. (AUI) in Alberta, Pacific Northern Gas Ltd. (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, and ENSTAR Natural Gas Company (ENSTAR) and a 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA), both of which are 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 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 returns and long-life cash flows. The Corporation also focuses on growing 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 worldwide demand for clean energy will provide opportunities for continued growth across all business segments.

STRATEGY

AltaGas invests in and operates energy infrastructure to serve producers, and to provide clean and affordable energy to its customers in North America. AltaGas' strategy is to capitalize on the supply and demand for natural gas and the increasing demand for clean energy by owning and operating assets in gas, power and utilities. 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.

Consistent with its mandate of overseeing and directing the Corporation's strategic direction, the Board of Directors of AltaGas (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 in North America 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 has been driven by new technology that has improved the economics of unconventional gas plays, including shale, tight gas and coal bed methane. New technology such as horizontal drilling and multi-stage hydraulic fracture drilling allow shale and other low productivity gas resources to be produced more economically. The abundant supply of natural gas 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 our Gas, Power and Utilities segments to add and optimize assets.

AltaGas plans to grow through expansion and optimization of its strategically located assets and through the addition of new assets to serve new customers and new markets. This new infrastructure is expected to include larger scale facilities supporting the vast reserves as well as the strong producer activity in liquids-rich areas in the WCSB. AltaGas' strategic investment in Petrogas enhances the services provided by the Gas segment by offering integrated midstream services to AltaGas' customers and creating value both for the Gas segment and for the Petrogas investment.

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 generation. Within the Power segment, growth is planned through the completion of the projects under construction, the expansion of existing assets, and through the development of its portfolio of clean energy generation in North America.

Within the Utilities segment, growth is expected through expansion of the existing distribution systems to acquire new customers, fuel switching as abundant natural gas provides a clean low-cost energy alternative and through investment into the existing distribution systems to ensure safe, reliable service for our customers. There are also natural gas storage opportunities currently under development in Alaska and Nova Scotia to increase reliability of supply to AltaGas' natural gas distribution customers in those areas.

The low-cost, abundant natural gas supply as well as the stable economic and political environment in Canada have also resulted in increased Asian demand for Canadian natural gas. Lower exports of natural gas from Canada to the United States has also increased the need for Canadian producers to seek new markets. In addition to owning the only natural gas pipeline to Kitimat and Prince Rupert, the investment in AIJVLP supports the Corporation's efforts to export liquefied natural gas (LNG) from the West Coast of Canada. The LNG export opportunities are also expected to provide further growth for each of AltaGas' business segments, ranging from natural gas processing infrastructure and pipeline development, to power generation.

Global demand for LPG has been strong in recent years and is expected to remain high into the future. With Western Canada's natural gas production becoming increasingly liquids-rich, supply to meet world NGL demand is expected to increase in AltaGas' operating areas. The Corporation expects its strategic relationships with Idemitsu, a global leader in the supply of energy, petroleum, lubricants and petrochemical products and services, and with Petrogas and its logistics network of rail cars, terminals and storage facilities, to foster growth opportunities for the export of LPG to North American and world markets.

AltaGas is an industry leading operator of energy infrastructure serving energy 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 over 1,500 employees building long-term relationships, and sustainable benefits in the communities in which AltaGas operates.

Maintain Financial Strength and Flexibility

Financial discipline is a fundamental cornerstone of the Corporation's strategy. AltaGas' financing strategy is to ensure the Corporation has sufficient liquidity to meet its capital requirements and 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 mitigation of exposure to certain market price risks. As a result, the Corporation has developed robust risk management processes that mitigate earnings volatility from commodity price 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.

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 the 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, growing from $2.1 billion in assets five years ago to total assets of $7.3 billion at the end of 2013. In the last three years, the Corporation has reported 26 percent and 6 percent compound annual growth rate in earnings and dividends per share, respectively. AltaGas delivers an effective balance between yield and growth.

2013 was a significant year for AltaGas, with the creation of AIJVLP and the strategic acquisition of the interest in Petrogas. These two developments were core to AltaGas' energy export initiatives. In addition, AltaGas' acquisition of Blythe increases the Corporation's portfolio of clean energy with stable cash flows under a seven-year PPA. The construction of the Northwest Projects is ongoing and continues to proceed ahead of schedule and on budget, with Forrest Kerr and Volcano Creek expected to be in service in mid-2014 and late 2014, respectively, and McLymont Creek expected to be in service in mid-2015. Throughout this growth cycle, the Corporation has maintained its financial strength and flexibility through a combination of internally-generated cash flows, the Corporation's dividend reinvestment program (DRIP), and the issuance of $1.2 billion of equity and long-term debt in 2013.

In 2013, AltaGas initiated further growth in all business lines with projects such as the completion of phase one and the development of the second phase of the Cold Lake expansion, with the construction of Cogeneration III at the Harmattan facility, with the expanded main replacement program at SEMCO, and with the compressed natural gas (CNG) developments at Heritage Gas and PNG.

In 2013, AltaGas also completed several financing transactions demonstrating its ability to maintain financial strength and flexibility. The Corporation extended its debt maturity profile and lowered its cost of capital with the $300 million and US$175 million senior medium-term notes (MTNs) issued in series. During the year, AltaGas filed a new $4 billion base shelf prospectus on August 23, 2013, and completed an approximate $405 million common share issuance, a $200 million preferred share issuance, and an approximate $100 million common equity issuance to the vendor of Petrogas. AltaGas also replaced a number of its borrowing facilities with a new $1.4 billion syndicated credit facility. At the end of 2013, AltaGas had approximately $1.1 billion of available credit facilities and debt-to-total capitalization of 53.1 percent.

During 2013, the Board of Directors approved two dividend increases for a total of a 6.25 percent increase from $1.44 per share to $1.53 per share on an annual basis. The dividend increases reflect the success of AltaGas' recent asset additions across all business segments and the progress AltaGas has made on the Northwest Projects as well as the strength and stability of its cash flows.

2013 GROWTH HIGHLIGHTS

AltaGas:

- Acquired a 507 MW natural gas-fired combined cycle plant, Blythe Energy Center for US$515 million. The facility is fully contracted under a PPA with SCE until July 31, 2020;
- Completed mechanical construction for the 195 MW Forrest Kerr project, which is expected to be in service by mid-2014 contingent on the availability of the NTL;
- Completed the powerhouse building, turbine foundations, powerhouse crane installation and penstock excavation for the 16 MW Volcano Creek project, with the penstock installation to commence in the spring of 2014. The project is expected to be in service in late 2014;
- Completed construction of the intake access road and excavation of the power portal for the 66 MW McLymont Creek project. Excavated approximately 50 percent of the 2,800 metre power tunnel, with installation of the powerhouse foundations ongoing. The project is expected to be in service in mid-2015;
- Formed AIJVLP to pursue opportunities to develop long-term natural gas supply and sales arrangements along with the liquefaction infrastructure to meet the growing demand for natural gas in Asia and to develop an LPG export business;
- Acquired a 25 percent interest in Petrogas, a privately-held leading North American integrated midstream company and subsequently announced plans to increase its effective ownership to 33 1/3 percent; and
- Through its wholly-owned subsidiary, PNG, AltaGas entered into Transportation Reservation Agreements (TRA) with both Douglas Channel Gas Services Ltd. and Triton LNG Limited Partnership (Triton LNG), a wholly-owned subsidiary of AIJVLP, for an aggregate of 520 Mmcf/d of natural gas transportation capacity on the proposed PNG pipeline expansion. The PNG expansion is expected to increase capacity of the PNG system to approximately 750 Mmcf/d;

2013 FINANCIAL HIGHLIGHTS

AltaGas:

- Normalized net income [1] of $175.8 million ($1.51 per share) in 2013, compared to $109.5 million ($1.15 per share) in 2012;
- Net income applicable to common shares of $181.5 million ($1.56 per share) in 2013, compared to $101.8 million ($1.07 per share) in 2012;
- Normalized EBITDA [1] of $508.9 million in 2013, compared to $336.9 million in 2012;
- Normalized funds from operations [1] of $402.7 million ($3.47 per share) in 2013, compared to $281.0 million ($2.96 per share) in 2012;
- Dividend payout as a percentage of normalized funds from operations [1] of 43 percent in 2013, compared to 47 percent in 2012;
- Net debt as at December 31, 2013 of $3,201.3 million, compared to $2,690.5 million as at December 31, 2012;
- Debt-to-total capitalization ratio as at December 31, 2013 of 53.1 percent, compared to 57.4 percent as at December 31, 2012;
- Issued 11,615,000 common shares on April 4, 2013, resulting in aggregate gross proceeds of approximately $405 million;
- Issued US$175 million senior unsecured MTNs on April 12, 2013. The notes carry a floating coupon rate of three month LIBOR plus 0.79 percent and mature on April 13, 2015;
- Issued $300 million senior unsecured MTNs on June 11, 2013. The notes carry a coupon rate of 3.57 percent and mature on June 12, 2023;
- Filed a $4 billion base shelf prospectus on August 23, 2013, valid for 25 months;
- Issued 8,000,000 five-year rate-reset Series E Preferred Shares on December 13, 2013 at a price of $25 per Series E Preferred Share for aggregate gross proceeds of $200 million; and
- Issued $100 million of common equity as partial consideration to the vendor of Petrogas.

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

2014 OUTLOOK

In 2014, AltaGas is expected to deliver another strong year in earnings and cash flow growth, with continued operational excellence, a full year of earnings from Petrogas and Blythe, the start of commercial operations of the Forrest Kerr and Volcano Creek projects, and improved results in the Gas segment as a result of increased producer activity in liquids-rich areas, partially offset by the impact of the sales of ECNG Energy L.P. (ECNG) and the Ante Creek facility (Ante Creek).

Natural gas demand in North America is expected to remain strong with increased gas consumption for power generation, industrial loads such as oil sands projects and NGL export projects. With the strong market demand for NGL it is expected that producers will continue to look to liquids-rich areas for their natural gas development.

In the Gas segment, volumes processed at plants in liquids-rich areas are expected to increase, including at the Gordondale facility where volumes are expected to increase to the capacity of 120 Mmcf/d and the Co-stream facility at Harmattan expected to operate at 250 Mmcf/d. Management estimates an average of approximately 7,300 Bbls/d will be exposed to frac spread in 2014. For 2014, approximately 70 percent of the estimated volumes exposed to frac spread have been hedged at an average price of approximately $25/Bbl prior to deducting extraction premiums.

AltaGas is expanding its Cold Lake natural gas transmission system to deliver natural gas to two heavy oil projects near Cold Lake, Alberta, offsetting decreased transmission volumes on existing systems. The first expansion project was completed in fourth quarter 2013 and the second expansion project is expected to be in service in late 2014. The expansion projects are underpinned by long-term take-or-pay transportation agreements.

In the Power segment, earnings growth is expected to be driven by the full year contribution from Blythe, and the addition of Forrest Kerr and Volcano Creek. Forrest Kerr and Volcano Creek are expected to generate annualized EBITDA of approximately $100 million. Blythe is scheduled for a major turnaround at the end of first quarter 2014 which is expected to reduce AltaGas' capacity payment earnings for 2014 by approximately US$3.0 million.

For first quarter 2014, AltaGas has hedged approximately 58 percent of volumes exposed to Alberta power prices at an average price of $66/MWh. For the second through fourth quarters of 2014, AltaGas has hedged approximately 25 percent of volumes exposed to Alberta power prices at an average price of $63/MWh. On a full year basis, AltaGas is approximately one-third hedged at an average price of $65/MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to the medium and long-term power prices as reflected in the current forward curves.

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 2014 driven by forecasted rate base growth of 10 percent in Canada, and continued customer growth in the United States franchise areas. If the US dollar continues to strengthen compared to the Canadian dollar, the earnings from SEMCO, ENSTAR and CINGSA will be proportionally higher in 2014. Earnings at AUI, SEMCO and ENSTAR are affected by the weather in their franchise areas. If the weather varies from the previous year, earnings at the utilities would be affected. In 2014, ENSTAR will file a general rate case with a decision expected in 2015. Also in the year, return on equity (ROE) decisions are expected for AUI and PNG, though they are not expected to materially impact results.

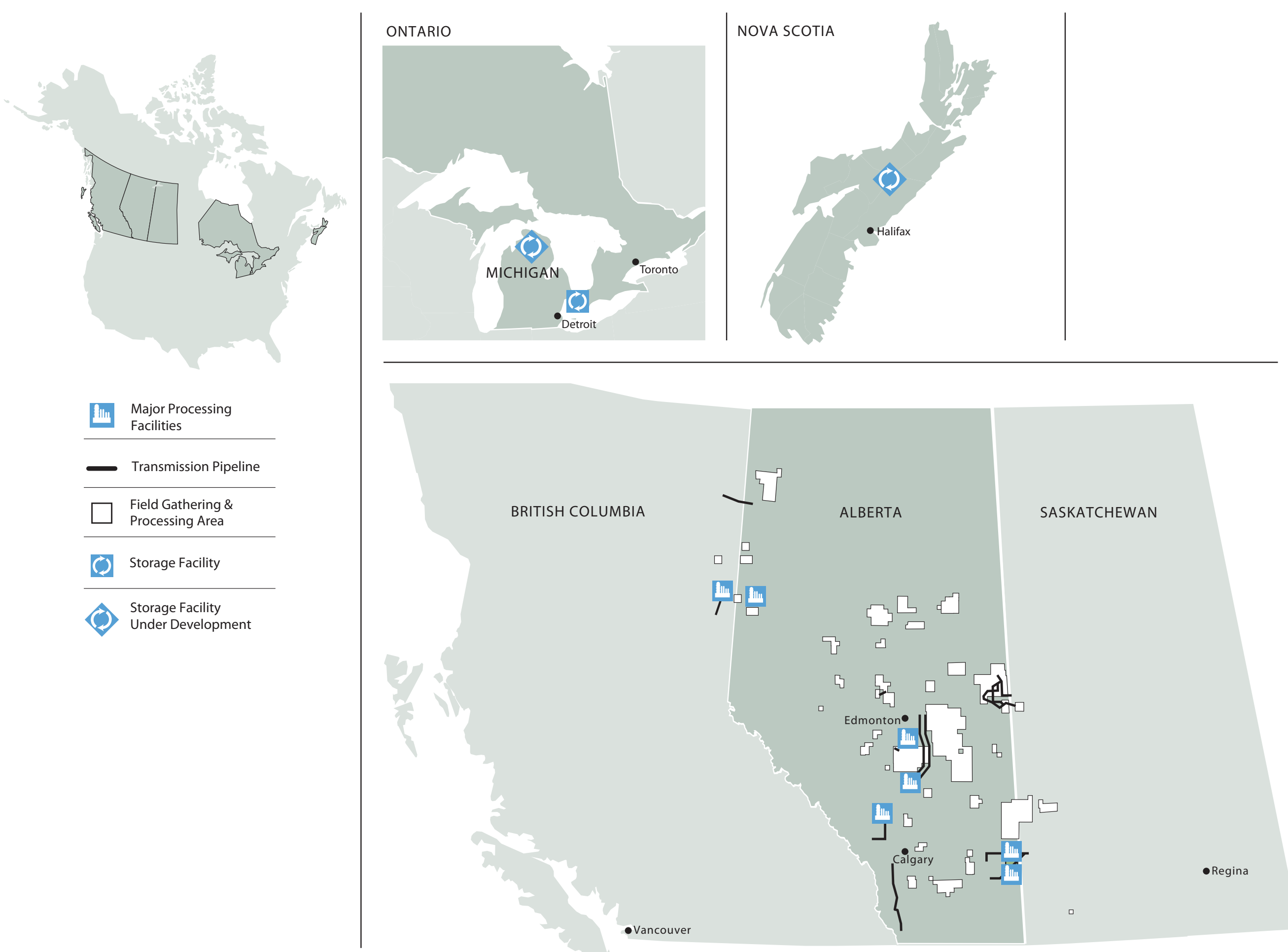
GAS

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 NGLs. 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, provides gas transportation, storage and gas marketing for producers, and sources gas supply to some of the Corporation's processing assets. The Gas segment also includes several expansion and greenfield projects under development, including the energy export projects at 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 an 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 North American integrated midstream company. Petrogas' extensive logistics network consists of over 1,500 rail cars and 24 rail and truck terminals, which provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities. On October 24, 2013 AltaGas announced it will increase its effective ownership of Petrogas to 33 1/3 percent. AltaGas plans to transfer its current 25 percent ownership to AIJVLP. AIJVLP will acquire an additional 41 2/3 percent interest in Petrogas. As a result of the transaction, Petrogas will be owned one-third by each of AltaGas, Idemitsu, and its current majority shareholder. All regulatory approvals have been obtained and the transaction is expected to close on March 1, 2014.

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 0.5 Bcf/d and four NGL pipelines with combined capacity of 189,300 Bbls/d. The transmission assets provide stable take-or-pay based revenues;
- More than 70 gathering and processing facilities in 32 operating areas in Western Canada and a network of 6,600 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. 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;
- A natural gas storage development project in Nova Scotia;
- 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; and
- 25 percent ownership in Petrogas, a leading North American integrated midstream company.

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 which is designed to reduce market commodity 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 through expansion and optimization of its strategically located assets and through the addition of new assets to serve new customers and new markets. This 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 both for the Gas segment and for the Petrogas investment. The Corporation's objectives are to:

- Capitalize on the infrastructure growth opportunities associated with growing natural gas supply in the WCSB;
- Increase throughput, utilization and efficiency of existing facilities;
- Provide the most cost-effective midstream services while delivering reliable and safe operations;
- Mitigate volume risk by directly recovering operating costs from customers and employing other contractual arrangements to mitigate the impact of declining volumes;
- Acquire and develop new gas infrastructure assets to meet customers' needs;
- Expand into new natural gas infrastructure markets such as regional LNG; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration of business lines across the energy value chain.

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, 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. Strong NGL prices have continued to drive producer focus on liquids-rich natural gas and oil 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.

The market demand, including the demand generated from the potential LPG and LNG export projects on the West Coast of Canada, 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 acquiring and constructing new facilities in areas with growing demand for natural gas processing, extraction, storage and transmission capacity.

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

The natural gas supply to AltaGas' extraction plants, with the exception of Harmattan and Younger extraction plant (Younger), depends on natural gas demand pull from residential, commercial and industrial usages 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 fractionation plant in the area, and is the third largest producer of NGL in the WCSB. There is significant demand for gas processing capacity at Harmattan as a result of the high volume of liquids-rich gas being produced in the area. The Co-stream facility at Harmattan completed in late 2012 is an example of optimizing and growing the existing assets while increasing the utilization at the existing plant.

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 northwestern Alberta, in response to the development of unconventional sources of gas, such as Montney and Duvernay shale gas plays. In addition, AltaGas is able to relocate units quickly and cost effectively to respond to the changing processing needs of its customers with certain skid-mounted field gas compression and processing units. The new Gordondale gas plant and the expansion of 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 should 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 enhanced further 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 value along the energy value chain and more effectively serve customers' needs.

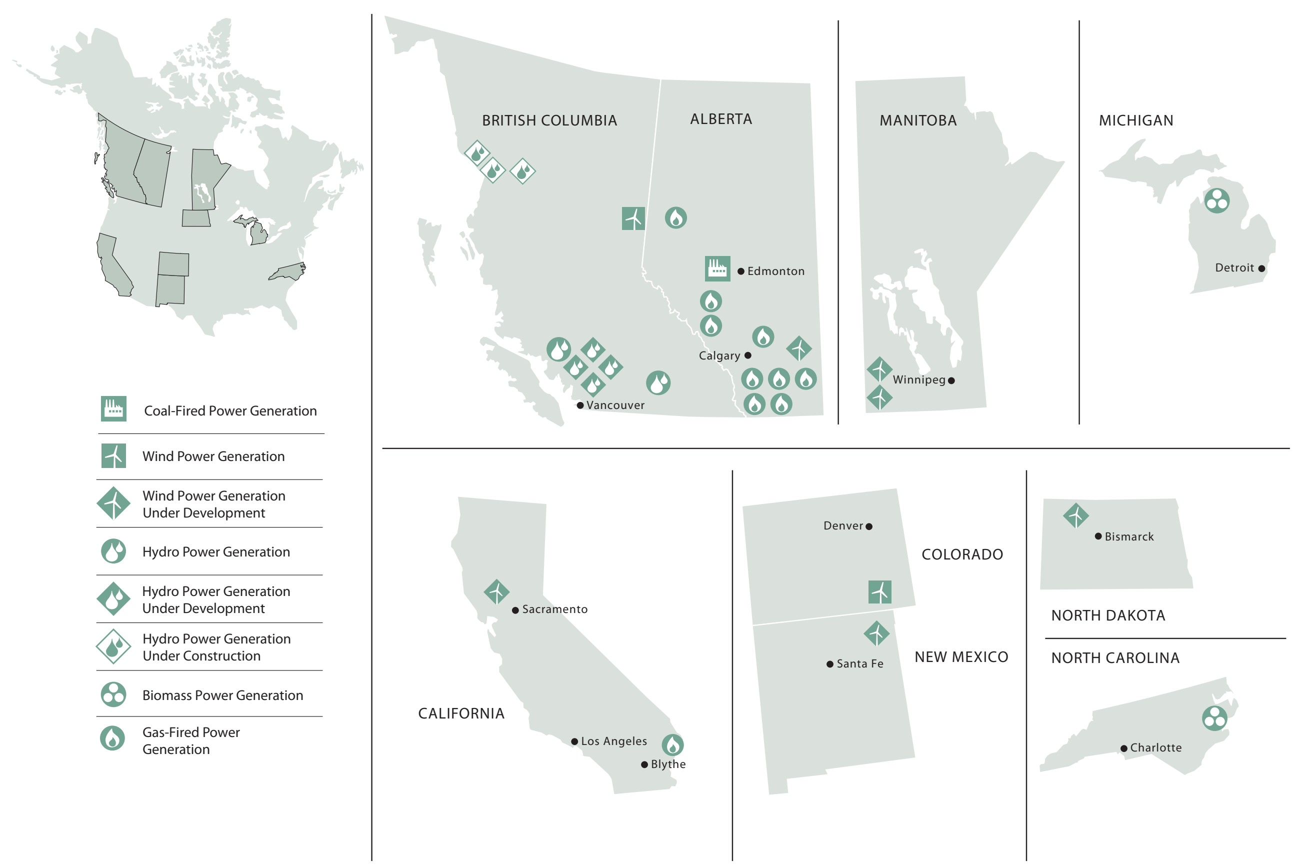
POWER

Description of Assets

The Power segment includes 1,096 MW of generating capacity from coal-fired, wind, gas-fired, biomass and run-of-river assets. Further power generation of 1,422 MW is in various stages of construction and development including 277 MW for the Northwest Projects, of which 211 MW are scheduled for completion in 2014.

AltaGas continues to expand its footprint into the United States and at the end of 2013 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 Energy Center 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 being available to produce power and not actual production, therefore providing stable cash flows. The current capacity is contracted until July 31, 2020, at which point the facility is uniquely positioned to potentially serve both the CAISO and DSW market. Blythe Energy Center is located on an owned 76-acre site which provides a significant geographic footprint 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 67-mile transmission line. The facility also has the capability of directly reconnecting to the DSW market. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth. Blythe adds to the wind and biomass assets acquired in the United States in 2012.

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 include 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.



The Power segment includes:

- 507 MW of gas-fired generating capacity in California at Blythe Energy Center;
- 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 and a further 1,087 MW in various stages of development. All operating wind generation is sold via long-term EPAs;
- 42 MW of gas-fired peaking plants in Alberta and a further 3 MW under construction. These gas-fired facilities provide partial backstopping to the Sundance B PPA;
- 35 MW of biomass generation in the United States. The plants have long-term EPAs with strong counterparties;
- 30 MW of cogeneration capacity in Alberta and a further 15 MW under construction;
- 12 MW of operating run-of-river generation, a further 277 MW under construction, and 40 MW under development. All run-of-river have long-term EPAs, 277 MW of the generation has 60-year EPAs; and
- Commercial and Industrial (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.

The Corporation employs a power economic 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 generating capacity of 277 MW. The 195 MW Forrest Kerr project is mechanically complete, and commissioning is ongoing. The project's in-service date is mid-2014, contingent on the availability of the NTL. Construction continues to progress well for the two smaller projects, 16 MW Volcano Creek and 66 MW McLymont Creek. These projects are expected to be in service in late 2014 and mid-2015, respectively. The Northwest Projects, estimated to cost approximately $1.0 billion, 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.

Capitalize on Opportunities

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;
- Grow and diversify the power generation portfolio by geography and fuel source;
- Acquire and develop power infrastructure backstopped by long-term power sales arrangements 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;
- Operate and dispatch the gas-fired peaking capacity to maximize revenue from both energy sales and ancillary services; and
- Minimize operating costs across its entire fleet of power generating assets.

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 based on economic fundamentals. Decreasing natural gas costs have made it such that gas-fired generation can compete on a marginal cost basis with coal in many parts of the United States. The economic benefit of gas-fired generation is amplified by capital costs and dispatch flexibility are accounted for.

The Sundance facility is among the lowest cost producers of power in Alberta, uniquely positioning AltaGas to maintain profitable operations during difficult economic conditions. The evolution of the Rate-Regulated Option (RRO) has changed the wholesale power market dynamics in Alberta. As of January 30, 2013, companies that offer the RRO are allowed to buy electricity up to 120 days in advance, as opposed to the 45-day lead time previously in effect. This change may reduce sudden price spikes for consumers. RRO providers submit their regulated rate proposals to the appropriate regulatory body for approval. The Alberta Utilities Commission (AUC) regulates investor owned utilities and approves RRO rates for the cities of Calgary and Edmonton, and rural Alberta. The RRO pricing mechanism has lowered liquidity in the long-term market. While the changing market dynamics have presented opportunities for AltaGas to benefit from the short-term price volatility, the RRO pricing mechanism results in fewer opportunities to enter into long-term hedges.

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 3 to 5-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 125 MW of fixed price sales to C&I customers for 2014, 100 MW for 2015, 30 MW for 2016, and 20 MW for 2017, with average prices in the low $60s 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. Blythe Energy Center, Bear Mountain Wind Park (Bear Mountain), Busch Ranch, Grayling Generating Station, Craven County wood biomass power facility and the Northwest Projects under construction are all examples of AltaGas' strategy in action.

AltaGas has approximately 1,127 MW of renewable power under development, including 1,087 MW of wind power and 40 MW of run-of-river hydroelectric, along with 277 MW run-of-river hydroelectric under construction and 18 MW of gas-fired power under construction. 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 United States, while the run-of-river projects are located in British Columbia.

In 2013, there was considerable 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 the First Nations in British Columbia, provide AltaGas a significant competitive advantage in its ability to capitalize on opportunities to increase its power generation portfolio to support LNG activities as they materialize.

UTILITIES

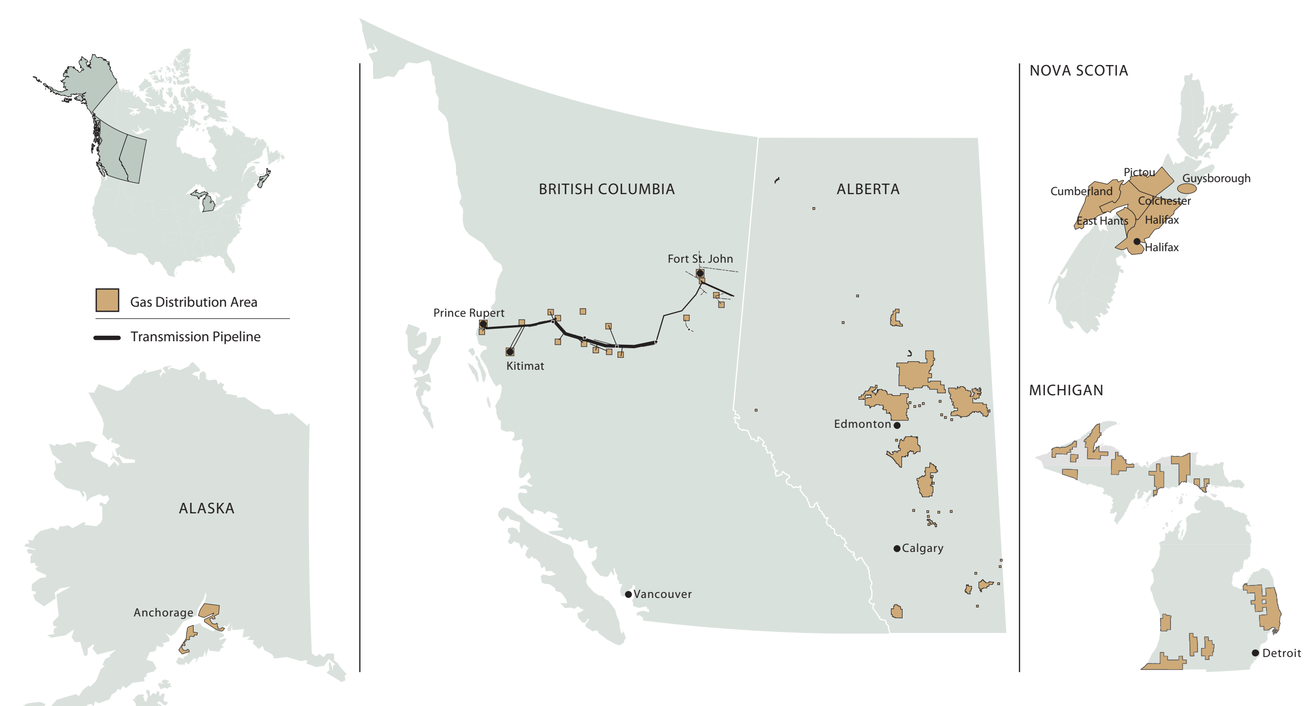
Description of Assets

AltaGas owns and operates utility assets that 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 which delivers natural gas to end-users in Inuvik, Northwest Territories.

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.

AUI in Alberta, PNG in British Columbia, Heritage Gas in Nova Scotia, SEMCO Gas in Michigan, and ENSTAR and CINGSA in Alaska are allowed the opportunity to earn regulated returns. This return on rate base comprises regulator allowed financing costs and 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 on its earnings of deliveries to certain customers caused principally by volatility in weather and the impact on deliveries.



SEMCO Energy, Inc.

SEMCO, through a wholly-owned subsidiary, owns and operates ENSTAR, a regulated natural gas distribution utility in Alaska and a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. SEMCO also owns and operates, through a wholly-owned subsidiary, SEMCO Gas, a regulated natural gas distribution utility in Michigan and an interest in a regulated natural gas storage facility in Michigan.

At the end of 2013, SEMCO Gas had approximately 300,000 customers and ENSTAR had approximately 136,000 customers (including regulated, transportation and non-regulated business lines). Of these customers, approximately 91 percent are residential. In 2013, SEMCO Gas and ENSTAR experienced customer growth of approximately 1.0 and 1.5 percent, respectively, reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas.

The rate base at year-end was approximately US$444 million for SEMCO Gas, US$225 million for ENSTAR and US$104 million for CINGSA (AltaGas' 65 percent share).

In 2013, the approved regulated ROE for SEMCO Gas was 10.35 percent on 50 percent equity, while the approved regulated return for ENSTAR was 12.55 percent on 51.4 percent equity and the approved regulated rate of return for CINGSA was 12.55 percent on 50 percent equity.

In December 2012, SEMCO Gas filed an application with the Michigan Public Service Commission (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 $4.4 million to $8.8 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.

ENSTAR will apply for updated rates in 2014 which are expected to be decided upon in 2015. The application is mandated by the settlement of ENSTAR's last rate case in 2010 and is expected to reflect the investments ENSTAR has made since 2009. SEMCO Gas is not expecting to apply for updated rates in 2014, but continues to assess if it will apply in 2015 or later. CINGSA is required to further update its rates in 2014 to reflect actual construction and operating costs. The CINGSA rate case is not expected to materially impact results. CINGSA is also required to file a base rate case with the Regulatory Commission of Alaska (RCA) in mid-2017 based upon data from a test year ending December 31, 2016. SEMCO Gas, ENSTAR and CINGSA operate under cost-of-service regulation and utilize actual results from the most recent completed fiscal year along with known and measureable changes in their application for new rates.

AltaGas Utilities Inc.

AUI owns and operates a regulated natural gas distribution utility in Alberta. At the end of 2013, AUI served approximately 75,000 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. Customer growth in 2013 was 2 percent, reflecting the continued strong growth of the Alberta market.

AUI's rate base at year-end was approximately $204 million.

For 2013, AUI's approved placeholder for regulated ROE was 8.75 percent (2012 – 8.75 percent) on a prescribed capital structure of 43 percent equity and 57 percent debt. In 2013, the AUC commenced a Generic Cost of Capital (GCOC) proceeding for which a hearing is scheduled in second quarter 2014. The decision, which will establish the ROE and capital structures for all AUC regulated utilities for 2013, 2014 and, possibly, future years, is not expected prior to fourth quarter 2014.

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. Under the PBR framework, utility rates are set using a formula that adjusts the prior year's rates for inflation, productivity, exogenous events, extra capital invested and other factors. The PBR framework is intended to incentivize utilities to be more efficient. The 2013 interim rates were approximately 2.65 percent higher than those approved for 2012 with a decision on final rates from the AUC expected in the second quarter of 2014. The initial PBR term will last for five years and the AUC will make a determination at the end of the initial term as to how it will proceed for future years. It is expected that AUI's framework will fundamentally remain a cost-of-service framework, however, the continued use of PBR is not known at this time.

In addition to capital expansion for new business and general plant, AUI spent $11.5 million in 2013 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 rate of return on the capital.

Pacific Northern Gas Ltd.

PNG operates a transmission and distribution system in the west central portion of northern British Columbia (PNG West) and in the areas of Dawson Creek and Fort St. John in northeastern British Columbia (PNG NE). PNG is also proposing to the BCUC a CNG filling station in northeastern British Columbia to serve additional customers in Dawson Creek and Tumbler Ridge. At the end of 2013, PNG served approximately 40,000 customers. Customer growth in 2013 was 0.9 percent, which is strong for PNG's mature network. PNG's residential customers comprised approximately 87 percent of its total customers.

PNG's rate base at year-end was approximately $180 million.

PNG is regulated by the BCUC. PNG is currently a participant in the GCOC proceeding established by the BCUC during 2012, which will determine the approved ROE for 2013 and possibly beyond. For PNG West and Tumbler Ridge division in PNG NE, PNG has proposed a 50 percent common equity ratio and a 9.75 percent common equity return which is one percent over the BCUC benchmark. For Fort St. John/Dawson Creek division in PNG NE, PNG has proposed a 45 percent common equity ratio and a 9.25 percent common equity return. A decision is expected in first half 2014.

PNG operates under cost-of-service regulation and filed its 2014 revenue requirement in November 2013. The applications sought approval to increase 2013 approved rates on an interim basis effective January 1, 2014 pending the BCUC's review of the applications. The BCUC approved interim rates effective January 1, 2014 at the levels set forth in the applications. The decision on 2014 revenue requirement application is expected in the third quarter of 2014.

Heritage Gas Limited

Heritage Gas has the exclusive rights to distribute natural gas through its distribution system to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality. At the end of 2013, Heritage Gas had over 5,000 customers. Customer growth in 2013 was 17 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 $220 million.

For 2013, Heritage Gas' approved regulated ROE was 11 percent (2012 – 11 percent) and debt recovery rate of 7.25 percent (2012 – 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 is not expecting to apply for updated rates in 2014, but continues to assess if it will apply in 2015 or later.

In 2012, Heritage Gas began to develop a CNG distribution system which will allow customers not connected through the distribution infrastructure to gain access to natural gas. Heritage Gas invested $8.7 million into the CNG business in 2013 (2012 – $3.7 million) and operations commenced in May 2013. This CNG project is being developed and operated initially as a non-regulated business.

Inuvik Gas Ltd. & Ikhil Joint Venture

AltaGas has a one-third equity interest in Inuvik Gas and a 33.3335 percent interest in the Ikhil Joint Venture (Ikhil) natural gas reserves, which supply Inuvik Gas with natural gas to be delivered to the Town of Inuvik. The Ikhil natural gas reserves have depleted more rapidly than expected. As such, alternative energy sources are being pursued. Inuvik Gas has installed a propane air mixture system to produce synthetic natural gas. Potential long-term energy solutions are being investigated and work continues with the Town of Inuvik, the government of Northwest Territories and other parties. In August 2013, Inuvik Gas gave notice to the Town of Inuvik that they did not intend on extending the natural gas distribution franchise when it expires in August 2014.

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:

- Grow its existing utility infrastructure through infill and expansion of services within current franchise or certificate areas;
- Continue to upgrade the delivery systems within each utility to maintain public and worker safety, and to ensure reliable and efficient long-term operation of the gas delivery systems;
- Continue to work within regulatory processes to ensure fair returns are earned for shareholders;
- Develop rate-regulated infrastructure supporting the growth of LNG exports to Asia; and
- Develop or acquire assets in new market areas in Canada and in the United States.

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.

Certain 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 approximately 600 Mmcf/d on 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)*	**2013**	2012	2011
			(restated)
Revenue	**2,042.9**	1,449.7	1,280.0
Net revenue [1]	**960.2**	664.4	513.1
Normalized operating income [1]	**352.7**	234.6	184.3
Normalized EBITDA [1]	**508.9**	336.9	265.8
Net income applicable to common shares	**181.5**	101.8	82.7
Normalized net income [1]	**175.8**	109.5	90.2
Total assets	**7,281.3**	5,932.4	3,556.2
Total long-term liabilities	**3,727.4**	3,357.4	1,637.6
Net additions to property, plant and equipment	**1,144.6**	1,532.1	642.6
Dividends declared [2]	**173.6**	132.8	112.2
Cash flows			
Normalized funds from operations [1]	**402.7**	281.0	219.0

($ per share, except shares outstanding)	**2013**	2012	2011
			(restated)
Normalized EBITDA [1]	**4.38**	3.55	3.16
Net income – basic	**1.56**	1.07	0.98
Net income – diluted	**1.52**	1.06	0.97
Normalized net income [1]	**1.51**	1.15	1.07
Dividends declared [2]	**1.50**	1.40	1.34
Cash flows			
Normalized funds from operations [1]	**3.47**	2.96	2.61
Shares outstanding – basic *(millions)*			
During the year [3]	**116.1**	95.0	84.0
End of year	**122.3**	105.3	89.2

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 $0.11 beginning July 1, 2010, $0.115 beginning October 27, 2011, $0.12 beginning September 10, 2012, $0.125 beginning April 24, 2013 and $0.1275 beginning July 31, 2013.*
3 *Weighted average.*

FULL YEAR 2013 CONSOLIDATED FINANCIAL REVIEW

Normalized net income was $175.8 million ($1.51 per share) for 2013, an increase of 61 percent compared to $109.5 million ($1.15 per share) reported for 2012. Results for 2013 reflect the strength of AltaGas' operations and the positive contributions from growth across all business segments in the year.

Normalized net income increased in the year primarily due to the addition of SEMCO in August 2012 and Blythe in May 2013, both of which exceeded expectations. The Corporation also benefitted from higher realized power prices in Alberta, adjustments to the deferred tax liability, increased volumes processed in the Gas segment, earnings contribution from Petrogas, and colder weather in Alberta, Michigan and Nova Scotia. These increases were partially offset by higher interest expense as a result of financing the Corporation's growth projects, lower realized frac prices, lower transmission revenue, and higher general and administrative expenses.

Net income applicable to common shares for 2013 was $181.5 million ($1.56 per share) compared to $101.8 million ($1.07 per share) for 2012. In addition to the factors described in normalized net income, PNG received regulatory approval for the amended acquisition agreement for the sale of its interest in Pacific Trail Pipelines Limited Partnership (PTP) resulting in a $32.8 million after-tax gain. The Corporation also recorded after-tax provisions of $16.5 million related to certain non-core gas and utility assets which are expected to be sold and a $3.2 million write-off of certain power assets in 2013. On December 16, 2013, AltaGas sold ECNG, an energy management business in Burlington, Ontario, resulting in an after-tax gain of $2.9 million. In addition to these amounts, net income applicable to common shares for 2013 also included unrealized losses on risk management contracts, realized and unrealized gain (loss) on long-term investments, development costs incurred at AIJVLP, the impact of statutory tax rate changes, and acquisition related transaction costs.

Increased earnings also resulted in growth in cash flow for 2013. Normalized EBITDA for 2013 was $508.9 million, a 51 percent increase, compared to $336.9 million for 2012. Normalized funds from operations for 2013 increased 43 percent to $402.7 million ($3.47 per share), compared to $281.0 million ($2.96 per share) for 2012.

Normalized operating income for 2013 was $352.7 million, 50 percent higher compared to $234.6 million for 2012. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest expense and income taxes.

Operating and administrative expense for 2013 was $430.5 million, compared to $323.0 million for 2012. The increases were primarily due to growth in assets and the energy export development initiatives in 2013. Amortization expense for 2013 was $152.5 million compared to $99.3 million for 2012 mainly due to the asset growth of the Corporation. In 2013, $22.6 million of provisions related to non-core assets were recorded, compared to $2.9 million in 2012. Accretion expense for 2013 was $3.7 million compared to $3.1 million for 2012.

Interest expense for 2013 was $102.1 million compared to $61.2 million for 2012. Interest expense increased due to a higher average debt balance of $2,966.4 million for 2013, compared to $1,894.8 million for 2012, and due to a lower capitalized interest of $30.6 million in 2013, compared to $35.2 million in 2012. The higher average debt balance was a result of the Corporation's growth in the past year, primarily due to the addition of SEMCO and Blythe, the construction of the Northwest Projects, the acquisition of a 25 percent interest in Petrogas and the addition of gas projects constructed in 2012. The increase in interest expense was partially offset by a lower average borrowing rate of 4.5 percent in 2013 (2012 – 5.1 percent).

AltaGas recorded income tax expense of $40.1 million for 2013 compared to $46.1 million for 2012. Income tax expense decreased as a result of adjustments to deferred income tax liabilities, unrealized losses on risk management contracts 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 the current and prior years. The decrease in income tax expense was partially offset by higher earnings from the businesses and the gains on asset dispositions during the year.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $400 million to $500 million for 2014. 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, 2013, the Corporation had approximately $1.1 billion available on its credit facilities.

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwestern British Columbia: Forrest Kerr, Volcano Creek and McLymont Creek. All three projects are currently in various phases of construction. 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.

Forrest Kerr

Construction of the 195 MW Forrest Kerr run-of-river project continues ahead of schedule and on budget. The nine turbine generator units are assembled, aligned and grouted into position. The project is mechanically complete and commissioning is ongoing with in-service date expected to be in mid-2014, contingent on the availability of the NTL. Based on progress made over the past six months, AltaGas expects the NTL to be available in time to enable Forrest Kerr to be in service by mid-2014.

Volcano Creek

Construction continues to progress well on the 16 MW Volcano Creek run-of-river project. Intake construction and weir installation have been completed. The powerhouse building, turbine foundations and powerhouse crane installation have also been completed. The penstock excavation is complete with penstock installation to commence in the spring of 2014. The project is expected to be in service in late 2014.

McLymont Creek

Construction continues to progress well on the 66 MW McLymont Creek run-of-river project. Construction of the 7-kilometre McLymont Creek intake access road is complete. Excavation of the McLymont Creek power portal has been completed and approximately 50 percent of the 2,800 metre power tunnel has been excavated. Excavation of the powerhouse foundation is complete and installation of the powerhouse foundations has commenced. The project is expected to be in service in mid-2015.

AltaGas Idemitsu Joint Venture Limited Partnership (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 an LPG export business, including logistics, plant refrigeration and storage facilities.

LNG Export Business

Triton LNG, a wholly-owned subsidiary of AIJVLP, is currently developing the proposed project feasibility study which is expected to be completed in 2014. Triton LNG is also preparing preliminary engineering designs for the construction of the liquefaction facilities and is in discussions for potential site locations. Triton LNG is currently in discussions with market participants to develop sales and supply agreements. On October 29, 2013 Triton LNG filed an application with the National Energy Board (NEB) to export up to 2.3 million tonnes per year of LNG. Subject to consultations with First Nations, and the completion of the feasibility study, permitting, regulatory approvals and facility construction, the proposed LNG exports could begin as early as 2017.

Triton LNG has signed a TRA with PNG for 325 Mmcf/day of natural gas transportation capacity related to the PNG expansion providing a vital pipeline link to the west coast region of British Columbia. The TRA commits Triton LNG to backstop development costs related to the expansion of the pipeline.

LPG Export Business

AIJVLP is currently developing the proposed project feasibility study for LPG exports which is expected to be completed in 2014. Preliminary engineering designs for the construction of the LPG facilities as well as discussions on potential site locations have begun. AIJVLP is currently in discussions with market participants to develop sales and logistics agreements. Subject to consultations with First Nations, and the completion of the feasibility study, permitting, regulatory approvals and facility construction, the proposed LPG export business could begin as early as 2016.

On October 1, 2013, AltaGas completed the acquisition of a 25 percent equity interest in Petrogas, a privately-held leading North American integrated midstream company. Petrogas' extensive logistics network consists of over 1,500 rail cars and 24 rail and truck terminals, which provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities. On October 24, 2013 AltaGas announced it will increase its effective ownership of Petrogas to 33 1/3 percent. AltaGas plans to transfer its current 25 percent ownership to AIJVLP. AIJVLP will acquire an additional 41 2/3 percent interest in Petrogas. As a result of the transaction, Petrogas will be owned one-third by each of AltaGas, Idemitsu, and its current majority shareholder. All regulatory approvals have been obtained and the transaction is expected to close on March 1, 2014.

Pacific Northern Gas Ltd. Pipeline Looping Project (PLP)

PNG continues to proceed with the development of the potential expansion of approximately 600 Mmcf/d on its transmission line. PNG has signed 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. Douglas Channel Gas Services Ltd., one of the parties, is currently in a Companies' Creditors Arrangement Act proceeding, of which the outcome is not known at this time. On July 24, 2013, the British Columbia Environmental Assessment Office issued an order accepting PNG's PLP into the environmental assessment process following PNG's filing of its project description. PNG expects to continue environmental and consultation processes with a final investment decision on PLP expected in late 2015.

Cold Lake System Expansion

AltaGas is expanding its Cold Lake natural gas transmission system to deliver natural gas to two heavy oil projects near Cold Lake, Alberta. The expansions are underpinned by long-term take-or-pay transportation agreements and estimated to cost approximately $30 million. The first expansion project was completed in fourth quarter 2013, ahead of schedule and below budget. The second expansion project is expected to be in service in late 2014.

Cogeneration III

AltaGas is expanding its Cogeneration fleet at Harmattan to 45 MW. 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. Cogeneration III is expected to be in service in first half 2015 with a total project cost estimated at $40 million.

Alton Natural Gas Storage Project

AltaGas is developing the Alton Natural Gas Storage Project (Alton), with up to 10 Bcf of natural gas storage located near Truro, Nova Scotia. The first phase of the project is 4.5 Bcf of storage and is expected to be in service in 2017 at a construction cost of approximately $100 million. Alton expects to complete a 20-year firm storage agreement with Heritage Gas for approximately 4 Bcf of the first phase, which will be subject to regulatory approval.

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 are 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)*	2013	2012	2011
			(restated)
Net revenue [1]	**$ 960.2**	$ 664.4	$ 513.1
Add (deduct):			
Other income (expenses)	**(41.2)**	(0.6)	9.4
Income from equity investments	**(112.2)**	(66.6)	(75.3)
Cost of sales	**1,236.2**	852.5	832.8
Revenue (GAAP financial measure)	**$2,042.9**	$1,449.7	$1,280.0

1 *Amounts may not add due to rounding.*

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 operating activities for the Corporation.

Normalized Operating Income

Years ended December 31 *($ millions)*	2013	2012	2011
			(restated)
Normalized operating income	**$352.7**	$234.6	$184.3
Add (deduct):			
Transaction costs related to acquisitions	**(2.4)**	(6.8)	(5.7)
Realized/unrealized gain (loss) on long-term investments	**(5.4)**	0.2	(9.1)
Provision on property, plant and equipment	**(22.6)**	(2.9)	(0.6)
Sundance force majeure arbitration decision	**–**	(11.0)	–
Gain on asset dispositions	**41.4**	–	6.2
Joint venture development costs	**(3.6)**	–	–
Operating income	**360.1**	214.1	175.1
Add (deduct):			
Unrealized gain (loss) on risk management contracts	**(9.2)**	22.0	(9.0)
Interest expense	**(102.1)**	(61.2)	(52.7)
Foreign exchange loss	**(0.3)**	(8.5)	(0.4)
Income tax expense	**(40.1)**	(46.1)	(20.3)
Net income applicable to non-controlling interests	**(7.3)**	(3.5)	–
Preferred share dividends	**(19.6)**	(15.0)	(10.0)
Net income applicable to common shares (GAAP financial measure)	**$181.5**	$101.8	$ 82.7

Operating income is a measure of AltaGas' profitability from its principal operating activities prior to how these activities are financed, how the results are taxed, or the impact of unrealized gains or losses on risk management contracts. The measure is used to assess operating performance since management believes that it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, interest expense, foreign exchange (gain) 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/unrealized gain (loss) on long-term investments, provision taken on property, plant and equipment, gain on asset dispositions and arbitration decisions. Normalized operating income also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs from AltaGas.

Normalized EBITDA

Years ended December 31 *($ millions)*	2013	2012	2011
			(restated)
Normalized EBITDA	**$508.9**	$336.9	$265.8
Add (deduct):			
Transaction costs related to acquisitions	**(2.4)**	(6.8)	(5.7)
Realized/unrealized gain (loss) on long-term investments	**(5.4)**	0.2	(9.1)
Gain on asset dispositions	**41.4**	–	6.2
Joint venture development costs	**(3.6)**	–	–
Sundance force majeure arbitration decision	**–**	(11.0)	–
EBITDA	**538.9**	319.3	257.2
Add (deduct):			
Unrealized gain (loss) on risk management contracts	**(9.2)**	22.0	(9.0)
Depreciation, depletion and amortization	**(152.5)**	(99.2)	(79.1)
Provision on property, plant and equipment	**(22.6)**	(2.9)	(0.6)
Accretion of asset retirement obligations	**(3.7)**	(3.1)	(2.4)
Interest expense	**(102.1)**	(61.2)	(52.7)
Foreign exchange loss	**(0.3)**	(8.5)	(0.4)
Income tax expense	**(40.1)**	(46.1)	(20.3)
Net income applicable to non-controlling interests	**(7.3)**	(3.5)	–
Preferred share dividends	**(19.6)**	(15.0)	(10.0)
Net income applicable to common shares (GAAP financial measure)	**$181.5**	$101.8	$ 82.7

EBITDA is a measure of AltaGas' operating profitability without the impact of risk management contracts and prior to how business activities are financed, assets are amortized or earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk 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 gains or losses on risk management contracts, depreciation, depletion and amortization, provision taken on property, plant and equipment, accretion of asset retirement obligations, interest expense, foreign exchange (gain) 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/unrealized gain (loss) on long-term investments, gain on asset dispositions and arbitration decisions. Normalized EBITDA also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs from AltaGas.

Normalized Net Income

Years ended December 31 *($ millions)*	2013	2012	2011
			(restated)
Normalized net income	**$175.8**	$109.5	$90.2
Add (deduct) after-tax:			
Unrealized gain (loss) on risk management contracts	**(6.9)**	16.4	(6.9)
Realized/unrealized gain (loss) on long-term investments	**(4.7)**	0.2	(8.0)
Transaction costs and foreign exchange loss related to acquisitions	**(1.6)**	(12.9)	(4.3)
Gain on asset dispositions	**36.2**	–	5.4
Provision on property, plant and equipment	**(16.6)**	(2.1)	(0.5)
Joint venture development costs	**(2.7)**	–	–
Sundance force majeure arbitration decision	**–**	(8.2)	–
Statutory tax rate change	**2.0**	(1.1)	6.8
Net income applicable to common shares (GAAP financial measure)	**$181.5**	$101.8	$82.7

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as transaction costs related to acquisitions including foreign exchange gains or losses, gain on asset dispositions, provision taken on property, plant and equipment, statutory tax rate changes and arbitration decisions. Normalized net income also includes an adjustment for the development costs incurred by AIJVLP, net of recovered costs by AltaGas.

Normalized Funds from Operations

Years ended December 31 *($ millions)*	2013	2012	2011
			(restated)
Normalized funds from operations	**$402.7**	$281.0	$219.0
Add (deduct):			
Transaction costs and foreign exchange loss related to acquisitions	**(2.4)**	(15.4)	(5.7)
Sundance force majeure arbitration decision	**–**	(11.0)	–
Funds from operations	**400.3**	254.6	213.3
Add (deduct):			
Net change in operating assets and liabilities	**(32.1)**	(105.9)	(27.0)
Asset retirement obligations settled	**(1.9)**	(2.3)	(0.9)
Cash from operations (GAAP financial measure)	**$366.3**	$146.4	$185.4

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 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, expenditures incurred to settle asset retirement obligations and non-operating related expenses.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized Operating Income [1]

Years ended December 31 *($ millions)*	2013	2012
Gas	**$113.2**	$ 93.8
Power	**122.7**	91.3
Utilities	**149.7**	79.6
Sub-total: Operating Segments	**385.6**	264.7
Corporate	**(32.9)**	(30.1)
	$352.7	$234.6

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

GAS

OPERATING STATISTICS

Years ended December 31	2013	2012
Extraction and Transmission (E&T)		
Extraction inlet gas processed *(net Mmcf/d)* [1]	**941**	889
Extraction ethane volumes *(Bbls/d)* [1]	**30,999**	25,499
Extraction NGL volumes *(Bbls/d)* [1]	**20,672**	14,593
Total extraction volumes *(Bbls/d)* [1,2]	**51,671**	40,092
Frac spread – realized *($/Bbl)* [1,3]	**24.96**	30.83
Frac spread – average spot price *($/Bbl)* [1,4]	**27.15**	29.22
Field Gathering and Processing (FG&P)		
Processing throughput *(gross Mmcf/d)* [1]	**420**	372
Energy Services		
Average volumes transacted *(GJ/d)* [1,5]	**356,271**	356,526

1 *Average for the year.*

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 year 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 year.*

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.*

In 2013, average Extraction inlet gas processed increased by 52 Mmcf/d, average ethane volumes produced increased by 5,500 Bbls/d and NGL volumes produced increased by 6,079 Bbls/d, compared to 2012. Higher ethane and NGL volumes for 2013 were due to the addition of the Co-stream facility at Harmattan, optimization of certain extraction facilities, and higher volumes processed at Younger due to increased volumes from the Septimus pipeline, partially offset by routine turnarounds at certain AltaGas facilities.

During 2013, the Co-stream facility operated at 40 percent of its designed capacity. Throughout the year, AltaGas experienced lower pressures on the third party pipeline upstream of the Co-stream facility and compression issues within the facility. The operational issues have been fixed and the facility is now operating at full capacity.

FG&P throughput for 2013 averaged 420 Mmcf/d, a 13 percent increase compared to 372 Mmcf/d in 2012. The increase was primarily driven by the addition of the Gordondale facility, the Blair Creek expansion and the acquisition of a 50 percent interest in the Quatro Resources Inc.'s midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas Plant, in second half 2012. In 2013, the Blair Creek facility operated at approximately 75 percent utilization and the Gordondale gas plant operated as expected, with volumes increasing throughout the year with a year-end exit utilization of approximately 84 percent.

Full Year Results 2013

The Gas segment reported normalized operating income of $113.2 million in 2013, compared to $93.8 million in 2012. The increase was a result of higher natural gas volumes processed, higher frac exposed volumes and the earnings contribution from Petrogas. These increases were partially offset by lower realized frac prices and lower transmission revenue. Operating income in the Gas segment was $96.2 million for 2013 (2012 – $93.6 million) which includes the provision related to non-core assets for sale, transaction costs and AIJVLP development costs.

For the year ended December 31, 2013, AltaGas hedged approximately 70 percent of frac exposed NGL production at an average price of $27/Bbl before deducting extraction premiums. For the year ended December 31, 2012, AltaGas hedged approximately 80 percent of frac exposed NGL production at an average price of $35/Bbl before deducting extraction premiums. The average spot NGL frac spread in 2013 was approximately $27/Bbl after deducting extraction premiums compared to approximately $30/Bbl for 2012 after deducting extraction premiums.

POWER
OPERATING STATISTICS

Years ended December 31	2013	2012
Volume of power sold *(GWh)*	**4,458**	3,317
Average price realized on the sale of power *($/MWh)* [1]	**76.82**	69.42
Alberta Power Pool average spot price ($/MWh)	**80.19**	64.32

1 Price received excludes Blythe as it earns fixed capacity payments under its PPA with SCE.

For the year ended December 31, 2013, volume of power sold increased by 1,141 GWh compared to 2012. Volumes sold during 2013 comprised of 4,004 GWh conventional power generation and 454 GWh renewable power generation, compared to 2,875 GWh conventional power generation and 442 GWh renewable power generation in 2012. The increase in power generated was primarily due to the Blythe acquisition in May 2013, which added 471 GWh of power and the addition of new power generation assets throughout 2012. The Sundance Unit 3 had lower generation in 2012 due to a prolonged outage.

Full Year Results 2013

For the year ended December 31, 2013, the Power segment reported normalized operating income of $122.7 million compared to $91.3 million for 2012. Normalized operating income increased primarily as a result of the addition of Blythe Energy Center, and higher realized power prices and higher generation in Alberta. Variances in the volume of power generated at Blythe do not generally affect its earnings as the PPA with SCE provides a fixed capacity payment for Blythe. Operating income in the Power segment was $117.4 million in 2013, compared to $76.9 million in 2012, and includes the impact of transaction costs related to acquisitions, while 2012 included a one-time $11.0 million charge for the Sundance force majeure arbitration decision.

For the year ended December 31, 2013, AltaGas was 62 percent hedged in Alberta at an average price of $66/MWh. In 2012, AltaGas was 70 percent hedged at an average price of $67/MWh.

UTILITIES
OPERATING STATISTICS

Years ended December 31	2013	2012
Canadian utilities		
Natural gas deliveries – end-use *(PJ)* [1]	**30.4**	28.5
Natural gas deliveries – transportation *(PJ)* [1]	**5.8**	6.8
U.S. utilities [2]		
Natural gas deliveries – end-use *(Bcf)* [1]	**70.1**	26.0
Natural gas deliveries – transportation *(Bcf)* [1]	**41.4**	13.9
Service sites [3]	**555,198**	547,977
Degree day variance from normal – AUI *(%)* [4]	**0.5**	(0.7)
Degree day variance from normal – Heritage Gas *(%)* [4]	**1.3**	(9.1)
Degree day variance from normal – SEMCO Gas *(%)* [2,5]	**9.0**	(0.2)
Degree day variance from normal – ENSTAR *(%)* [2,5]	**(1.0)**	9.6

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

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

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

4 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.

5 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	2013	2012
Approved ROE *(%)*		
Canadian utilities *(average)*	10.0	10.0
U.S. utilities *(average)* [2]	11.3	11.3
Approved return on debt *(%)*		
Canadian utilities *(average)*	6.1	6.5
U.S. utilities *(average)* [2]	5.6	5.6
Rate base *($ millions)* [1]		
Canadian utilities	604.8	569.6
U.S. utilities [2,3,4]	773.0	741.0

1 *Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application, which may be different from that indicated above.*

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

3 *In US dollars.*

4 *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 $53.1 million (2012 $16.4 million) through a carry cost component. ENSTAR will determine, in association with its next rate case, the best way to be compensated for the cost associated with gas in storage, either as part of the rate base or through a carry cost component, and present that approach in its 2014 rate case filing for approval.*

Full Year Results 2013

For the year ended December 31, 2013, the Utilities segment reported normalized operating income of $149.7 million compared to $79.6 million for 2012. Normalized operating income increased mainly due to the acquisition of SEMCO which reported its first full year of earnings and performed better than expected. Colder weather in Michigan, Alberta and Nova Scotia and rate base growth at the utilities also added to earnings in the year.

Operating income in the Utilities segment was $184.2 million for 2013 (2012 – $80.7 million) and includes the pre-tax gain on the sale of PTP of $37.5 million and the provision related to certain assets.

CORPORATE

Full Year Results 2013

The normalized operating loss for the year ended December 31, 2013 was $32.9 million, compared to $30.1 million in 2012. The higher normalized loss was due to increased administrative expenses mainly for the energy export development initiatives. Operating loss in the Corporate segment was $37.7 million for 2013 (2012 – $37.1 million) and includes the impact of acquisition related transaction costs, the unrealized mark-to-market loss and a reclassification from other comprehensive income (OCI) to earnings for the period of $4.3 million of a pre-tax other than temporary loss on one of the Corporation's long-term investments.

INVESTED CAPITAL

For the year ended December 31, 2013, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $1,427.1 million, compared to $1,586.3 million in 2012. The net invested capital was $1,412.0 million for the year ended December 31, 2013, compared to $1,554.2 million in 2012.

Invested Capital – Investment Type

Year ended December 31, 2013 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$ 36.9**	**$877.9**	**$148.7**	**$ 4.8**	**$1,068.3**
Intangible assets	**3.6**	**–**	**5.6**	**11.6**	**20.8**
Long-term investments	**338.0**	**–**	**–**	**–**	**338.0**
	378.5	**877.9**	**154.3**	**16.4**	**1,427.1**
Disposals:					
Property, plant and equipment	**(15.1)**	**–**	**–**	**–**	**(15.1)**
Net Invested capital	**$363.4**	**$877.9**	**$154.3**	**$16.4**	**$1,412.0**

Invested Capital – Investment Type

Year ended December 31, 2012 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$361.5	$316.8	$882.9	$0.8	$1,562.0
Intangible assets	2.4	–	17.9	1.4	21.7
Long-term investments	0.8	–	1.8	–	2.6
	364.7	316.8	902.6	2.2	1,586.3
Disposals:					
Property, plant and equipment	(0.5)	(31.6)	–	–	(32.1)
Net Invested capital	$364.2	$285.2	$902.6	$2.2	$1,554.2

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

Invested Capital – Use

Year ended December 31, 2013 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	**$ 14.5**	**–**	**–**	**–**	**$ 14.5**
Growth	**363.3**	**877.9**	**154.3**	**0.4**	**1,395.9**
Administrative	**0.7**	**–**	**–**	**16.0**	**16.7**
Invested capital	**$378.5**	**$877.9**	**$154.3**	**$16.4**	**$1,427.1**

Invested Capital – Use

Year ended December 31, 2012 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	$ 9.4	$ 2.1	–	–	$ 11.5
Growth	352.7	314.7	902.6	0.2	1,570.2
Administrative	2.6	–	–	2.0	4.6
Invested capital	$364.7	$316.8	$902.6	$2.2	$1,586.3

For the year ended December 31, 2013, growth capital expenditures were $1,395.9 million (2012 – $1,570.2 million). In the Gas segment, growth capital included $330.5 million for the Petrogas acquisition, $10.8 million for completion of the Co-stream facility, $7.0 million invested in AIJVLP, and $15.0 million for various small Gas related projects. In the Power segment, growth capital projects included $544.5 million related to the Blythe acquisition, $263.4 million for Forrest Kerr, $36.1 million for McLymont Creek, $19.5 million for Volcano Creek, $12.3 million for Cogeneration III and $2.1 million for other power assets. The Utilities segment invested $76.2 million of capital at the U.S. utilities, $69.4 million at the Canadian utilities and $8.7 million related to the CNG business at Heritage Gas. The Corporate segment invested $0.4 million in 2013.

Maintenance and administrative capital expenditures for the year ended December 31, 2013 were $14.5 million and $16.7 million, respectively (2012 – $11.5 million and $4.6 million, respectively).

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 2013, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 19 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 energy services division transacts primarily on this basis.

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 $0.00/MWh to $1,000.00/MWh in both 2013 and 2012. The average Alberta spot price was $80.19/MWh in 2013 (2012 – $64.32/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, excluding Blythe which earns fixed capacity payments under its PPA with SCE, was $76.82/MWh in 2013 (2012 – $69.42/MWh). AltaGas is approximately one-third hedged for 2014 at an average price of approximately $65/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 2013, the Corporation had NGL frac spread hedges for an average of 4,000 Bbls/d at an average price of approximately $27/Bbl. The average spot NGL frac spread for 2013 was approximately $27/Bbl (2012 – $29/Bbl). The average NGL frac spread realized by AltaGas in 2013 was $25/Bbl (2012 – $31/Bbl). For 2014, AltaGas has hedged approximately 70 percent of its estimated volumes that are exposed to frac spread at an average price of $25/Bbl prior to 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, 2013, the Corporation had no interest rate swaps outstanding. At December 31, 2013, the Corporation had fixed the interest rate on 72.7 percent of its debt (December 31, 2012 – 73.5 percent).

Foreign Exchange Forward Contracts

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold. As at December 31, 2013, management designated US$570.0 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2012 – US$396.5 million).

Business Risks

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

Risks	Strategies and Organizational Capability to Mitigate Risks
Long-term natural gas volume declines	• Contract provisions underpin capital commitments • 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
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 facilities • Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs • Long-term maintenance contract with wind turbine manufacturer (Enercon) • 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
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 • Disciplined hedging strategy with hedge targets approved by the Board of Directors • Monitor hedge transactions through Risk Management Committee • AltaGas' policy dealing with commodity risk (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 • 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 • Execute long-term inflation adjusted electricity purchase arrangements with power buyers

Risks	Strategies and Organizational Capability to Mitigate Risks
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty credit worthiness • Establish credit thresholds using conservative 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
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
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 which means variations in weather do not materially affect PNG's earnings
Regulatory and First Nations	• Regulatory and commercial personnel monitor and react to regulatory issues • Proactive regulatory and government relations group, with strong working relationships with First Nations and their stakeholders, and the respective regulators and their staff • 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, which AltaGas continually strives to improve • Focus on mitigating the impact of the Specified Gas Emitters Regulations
Labour relations	• Access to a strong labour market to attract qualified talent to the organization • Positive employee relations to retain existing talent and maintain strong relations with unions

LIQUIDITY

Cash Flows

Years ended December 31 *($ millions)*	**2013**	2012
Cash from operations	**$366.3**	$146.4
Investing activities	**(1,264.8)**	(1,624.5)
Financing activities	**930.8**	1,487.1
Effect of exchange rate	**0.6**	–
Change in cash	**$ 32.9**	$ 9.0

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $366.3 million in 2013 compared to $146.4 million in 2012. The increase in cash from operations was primarily due to earnings from new and expanded assets, higher realized power prices and higher generation in Alberta, and higher distributions from equity investments, partially offset by lower realized frac prices. In addition, cash from operating assets and liabilities decreased by $32.1 million compared to a decrease of $105.8 million in 2012 mainly due to seasonality of the new U.S. utility assets and the timing of asset acquisitions in 2012.

Working Capital

As at December 31 *($ millions except current ratio)*	**2013**	2012
Current assets	**$618.4**	$607.7
Current liabilities	**724.4**	575.2
Working capital	**(106.0)**	32.5
Current ratio	**0.85**	1.06

Working capital was in a deficit position of $106.0 million as at December 31, 2013, compared to a working capital surplus of $32.5 million as at December 31, 2012. The working capital ratio was 0.85 at the end of 2013 compared to 1.06 at the end of 2012. The working capital ratio decreased mainly due to the reclassification of $200 million of AltaGas' MTNs with maturity of April 1, 2014 as current portion of long-term debt.

Investing Activities

Cash used for investing activities in 2013 was $1,264.8 million compared to $1,624.5 million in 2012. Investing activities in 2013 were primarily comprised of $536.8 million related to the Blythe acquisition, $501.2 million related to construction of capital projects, $230.5 million related to the investment in Petrogas and $46.5 million for intangible assets, compared to investing activities in 2012 of $806.0 million related to the SEMCO and Decker acquisitions, $768.7 million related to construction activity and $52.8 million for intangible assets. During 2013, the Corporation received $51.0 million (2012 – $18.3 million) as proceeds from disposition of assets, primarily related to the sale of PTP and ECNG.

Financing Activities

Cash received from financing activities was $930.8 million in 2013 compared to $1,487.1 million in 2012. Financing activities in 2013 were primarily comprised of net proceeds from issuance of $2.1 billion of long-term debt, issuance of common shares of $447.6 million from DRIP and stock option exercises, and issuance of preferred shares of $194.9 million, partially offset by $1.6 billion repayment of long-term debt. Financing activities in 2012 were primarily comprised of $1,054.0 million from issuance of MTNs and other long-term debt, $105.1 million of long-term debt repayment, and net proceeds from issuance of common shares of $419.4 million, primarily related to the acquisition of SEMCO, and issuance of preferred shares of $199.0 million. Dividends paid to common and preferred shareholders in 2013 were $189.8 million, compared to $145.3 million in 2012.

CAPITAL RESOURCES

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

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

As at December 31, 2013, AltaGas had $2,111.1 million in MTNs outstanding, PNG debenture notes of $60.9 million, SEMCO long-term debt of $405.8 million and $822.5 million drawn from bank credit facilities. As at December 31, 2013, AltaGas' current portion of long-term debt was $209.1 million.

AltaGas' earnings interest coverage for the rolling twelve months ended December 31, 2013 was 2.64 times.

AltaGas' debt-to-total capitalization ratio as at December 31, 2013 was 53.1 percent (December 31, 2012 – 57.4 percent).

($ thousands)	**December 31, 2013**	December 31, 2012
Debt		
Short-term debt	**$ 84,350**	$ 66,938
Current portion of long-term debt	**209,069**	9,302
Long-term debt	**2,952,673**	2,626,086
Less: cash and cash equivalent	**(44,812)**	(11,827)
Net debt	**3,201,280**	2,690,499
Shareholders' equity	**2,791,707**	1,959,791
Non-controlling interests	**37,763**	40,006
Total capitalization	**$6,030,750**	$4,690,296
Debt-to-total capitalization ratio *(%)*	**53.1**	57.4

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, 2013:

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

As at December 31, 2013, the Corporation had approximately $1.1 billion of available credit facilities and $44.8 million in cash and cash equivalents.

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

On September 28, 2012, AltaGas issued $350 million of senior unsecured MTNs. The notes carry a coupon rate of 3.72 percent and mature on September 28, 2021.

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

On April 4, 2013, AltaGas closed a public offering of 11,615,000 common shares at a price of $34.90 per common share for aggregate gross proceeds of approximately $405 million.

On April 12, 2013, AltaGas issued US$175 million of senior unsecured MTNs. The notes carry a floating rate coupon of three-month LIBOR plus 0.79 percent and mature on April 13, 2015.

On May 17, 2013, the CINGSA construction credit facility for US$90 million was converted to a term loan of US$82.1 million with maturity of November 13, 2015.

On June 7, 2013, PNG repaid and cancelled its $35 million term revolver. The majority of the funds used to repay the term revolver were sourced from PNG's new 5-year $70 million revolving term facility provided by AltaGas.

On June 11, 2013, AltaGas issued $300 million of senior unsecured MTNs. The notes carry a coupon rate of 3.57 percent and mature on June 12, 2023.

On August 23, 2013, a new $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, 2013, $3.8 billion remains available on the base shelf prospectus.

On December 13, 2013, AltaGas issued 8,000,000 five-year rate-reset Series E Preferred Shares, at a price of $25 per Series E Preferred Share for aggregate gross proceeds of $200 million.

On December 20, 2013, SEMCO amended its US$100 million unsecured credit facility dated August 30, 2012 by increasing the size of the facility to US$150 million and extending the maturity date to December 20, 2018.

On December 20, 2013 AltaGas entered into an agreement for a $1.4 billion unsecured credit facility which expires on December 15, 2017. This facility replaces the $200 million Utility Group revolving credit facility, the US$300 million unsecured credit facility and the $600 million AltaGas Ltd. revolving credit facility.

Credit Facilities

($ millions)	Borrowing capacity	**Drawn at December 31, 2013**	Drawn at December 31, 2012
Demand operating facilities	$ 70.0	**$ 10.8**	$ 6.1
Extendible revolving letter of credit facility	150.0	**67.5**	50.0
PNG operating facility	25.0	**15.3**	15.4
PNG term revolver [1]	–	**–**	30.0
Bilateral letter of credit facility	125.0	**67.6**	89.8
AltaGas Ltd. revolving credit facility [2,3]	1,400.0	**597.6**	227.3
Utility Group revolving credit facility [3]	–	**–**	131.3
US$ unsecured credit facility [2,3]	–	**–**	169.1
SEMCO Energy US$ unsecured credit facility [2,4]	150.0	**63.7**	50.0
CINGSA US$ secured construction and term loan facility [2,4,5]	–	**–**	77.1
	$1,920.0	**$822.5**	$846.1

1 The facility was paid and cancelled in June 2013.

2 Amount drawn at December 31, 2013 converted at December 2013 month-end rate of 1 US dollar = 1.0636 Canadian dollar (Amount drawn at December 31, 2012 converted at December 2012 month-end rate of 1 US dollar = 0.9949 Canadian dollar).

3 On December 20, 2013, these facilities were consolidated into the $1.4 billion AltaGas Ltd. revolving credit facility.

4 Borrowing capacity assumed at par.

5 Converted into long-term debt with maturity of November 14, 2015.

CONTRACTUAL OBLIGATIONS

December 31, 2013	Payments Due by Period				
($ millions)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	$3,161.2	$210.4	$ 578.5	$ 971.7	$1,400.6
Capital leases	0.4	–	–	–	0.4
Operating leases	36.8	7.4	12.1	7.0	10.3
Purchase obligations	1,326.8	278.9	548.8	454.4	44.7
Capital project commitments	267.2	65.6	35.0	19.6	147.0
Pension plan and retiree benefits	193.0	28.9	29.1	32.5	102.5
Total contractual obligations	$4,985.4	$591.2	$1,203.5	$1,485.2	$1,705.5

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

Capital project commitments are related to the construction costs of the Northwest Projects and Gas projects. Amounts are estimates and are subject to variability depending on actual construction costs.

RELATED PARTY TRANSACTIONS

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 (December 31, 2012 – $750,000).

For the year ended December 31, 2013, AltaGas recovered $830,000 from AIJVLP, inclusive of $600,000 for staffing costs and $230,000 for office rent and administrative services (2012 – Nil).

CREDIT RATINGS

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

On December 4, 2013, DBRS Limited (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).

On September 24, 2012, DBRS reaffirmed the BBB and Pfd-3 ratings for AltaGas.

On May 31, 2012, DBRS commenced rating of the Series C Preferred Shares with a rating of Pfd-3.

On May 30, 2012, S&P commenced rating of the Series C 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" and "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, 2013, AltaGas had 122.3 million common shares, 8.0 million series A Preferred Shares, 8.0 million series C US$ Preferred Shares and 8.0 million series E Preferred Shares outstanding with a combined market capitalization of approximately $5.6 billion based on a closing trading price on December 31, 2013 of $40.77 per common share, $25.32 per series A Preferred Share, $24.87 per series C US$ Preferred Share and $25.40 per series E Preferred Share respectively.

As at December 31, 2013, there were 5.6 million options outstanding and 2.9 million options exercisable under the terms of the share option plan.

DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends are determined by giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements.

On October 27, 2011, the Board of Directors approved an increase in the monthly dividend to $0.115 per common share from $0.11 per common share effective with the November dividend.

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.

The following table summarizes AltaGas' dividend declaration history:

Dividends

Years ended December 31 *($ per common share)*	**2013**	2012	2011
First quarter	**$ 0.36**	$0.345	$ 0.33
Second quarter	**0.37**	0.345	0.33
Third quarter	**0.38**	0.35	0.33
Fourth quarter	**0.3825**	0.36	0.34
Total	**$1.4925**	$1.40	$1.33

Series A Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2013**	2012	2011
First quarter	**$0.3125**	$0.3125	$0.3125
Second quarter	**0.3125**	0.3125	0.3125
Third quarter	**0.3125**	0.3125	0.3125
Fourth quarter	**0.3125**	0.3125	0.3125
Total	**$ 1.25**	$ 1.25	$ 1.25

Series C Preferred Share Dividends

Years ended December 31 *(US$ per preferred share)*	**2013**	2012	2011
First quarter	**$0.275**	–	–
Second quarter	**0.275**	–	–
Third quarter	**0.275**	0.3473	–
Fourth quarter	**0.275**	0.2750	–
Total	**$ 1.10**	$0.6223	–

The first dividend declaration for Series E Preferred Shares is expected in March 2014.

SUBSEQUENT EVENTS

On October 24, 2013, AltaGas announced that it will increase its effective ownership of Petrogas to 33 1/3 percent. AltaGas plans to transfer its current 25 percent ownership to AIJVLP. AIJVLP will acquire an additional 41 2/3 percent interest in Petrogas. As a result of the transaction, Petrogas will be owned one-third by each of AltaGas, Idemitsu, and its current majority shareholder. All regulatory approvals have been obtained and the transaction is expected to close on March 1, 2014.

On December 20, 2013, AltaGas entered in a unit and share purchase agreement for the acquisition of the remaining 50 percent ownership interest in Alton that it does not already own. The transaction closed on February 20, 2014.

On January 13, 2014, AltaGas issued $200 million of senior unsecured MTNs with a coupon rate of 4.40 percent and maturity of March 15, 2024 and $100 million senior unsecured MTNs with a coupon rate of 5.16 percent and maturity of January 13, 2044.

On January 24, 2014, AltaGas Processing Partnership, a wholly-owned subsidiary of AltaGas, entered in a sale agreement for Ante Creek, a 58.5 Mmcf/d (licensed capacity) 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 approximately $12 million.

On February 14, 2014, AltaGas redeemed $200 million of senior unsecured MTNs early, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014.

CRITICAL ACCOUNTING ESTIMATES

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

AltaGas' critical accounting estimates continue to be financial instruments, depreciation, depletion, amortization and impairment 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 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. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is uncertainty related to assumptions about reserve quantities; 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 the 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 consistent 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 17 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, AUI, Heritage Gas, and PNG engage in the delivery and sale of natural gas and are regulated by the MPSC and RCA, AUC, NSUARB and BCUC, respectively.

The MPSC, RCA, AUC, NSUARB and BCUC 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 MPSC, RCA, AUC, NSUARB and BCUC, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation.

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.

OFF-BALANCE SHEET ARRANGEMENTS

AltaGas is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. AltaGas has no obligation under derivative instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services.

DISCLOSURE CONTROLS AND PROCEDURES (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.

- 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 Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR and concluded that AltaGas' DCP and ICFR were effective at December 31, 2013. 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 2013, 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

Three months ended December 31 *($ millions)*	2013	2012
Gas [1]	**$38.8**	$26.5
Power [2]	**29.6**	28.1
Utilities	**55.4**	50.5
Sub-total: Operating Segments	**123.8**	105.1
Corporate [3]	**(11.9)**	(8.7)
	$111.9	$96.4

1 *Excludes transaction costs, gains on asset disposition and AIJVLP development costs.*

2 *Excludes transaction costs, and provision on property, plant and equipment.*

3 *Excludes transaction costs, realized/unrealized gain/loss on long-term investments and recovery of costs from joint venture.*

Fourth quarter results reflect the seasonality of earnings from the natural gas distribution utilities. Natural gas distribution utilities earn the majority of revenue in first and fourth quarters during the winter heating season.

Normalized net income for fourth quarter 2013 was $59.9 million, an increase of 29 percent compared to $46.6 million reported in fourth quarter 2012. On a per share basis, earnings increased 11 percent to $0.49 compared to $0.44 for same quarter last year. Normalized net income increased primarily due to asset growth and positive earnings contributions across all three business segments driven by higher frac exposed volumes, adjustments to the deferred tax liability, higher volumes at Bear Mountain, and colder weather in Michigan and Nova Scotia compared to fourth quarter 2012. The increases were partially offset by lower realized frac prices, higher interest expense, lower realized Alberta power prices, and higher general and administrative expenses.

Net income applicable to common shares for fourth quarter 2013 was $53.2 million ($0.44 per share) compared to $26.7 million ($0.25 per share) in fourth quarter 2012. In addition to the items noted in normalized net income, the Corporation recorded a $2.0 million after-tax write down of certain power assets under development. On December 16, 2013, AltaGas sold ECNG, an energy management business in Burlington, Ontario, resulting in an after-tax gain of $2.9 million.

Net income applicable to common shares for fourth quarter 2013 was normalized for after-tax amounts related to the following: the gain on the sale of assets, provision taken on non-core assets, unrealized gains on risk management contracts, development costs incurred for the AIJVLP projects, realized and unrealized losses on long-term investments and acquisition related transaction costs.

Normalized EBITDA for fourth quarter 2013 was $153.3 million, an 18 percent increase, compared to $129.4 million in same quarter 2012. Normalized funds from operations for fourth quarter 2013 increased five percent to $117.1 million ($0.96 per share), compared to $112.0 million ($1.07 per share) in same quarter 2012. The lower normalized funds from operations on a per share basis was due to the timing of cash distributions from equity-owned investments.

Normalized operating income for fourth quarter 2013 was 16 percent higher at $111.9 million compared to $96.4 million in same quarter 2012. Normalized operating results were driven by the same factors as described above related to normalized net income excluding interest expense and income taxes.

Operating and administrative expense for fourth quarter 2013 was $117.6 million, compared to $98.7 million in same quarter 2012. The increases were primarily due to growth in assets and the energy export development initiatives in fourth quarter 2013. Amortization expense for fourth quarter 2013 increased to $40.4 million compared to $32.3 million in same quarter 2012 mainly due to the asset growth of the Corporation. Accretion expense for fourth quarter 2013 was $0.9 million compared to $0.8 million in same quarter 2012.

Interest expense for fourth quarter 2013 was $27.1 million compared to $21.6 million in same quarter 2012. Interest expense increased due to a higher average debt balance of $3,331.0 million in fourth quarter 2013 (fourth quarter 2012 – $2,637.3 million) and lower capitalized interest of $9.1 million in fourth quarter 2013 (fourth quarter 2012 – $9.7 million). The higher debt was a result of the Corporation's growth in the past year. The increase in interest expense was partially offset by a lower average borrowing rate of 4.3 percent in fourth quarter 2013 (fourth quarter 2012 – 4.7 percent).

AltaGas recorded an income tax expense of $14.5 million for fourth quarter 2013 compared to income tax expense of $18.5 million in same quarter 2012. Income tax expense decreased as a result of an adjustment to the deferred income tax liability, partially offset by higher earnings from the business and lower unrealized losses on risk management contracts in fourth quarter 2013.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2014 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per share
Gathering and Processing volumes	5 Mmcf/d	$0.01
Gathering and Processing operating margin per Mcf	1 cent/Mcf	$0.01
Alberta electricity prices [1]	$1/MWh	$0.01
Natural gas liquids fractionation spread [2]	$1/Bbl	less than $ 0.01
Degree day variance from normal – Canadian utilities [3]	5 percent	$0.02
Degree day variance from normal – U.S. utilities [4]	5 percent	$0.02
Change in CAD per US$ exchange rate	$0.05	$0.02

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

2 *Based on approximately two-thirds 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 [1]

($ millions)	Q4-13	Q3-13	Q2-13	Q1-13	Q4-12	Q3-12	Q2-12	Q1-12
Total revenue	**581.2**	**389.7**	**458.6**	**613.5**	525.8	290.0	272.2	361.7
Net revenue [2]	**264.6**	**246.6**	**211.8**	**237.1**	207.6	146.2	144.0	166.5
Operating income [2]	**104.7**	**80.9**	**66.8**	**107.7**	81.7	33.4	29.4	69.6
Net income before taxes	**75.1**	**57.4**	**39.6**	**76.4**	51.8	18.8	37.9	57.8
Net income applicable to common shares	**53.2**	**43.3**	**35.9**	**49.0**	26.7	8.0	25.8	41.3

($ per share)	Q4-13	Q3-13	Q2-13	Q1-13	Q4-12	Q3-12	Q2-12	Q1-12
Net income applicable to common shares								
Basic	**0.44**	**0.36**	**0.31**	**0.46**	0.25	0.08	0.29	0.46
Diluted	**0.43**	**0.35**	**0.30**	**0.45**	0.25	0.08	0.28	0.45
Dividends declared	**0.38**	**0.38**	**0.37**	**0.36**	0.36	0.35	0.345	0.345

1 *Amounts may not add due to rounding.*

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

Significant items that impacted individual quarterly earnings were as follows:

- In second quarter 2012, AltaGas recorded $3.5 million gain from the settlement of a dispute with a gas processing customer;
- In third quarter 2012, AltaGas completed the acquisition of SEMCO for total consideration of US$1.156 billion including US$371 million in assumed debt, adding approximately US$725 million in regulated rate base. In the quarter, AltaGas recorded $12.5 million in pre-tax transaction costs and foreign exchange losses primarily related to the acquisition of SEMCO and other business development related activities;
- In fourth quarter 2012, AltaGas wrote down $2.9 million related to three wind projects under development;
- In fourth quarter 2012, AltaGas received an independent arbitration panel ruling regarding a claim of force majeure on Sundance Unit 3. As a result, AltaGas recorded a $11.0 million charge in cost of sales which was previously accrued in accounts receivable;
- In second quarter 2013, AltaGas completed the acquisition of Blythe for total consideration of US$515 million. AltaGas recorded $1.3 million in pre-tax transaction costs;
- In second quarter 2013, AltaGas recorded an adjustment 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 $37.5 million pre-tax gain on the sale of PTP by PNG;
- In third quarter 2013, AltaGas recorded provisions of $18.9 million related to the planned sale of certain non-core gas and utility assets;
- In fourth quarter 2013, AltaGas sold its Energy Management business in Burlington, Ontario to an unrelated third party. AltaGas recorded a pre-tax gain of $3.9 million and transaction costs of $0.5 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 2.8 million shares priced at $35.69 per share and $230.5 million of cash;
- In fourth quarter 2013, AltaGas reclassified an other-than-temporary pre-tax loss of $4.3 million on its investment in Alterra from OCI to income for the period; and
- In fourth quarter 2013, AltaGas recorded pre-tax provisions of $3.1 million related to six wind projects under development.

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 2013 to that in 2012. 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, 2013, 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, 2013 and 2012, 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, 2013 and 2012 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 26, 2014

Ernst & Young LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at *($ thousands)*	December 31 2013	December 31 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 44,812	$ 11,827
Accounts receivable *(note 19)*	368,296	382,610
Inventory *(note 8)*	123,408	94,709
Restricted cash holdings from customers	2,662	28,626
Regulatory assets *(note 18)*	6,046	4,345
Risk management assets *(note 19)*	34,988	47,788
Prepaid expenses and other current assets	33,224	21,456
Deferred income taxes *(note 17)*	4,975	16,375
	618,411	607,736
Property, plant and equipment *(note 9)*	4,952,526	3,949,166
Intangible assets *(note 10)*	195,259	189,790
Goodwill *(note 11)*	743,101	714,902
Regulatory assets *(note 18)*	241,210	275,263
Risk management assets *(note 19)*	12,250	18,132
Deferred income taxes *(note 17)*	836	4,060
Restricted cash holdings from customers	12,763	–
Long-term investments and other assets *(notes 12 and 19)*	25,864	24,969
Investments accounted for by equity method *(note 13)*	479,083	148,358
	$7,281,303	$5,932,376
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 19)*	$ 318,982	$ 370,011
Dividends payable	15,594	12,640
Short-term debt *(note 14)*	84,350	66,938
Current portion of long-term debt *(notes 15 and 19)*	209,069	9,302
Customer deposits	34,955	51,756
Regulatory liabilities *(note 18)*	1,838	1,971
Risk management liabilities *(note 19)*	44,675	39,734
Deferred income taxes *(note 17)*	508	12,539
Other current liabilities	14,478	10,301
	724,449	557,192
Long-term debt *(notes 15 and 19)*	2,952,673	2,626,086
Asset retirement obligations *(note 16)*	76,125	56,632
Deferred income taxes *(note 17)*	442,844	399,171
Regulatory liabilities *(note 18)*	124,262	104,282
Risk management liabilities *(note 19)*	7,071	10,526
Other long-term liabilities	52,584	33,786
Future employee obligations *(note 23)*	71,825	126,904
	4,451,833	3,932,579

CONSOLIDATED BALANCE SHEETS (continued)

As at *($ thousands)*	**December 31 2013**	December 31 2012
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 122.3 million issued and outstanding *(note 20)*	**2,211,400**	1,639,895
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**194,126**	194,126
Preferred shares Series C cumulative redeemable five-year; par value US$25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**200,626**	200,626
Preferred shares Series E cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 20)*	**194,873**	–
Contributed surplus	**13,350**	10,570
Accumulated deficit	**(62,148)**	(69,979)
Accumulated other comprehensive income (loss)	**39,480**	(15,447)
Total shareholders' equity	**2,791,707**	1,959,791
Non-controlling interests	**37,763**	40,006
	$7,281,303	$5,932,376

Commitments *(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
Director

CONSOLIDATED STATEMENTS OF INCOME

For the years ended December 31 *($ thousands except per share amounts)*	2013	2012
REVENUE		
Sales	**$747,466**	$674,156
Services	**416,910**	436,765
Regulated operations	**888,933**	313,041
Other revenue (loss)	**(1,135)**	3,661
Unrealized gain (loss) on risk management contracts *(note 19)*	**(9,242)**	22,057
	2,042,932	1,449,680
EXPENSES		
Cost of sales, exclusive of items shown separately	**1,236,157**	852,545
Operating and administrative	**430,479**	323,012
Accretion of asset retirement obligations *(note 16)*	**3,736**	3,115
Depreciation, depletion and amortization *(notes 9 and 10)*	**152,485**	99,275
Provision on property, plant and equipment *(note 4)*	**22,593**	2,853
	1,845,450	1,280,800
Income from equity investments *(note 13)*	**112,175**	66,597
Other income (expenses) *(notes 5 and 7)*	**41,221**	580
Foreign exchange loss	**(290)**	(8,512)
Interest expense		
Short-term debt	**2,292**	1,552
Long-term debt	**99,782**	59,685
Income before income taxes	**248,514**	166,308
Income tax expense *(note 17)*		
Current	**19,835**	8,973
Deferred	**20,252**	37,077
Net income after-taxes	**208,427**	120,258
Net income applicable to non-controlling interests	**7,331**	3,489
Net income applicable to controlling interests	**201,096**	116,769
Preferred share dividends	**19,630**	14,922
Net income applicable to common shares	**$181,466**	$101,847
Net income per common share *(note 21)*		
Basic	**$ 1.56**	$ 1.07
Diluted	**$ 1.52**	$ 1.06
Weighted average number of common shares outstanding *(notes 20 and 21)* *($ thousands)*		
Basic	**116,068**	94,986
Diluted	**119,509**	96,311

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 *($ thousands)*	2013	2012
Net income after-taxes	**$208,427**	$120,258
Total other comprehensive income (loss) (net of taxes)	**54,927**	(3,607)
Comprehensive income attributable to common shareholders and non-controlling interests (net of tax)	**$263,354**	$116,651
Comprehensive income attributable to:		
Non-controlling interests	**$7,331**	$3,489
Common shareholders	**256,023**	113,162
	$263,354	$116,651

CONSOLIDATED ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)[1]

($ thousands)	Available-for-sale	Cash flow hedges	Defined benefit pension plans	Hedge net investments	Translation foreign operations	Total
Opening balance, January 1, 2013	$(5,787)	$ (994)	$(10,246)	$ (2,263)	$ 3,843	$(15,447)
Other comprehensive income before reclassification	(879)	(10,147)	3,898	(33,663)	90,633	49,842
Amounts reclassified from other comprehensive income *(note 3)*	3,721	734	630	–	–	5,085
Net current period other comprehensive income (loss)	$ 2,842	$ (9,413)	$ 4,528	$(33,663)	$90,633	$ 54,927
Ending balance, December 31, 2013 [2,3,4,5]	**$(2,945)**	**$(10,407)**	**$ (5,718)**	**$(35,926)**	**$94,476**	**$ 39,480**
Opening balance, January 1, 2012	$(5,895)	$ (2,803)	$ (3,142)	–	–	$(11,840)
Other comprehensive income (loss) before reclassification	108	–	(6,770)	(2,263)	3,843	(5,082)
Amounts reclassified from other comprehensive income *(note 3)*	–	1,809	(334)	–	–	1,475
Net current period other comprehensive income (loss)	$ 108	$ 1,809	$ (7,104)	(2,263)	3,843	$ (3,607)
Ending balance, December 31, 2012 [2,3,4,5]	$(5,787)	$ (994)	$(10,246)	(2,263)	3,843	$(15,447)

1 All amounts are net of tax where applicable. Amounts in parenthesis indicate debits.
2 Available-for-sale – net of tax recovery $427 (December 31, 2012 – tax recovery $723)
3 Cash flow hedges – net of tax recovery $3,415 (December 31, 2012 – Nil).
4 Defined benefit pension plans – net of tax recovery $1,009 (December 31, 2012 – tax recovery $2,480).
5 Hedge net investment – net of tax recovery $5,175 (December 31, 2012 – tax recovery $323).

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

For the years ended December 31 *($ thousands)*	2013	2012
Common shares *(note 20)*		
Balance, beginning of year	$1,639,895	$1,204,269
Shares issued for cash on exercise of options	18,916	16,197
Shares issued under DRIP [1]	60,305	41,071
Shares issued on private issuance *(note 6)*	100,000	–
Shares issued on public offering	392,284	–
Shares issued on conversion of subscription receipts	–	378,358
Balance, end of year	2,211,400	1,204,269
Preferred shares *(note 20)*		
Balance, beginning of year	394,752	194,126
Series C issued	–	200,626
Series E issued	194,873	–
Balance, end of year	589,625	394,752
Contributed surplus		
Balance, beginning of year	10,570	7,441
Share options expense	4,575	4,032
Exercise of share options	(1,386)	(649)
Forfeiture of share options	(409)	(254)
Balance, end of year	13,350	10,570
Accumulated deficit		
Balance, beginning of year	(69,979)	(38,634)
Net income applicable to controlling interests	201,096	116,769
Acquisition of non-controlling interest	–	(405)
Common share dividends	(173,635)	(132,787)
Preferred share dividends	(19,630)	(14,922)
Balance, end of year	(62,148)	(69,979)
Accumulated other comprehensive income (loss)		
Balance, beginning of year	(15,447)	(11,840)
Other comprehensive income (loss)	54,927	(3,607)
Balance, end of year	39,480	(15,447)
Total shareholders' equity	2,791,707	1,959,791
Non-controlling interests		
Balance, beginning of year	40,006	5,426
Net income applicable to non-controlling interests	7,331	3,489
Business acquisition	–	36,439
Acquisition of non-controlling interests	–	(5,438)
Distribution by subsidiaries to non-controlling interests	(9,574)	(1,357)
Contributions from subsidiaries to non-controlling interests	–	1,447
Balance, end of year	37,763	40,006
Total equity	$2,829,470	$1,999,797

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 *($ thousands)*	2013	2012
Cash from operations		
Net income after-taxes	**$208,427**	$120,258
Items not involving cash:		
Depreciation, depletion and amortization	**152,485**	99,275
Provision on property, plant and equipment	**22,593**	2,853
Accretion of asset retirement obligations	**3,736**	3,115
Share-based compensation	**4,166**	3,129
Deferred income tax expense	**20,252**	37,077
Gain on sale of assets	**(41,512)**	(73)
Income from equity investments	**(112,175)**	(66,597)
Unrealized (gain)/loss on risk management contracts	**9,242**	(22,057)
Realized/unrealized (gain)/loss on long-term investments	**5,379**	(173)
Other	**5,296**	3,734
Asset retirement obligations settled	**(1,859)**	(2,329)
Distributions from equity investments	**122,381**	73,978
Changes in operating assets and liabilities:		
Accounts receivable	**28,045**	(107,977)
Inventory	**(18,774)**	(10,050)
Other current assets	**(8,987)**	17,135
Regulatory assets (current)	**(1,490)**	827
Accounts payable and accrued liabilities	**(48,633)**	33,742
Customer deposits	**(8,259)**	4,763
Regulatory liabilities (current)	**(372)**	1,147
Other current liabilities	**2,668**	(17,849)
Other operating assets and liabilities	**23,732**	(27,571)
	366,341	146,357
Investing activities		
Change in restricted cash holdings from customers	**6,058**	(6,802)
Acquisition of property, plant and equipment	**(501,156)**	(768,651)
Acquisition of intangible assets	**(46,530)**	(52,809)
Proceeds from dispositions of assets	**50,999**	18,261
Contributions to equity investments	**(6,841)**	(2,606)
Business acquisitions, net of cash acquired	**(536,795)**	(806,014)
Acquisition of equity investment	**(230,500)**	–
Acquisition of non-controlling interest	**–**	(5,843)
	(1,264,765)	(1,624,464)

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

For the years ended December 31 *($ thousands)*	2013	2012
Financing activities		
Net issuance of short-term debt	**14,555**	48,905
Issuance of long-term debt, net of debt issuance costs	**2,091,724**	1,053,949
Repayment of long-term debt	**(1,637,420)**	(105,071)
Dividends – common shares	**(170,681)**	(130,411)
Dividends – preferred shares	**(19,159)**	(14,922)
Distributions to non-controlling interest	**(9,574)**	(1,357)
Distributions from non-controlling interest	**–**	1,447
Net proceeds from shares issued on exercise of options	**18,916**	16,197
Net proceeds from issuance of common shares	**447,556**	419,429
Net proceeds from issuance of preferred shares	**194,898**	198,975
	930,815	1,487,141
Effect of exchange rate changes on cash and cash equivalents	**594**	(82)
Change in cash and cash equivalents	**32,391**	9,034
Cash and cash equivalents, beginning of year	**11,827**	2,875
Cash and cash equivalents, end of year	**$44,812**	$11,827

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

For the years ended December 31 *($ thousands)*	2013	2012
Interest paid (net of capitalized interest)	**$98,942**	$55,850
Income taxes paid	**$ 5,181**	$11,824

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in thousands of 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., SEMCO Energy, Inc. (SEMCO) and AltaGas Power Holdings (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. Gas segment also includes the liquefied natural gas (LNG) export and liquefied petroleum gas (LPG or propane) development projects.

The Power segment includes 1,096 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets in Canada and United States, along with an additional 277 MW of run-of-river assets under construction.

The Utilities segment is predominantly comprised of natural gas distribution rate-regulated utilities, where financial results are generally based on a regulated allowed return on capital invested. AltaGas owns and operates regulated natural gas utilities in Canada and 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 of AltaGas include the accounts of the Corporation and all of its wholly-owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership.

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, 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.

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

Restricted Cash Holdings from Customers

Cash deposited 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), and 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	
Extraction and transmission (E&T)	15-45 years
Field gathering and processing (FG&P)	15-36 years
Other	1-32 years
Power generation assets	5-30 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
E&T contracts	10-20 years
Electricity service agreement	60 years
Computer software	28-60 months
Land rights	25-60 years
Franchises and consents	9-25 years

The electricity service agreement relates to the 60-year Energy Purchase Arrangement (EPA) fully indexed to the Consumer Price Index (CPI) for the Forrest Kerr run-of-river project (Forrest Kerr). Until commercial operation, the asset is not subject to amortization.

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 use accrual accounting 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 instruments. Loans and receivables are recognized at amortized cost using the effective interest method. The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially recorded at fair value and changes to fair value are recorded through "Other comprehensive income" (OCI). 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 revenue (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 stand-alone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the normal purchase and 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

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 long-term debt denominated in U.S. dollar (US dollar or US$) 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 Equity Method

Investments in entities in which AltaGas has the ability to exercise significant influence but not control, are accounted for using the equity method.

AltaGas accounts for its investments in less than majority owned corporate joint ventures and affiliates (equity investments) under the equity method. AltaGas applies the equity method to the equity investments when it has the ability to exercise significant influence over the operating and financial policies of the joint venture and affiliate. Under this method, the assets and liabilities of the joint ventures and affiliates are not consolidated. The investments in net assets of the equity investments are recorded in the Consolidated Balance Sheets 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 as equity in the income statement under the caption "Income from equity investments".

Development Costs

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

In the Gas and Power reporting segments, revenue is recognized at the time the product or service is delivered.

Electricity sold via a power purchase agreement (PPA) is accounted for as an operating lease whereby minimum lease payments are recorded on a straight-line basis over the term of the contract.

The Utilities reporting segment recognizes revenue when the product or service is delivered on the basis of regular meter readings or estimates of usage and is consistent with the underlying rate-setting mechanism mandated by the applicable regulatory authority.

Realized gains and losses from risk management activities related to commodity prices are recognized when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheet 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 calculations at the end of the reporting period in the Corporate reporting segment.

Transaction Costs Related to Financial Instruments

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

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 Statement of Income. Non-monetary assets and liabilities are converted at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

For foreign entities with a functional currency other than Canadian dollars, AltaGas' reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. The exchange rate used to convert a US dollar to a Canadian dollar for the year ended December 31, 2013 was 1.0636 (December 31, 2012 – 0.9949). 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, 2013 was 1.0301 (December 31, 2012 – 0.9837).

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 option rights 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 12.7 years and 12.9 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 respectively using the weighted average number of common shares and the weighted average number of common shares that could potentially dilute earnings during a reporting period (share-based compensation awards). 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' stock-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

Balance Sheet Disclosures – Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update (ASU) No. 2011-11 which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position.

In January 2013, FASB issued ASU No. 2013-01 "Clarifying the Scope of Disclosure about Offsetting Assets and Liabilities". The objective of ASU No. 2013-01 is to clarify that the scope of ASU No. 2011-11 would apply to derivatives including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions. ASU No. 2011-11 and ASU No. 2013-01 are effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. The update required additional disclosure with no impact on the financial results.

Comprehensive Income and Equity

In June 2011, FASB issued ASU No. 2011-05, "Other Comprehensive Income". In February 2013, FASB issued ASU No. 2013-02 "Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income". These standards amend Accounting Standards Codification (ASC) 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The adoption of these updates change the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, with no other impact to the financial statements. These amendments were effective on or after December 15, 2012. The update required additional disclosure with no impact on the financial results.

FUTURE CHANGES IN ACCOUNTING POLICIES

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, FASB issued ASU No. 2013-04, "Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is fixed at the Reporting Date". The objective of this update is to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The update is effective for fiscal years, and interim periods within those years, beginning after December 31, 2013. Management has assessed that this update does not have any impact on the preparation and presentation of AltaGas' Consolidated Financial Statements at December 31, 2013.

Parent's Accounting for the Cumulative Translation Adjustment

In March 2013, FASB issued ASU No. 2013-05, "Parent's accounting for the Cumulative Translation Adjustment upon De-recognition of Certain Subsidiaries or Group of Assets within a Foreign Entity or of an Investment in a Foreign Entity". This update applies to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets within a foreign entity. The update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. Management has assessed that this update does not have any impact on the preparation and presentation of AltaGas' Consolidated Financial Statements at December 31, 2013.

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

AOCI components reclassified	Income Statement line item	Year ended December 31, 2013	Year ended December 31, 2012
Cash flow hedges			
Commodity contracts – NGL (ineffective hedge)	Unrealized gains on risk management contracts	–	$1,506
Commodity contracts – Bond forward	Interest expense – Long-term debt	734	679
Defined benefit pension plans	Operating and administrative expense	1,269	(548)
Available-for-sale	Other income (expenses)	4,257	–
	Total before income taxes	6,260	1,637
Deferred income taxes	Income tax expenses – Deferred	(1,175)	(162)
		$5,085	$1,475

4. PROVISION ON PROPERTY, PLANT AND EQUIPMENT

	December 31 2013	December 31 2012
Gas	$15,904	–
Power	3,689	2,853
Utilities	3,000	–
	$22,593	$2,853

In 2013, the Gas segment identified certain of its non-core assets that it expects to sell. AltaGas recorded a provision for the value of these assets expected to be realized in the sale process. In addition, a gas-fired peaking unit was damaged and written off during the year.

In 2013, the Power segment recorded a provision for six wind projects under development (2012 – two wind projects under development) due to their unlikely probability of reaching commercial operations.

In 2013, the Utilities segment tested certain of its assets for impairment and determined that the expected undiscounted cash flows were less than the carrying value for the assets.

5. OTHER INCOME (EXPENSES)

On March 2, 2011, 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. BUSINESS ACQUISITION

PETROGAS

On October 1, 2013 AltaGas completed the acquisition of a 25 percent interest in Petrogas Energy Corp. (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, truck and transportation equipment, loading and terminaling facilities and crude oil blending facilities. Petrogas and its subsidiaries have operations throughout Canada and seven states in the United States.

On October 24, 2013, AltaGas announced it will increase its effective ownership of Petrogas to 33 1/3 percent. AltaGas plans to transfer its current 25 percent ownership to the AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP). AIJVLP will acquire an additional 41 2/3 percent interest in Petrogas for consideration of cash and a note payable to the vendor. As a result of the note payable to the vendor, no further consideration is required from AltaGas. As a result of the transaction, Petrogas will be owned one-third by each of AltaGas, Idemitsu Kosan Co., Ltd. (Idemitsu), and its current majority shareholder. All regulatory approvals have been obtained and the transaction is expected to close on March 1, 2014.

AltaGas paid for the initial 25 percent interest with approximately 2.8 million common shares priced at $35.69 per share and $230.5 million of cash. The Petrogas investment is accounted for using the equity method.

BLYTHE

On May 16, 2013, AltaGas, through a wholly-owned subsidiary, AltaGas Power Holdings (U.S.) Inc., completed the acquisition of Blythe Energy Inc. (Blythe) for US$515 million before adjustments for working capital. Blythe owns 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 Energy Center is contracted under a PPA through to July 2020 with Southern California Edison (SCE). Contract provisions match PPA revenues to all major plant costs.

AltaGas paid an aggregate purchase price of $536.8 million. AltaGas financed the acquisition through a combination of $405 million gross proceeds from 11,615,000 common shares public offering and the remainder from a US$300 million senior unsecured revolving credit facility with three Canadian chartered banks. Transaction costs such as legal, accounting, valuation and other professional fees related specifically to the acquisition were $1.6 million pre-tax and have been expensed in the Consolidated Statement of Income, within "Operating and administrative expenses".

Below is a provisional purchase price allocation based on the statement of financial position as at May 16, 2013, using an exchange rate of 1.0163 to convert a US dollar to Canadian dollar.

Cash consideration	$536,795
Total consideration	$536,795
Purchase price allocation	
Assets acquired:	
Current assets	$ 20,144
Property, plant and equipment	546,235
Non-current assets	4,924
	571,303
Less liabilities assumed:	
Current liabilities	10,618
Deferred income taxes	21,648
Asset retirement obligations	2,242
	34,508
	$536,795

7. SALE OF SUBSIDIARY

On December 16, 2013, AltaGas sold its 100 percent ownership in a non-core business entity, ECNG Energy L.P. (ECNG) to an unrelated third party. ECNG provides energy consulting and supply management services and arranges natural gas and power supply for non-residential end-users. After deconsolidation, AltaGas does not retain any investment in ECNG with no continuing involvement and the acquiring third party remains unrelated to the Corporation. AltaGas recorded a pre-tax gain of $3.9 million from this transaction, which is shown on the Consolidated Statement of Income, within "Other income (expenses)". Transaction related costs of $0.5 million have been recognized in "Operating and administrative expenses".

8. INVENTORY

As at December 31	2013	2012
Natural gas held in storage	**$106,715**	$86,005
Other inventory	**16,693**	8,704
	$123,408	$94,709

9. PROPERTY, PLANT AND EQUIPMENT

As at December 31	2013			2012		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas						
E&T assets	**$1,172,177**	**$ (202,794)**	**$ 969,383**	$1,137,218	$(174,365)	$ 962,853
FG&P assets	**1,082,436**	**(330,769)**	**751,667**	1,074,891	(282,443)	792,448
Energy services assets	**1,015**	**(661)**	**354**	1,808	(1,368)	440
Other assets	**14,249**	**(11,718)**	**2,531**	13,821	(10,157)	3,664
Power	**1,759,575**	**(50,968)**	**1,708,607**	853,375	(28,276)	825,099
Utilities	**1,568,990**	**(65,946)**	**1,503,044**	1,376,010	(27,764)	1,348,246
Corporate	**25,210**	**(8,270)**	**16,940**	21,930	(5,514)	16,416
	$5,623,652	**$ (671,126)**	**$4,952,526**	$4,479,053	$(529,887)	$3,949,166

Interest capitalized on long-term capital construction projects for the year ended December 31, 2013 was $30.6 million (2012 – $35.2 million).

As at December 31, 2013, the Corporation had spent approximately $943.3 million (2012 – $578.7 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, 2013 was $142.3 million (2012 – $91.5 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. Utilities assets not yet subject to amortization were $36.7 million as at December 31, 2013 (December 31, 2012 – $31.9 million).

10. INTANGIBLE ASSETS

As at December 31	2013			2012		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
E&T contracts	$ 57,298	$(18,922)	$ 38,376	$ 57,798	$(16,616)	$ 41,182
Electricity service agreement	90,000	–	90,000	90,000	–	90,000
Energy services relationships	10,249	(5,388)	4,861	20,892	(9,494)	11,398
Computer software	73,523	(29,757)	43,766	54,030	(23,762)	30,268
Land rights	17,290	(1,639)	15,651	15,853	(1,571)	14,282
Franchises and consents	3,622	(1,017)	2,605	3,622	(962)	2,660
	$251,982	$(56,723)	$195,259	$242,195	$(52,405)	$189,790

The electricity service agreement relates to a 60-year EPA fully indexed to the CPI not yet subject to amortization.

Amortization expense related to intangible assets for the year ended December 31, 2013 was $10.2 million (2012 – $7.8 million).

As at December 31, 2013, the Corporation had accrued approximately $11.5 million in software costs (2012 – Nil), not yet subject to amortization.

The following table sets forth the estimated amortization expense of intangible assets for the years ended December 31:

2014	$ 11,903
2015	12,543
2016	11,951
2017	10,637
2018	10,412
Thereafter	$131,480

11. GOODWILL

As at December 31	2013	2012
Balance, beginning of period	$ 714,902	$ 281,123
Business acquisition	–	430,024
Other changes	(1,679)	–
Foreign exchange translation	29,878	3,755
	$743,101	$714,902

In 2008, the Corporation recognized $143.7 million of goodwill on the acquisition of 100 percent interest in Taylor NGL Limited Partnership (Taylor). In 2009, the Corporation recognized $61.2 million of goodwill on the acquisitions of 100 percent interests in AUI and Heritage Gas. In 2010, the Corporation recognized $17.7 million of goodwill on the acquisition of 100 percent interest in Landis Energy Corporation. In 2011, the Corporation recognized $58.6 million on the acquisition of 100 percent interest in PNG. In 2012, the Corporation recognized $430.6 million on the acquisition of 100 percent interest in SEMCO. In 2013, AltaGas finalized the purchase price allocation for the SEMCO' acquisition with a reduction in previously allocated goodwill by $1.7 million.

Goodwill has been assessed for impairment with no evidence of an impairment loss.

12. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at December 31	2013	2012
Investments in publicly-traded entities	$ 4,990	$ 7,151
Investment in private equities	676	864
Debt financing costs	17,017	14,818
Loan to employees	750	750
Other	2,431	1,386
	$25,864	$24,969

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (Alterra), through a private equity offering. These shares were classified as available-for-sale. In December 2013, an other-than-temporary pre-tax loss of $4.2 million was reclassified from OCI and recognized in the Consolidated Statement of Income under "Other income (expenses)". The recognition of the other-than-temporary loss was the result of the length of time and extent to which the market value of Alterra's shares has been less than cost. The remaining accumulated amount in OCI was an unrealized pre-tax loss of $2.9 million as at December 31, 2013 (December 31, 2012 – unrealized pre-tax loss of $5.8 million).

In July 2009, AltaGas purchased additional shares of Alterra as part of its initial public offering. These shares were classified as held-for-trading. In July 2010, AltaGas purchased a second tranche of common shares in Alterra, which were classified as held-for-trading. All shares of Alterra are reported under "Long-term investments and other assets". Unrealized gains (losses) on held-for-trading are recognized in the Consolidated Statement of Income under "Other income (expenses)".

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

For the years ended December 31	2013	2012
Financial assets held-for-trading	$(1,122)	$173

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

For the years ended December 31	2013	2012
Changes in fair value	$ (879)	$108
Other-than-temporary loss	3,721	–
	$2,842	$108

13. INVESTMENTS ACCOUNTED FOR BY EQUITY METHOD

Investments in entities in which AltaGas has the ability to exercise significant influence but not control are accounted for using the equity method. Investments accounted for by equity method balance breakdown is as follows:

As at December 31	2013	2012
Affiliates	**$338,801**	$ 3,134
Joint ventures	**140,282**	145,224
	$479,083	$148,358

AltaGas accounts for its investments in joint ventures where the Corporation has an undivided interest in the assets and liabilities using the proportionate consolidation method and in joint ventures with jointly controlled interests and affiliates using the equity method of accounting. The proportionate consolidation and equity methods are applied using the pro-rata share of interest controlled by AltaGas.

Description, as at December 31, 2013	Location	Ownership Percentage	Accounting Method
AltaGas Idemitsu Joint Venture LP	Canada	50	Equity
AltaGas Idemitsu Management Inc.	Canada	50	Equity
Alton Natural Gas Storage Inc.	Canada	50	Equity
Alton Natural Gas Storage LP	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
Petrogas Energy Corp.	Canada	25	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 investee financial information.

For the year ended December 31, 2013	**Proportionate Consolidation Method**	**Equity Method**	**Total**
Revenues	**$194,897**	**$716,438**	**$911,335**
Expenses	**148,411**	**284,212**	**432,623**
	$ 46,486	**$432,226**	**$478,712**
As at December 31, 2013			
Current assets	**57,625**	**677,391**	**735,016**
Property, plant and equipment	**313,228**	**363,301**	**676,529**
Intangible assets	**20,000**	**85,813**	**105,813**
Long-term investments and other assets	**1,229**	**12,540**	**13,769**
Current liabilities	**(4,174)**	**(406,433)**	**(410,607)**
Other long-term liabilities	**(41,852)**	**(65,949)**	**(107,801)**

For the year ended December 31, 2012	Proportionate Consolidation Method	Equity Method	Total
Revenues	$149,561	$355,026	$504,587
Expenses	109,209	230,196	339,405
	$ 40,352	$124,830	$165,182
As at December 31, 2012			
Current assets	56,149	92,966	149,115
Property, plant and equipment	313,845	113,761	427,606
Intangible assets	16,000	98,072	114,072
Long-term investments and other assets	1	5,013	5,014
Current liabilities	(15,674)	(84,197)	(99,871)
Other long-term liabilities	(5,263)	(5,401)	(10,664)

14. SHORT-TERM DEBT

As at December 31	**2013**	2012
Bank indebtedness	**$ 3,454**	$ 2,149
$50 million demand operating facility	**7,190**	2,675
US$150 million operating facility	**62,752**	49,745
$25 million operating facility	**10,954**	12,369
$20 million demand operating facility	**–**	–
$150 million unsecured revolving letter of credit facility	**–**	–
$125 million unsecured bilateral letter of credit facility	**–**	–
	$84,350	$66,938

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, 2013 was 3.0 percent (December 31, 2012 – 3.0 percent).

Revolving Operating Credit Facilities

As at December 31, 2013, the Corporation held a $50.0 million (December 31, 2012 – $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, 2013 were $0.02 million (December 31, 2012 – $0.02 million).

As at December 31, 2013, SEMCO held a US$150.0 million (December 31, 2012 – US$100.0 million) unsecured revolving operating credit facility with a Canadian chartered bank with a maturity date of December 15, 2018. Draws on the facility can be by way of U.S. base-rate loans, letters of credits and LIBOR loans. Letters of credit outstanding at December 31, 2013 were $1.0 million (December 31, 2012 – $0.2 million).

As at December 31, 2013, AltaGas held a $25.0 million (December 31, 2012 – $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' acceptance or letters of credits at the bank's prime rate or for a fee. Letters of credit outstanding at December 31, 2013 were $4.2 million (December 31, 2012 – $3.0 million).

As at December 31, 2013, the Utility Group held a $20.0 million (December 31, 2012 – $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 or bankers' acceptances and LIBOR loans. Letters of credit outstanding at December 31, 2013 were $3.6 million (December 31, 2012 – $3.4 million).

As at December 31, 2013, AltaGas held a $150.0 million (December 31, 2012 – $75.0 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 letter of credit facility. Letters of credit outstanding at December 31, 2013 were $67.5 million (December 31, 2012 – $50.0 million).

As at December 31, 2013, AltaGas held a $125.0 million (December 31, 2012 – $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, 2013 were $67.6 million (December 31, 2012 – $89.8 million).

15. LONG-TERM DEBT

As at December 31	Maturity date	2013	2012
Credit facilities			
$35 million PNG 5-year revolver – 4.36 percent [1,2]	30-Jan-2015	**–**	$ 30,000
$200 million Utility Group [3]	17-Nov-2015	**–**	131,342
$600 million Unsecured extendible revolving [3]	30-May-2016	**–**	227,345
$1,400 million Unsecured extendible revolving [4]	15-Dec-2017	**578,566**	–
US$300 million Unsecured [3]	02-Sep-2014	**–**	169,133
Medium-term notes			
$200 million Senior unsecured – 7.42 percent	29-Apr-2014	**200,000**	200,000
$200 million Senior unsecured – 4.10 percent	24-Mar-2016	**200,000**	200,000
$100 million Senior unsecured – 6.94 percent	29-Jun-2016	**100,000**	100,000
$200 million Senior unsecured – 5.49 percent	27-Mar-2017	**200,000**	200,000
$175 million Senior unsecured – 4.60 percent	15-Jan-2018	**175,000**	175,000
$200 million Senior unsecured – 4.55 percent	17-Jan-2019	**200,000**	200,000
$200 million Senior unsecured – 4.07 percent	01-Jun-2020	**200,000**	200,000
$350 million Senior unsecured – 3.72 percent	28-Sep-2021	**350,000**	350,000
$300 million Senior unsecured – 3.57 percent	12-Jun-2023	**300,000**	–
US$175 million Senior unsecured – floating [5]	13-Apr-2015	**186,130**	–
SEMCO long-term debt			
US$5 million SEMCO secured – 7.03 percent	25-Nov-2013	**–**	4,923
US$90 million CINGSA secured construction and term loan [6]	14-Nov-2015	**86,258**	77,105
US$300 million SEMCO Senior secured – 5.15 percent [7]	21-Apr-2020	**319,080**	298,470
Debenture notes			
PNG RoyNat Debenture – 3.72 percent [1]	15-Sep-2017	**11,000**	12,200
PNG 2018 Series Debenture – 8.75 percent [1]	15-Nov-2018	**11,000**	11,600
PNG 2024 CFI Debenture – 7.39 percent [8]	01-Nov-2024	**7,899**	8,353
PNG 2025 Series Debenture –9.30 percent [1]	18-Jul-2025	**15,000**	15,500
PNG 2027 Series Debenture – 6.90 percent [1]	02-Dec-2027	**16,000**	16,500
Loan from Province of Nova Scotia [9]	31-Jul-2017	**3,060**	3,964
SEMCO capital lease obligation – 3.50 percent	01-May-2040	**471**	445
Promissory notes	25-Oct-2015	**1,946**	2,866
Other long-term debt		**332**	642
		3,161,742	2,635,388
Less current portion		**209,069**	9,302
		$2,952,673	$2,626,086

1 *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.*

2 *The facility was repaid and cancelled on June 7, 2013.*

3 *The facilities were paid in full on December 20, 2013 through the issuance of the $1,400 million unsecured extendible revolving. See (4) below.*

4 *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, 2013 were $19.0 million (December 31, 2012 – Nil).*

5 *The notes carry a floating rate coupon of three months LIBOR plus 0.79 percent.*

6 *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.*

7 *Collateral for the US$ MTNs is certain SEMCO assets.*

8 *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 in McNair Creek.*

9 *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.*

16. ASSET RETIREMENT OBLIGATIONS

	2013	2012
Balance, beginning of year	**$56,632**	$44,318
New obligations	**293**	6,421
Obligations settled	**(1,859)**	(2,329)
Revision in estimated cash flow	**14,952**	(5,220)
Accretion expense	**3,736**	3,115
Business acquisitions	**2,242**	10,238
Foreign exchange translation	**129**	89
Balance, end of year	**$76,125**	$56,632

The majority of the asset retirement obligations are associated with FG&P and extraction facilities in the Gas segment.

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2013 was $271.3 million (December 31, 2012 – $221.9 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 5.0 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.

17. 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	2013	2012
Income before income taxes – consolidated	**$248,514**	$166,308
Financial instruments – net	**9,242**	(22,057)
Income before financial instruments and income taxes	**257,756**	144,251
Income before income taxes – operating subsidiaries	**257,756**	144,251
Statutory income tax rate (%)	**25.18**	25.13
Expected taxes at statutory rates	**64,903**	36,250
Add (deduct) the tax effect of:		
Financial instruments	**(2,294)**	5,568
Rate adjustments to enacted Canadian rates	**(2,178)**	593
Permanent differences between accounting and tax basis of assets and liabilities	**1,230**	2,190
Non-taxable portion of capital (gains) losses on disposition of assets and investments	**(4,549)**	22
Rate adjustment [1]	**639**	1,125
Tax on preferred shares	**981**	2,623
Change in enacted rates on preferred shares	**(3,083)**	–
Other	**(549)**	984
Deferred income tax recovery on regulated assets	**(4,433)**	(5,617)
Prior year adjustment	**(10,580)**	2,312
	40,087	46,050
Income tax provision		
Current		
Canada	**11,059**	7,344
United States	**8,776**	1,629
	19,835	8,973
Deferred		
Canada	**3,837**	32,122
United States	**16,415**	4,955
	$ 20,252	$ 37,077
Effective income tax rate *(%)*	**16.13**	27.69

1 *During 2013, the enacted statutory provincial income tax rate for British Columbia was increased to 11 percent from the previously enacted rate of 10 percent. During 2013, there was a change in the enacted multiplier on Part V1.1 to 3.5 from multiplier rates in prior years. During 2012, the enacted statutory provincial income tax rate for Ontario was increased to 11.5 percent from the previously enacted rate of 10 percent.*

In 2013, $22.7 million of deferred income tax liabilities were assumed on the acquisition of Blythe. In 2012, $96.2 million of deferred income tax liabilities were assumed on the acquisition of SEMCO.

Deferred income taxes were composed of the following:

As at December 31	2013	2012
PPE and Intangible assets	**$437,846**	$384,400
Regulatory assets	**124,603**	101,956
Deferred financing	**(9,770)**	(6,120)
Deferred compensation	**3,600**	195
Financial instruments	**(6,709)**	3,452
Non-capital losses	**(113,907)**	(93,370)
Other	**1,878**	762
	$437,541	$391,275

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, 2013 the Corporation had tax-affected non-capital losses of approximately $114.0 million for tax purposes, which will be available to offset future taxable income. If not used, these losses will expire between 2014 and 2032.

Undistributed earnings of the Corporation's operations in the United States amounted to approximately $79.0 million at December 31, 2013. Those earnings are considered to be indefinitely reinvested; accordingly no provision for U.S. federal withholding taxes has been provided thereon. Upon repatriation of those earnings, in the form of dividends, the Corporation would be subject to U.S. withholding taxes payable to the United States.

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 2012 remain subject to examination by taxation authorities. In the United States both the federal and state tax returns filed for the years 2009 to 2012 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	2013	2012
Balance, beginning of year	**$3,303**	–
Increases as a result of business combinations	**–**	3,675
Increases as a result of positions taken during the year	**–**	466
Decreases due to expiration of statute of limitations	**–**	(838)
Balance, end of year	**$3,303**	$3,303

18. 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 ratemaking 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, 2013 and 2012, over which the Corporation expects to realize or settle the assets or liabilities:

	December 31, 2013	December 31, 2012	Recovery Period
Regulatory assets – current			
Deferred cost of gas	$ 6,046	$ 3,965	Less than one year
Deferred property taxes	–	323	Less than one year
Other	–	57	Less than one year
	$ 6,046	$ 4,345	
Regulatory assets – non-current			
Deferred regulatory costs and rate stabilization adjustment mechanism	**10,976**	6,248	1-3 years
Pipeline rehabilitation costs	**6,669**	5,251	10 years
Future recovery of pension and other retirement benefits (a)	**70,396**	119,205	Various
Deferred environmental costs	**21,484**	19,742	1-10 years
Deferred loss on reacquired debt	**3,212**	3,508	4-7 years
Deferred depreciation and amortization (b)	**16,995**	12,808	Various
Deferred future income taxes (c)	**71,219**	63,588	Various
Revenue deficiency account (d)	**40,007**	44,508	Various
Other	**252**	405	1-3 years
	$241,210	$275,263	
Regulatory liabilities – current			
Deferred cost of gas	**1,388**	1,710	Less than one year
Deferred property taxes	**365**	–	Less than one year
Deferred regulatory costs	**85**	261	Less than one year
	$1,838	$1,971	
Regulatory liabilities – non-current			
Termination payment deferral	–	1,862	Various
Option fees deferral (e)	**1,583**	3,033	Various
Refundable tax credit (f)	**12,763**	–	Various
Future removal and site restoration costs (g)	**107,484**	98,283	Various
Load balancing	**1,342**	–	Various
Insurance recovery of environmental costs	**1,090**	1,104	6 years
	$124,262	$104,282	

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

b. Pursuant to the NSUARB decision dated February 12, 2009, Heritage Gas was ordered to suspend amortization of property, plant and equipment and intangible assets for regulatory purposes for the fiscal periods from 2009 to 2011 inclusively. The NSUARB, in its most recent decision dated November 24, 2011, continued the order to suspend amortization for regulatory purposes for the fiscal periods from 2012 to 2013 inclusively, however amortization should resume for regulatory purposes in 2014 at 25 percent of authorized rates; 2015 at 50 percent of authorized rates; 2016 at 75 percent of authorized rates; and 2017 at 100 percent of authorized rates. As a result of this order, the Corporation recognizes a regulatory asset equal to the amortization that would have otherwise been included in rates. The deferred regulatory asset is expected to be recovered over the remaining useful life of related assets commencing 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. In 2009, Merrill Lynch paid $2.5 million in option and extension fees to PNG to secure excess firm pipeline capacity. In 2010, further deposits totaling $2.0 million were paid to PNG and the agreement between PNG and Merrill Lynch was assigned and novated by Merrill Lynch to LNG Partners, LLC (LNG Partners). In 2011 and 2012, further deposits totaling $2.0 million and $1.0 million, respectively, were paid to PNG. Pursuant to the BCUC approved 2009, 2010 and 2011 negotiated settlement agreement, PNG has recorded these amounts as an interest-bearing, non-rate base regulatory liability to be credited to cost-of-service in future years. The 2013 closing balance reflects total contributions of $7.5 million of which PNG has drawn down $6 million.

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

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

19. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

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

Fair Values of Financial Instruments

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

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

Cash, Cash Equivalents, Accounts Receivable, Accounts Payable, 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 and Long-term debt – the fair value of current portion of long-term debt and long-term debt have been estimated based on discounted future interest and principal payments using estimated interest rates.

Summary of Fair Values	December 31 2013	December 31 2012
Current portion of long-term debt		
Carrying amount	**$209,069**	$ 9,302
Fair value of current portion of long-term debt	**$212,354**	$10,243

Summary of Fair Values	December 31 2013	December 31 2012
Long-term debt excluding non-financial instruments		
Carrying amount	**$2,952,673**	$2,626,086
Fair value of long-term debt excluding non-financial instruments	**$3,062,636**	$2,800,759

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, 2013	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	$44,812	–	–	$ 44,812
Risk management assets – current	–	$ 34,988	–	$ 34,988
Risk management assets – non-current	–	$ 12,250	–	$ 12,250
Long-term investments and other assets [1]	$5,365	–	–	$ 5,365
Financial liabilities				
Risk management liabilities – current	–	$ 44,675	–	$ 44,675
Risk management liabilities – non-current	–	$ 7,071	–	$ 7,071
Current portion of long-term debt	–	$ 212,354	–	$ 212,354
Long-term debt	–	$3,062,636	–	$3,062,636

December 31, 2012	Level 1	Level 2	Level 3	Total
Financial assets				
Cash and cash equivalents	$11,827	–	–	$ 11,827
Risk management assets – current	–	$ 47,788	–	$ 47,788
Risk management assets – non-current	–	$ 18,132	–	$ 18,132
Long-term investments and other assets [1]	$ 7,715	–	–	$ 7,715
Financial liabilities				
Risk management liabilities – current	–	$ 39,734	–	$ 39,734
Risk management liabilities – non-current	–	$ 10,526	–	$ 10,526
Current portion of long-term debt	–	$ 10,243	–	$ 10,243
Long-term debt	–	$2,800,759	–	$2,800,759

1 *Excludes non-financial assets and financial assets carried at cost.*

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

For the years ended December 31	2013	2012
Natural gas	$ (753)	$ (9,976)
Storage optimization	(1,448)	296
NGL Frac Spread	(3,933)	15,940
Power	(2,253)	15,960
Heat rate	182	(578)
Interest rate swaps	–	7
Foreign exchange	(540)	16
Embedded derivative	(497)	392
	$(9,242)	$22,057

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

	Unrealized Losses	Tax Recovery	Year ended December 31 2013	Unrealized Losses	Tax Recovery	Year Ended December 31 2012
Bond forward	$ (260)	–	(260)	$(994)	–	$(994)
NGL Frac Spread	(13,562)	3,415	(10,147)	–	–	–
AOCI	$(13,822)	$3,415	$(10,407)	$(994)	–	$(994)

Offsetting of Derivative Assets and Derivative Liabilities

As at December 31, 2013

Risk management assets [1]	Gross amounts of recognized assets/ liabilities	Gross amounts offset in Balance Sheet	Net amounts presented in Balance Sheet
Natural gas	$88,223	$57,465	$30,758
Storage optimization	1,910	1,204	706
	$90,133	$58,669	$31,464
Risk management liabilities [2]			
Natural gas	$84,106	$57,465	$26,641
Storage optimization	3,126	1,204	1,922
Total	$87,232	$58,669	$28,563

1 *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $27,177 and risk management assets (non-current) balance of $4,287.*

2 *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $25,376 and risk management liabilities (non-current) balance of $3,187.*

As at December 31, 2012

Risk management assets [1]	Gross amounts of recognized assets/ liabilities	Gross amounts offset in Balance Sheet	Net amounts presented in Balance Sheet
Natural gas	$110,809	$ 73,573	$37,236
Storage optimization	30,574	27,114	3,460
	$141,383	$100,687	$40,696
Risk management liabilities [2]			
Natural gas	$105,940	$ 73,573	$32,367
Storage optimization	30,342	27,114	3,228
Total	$136,282	$100,687	$35,595

1 *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $34,383 and risk management assets (non-current) balance of $6,313.*

2 *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $31,432 and risk management liabilities (non-current) balance of $4,163.*

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

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 2018. AltaGas had the following contracts outstanding:

December 31, 2013			**Notional volume (GJ)**		
Derivative Instruments	**Fixed price (per GJ)**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Commodity forward	**$3.05 to $11.20**	**1-58**	**79,260,225**	**–**	**$3,328**
Commodity forward	**$3.06 to $11.80**	**1-58**	**–**	**74,652,589**	**$ 747**

December 31, 2012			Notional volume (GJ)		
Derivative Instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$2.56 to $9.85	1-58	113,661,098	–	$(5,244)
Commodity forward	$2.57 to $8.80	1-58	–	99,215,653	$ 7,028

AltaGas had the following commodity swaps outstanding related to the storage optimization activities:

December 31, 2013			**Notional volume (MMBTU)**		
Derivative Instruments	**Fixed price (per MMBTU)**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Swaps	**$4.19 to $4.41**	**1-3**	**–**	**18,000**	**–**

December 31, 2012			Notional volume (MMBTU)		
Derivative Instruments	Fixed price (per MMBTU)	Period (months)	Sales	Purchases	Fair value
Swaps	$3.27 to $4.03	1-2	4,225,155	–	$(12,438)
Swaps	$3.32 to $3.51	1-2	–	4,225,155	$ 15,807

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, 2013			**Notional volume**		
Product	**Fixed price**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Propane	**$0.7895 to $1.0464 US/gallon**	**1-12**	**56,107,800 gallons**	**–**	**$(14,034)**
Butane	**$1.15 to $1.3017 US/gallon**	**1-12**	**14,103,600 gallons**	**–**	**$ (1,385)**
WTI	**$91.68 to $96.80 US/Bbl**	**1-12**	**153,300 Bbl**	**–**	**$ (399)**
US$ swaps	**$1.03**	**1-12**	**–**	**$34,662,298**	**$ (621)**
Natural gas	**$3.145 to $3.49/GJ**	**1-12**	**–**	**7,040,580 GJ**	**$ 2,877**

December 31, 2012			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$1.2525 to $1.2824 US/gallon	1-12	20,958,000 gallons	–	$ 188
Butane	$1.51 to $1.7577 US/gallon	1-12	6,661,200 gallons	–	$ 5,077
WTI	$91.40 to $100.73 US/Bbl	1-12	72,300,661 gallons	–	$ (223)
US$ swaps	$1.0232	1-12	–	$21,928,630	$ 521
Natural gas	$3.1950 to $4.0150/GJ	1-12	–	3,109,700 GJ	$(1,629)

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, 2013, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following commodity forward contracts on electrical power outstanding:

December 31, 2013			**Notional volume (MWh)**		
Derivative Instruments	**Fixed price (per MWh)**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Commodity forward	**$43.94 to $94.10**	**1-48**	**1,631,338**	**–**	**$ 7,851**
Commodity forward	**$48.50 to $105.50**	**1-60**	**–**	**1,825,960**	**$(1,336)**

December 31, 2012			Notional volume (MWh)		
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$43.94 to $94.10	1-60	1,780,422	–	$ 6,412
Commodity forward	$48.50 to $99.90	1-60	–	1,637,641	$(1,227)

AltaGas had the following commodity swaps outstanding:

December 31, 2013			**Notional volume (MWh)**		
Derivative Instruments	**Fixed price (per MWh)**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Swaps	**$58.75 to $66.00**	**1-12**	**111,360**	**–**	**$ 230**
Swaps	**$56.50**	**1-48**	**–**	**105,192**	**$(544)**

December 31, 2012			Notional volume (MWh)		
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Swaps	$64.00 to $77.00	1-12	412,560	–	$3,739
Swaps	$56.50	1-60	–	131,472	$ (470)

AltaGas had the following heat rate hedges outstanding:

December 31, 2013			**Notional volume (GJ or MWh)**		
Derivative Instruments	**Fixed price (per GJ or MWh)**	**Period (months)**	**Sales**	**Purchases**	**Fair value**
Natural gas	**$3.085 to $3.7875**	**2**	**–**	**122,400**	**$ 74**
Power	**$66.00 to $86.63**	**2**	**28,800**	**–**	**$188**

December 31, 2012			Notional volume (GJ or MWh)		
Derivative Instruments	Fixed price (per GJ or MWh)	Period (months)	Sales	Purchases	Fair value
Natural gas	$2.975	1	–	124,000	$ (1)
Power	$91.9 to $95.35	1	12,400	–	$79

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, 2013 and 2012.

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, 2013 and 2012.

Bond Forward

In April 2009 AltaGas issued $200 million of senior unsecured MTNs with a maturity date of April 2014. To partially hedge against the risk of rising interest rates, AltaGas entered into a $50 million bond forward contract with a Canadian chartered bank in December 2008, to lock in a five-year Government of Canada bond yield of approximately 3.28 percent. AltaGas settled the bond forward contract in April 2009, and the $3.4 million payment was recorded in other comprehensive income and is being amortized to interest expense over the term of the MTN.

Sensitivity Analysis

The sensitivity analysis is estimated based on the notional volumes of each commodity contract and equity security outstanding, taking into consideration 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, 2013:

Factor Share	Increase or decrease [1]	Increase or decrease in net income	Increase or decrease in OCI
Alberta electricity average pool prices	$1/MWh	$282	–
Natural gas spot price (AECO)	$0.50/GJ	$868	–
NGL frac spread:			
Propane	$1/Bbl	–	$1,000
Butane	$1/Bbl	–	$158
WTI	$1/Bbl	–	$115
Natural gas to replace heat value of NGL	$0.50/GJ	–	$2,634
Change in CAD per US$ exchange rate	1 percent	–	$240
Equity risk	1 percent	$23	$21

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, 2013, 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 receivables:

			Receivables by period and not impaired			
	As at December 31, 2013	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$370,536	$3,803	$343,734	$14,098	$4,727	$4,174
Other	1,563	–	–	–	–	1,563
Allowance for credit losses	(3,803)	(3,803)	–	–	–	–
	$368,296	–	$343,734	$14,098	$4,727	$5,737

Allowance for credit losses	As at December 31, 2013
Allowance for credit losses, beginning of year	$3,595
Foreign exchange translation	86
New allowance	1,547
Allowance applied to uncollectible customer accounts	(1,425)
Allowance for credit losses, end of year	$3,803

			Receivables by period and not impaired			
	As at December 31, 2012	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$370,993	$3,595	$348,149	$8,747	$8,801	$1,701
Other receivable	15,212	–	13,750	–	–	1,462
Allowance for credit losses	(3,595)	(3,595)	–	–	–	–
	$382,610	–	$361,899	$8,747	$8,801	$3,163

Allowance for credit losses	As at December 31, 2012
Allowance for credit losses, beginning of year	$2,099
Business acquisition	1,594
Foreign exchange translation	(14)
New allowance	255
Allowance applied to uncollectible customer accounts	(339)
Allowance for credit losses, end of year	$3,595

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, 2013	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**$ 318,982**	**$318,982**	**–**	**–**	**–**
Dividends payable	**15,594**	**15,594**	**–**	**–**	**–**
Short-term debt	**84,350**	**84,350**	**–**	**–**	**–**
Current portion of long-term debt	**209,069**	**209,069**	**–**	**–**	**–**
Long-term debt	**2,952,673**	**–**	**789,874**	**762,230**	**1,400,569**
	$3,580,668	**$627,995**	**$789,874**	**$762,230**	**$1,400,569**

			Payments Due by period		
As at December 31, 2012	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$ 370,011	$370,011	–	–	–
Dividends payable	12,640	12,640	–	–	–
Short-term debt	66,938	66,938	–	–	–
Current portion of long-term debt	9,302	9,302	–	–	–
Long-term debt	2,626,086	–	620,400	741,732	1,263,954
	$3,084,977	$458,891	$620,400	$741,732	$1,263,954

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 closed a public offering of 11,615,000 common shares at a price of $34.90 per common share for aggregate gross proceeds of approximately $405 million.

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.

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 was 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 sum of the floating quarterly dividend rate by US$25 per share and multiplying that product by a fraction, the numerator of which is the actual 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 will be payable 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.

Common Shares Issued and Outstanding	Number of shares	Amount
January 1, 2012	89,248,374	$1,204,269
Shares issued for cash on exercise of options	779,969	16,197
Shares issued under DRIP	1,393,541	41,071
Shares issued on conversion of subscription receipts	13,915,000	378,358
December 31, 2012	105,336,884	$1,639,895
Shares issued for cash on exercise of options	806,093	18,916
Shares issued under DRIP	1,745,411	60,305
Shares issued on private issuance	2,801,905	100,000
Shares issued on public offering	11,615,000	392,284
Issued and outstanding at December 31, 2013	**122,305,293**	**$2,211,400**

Preferred Shares Series A Issued and Outstanding	Number of shares	Amount
January 1, 2012	8,000,000	194,126
December 31, 2012	8,000,000	$194,126
Issued and outstanding at December 31, 2013	**8,000,000**	**$194,126**

Preferred Shares Series C Issued and Outstanding	Number of shares	Amount
January 1, 2012	–	–
Shares issued on public offering	8,000,000	200,626
December 31, 2012	8,000,000	$200,626
Issued and outstanding at December 31, 2013	**8,000,000**	**$200,626**

Preferred Shares Series E Issued and Outstanding	Number of shares	Amount
Shares issued on public offering	8,000,000	194,873
Issued and outstanding at December 31, 2013	**8,000,000**	**$194,873**

Weighted Average Shares Outstanding	2013	2012
Number of shares – basic	**116,068,088**	94,986,369
Dilutive equity instruments [1]	**3,440,922**	1,324,669
Number of shares – diluted	**119,509,010**	96,311,038

1 Includes all options that have a strike price lower than the market share price of AltaGas' common shares at December 31, 2013 and 2012, 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, 2013, 6,669,024 shares were reserved for issuance under the plan. As at December 31, 2013, options granted under the plan generally have a term of 6 to 10 years until expiry and vest no longer than over a four-year period.

As at December 31, 2013, the unexpensed fair value of share option compensation cost associated with future periods was $6.2 million (December 31, 2012 – $7.9 million). As at December 31, 2013, the compensation expense recorded for share options was $4.2 million (December 31, 2012 – $3.1 million).

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

	Options outstanding			
	2013		2012	
	Number of options	Exercise price [1]	Number of options	Exercise price [1]
Share options outstanding, beginning of year	**5,846,460**	**$25.01**	5,337,705	$20.37
Granted	**801,500**	**37.72**	1,544,500	31.15
Exercised	**(806,093)**	**21.75**	(781,220)	19.93
Forfeited	**(280,362)**	**26.38**	(254,525)	22.17
Share options outstanding, end of year	**5,561,505**	**$27.25**	5,846,460	$25.01
Share options exercisable, end of year	**2,917,955**	**$23.28**	2,720,298	$21.66

1 Weighted average.

The following table summarizes the employee share option plan as at December 31, 2013:

	Options outstanding			Options exercisable	
	Number outstanding	**Weighted average exercise price**	**Weighted average remaining contractual life**	**Number exercisable**	**Exercise price**
$9.48 to $18.00	**570,480**	**$15.65**	**5.41**	**523,105**	**$15.50**
$18.01 to $25.08	**1,509,975**	**20.90**	**6.10**	**1,248,488**	**20.77**
$25.09 to $41.00	**3,481,050**	**31.90**	**7.49**	**1,146,362**	**29.55**
	5,561,505	**$27.25**	**6.90**	**2,917,955**	**$23.28**

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	2013	2012
Risk-free interest rate *(%)*	**1.41-2.34**	2.55
Expected life *(years)*	**6-10**	10
Expected volatility *(%)*	**23.59-24.46**	24.54
Annual dividend per share *($)*	**1.53**	1.44

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 three years. For the year ended December 31, 2013, the compensation expense recorded was $3.3 million (2012 – $5.5 million).

As at December 31, 2013, the unexpensed fair value of equity-based compensation cost associated with future periods was $9.2 million (December 31, 2012 – $8.8 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	2013	2012
Numerator:		
Net income applicable to controlling interests	**$201,096**	$116,769
Less: Preferred share dividends	**19,630**	14,922
Net income applicable to common shares	**$181,466**	$101,847
Denominator:		
Weighted average number of common shares outstanding	**116,068**	94,986
Dilutive equity instruments [1]	**3,441**	1,325
Weighted average number of common shares outstanding – diluted	**119,509**	96,311
Basic net income applicable per common share	**$ 1.56**	$ 1.07
Diluted net income applicable per common share	**$ 1.52**	$ 1.06

1 Includes all options that have a strike price lower than the market share price of AltaGas' common shares at December 31, 2013 and 2012, respectively.

For year ended December 31, 2013, 805,500 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (year ended December 31, 2012 – 668,516 options).

22. COMMITMENTS

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

Future payments of these commitments at December 31, 2013 are estimated as follows:

	2014	2015	2016	2017	2018	2019 and beyond	Total
Gas purchase	$274,676	$263,094	$275,625	$297,675	$146,496	–	**$1,257,566**
Service agreement	866	1,644	1,644	1,644	1,644	4,933	**12,375**
Storage services	3,366	3,389	3,413	3,436	3,460	39,719	**56,783**
Purchase obligations	4,232	5,033	5,057	5,081	5,105	44,652	**69,160**
Capital projects	65,607	25,233	9,800	9,800	9,800	147,000	**267,240**
Leases	7,341	6,230	5,885	5,097	1,945	10,312	**36,810**
	$356,088	**$304,623**	**$301,424**	**$ 322,733**	**$168,450**	**$246,616**	**$1,699,934**

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 2013 to 2019, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $12.6 million over the next 8 years, of which $7.4 million is payable in the next five years.

In 2009, AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. AltaGas is obligated to pay approximately $3.4 million per annum over the term of the contract for storage services.

In 2010, AltaGas entered into a 60-year Consumer Price Index indexed EPA with BC Hydro for the Northwest run-of-river projects. As at December 31, 2013, AltaGas is committed to pay approximately $61.2 million for construction work related to these projects which are expected to be in service in 2014 and 2015. As at December 31, 2013, AltaGas paid $90 million, recognized as "Intangible assets", to BC Hydro in support of the construction and operation of the Northwest Transmission Line. After commercial operation date, AltaGas shall make a series of 20 annual payments (annual considerations), the first of which shall be in the amount of approximately $4.9 million, and annually thereafter in the amount of approximately $9.8 million adjusted for inflation. Annual considerations have not been recognized in the statement of financial position as at December 31, 2013 and are included in the commitments payable in next years.

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 defined contribution plan was $4.8 million for the year ended December 31, 2013 (2012 – $2.5 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 the 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, 2013. 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, 2014.

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, 2013	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Accrued benefit obligation						
Balance, beginning of year	**$109,219**	**$13,769**	**$181,639**	**$ 53,142**	**$290,858**	**$ 66,911**
Actuarial (gain) loss	**(7,551)**	**(2,820)**	**(19,226)**	**2,443**	**(26,777)**	**(377)**
Current service cost	**6,298**	**620**	**6,212**	**1,313**	**12,510**	**1,933**
Member contributions	**29**	**130**	**–**	**–**	**29**	**130**
Interest cost	**4,557**	**451**	**7,761**	**2,314**	**12,318**	**2,765**
Benefits paid	**(4,166)**	**(275)**	**(6,714)**	**(2,047)**	**(10,880)**	**(2,322)**
Foreign exchange translation	**–**	**–**	**12,543**	**3,670**	**12,543**	**3,670**
Balance, end of year	**108,386**	**11,875**	**182,215**	**60,835**	**290,601**	**72,710**
Plan assets						
Fair value, beginning of year	**67,156**	**2,312**	**119,049**	**40,271**	**186,205**	**42,583**
Actual return on plan assets	**7,567**	**106**	**24,969**	**8,318**	**32,536**	**8,424**
Employer contributions	**9,376**	**1,489**	**11,739**	**529**	**21,115**	**2,018**
Member contributions	**137**	**–**	**–**	**–**	**137**	**–**
Benefits paid	**(4,166)**	**(275)**	**(6,714)**	**(1,531)**	**(10,880)**	**(1,806)**
Foreign exchange translation	**–**	**–**	**8,221**	**2,781**	**8,221**	**2,781**
Fair value, end of year	**80,070**	**3,632**	**157,264**	**50,368**	**237,334**	**54,000**
Accrued benefit liability	**$ (28,316)**	**$ (8,243)**	**$ (24,951)**	**$(10,467)**	**$ (53,267)**	**$(18,710)**

	Canada		United States		Total	
Year ended December 31, 2012	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Accrued benefit obligation						
Balance, beginning of year	$85,631	$ 10,064	–	–	$ 85,631	$ 10,064
Assumed through acquisition [1]	–	–	180,640	55,099	180,640	55,099
Transfer of obligations	220	–	–	–	220	–
Actuarial (gain) loss	18,808	3,003	(3,633)	(1,131)	15,175	1,872
Current service cost	4,905	434	1,666	316	6,571	750
Member contributions	22	–	–	–	22	–
Interest cost	4,469	533	2,449	740	6,918	1,273
Benefits paid	(4,836)	(265)	(1,540)	(563)	(6,376)	(828)
Plan amendments	–	–	–	(1,946)	–	(1,946)
Foreign exchange translation	–	–	2,057	627	2,057	627
Balance, end of year	109,219	13,769	181,639	53,142	290,858	66,911
Plan assets						
Fair value, beginning of year	56,924	1,716	–	–	56,924	1,716
Assumed through acquisition [1]	–	–	111,616	37,840	111,616	37,840
Transfer of assets	220	–	–	–	220	–
Actual return on plan assets	5,714	56	4,790	–	10,504	56
Employer contributions	9,006	805	2,912	1,618	11,918	2,423
Member contributions	128	–	–	382	128	382
Benefits paid	(4,836)	(265)	(1,540)	–	(6,376)	(265)
Actual plan expenses	–	–	–	–	–	–
Foreign exchange translation	–	–	1,271	431	1,271	431
Fair value, end of year	67,156	2,312	119,049	40,271	186,205	42,583
Accrued benefit liability	$(42,063)	$(11,457)	$(62,590)	$(12,871)	$(104,653)	$(24,328)

1 *Includes the plans acquired in the acquisition of SEMCO on August 30, 2012.*

The following amounts were included in the Consolidated Balance Sheets:

	Defined Benefit 2013	Post-Retirement Benefits 2013	Defined Benefit 2012	Post-Retirement Benefits 2012
Prepaid expenses and other current assets	**$ (418)**	**–**	–	–
Other current liabilities	**570**	**–**	2,077	–
Future employee obligations	**53,115**	**18,710**	102,576	24,328
	$53,267	**$18,710**	$104,653	$24,328

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, 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	**$ 108**	**$ 1**	**$(193)**	**–**	**$ (85)**	**$ 1**
Past service cost	**(299)**	**–**	**–**	**–**	**(299)**	**–**
Net actuarial loss	**(7,107)**	**(287)**	**–**	**–**	**(7,107)**	**(287)**
Total accumulated other comprehensive income (loss) on a pre-tax basis	**(7,298)**	**(286)**	**(193)**	**–**	**(7,491)**	**(286)**
Increase (decrease) by the amount included in deferred tax liabilities	**1,785**	**74**	**200**	**–**	**1,985**	**74**
Net amount in accumulated other comprehensive income (loss) after-tax	**$(5,513)**	**$(212)**	**$ 7**	**–**	**$(5,506)**	**$(212)**

	Canada		United States		Total	
Year ended December 31, 2012	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	$(1,503)	$ (48)	$(718)	–	$(2,221)	$ (48)
Past service cost	77	–	–	–	77	–
Net actuarial loss	(10,998)	(615)	–	–	(10,998)	(615)
Total accumulated other comprehensive income (loss) on a pre-tax basis	(12,424)	(663)	(718)	–	(13,142)	(663)
Increase (decrease) by the amount included in deferred tax liabilities	3,106	166	287	–	3,393	166
Net amount in accumulated other comprehensive income (loss) after-tax	$(9,318)	$(497)	$(431)	–	$(9,749)	$(497)

Amounts to be amortized in the next fiscal year	Defined Benefit	Post-Retirement Benefits
Actuarial losses	$3,339	$489

The following are the benefit cost components:

	Canada		United States		Total	
Year ended December 31, 2013	**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	**$6,190**	**$ 620**	**$6,212**	**$1,313**	**$12,402**	**$1,933**
Interest cost	**4,557**	**581**	**7,761**	**2,314**	**12,318**	**2,895**
Expected return on plan assets	**(3,863)**	**(74)**	**(10,356)**	**(3,390)**	**(14,219)**	**(3,464)**
Amortization of actuarial loss on accrued benefit obligation	**2,451**	**267**	**4,350**	**310**	**6,801**	**577**
Costs arising in the year	**$9,335**	**$1,394**	**$7,967**	**$ 547**	**$17,302**	**$1,941**

	Canada		United States		Total	
Year ended December 31, 2012	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	$4,800	$434	$1,647	$312	$6,447	$ 746
Interest cost	4,470	533	2,421	732	6,891	1,265
Expected return on plan assets	(3,345)	(59)	(2,722)	(940)	(6,067)	(999)
Amortization of actuarial loss on accrued benefit obligation	1,057	76	1,004	45	2,061	121
Costs arising in the year	$6,982	$984	$2,350	$149	$9,332	$1,133

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 set an overall objective to have a target asset allocation for the Canadian plans of 45 percent to 55 percent of fixed income assets. This objective has taken into account the nature of the liabilities and the risk reward tolerance of the Corporation

The target asset allocation for the U.S. plans is 67 percent equities and 33 percent debt instruments.

The collective investment mixes for the plans are as follows as at December 31, 2013:

	Fair value	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$3,438**	**$3,438**	**–**	**1.18**
Canadian Equities	**27,715**	**27,715**	**–**	**9.51**
Foreign Equities	**154,225**	**154,225**	**–**	**52.94**
Fixed Income	**103,197**	**103,197**	**–**	**35.42**
Real Estate	**2,759**	**–**	**2,759**	**0.95**
	$291,334	**$288,575**	**$2,759**	**100.00**

	Defined Benefit 2013	Post-Retirement Benefits 2013	Defined Benefit 2012	Post-Retirement Benefits 2012
Significant actuarial assumptions used as at December 31				
Discount rate (%)	**3.20-5.00**	**0.00-5.00**	3.20-4.40	3.95-4.40
Expected long-term rate of return on plan assets (%)	**0.00-8.00**	**0.00-8.00**	0.00-8.00	0.00-8.00
Rate of compensation increase (%)	**0.00-4.00**	**0.00-3.50**	0.00-4.00	0.00-4.00
Average remaining service life of active employees (years)	**12.7**	**12.9**	12.3	12.4

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 2013:

	Increase	Decrease
Service and interest costs	$ 11,544	$ (9,007)
Accrued benefit obligation	$69,865	$(49,574)

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:		
2014	$14,240	$ 3,187
Expected benefit payments:		
2014	$ 9,370	$ 2,135
2015	$11,329	$ 2,337
2016	$12,959	$ 2,517
2017	$12,892	$ 2,760
2018	$13,789	$ 3,021
2019-2023	$83,990	$18,518

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, 2013	
Due from related parties	
Accounts receivable [1]	**$ 1,076**
Long-term investments and other assets [2]	**750**
	$ 1,826
Due to related parties	
Accounts payable [3]	**$20,620**
Long-term debt [4]	**332**
	$20,952

1 *Receivable from joint ventures and an affiliate.*

2 *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.*

3 *Payables to joint ventures.*

4 *Due to an affiliate of the Corporation.*

Year ended December 31, 2013	
Revenue [1]	**$24,032**
Cost of sales [2]	**12,493**
Operating and administrative expenses [3]	**1,272**
Other income (expenses)	**121**
Interest expense on long-term debt	**164**

1 *In the ordinary course of business, AltaGas sold natural gas to an affiliate.*

2 *In the ordinary course of business, AltaGas purchased natural gas from two of its joint ventures.*

3 *Administrative costs recovered from joint ventures.*

25. COMPARATIVE FIGURES

Certain comparative figures related to deferred income tax assets and deferred income tax liabilities for the year ended December 31, 2012 have been reclassified to conform to the US GAAP financial statement presentation.

26. SUBSEQUENT EVENTS

Subsequent events have been reviewed through February 26, 2014, the issuance date of these financial statements.

On October 24, 2013, AltaGas announced that it will increase its effective ownership of Petrogas to 33 1/3 percent. AltaGas plans to transfer its current 25 percent ownership to AIJVLP. AIJVLP will acquire an additional 41 2/3 percent interest in Petrogas. As a result of the transaction, Petrogas will be owned one-third by each of AltaGas, Idemitsu, and its current majority shareholder. All regulatory approvals have been obtained and the transaction is expected to close on March 1, 2014.

On December 20, 2013, AltaGas entered in an unit and share purchase agreement for the acquisition of the remaining 50 percent ownership interest in Alton Natural Gas Storage that it does not already own. The transaction closed on February 20, 2014.

On January 13, 2014, AltaGas issued $200 million of senior unsecured MTNs with a coupon rate of 4.40 percent and maturity of March 15, 2024 and $100 million senior unsecured MTNs with a coupon rate of 5.16 percent and maturity of January 13, 2044.

On January 24, 2014, AltaGas Processing Partnership, a wholly-owned subsidiary of AltaGas, entered into a sale agreement for Ante Creek, a 58.5 Mmcf/d (licensed capacity) 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 approximately $12 million.

On February 14, 2014, AltaGas redeemed $200 million of senior unsecured MTNs early, which had a coupon rate of 7.42 percent and a maturity of April 29, 2014.

27. 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; and • LNG and LPG development projects.
Power	• coal-fired, gas-fired, wind, biomass and run-of-river power output under power purchase arrangements; both operational and under construction; • gas-fired power plants in Alberta; 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	2013	2012
Revenue [1]		
Canada	**$1,376,019**	$1,207,426
United States	**676,155**	220,197
Total	**$2,052,174**	$1,427,623

As at December 31	2013	2012
Property, plant and equipment		
Canada	**$3,418,878**	$3,083,197
United States	**1,533,648**	865,969
Total	**$4,952,526**	$3,949,166

1 Operating revenue from external customers.

The following tables show the composition by segment:

Year ended December 31, 2013	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$1,019,793	$ 300,435	$ 894,415	–	$(162,469)	$2,052,174
Unrealized gain on risk management	–	–	-	(9,242)	–	(9,242)
Cost of sales	(658.103)	(231,765)	(502,465)	–	156,176	(1,236,157)
Operating and administrative	(184,708)	(33,135)	(190,125)	(28,804)	6,293	(430,479)
Accretion of asset retirement obligations	(3,576)	(126)	(34)	–	–	(3,736)
Depreciation, depletion and amortization	(68,525)	(22,766)	(57,254)	(3,940)	–	(152,485)
Provision on property, plant and equipment	(15,905)	(3,688)	(3,000)	–	–	(22,593)
Income from equity investments	1,620	108,041	2,514	–	–	112,175
Other income (expenses)	5,590	370	40,193	(4,932)	–	41,221
Foreign exchange loss	–	–	–	(290)	–	(290)
Interest expense	–	–	–	(102,074)	–	(102,074)
Income (loss) before income taxes	$ 96,186	$ 117,366	$ 184,244	$(149,282)	–	$248,514
Net additions (reductions) to:						
Property, plant and equipment [1]	$ 42,138	$ 333,801	$ 765,379	$ 3,280	–	$1,144,598
Intangible assets	$ (6,997)	$ (209)	$ 6,472	$ 9,246	–	$ 8,512
Investments accounted for by equity method	$ 337,533	$ (7,988)	$ 1,180	–	–	$ 330,725
As at December 31, 2013:						
Goodwill	$ 161,401	–	$ 581,700	–	–	$ 743,101
Segmented assets	$2,451,736	$1,924,549	$2,765,889	$ 139,129	–	$7,281,303

Year ended December 31, 2012	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 843,998	$ 216,137	$ 437,638	–	$(70,150)	$1,427,623
Unrealized loss on risk management	–	–	–	22,057	–	22,057
Cost of sales	(522,615)	(172,230)	(225,819)	–	68,119	(852,545)
Operating and administrative	(168,224)	(18,075)	(104,542)	(34,202)	2,031	(323,012)
Accretion of asset retirement obligations	(3,010)	(83)	(22)	-	–	(3,115)
Depreciation, depletion and amortization	(57,177)	(11,122)	(27,457)	(3,519)	–	(99,275)
Provision on property, plant and equipment	–	(2,853)	–	–	–	(2,853)
Income from equity investments	622	65,116	859	–	–	66,597
Other income (expenses)	–	–	–	580	–	580
Foreign exchange loss	–	–	–	(8,512)	–	(8,512)
Interest expense	–	–	–	(61,237)	–	(61,237)
Income (loss) before income taxes	$ 93,594	$ 76,890	$ 80,657	$ (84,833)	–	$ 166,308
Net additions (reductions) to:						
Property, plant and equipment [1]	$ 362,945	$ 302,662	$ 866,236	$ 254	–	$1,532,097
Intangible assets	$ (81)	$ 613	$ 12,020	$ (278)	–	$ 12,274
Investments accounted for by equity method	$ 2,340	$ 34,551	$ 23,984	–	–	$ 60,875
As at December 31, 2012:						
Goodwill	$161,401	–	$ 553,501	–	–	$ 714,902
Segmented assets	$2,196,540	$1,050,180	$2,541,500	$144,156	–	$5,932,376

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

Ten-Year Review of Financial Information

($ millions unless otherwise indicated)	2013	2012	2011
			(restated)
Financial Highlights [1]			
Income Statement			
Revenue	**2,042.9**	1,449.7	1,280.0
Net revenue [2]	**960.2**	664.4	513.1
EBITDA [2]	**538.9**	319.3	257.2
Operating Income [2]			
Gas	**96.2**	93.6	105.2
Power	**117.4**	76.9	86.7
Utility	**184.2**	80.7	24.2
Corporate	**(37.7)**	(37.1)	(41.0)
	360.1	214.1	175.1
Net income	**181.5**	101.8	82.7
Net income per basic share	**$1.56**	$1.07	$0.98
EBITDA per basic share [2]	**$4.64**	$3.36	$3.06
Cash Flow			
Funds from operations [2]	**400.3**	254.6	213.3
Funds from operations per basic share [2]	**$3.45**	$2.68	$2.54
Dividends/distributions per share declared [3]	**$1.50**	$1.40	$1.34
Balance Sheet			
Property, plant and equipment	**4,952.5**	3,949.2	2,486.1
Intangible assets	**195.3**	189.8	177.5
Total assets	**7,281.3**	5,932.4	3,556.2
Short-term debt	**84.4**	66.9	16.8
Long-term debt	**2,952.7**	2,626.1	1,214.3
Shareholders' equity	**2,791.7**	1,959.8	1,355.4
Share Data *(millions)*			
Shares outstanding at year-end	**122.3**	105.3	89.2
Weighted average shares outstanding for the year *(basic)*	**116.1**	95.0	84.0
Ratios *(%)*			
Return on average equity	**9.4**	7.8	8.0
Return on average invested capital	**8.5**	7.7	8.5
Debt as a percentage of total capitalization	**53.1**	57.4	49.5

1 Financial results 2010 and 2011 were restated to comply with US GAAP.
2 Non-GAAP financial measure. See discussion on the "Non-GAAP Financial Measures" section of the MD&A.
3 On July 1, 2010, AltaGas converted from a Trust to a Corporation.

2010	2009	2008	2007	2006	2005	2004
(restated)						
1,192.4	1,268.3	1,816.8	1,428.4	1,362.6	1,502.3	864.6
504.8	456.6	476.5	324.0	318.9	296.9	250.4
234.9	247.8	245.4	245.4	172.6	156.8	134.5
95.0	102.9	103.6	59.3	63.4	60.1	47.9
76.4	88.0	117.9	94.6	90.9	48.7	35.8
24.6	7.5	–	–	–	6.2	7.9
(43.9)	(27.7)	(43.1)	(27.3)	(27.6)	(6.9)	–
152.1	170.6	178.4	125.5	126.7	108.1	91.6
117.0	141.3	163.6	108.8	114.5	90.3	65.8
$1.43	$1.80	$2.38	$1.90	$2.06	$1.67	$1.33
$2.88	$3.16	$3.57	$4.28	$3.10	$2.90	$2.72
191.7	202.3	217.1	162.9	161.7	129.0	108.6
$2.35	$2.58	$3.15	$2.84	$2.92	$2.39	$2.20
$1.74	$2.16	$2.13	$2.065	$1.995	$1.85	$1.31
1,923.5	1,857.1	1,436.7	682.3	677.9	645.4	746.7
80.0	128.9	138.9	95.7	103.3	110.9	113.1
2,743.1	2,628.9	2,132.3	1,172.7	1,109.6	1,068.3	1,108.6
9.5	14.5	4.5	3.6	-	2.7	7.0
903.0	1,000.1	560.8	217.2	265.5	266.3	352.5
1,209.9	1,048.9	957.4	584.7	529.4	478.6	483.5
82.5	80.3	71.9	58.1	56.4	54.6	53.2
81.5	78.5	68.8	57.4	55.5	54.0	49.4
9.4	13.6	19.6	19.8	22.7	18.4	15.7
8.2	10.0	13.6	16.2	16.3	13.0	11.6
42.8	49.2	37.8	27.4	33.4	36.0	42.6

Ten-Year Review of Operating Information

	2013	2012	2011
Operating Statistics			
Gas			
Extraction inlet gas processed *(Mmcf/d)* [1]	**941**	889	883
Extraction ethane volumes *(Bbls/d)* [1]	**30,999**	25,499	26,565
Extraction NGL volumes *(Bbls/d)* [1]	**20,672**	14,593	14,513
Total extraction volumes *(Bbls/d)* [1,2]	**51,671**	40,092	41,078
Frac spread – realized *($/Bbl)* [1,3]	**24.96**	30.83	33.67
Frac spread – average spot price *($/Bbl)* [1,4]	**27.15**	29.22	42.88
Field processing throughput *(gross Mmcf/d)* [1]	**420**	372	391
Field processing capacity Utilization *(%)* [1]	**30**	30	33
Average gas volumes marketed *(GJ/d)* [1,5]	**356,271**	356,526	369,603
Power			
Volume of power sold *(GWh)*	**4,458**	3,317	3,003
Price received on the sale of power *($/MWh)* [6]	**76.82**	69.42	75.94
Alberta Power Pool price *($/MWh)*	**80.19**	64.32	76.22
Canadian utilities			
Natural gas deliveries – end-use *(PJ)* [7]	**30.4**	28.5	21.8
Natural gas deliveries – transportation *(PJ)* [7]	**5.8**	6.8	4.6
U.S. utilities [8]			
Natural gas deliveries – end-use *(Bcf)* [7]	**70.1**	26.0	–
Natural gas deliveries – transportation *(Bcf)* [7]	**41.4**	13.9	–
Service sites [9]	**555,198**	547,977	115,011
Degree day variance from normal *(%)*			
AUI [10]	**0.5**	(0.7)	–
Heritage Gas [10]	**1.3**	(9.1)	(12.7)
SEMCO Gas [8,11]	**9.0**	(0.2)	–
ENSTAR [8,11]	**(1.0)**	9.6	–

1 *Average for the year.*

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 year 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 year.*

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.*

2010	2009	2008	2007	2006	2005	2004
–	–	–	–	–	–	–
25,453	26,817	24,795	13,355	13,132	13,155	8,602
12,654	13,236	12,242	6,752	6,564	6,202	4,834
38,107	40,053	37,037	20,108	19,696	19,357	13,436
27.27	23.46	26.97	21.38	18.47	9.31	10.51
31.95	19.51	28.79	22.48	18.47	9.31	10.51
423	453	541	527	555	563	560
35	39	46	52	54	60	61
386,004	354,513	302,392	388,217	327,057	312,272	174,337
2,828	2,726	2,623	2,661	2,878	3,466	3,481
66.79	68.97	84.51	68.59	69.26	54.59	48.77
50.76	47.84	89.95	66.84	80.48	70.19	54.54
19.90	6.62	–	–	–	10.5	14.7
5.30	0.55	–	–	–	9.5	11.6
–	–	–	–	–	–	–
–	–	–	–	–	–	–
74,664	72,717	–	–	–	61,447	60,430
(1.60)	9.90	–	–	–	(1.4)	2.6
(13.20)	(1.00)	–	–	–	(5.7)	2.3
–	–	–	–	–	–	–
–	–	–	–	–	–	–

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

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

2013 Dividend Declaration History

Ex-Dividend Date	Record Date	Payment Date	Amount
January 23, 2013	January 25, 2013	February 15, 2013	$0.120
February 21, 2013	February 25, 2013	March 15, 2013	$0.120
March 21, 2013	March 25, 2013	April 15, 2013	$0.120
April 23, 2013	April 25, 2013	May 15, 2013	$0.120
May 23, 2013	May 27, 2013	June 17, 2013	$0.125
June 21, 2013	June 25, 2013	July 15, 2013	$0.125
July 23, 2013	July 25, 2013	August 15, 2013	$0.125
August 22, 2013	August 26, 2013	September 16, 2013	$0.1275
September 23, 2013	September 25, 2013	October 15, 2013	$0.1275
October 23, 2013	October 25, 2013	November 15, 2013	$0.1275
November 23, 2013	November 25, 2013	December 16, 2013	$0.1275
December 23, 2013	December 27, 2013	January 15, 2014	$0.1275
Total 2013 Dividends			$1.4925

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

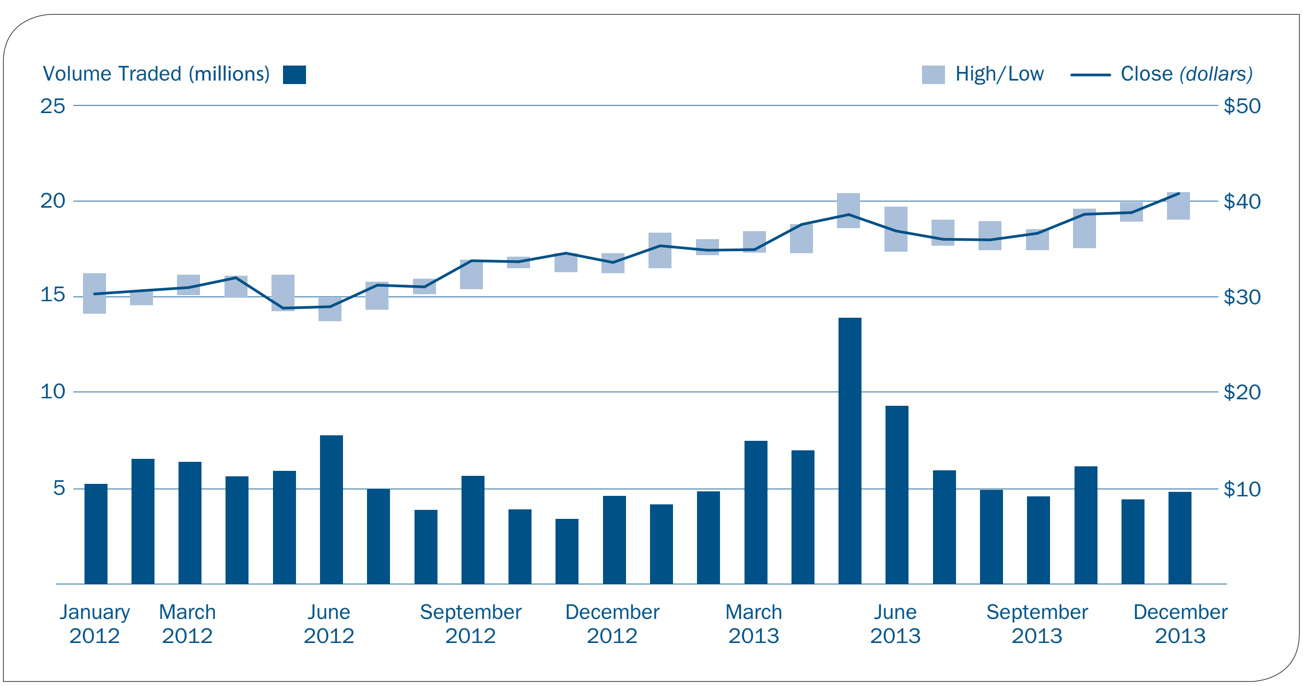
AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan ("Plan") for holders of common shares of AltaGas Ltd.

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

Management Team

David W. Cornhill
Chairman and Chief Executive Officer

Dennis A. Dawson
Vice President General Counsel
and Corporate Secretary

David M. Harris
Chief Operating Officer

John E. Lowe
Executive Vice President
Corporate Development

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

Kent E. Stout
Vice President
Corporate Resources

David R. Wright
Executive Vice President

Auditors
Ernst & Young LLP
Calgary, Alberta, Canada

Transfer Agent
Computershare Trust Company of Canada
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Toll-free: 1-800-564-6253
Email: service@computershare.com

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

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

Annual Meeting
The annual meeting will be held at 3:30 p.m. MDT on Thursday, May 1, 2014 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

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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**

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