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OFFICE OF INTERNATIONAL CORPORATE FINANCE

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ALTAGAS INCOME TRUST

Annual Information Form

For the year ended December 31, 2009

Dated: March 4, 2010

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All dollar amounts in this Annual Information Form are in Canadian dollars unless otherwise stated.

FORWARD-LOOKING INFORMATION

This Annual Information Form contains forward-looking statements. When used in this Annual Information Form the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this Annual Information Form contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results.

Specifically, such forward-looking statements are set forth in respect of the Trust's overall strategy under the heading "Objective of the Trust – AltaGas' Strategy", including with respect to the relative contribution of power and gas to revenue growth and statements as they relate to gas opportunities with respect to: expectations for the WCSB; growth opportunities from plant modifications, increasing interests, acquiring and constructing infrastructure and growing demand; the anticipated impact of the Harmattan Co-Stream Project; the contribution of the Trust's extraction infrastructure to throughput, utilization and profitability; the availability of opportunites to build or acquire gathering infrastructure and generate operating synergies; and the impact of growing natural gas production in northeast British Columbia and northwest Alberta, and as they relate to power opportunities with respect to: power demand growth and price recovery; the timing of new power generation; and the impact of the planned decommissioning of thermal plants on opportunities to develop new clean power generation capacity. In addition, such forward-looking statements are set forth under:

- "Operating Segments – Gas Segment – Transmission", including in respect of expectations for volume commitments for 2010 and thereafter in relation to Suffield, the extension of an existing contract on similar terms in relation to Porcupine Hills and the termination of a transportation agreement in relation to Kahntah;
- "Operating Segments – Gas Segment – Field Gathering and Processing", including in respect of expectations with respect to levels of producer activity and demand for gathering and processing facilities and services and the Trust's competitiveness in the midstream marketplace;
- "Operating Segments – Gas Segment – Natural Gas Distribution", including in respect of expectations for growth in new service sites and activations, capital expenditures for 2010 and access to adequate supplies of natural gas;
- "Operating Segments – Power Segment", including in respect of expectations for growth through renewable energy projects, the the timing of development and the environmental attributes of the Glenridge Wind Development project, the timing of construction for the Log Creek and Kookipi Creek run-of-river plants, the ability to generate further growth for the power infrastructure business with its renewable energy portfolio, the long term price environment for power, the drivers of growth in the power business and the timing of development and intentions with respect to the development of the Trust's hydroelectric and other wind power development projects in Canada and the United States.

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 the Trust's 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, and general economic conditions and the other factors discussed under the heading "Risk Factors" in this Annual Information Form.

Many factors could cause the Trust's or any particular segment's actual results, performance or achievements to vary from those described in this Annual Information Form, including without limitation those listed above and the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Annual Information Form as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this Annual Information Form, should not be unduly relied upon. Such statements speak only as of the date of this Annual Information Form. The Trust 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 Annual Information Form are expressly qualified by this cautionary statement.

Financial outlook information contained in this Annual Information Form 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 Annual Information Form should not be used for purposes other than for which it is disclosed herein.

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GLOSSARY

In this Annual Information Form, unless the context otherwise requires, the following terms have the indicated meanings. A reference to an agreement means the agreement as amended, supplemented or restated from time to time.

"Administration Agreement" means the administration agreement dated May 1, 2004 among the Trust, the General Partner, AltaGas Ltd. as administrator, Holding Trust, AltaGas LP #1 and AltaGas LP #2 as described under "Management of the Trust – Administration Agreement";

"AESO" means Alberta Electric System Operator;

"AltaGas" means AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership and the other operating affiliates of the Trust;

"AltaGas LP #1" means AltaGas Holding Limited Partnership No. 1;

"AltaGas LP #1 B units" means Class B limited partnership units of AltaGas LP #1;

"AltaGas LP #2" means AltaGas Holding Limited Partnership No. 2;

"AltaGas LP #2 B units" means Class B limited partnership units of AltaGas LP #2;

"AltaGas Services" or **"ASI"** means AltaGas Services Inc., a predecessor by amalgamation to AltaGas Ltd.;

"Arrangement" means the arrangement, under the provisions of section 192 of the CBCA, involving, among others, AltaGas Services, the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2, pursuant to which the business of AltaGas Services was reorganized into an income trust effective May 1, 2004;

"ASTC Partnership" or **"ASTC"** means ASTC Power Partnership;

"AUI" means AltaGas Utilities Inc.;

"AUC" means the Alberta Utilities Commission;

"Balancing Pool" means the Alberta governmental agency established to manage unsold PPAs from the original PPA auction, and which serves as a liability backstop for all PPAs;

"Bankruptcy Act" means the *Bankruptcy and Insolvency Act* (Canada);

"Bbls" means stock tank barrels of ethane and NGLs, expressed in standard 42 U.S. gallon barrels or 34.972 imperial gallon barrels;

"Bbls/d" means Bbls per day;

"Bcf" means 1,000,000 Mcf of natural gas;

"Bcf/d" means Bcf per day;

"BMWLP" means Bear Mountain Wind Limited Partnership;

"Board of Directors" means the board of directors of the General Partner, as from time to time constituted;

"BPA" means the Balancing Pool Administrator;

"Cash Flow of the Trust" means for, or in respect of, any Distribution Period: (i) all cash amounts which are received by the Trust for, or in respect of, the Distribution Period, including, without limitation, interest, dividends, distributions, proceeds from the disposition of securities, returns of capital and repayments of indebtedness; plus (ii) the proceeds of any issuance of Trust units or any other securities of the Trust, net of the expenses of distribution, and, if applicable, the use of proceeds of any such issuance for the intended purposes; less the sum of (iii) all amounts which relate to the redemption of Trust units and which have become payable in cash by the Trust in the Distribution Period and any expenses of the Trust in the Distribution Period; and (iv) any other amounts (including taxes) required by law or the Declaration of Trust to be deducted, withheld or paid by or in respect of the Trust in such Distribution Period;

"CBCA" means the *Canada Business Corporations Act*, R.S.C. 1985, c. C 44, as amended from time to time, including the regulations from time to time promulgated thereunder;

"**CBM**" means coal bed methane;

"**CIAC**" means contributions in aid of construction;

"**Closing Market Price**" means: (i) an amount equal to the closing price of the Trust units if there was a trade on the date on which Trust units were tendered for redemption and the exchange or market provides a closing price; (ii) an amount equal to the average of the highest and lowest prices of the Trust units on the date on which the Trust units were tendered for redemption if there was trading and the exchange or other market provides only the highest and lowest prices of Trust units traded on a particular day; or (iii) the average of the last bid and last ask prices if there was no trading on the date;

"**Committee**" means the Audit Committee of the Board of Directors;

"**DBRS**" means DBRS Limited;

"**Declaration of Trust**" means the declaration of trust dated as of March 26, 2004 between the settlor and the Trustee, pursuant to which the Trust was created, as from time to time amended, supplemented or restated;

"**Delegation Agreement**" means the delegation agreement dated May 1, 2004 among the Trust, the General Partner and the Trustee described under "Management of the Trust – Delegation Agreement";

"**Distribution Period**" means each calendar month, or such other periods as may be determined from time to time by the General Partner on behalf of the Trustee from and including the first day thereof and to and including the last day thereof;

"**Degree Day**" means the amount that the daily mean temperature deviates below 15 degrees Celsius, such that a one degree difference equates to one Degree Day;

"**EDS**" means Ethylene Delivery System;

"**EEEP**" means the Edmonton ethane extraction plant and related facilities;

"**ERCB**" means the Alberta Energy Resources Conservation Board;

"**Exchangeable units**" means AltaGas LP #1 B units and AltaGas LP #2 B units, if any;

"**Exempt Plans**" means, collectively, trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax-free savings accounts, each as defined in the Tax Act;

"**General Partner**" means AltaGas General Partner Inc., a direct wholly owned subsidiary of the Trust and the general partner of AltaGas LP #1 and AltaGas LP #2;

"**GJ**" means gigajoule or 1,000,000,000 joules;

"**GJ/d**" means GJ per day;

"**GreenWing**" means GreenWing Energy Development Limited Partnership;

"**GWh**" means gigawatt-hour or 1,000,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"**Harmattan Complex**" means the Harmattan natural gas liquids extraction plant and associated facilities;

"**Heritage Gas**" means Heritage Gas Limited;

"**Holding Declaration of Trust**" means the declaration of trust dated as of March 26, 2004 between the Trust, as settlor, and the Holding Trust Trustee, pursuant to which Holding Trust was created;

"**Holding Trust**" means AltaGas Holding Trust, an unincorporated investment trust, all of the beneficial interests of which are owned by the Trust;

"**Holding Trust Note Indenture**" means the agreement dated as of March 26, 2004 between Holding Trust and Computershare Trust Company of Canada, as note trustee, pursuant to which Holding Trust Notes have been, and may in the future be, issued by Holding Trust, as from time to time amended, supplemented or restated;

"Holding Trust Notes" means the unsecured subordinated notes issued pursuant to the Holding Trust Note Indenture and described in greater detail under "Holding Trust – Holding Trust Notes";

"Holding Trust Trustee" means AltaGas Holding Trust Corp., as initial trustee of Holding Trust;

"Inuvik Gas" means Inuvik Gas Ltd.;

"JEEP" means the Joffre ethane extraction plant and related facilities;

"JFP" means Joffre Feedstock Pipeline;

"km" means kilometre;

"m^3" means a cubic metre of natural gas at standard conditions of measurement;

"Market Price" means an amount equal to the simple average of the closing price of the Trust units for each of the trading days on which there was a closing price; provided that if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust units traded on a particular day, the market price shall be an amount equal to the simple average of the highest and lowest prices for that trading day if there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days before the applicable date, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the bid and ask prices for each day on which there was no trading; the weighted average trading price of the Trust units for each day that there was trading if the exchange or market provides a weighted average trading price; and the average of the highest and lowest prices of the Trust units for each day that there was trading, if the market provides only the highest and lowest prices of Trust units traded on a particular day;

"MBbls" means 1,000 Bbls;

"Mcf" means a thousand cubic feet of natural gas at standard imperial conditions of measurement;

"Mcf/d" means Mcf per day;

"Mm" means millions;

"Mmcf" means a million cubic feet of natural gas at standard conditions of measurement;

"Mmcf/d" means Mmcf per day;

"MW" means megawatt; one MW is 1,000,000 watts; the watt is the basic electrical unit of power;

"MWh" means megawatt-hour or 1,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"NGL" or **"NGLs"** means natural gas liquids, which includes primarily propane, butane and condensate;

"NW Projects" means the three run-of-river hydroelectric development projects in Northwest B.C.: Forrest Kerr, McLymont Creek and Volcano Creek;

"NovaGreen" means NovaGreen Power Inc;

"NSUARB" means the Nova Scotia Utility and Review Board;

"NWTPUB" means the Northwest Territories Public Utility Board;

"Plan" means the Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan of the Trust;

"Pool" means the Alberta Power Pool;

"PJ" means Petajoule which is one million GJ;

"PPA" means power purchase arrangement;

"Provident" means Provident Energy Trust;

"RAPP" means the rolling 30-day average Pool price of electricity in Alberta;

"Rep Agreements" mean the Representation, Management and Processing Agreements at the Harmattan Complex;

"S&P" means Standard & Poor's Ratings Services;

"Special Voting Unit" means the special voting unit of the Trust issued by the Trust and deposited with the Voting and Exchange Trustee to which is attached that number of voting rights (each such voting right being equal to the voting rights attached to one Trust unit) equal to the number of outstanding Exchangeable units held, other than by the Trust and its affiliates;

"Tax Act" means the *Income Tax Act* (Canada), including the regulations thereunder, as amended from time to time;

"Taylor" means Taylor NGL Limited Partnership, a limited partnership created pursuant to the laws of Ontario;

"Tcf" means 1,000,000,000 Mcf;

"TransAlta" means TransAlta Utilities Corporation;

"TransCanada" means TransCanada Energy Ltd.;

"Trust" means AltaGas Income Trust and, where appropriate, includes its affiliates;

"Trust options" means options to acquire Trust units granted pursuant to AltaGas' trust unit option plan;

"Trust units" means trust units of the Trust;

"Trustee" means Computershare Trust Company of Canada, as initial trustee pursuant to the Declaration of Trust;

"TSX" means the Toronto Stock Exchange;

"Unanimous Shareholder Agreement" means the agreement entered into on May 1, 2004 among the General Partner, AltaGas LP #1, AltaGas LP #2 and AltaGas Ltd., as from time to time amended, supplemented or restated as described under "General Partner – Unanimous Shareholders Agreement";

"Unit" or **"units"** means Trust units and Exchangeable units;

"unitholders" means the holders of Trust units and Exchangeable units;

"Utility Group" means AltaGas Utility Group Inc.;

"Voting and Exchange Trust Agreement" means the agreement dated May 1, 2004 among the Trust, AltaGas LP #1, AltaGas LP #2 and the Voting and Exchange Trustee, as from time to time amended, supplemented or restated;

"Voting and Exchange Trustee" means Computershare Trust Company of Canada, as initial trustee under the Voting and Exchange Trust Agreement, or such other person as becomes the trustee under the Voting and Exchange Trust Agreement in accordance with such agreement;

"WCSB" means Western Canada Sedimentary Basin; and

"Younger Extraction Plant" means the Younger extraction plant and related facilities.

METRIC CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply by
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	6.290
tonnes	long tons	0.984
feet	metres	0.305

To Convert From	To	Multiply By
metres	feet	3.281
miles	km	1.609
km	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoule	Mcf	0.9482

ALTAGAS INCOME TRUST

AltaGas Income Trust is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to the Declaration of Trust. See "Declaration of Trust and Description of Units". The Trust indirectly holds all of the assets, liabilities and businesses formerly owned by AltaGas Services. AltaGas Services was incorporated on August 30, 1993 under the CBCA as 2950341 Canada Ltd. and commenced operations on April 1, 1994. Effective May 1, 2004 the business of AltaGas Services was reorganized pursuant to the Arrangement and holders of common shares of AltaGas Services received Trust units and/or Exchangeable units in exchange for their common shares. AltaGas Services became an indirect subsidiary of the Trust and was amalgamated to form AltaGas Ltd.

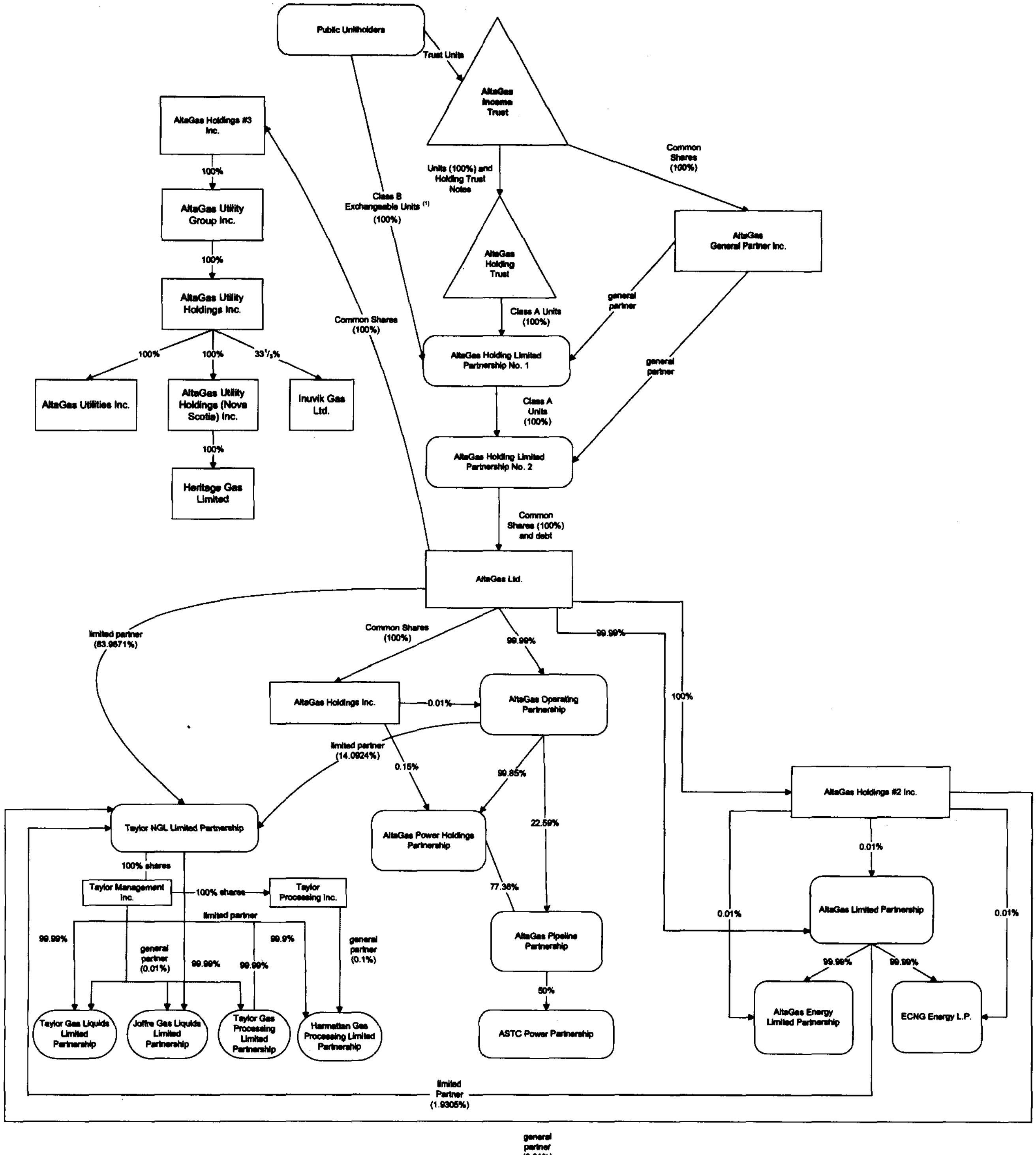
At December 31, 2009 the Trust had 78,231,948 outstanding Trust units and 2,083,656 outstanding Exchangeable units consisting entirely of AltaGas LP #1 B units.

The Trust's fiscal year-end is December 31 and references in this Annual Information Form to particular years mean the Trust's fiscal years unless otherwise indicated. Unless expressly stated, all numbers in this Annual Information Form are as at December 31, 2009.

The head and principal office of the Trust is located at 1700, 355 – 4th Avenue S.W., Calgary, Alberta, T2P 0J1.

TRUST STRUCTURE

The Trust and its material affiliates are shown in the following chart.



Notes:

(1) The Exchangeable units are exchangeable for Trust units at the option of the holder on a one-for-one basis, are entitled to vote with unitholders and are entitled to the same cash payments per Exchangeable unit as the cash distributions made on a Trust unit. See "Declaration of Trust and Description of Units".

(2) The Trust, Holding Trust, and each of the partnerships, other than Taylor, are established under the laws of Alberta. Each of the General Partner, AltaGas Ltd., AltaGas Holdings Inc., AltaGas Holdings #3 Inc., AltaGas Utility Group Inc., AltaGas Utility Holdings Inc., AltaGas Utilities Inc., Heritage Gas Limited and Inuvik Gas Ltd. is a corporation incorporated or formed by amalgamation or continuance under the CBCA. Taylor was established under the laws of Ontario. Each of AltaGas Holdings #2 Inc., Taylor Processing Inc., Taylor Management Inc. and AltaGas Utility Holdings (Nova Scotia) Inc. is a corporation incorporated under the *Business Corporations Act* (Alberta).

OBJECTIVE OF THE TRUST

The objective of the Trust is to grow and operate its businesses, indirectly through its operating affiliates, in a manner that builds long-term value and delivers stable results to unitholders. The Trust's objectives, through its operating affiliates, are to:

- Maximize the profitability and long-term value of its existing infrastructure and services;
- Build on the current mix of energy assets and services with a continued focus on predictable, long-term cash flow horizons using cost-of-service, fixed-fee and margin-based contract terms and with minimal or managed exposure to commodity prices;
- Grow its gas and power infrastructure and related services through development, consolidations, expansions and acquisitions in Canada and the northern and western United States;
- Focus on projects that are accretive to earnings and cash flow with the appropriate risk and return balance;
- Diversify infrastructure by fuel source, contractual terms, exposure to industry cycles and geographic location;
- Focus on expanding its clean energy footprint, such as through wind and hydroelectric power generation, as well as natural gas-fired generation;
- Generate green credits through technology, such as acid gas injection and renewable projects to decrease environmental impacts and hedge against environmental costs; and
- Maintain the Trust's investment-grade credit ratings.

The Trust strives to provide unitholders with stable and growing cash distributions. The Trust employs a strategy to provide unitholders with a competitive annual cash-on-cash yield by making monthly cash distributions that are supported by a sound financial strategy and strong business performance.

OVERVIEW OF THE BUSINESS

AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the northern and western United States. To achieve its vision, AltaGas capitalizes on its solid base business, operational expertise and financial strength and focuses on increasing the value and profitability of its existing assets and growing and diversifying its business.

AltaGas is a natural gas and power infrastructure business with physical and economic links along the energy value chain. AltaGas' efficient, reliable and profitable assets, market knowledge and financial discipline have resulted in the creation of long-term value for its investors. AltaGas focuses on maximizing the profitability of its assets, providing services that are complementary to its existing business, and growing through the acquisition and development of additional energy infrastructure.

AltaGas' gas infrastructure touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, transmission, distribution and storage. The power infrastructure includes conventional power generation in Alberta and renewable power generation in British Columbia.

ALTAGAS' STRATEGY

AltaGas' strategy is to increase unitholder value through the delivery of sustainable and increasing earnings and cash flow from its existing assets, as well as from the growth of its business through acquisition and construction of new gas and power infrastructure with long economic lives. Investments are diversified by revenue source, fuel source, contractual term, exposure to industry cycle and location. The Trust expects growth in its business to be evenly split between gas and power over the long-term through investments in Canada and the northern and western United States. The Trust has a strong track record of employing its operational expertise, energy market knowledge and financial discipline and strength to deliver sustainable returns to its investors. The Trust positions its services along the energy value chain linking energy production to energy users. The sound long-term supply and demand fundamentals for gas and power form the foundation for AltaGas' strategy.

As part of its growth strategy, AltaGas plans to acquire and construct both gas and power infrastructure. In executing its growth strategy for new construction projects, AltaGas employs project management processes and disciplines. Engineering design is performed by outside engineering firms selected on the basis of best fit for a given project. For large projects, construction management is also provided by outside experts with specific experience in the execution of similar projects. AltaGas project management processes coordinate the contracting and deployment of internal and external expertise to manage execution risk.

AltaGas identifies, evaluates and pursues growth opportunities that offer strong financial returns and earnings and cash flow accretion, as well as providing the appropriate balance between risk and return. AltaGas remains open to opportunities and may deploy capital in gas and power infrastructure not currently represented within its portfolio.

AltaGas differentiates itself from its peers and competitors by linking its operating experience, gas and power market knowledge, business and financial expertise and by capitalizing on the natural hedges within its business and its strong risk management expertise.

Gas - Business Strategy

AltaGas' gas infrastructure touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, transmission, distribution and storage. 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 pipeline 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 1.2 Bcf/d of raw gas processing capacity.

Transmission pipelines deliver natural gas and NGLs to distribution systems, end users or other downstream pipelines. With the 2009 acquisition of Utility Group and Heritage Gas, AltaGas owns and operates natural gas distribution assets that deliver natural gas to end-users. These regulated assets are located in Alberta, Nova Scotia and the Northwest Territories. AltaGas uses its market knowledge and expertise to create value. It provides energy consulting and supply management services to non-residential end-users, buys and resells energy, provides gas transportation and storage, and markets gas for producers.

AltaGas' Gas Segment includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1,594 Mmcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin-based revenues;

- Five natural gas transmission systems with combined transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d;

- More than 70 gathering and processing facilities in 30 operating areas in western Canada and a network of 6,500 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;

- Ownership in three natural gas distribution businesses serving more than 72,000 customers, including 100 percent of both AUI and Heritage Gas, one-third of Inuvik Gas and a 33.335 percent interest in the Ikhil Joint Venture. The businesses were acquired in fourth quarter 2009 through the purchase of 81.7 percent of Utility Group not already owned by AltaGas and 75.1 percent of Heritage Gas not already owned by AltaGas; and

- A 50 percent partnership interest in Sarnia Storage Pool Limited Partnership, which owns 5.3 Bcf of gas storage capacity that became operational in second quarter 2009. Storage in the pool is marketed on a fee-for-service basis to credit-worthy third parties.

In addition to the segment's physical assets, AltaGas offers gas procurement, management and optimization services through its Energy Services business, which help enhance the asset base. Energy Services provides support for the infrastructure-based businesses by contracting supply and shrinkage gas for the extraction facilities, contracting and reselling capacity on the transmission pipelines and providing gas control services to balance gas flows. Energy Services also markets gas for Field Gathering and Processing customers, earning margins, managing credit exposure, and providing additional value added services to AltaGas' customers. In addition, it contracts and manages gas for AltaGas' gas-fired power peaking plants. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third party pipeline transportation requirements for many of its gas marketing customers.

Gas - Opportunities

AltaGas pursues opportunities in its gas business to enhance long-term unitholder value. AltaGas' objectives are to:

- Increase throughput and utilization of existing facilities;
- Manage costs and improve reliability and efficiencies;
- Increase returns and mitigate volume risk by directly recovering operating costs from customers;

- Acquire and develop new gas infrastructure assets to meet customer demand;
- Enter into commercial arrangements that have long-term fixed-fee or cost-of-service components; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration with other business segments.

AltaGas' Gas Segment provides safe and reliable gathering, processing, extraction, transportation, storage and distribution services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share and redeploying assets to capitalize on increased exploration and drilling activities in the WCSB. AltaGas also focuses on increasing long-term, fixed-fee and cost-of-service contracts.

While the WCSB is considered a maturing basin, 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 basin and a return to stronger gas prices. The emergence of unconventional gas plays in the WCSB such as Montney and Horn River, as well as increased focus on horizontal multi-frac technology is expected to provide renewed life to the basin.

Growth opportunities in AltaGas' Gas Segment are expected to arise from plant modifications to increase product recoveries or throughput at facilities and by increasing interests in existing plants, acquiring facilities and constructing new facilities in emerging markets or with growing demand.

The natural gas supply to all extraction plants depend 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, propane heating and Canadian oil and gas industries. The Empress extraction plants rely on Alberta supply of natural gas to the NGTL eastern gate for their supply, while the Younger Extraction Plant is supplied from the robust natural gas producing region of northeast British Columbia. The Harmattan Complex is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Stream Project is also expected to increase processing capability at the plant. Overall, the diverse nature of its extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

Due to the integrated nature of AltaGas' businesses, 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 market demands.

AltaGas 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 dedicating capital to non-core activities such as processing. There are also expected to be opportunities to increase volumes by tying in new wells and building or purchasing adjoining facilities and systems to create larger franchise areas to capture operating synergies. Based on its existing infrastructure, the Trust expects to capitalize on growing natural gas production in northeast B.C. and northwest Alberta, as well as unconventional sources of gas such as shale and coal bed methane. In addition, most of its gas compression and processing units are skid-mounted. AltaGas is able to relocate units quickly and cost-effectively to respond to the changing processing needs of its customers.

The acquisition of natural gas distribution assets in 2009 is an example of AltaGas' strategy at work. The low-risk, long-life energy infrastructure is underpinned by regulated returns and cost-of-service recovery that provide stable and predictable cash flows. The addition of Utility Group's investments, people and growth opportunities expands, diversifies and strengthens the Gas Segment. AltaGas plans to grow its existing natural gas distribution business through infill and expansion of services within current franchise areas and by developing systems in new market areas. Heritage Gas offers strong growth potential in its franchise areas such as the planned expansion to Bedford within the Halifax Regional Municipality and through on-going conversion of customers with existing access to natural gas.

The Energy Services business provides gas control and gas supply contracting services to the gas and power segments, as well as gas storage. AltaGas pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure-based businesses. These include increasing margins earned in transmission, maintaining the cost effective flow of gas through extraction plants and increasing services provided to producers. Energy Services also shares gas and electricity market knowledge across all AltaGas businesses and enhances the energy value chain to more effectively serve customers across Canada.

Power - Business Strategy

The Power Segment includes conventional power generation in Alberta and renewable power generation in British Columbia.

Conventional Power

The conventional power business comprises 392 MW of total power generation capacity in Alberta. AltaGas owns 50 percent of the Sundance B PPAs giving it the rights to power output and ancillary services from 353 MW of coal-fired base-load generation until December 31, 2020. PPAs were established in 1999 under Alberta's program of power industry deregulation in order to separate ownership of the physical power generation assets from marketing of output.

In addition, AltaGas has 39 MW of gas-fired power peaking capacity in southern Alberta. This 39 MW of gas-fired peaking capacity provides fuel diversity to AltaGas' conventional power business and partial backstopping to outages at Sundance. Due to their quick ramp-up capability, the peaking plants also provide revenue from the sale of energy and ancillary services.

Renewable Power

AltaGas' renewable power generation includes the 102-MW Bear Mountain Wind Park near Dawson Creek, British Columbia and a 25 percent interest in a 7-MW run-of-river hydroelectric generation facility.

Bear Mountain Wind Park achieved commercial operations in October 2009. The wind park is backstopped by a 25-year electricity purchase agreement with BC Hydro. AltaGas retained the green attributes and renewable energy credits related to the project. In addition, the Bear Mountain Wind Park has qualified for the Federal Government of Canada's ecoEnergy renewable initiative or eRPI, which grants $10 per MWh generated by the Bear Mountain Wind Park for ten years beginning on October 31, 2009. AltaGas has entered into a long-term service agreement with Enercon GmbH to operate and maintain the wind turbines.

Power - Opportunities

AltaGas pursues opportunities in its power business to enhance long-term unitholder value. The Trust's objectives are to:

- Execute power hedge strategies as appropriate to increase earnings stability and growth from the Sundance B PPAs;
- Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy sales and ancillary services;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Capitalize on internal synergies and integration efforts with other operating lines;
- Acquire and develop power infrastructure backstopped by long-term power sales arrangements or supported by strong power supply and demand fundamentals;
- Diversify power generation portfolio by geography and fuel source;
- Develop operating capability in other energy sources; and
- Capitalize on increasing demand for clean power by investing in renewable power projects across Canada and the northern and western U.S.

AltaGas' strategy is to expand its power infrastructure to ensure the long-term sustainability of this business and offset the expiration of the Sundance B PPAs on December 31, 2020. Growth is focused on clean and renewable sources of energy.

The demand for renewable and clean generating capacity continues to be strong across North America, as industry prepares to address climate change legislation and utilities are faced with renewable portfolio standards. The poor economic environment has resulted in reduced demand for power and in Alberta specifically, average power demand has remained essentially unchanged since 2008, notwithstanding the fact that new peak demand records were set in December 2009. AltaGas expects power demand growth to follow suit with a broader economic recovery, which will subsequently lead to a recovery in power prices. AltaGas expects that any significant new generation project that is not already committed to will be deferred until forward prices recover. The Sundance B facility is among the lowest-cost producers of power in the province, positioning AltaGas to maintain profitable operations during difficult economic conditions. The power generated by the Bear Mountain Wind Park is sold to BC Hydro at a fixed price with 50 percent CPI escalators for 25 years and is therefore not exposed to fluctuations in the market value of power.

Opportunities to develop and own additional power generation are likely to arise due to the growing North American demand for cleaner energy sources such as natural gas, hydroelectric and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, in Alberta, may prompt additional growth opportunities to develop new clean power generation capacity. The 102-MW Bear Mountain Wind Park, which commenced commercial operations October 24, 2009, is an example of a clean energy project and of AltaGas' strategy in action.

AltaGas has approximately 1,900 MW of renewable power under development including 1,500 MW of wind power developments and 400 MW of run-of-river hydroelectric developments. The wind projects are geographically dispersed in western North America, with 500 MW in Canada and 1,000 MW in the northern and western United States, while the run-of-river projects are focused in British Columbia.

REPORTING SEGMENTS

At December 31, 2009 the Trust reported consolidated financial and operating results on the basis of three segments; gas, power and corporate. The gas segment's business activities include extraction and transmission, field gathering and processing, energy services, and natural gas distribution. The power segment's business activities consist of conventional coal-fired generation, gas-fired peaking plants generation, wind power generation and hydroelectric generation. The corporate segment consists of opportunistic investments, risk management contract results and revenues and expenses not directly identifiable with the operating segments.

Gas Segment

- Extraction and Transmission consists of AltaGas' interests in ethane and NGL extraction plants and natural gas and NGL transmission systems:
- Field Gathering and Processing includes natural gas gathering pipelines and processing facilities as well as AltaGas' investments in businesses ancillary to the field gathering and processing business:
- Natural Gas Distribution includes regulated natural gas transmission and distribution facilities in Alberta, Nova Scotia and the Northwest Territories, Canada.
- Energy Services consists of two main businesses: energy management services and gas services.

Power Segment

- Power Generation consists of AltaGas' interests in coal-fired and gas-fired generation, wind power, run-of-river power and interests in wind and run-of-river renewable power projects under development.

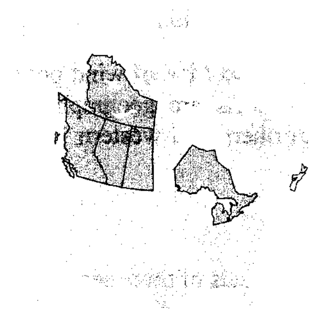
Corporate Segment

- Corporate includes the cost of providing services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities.

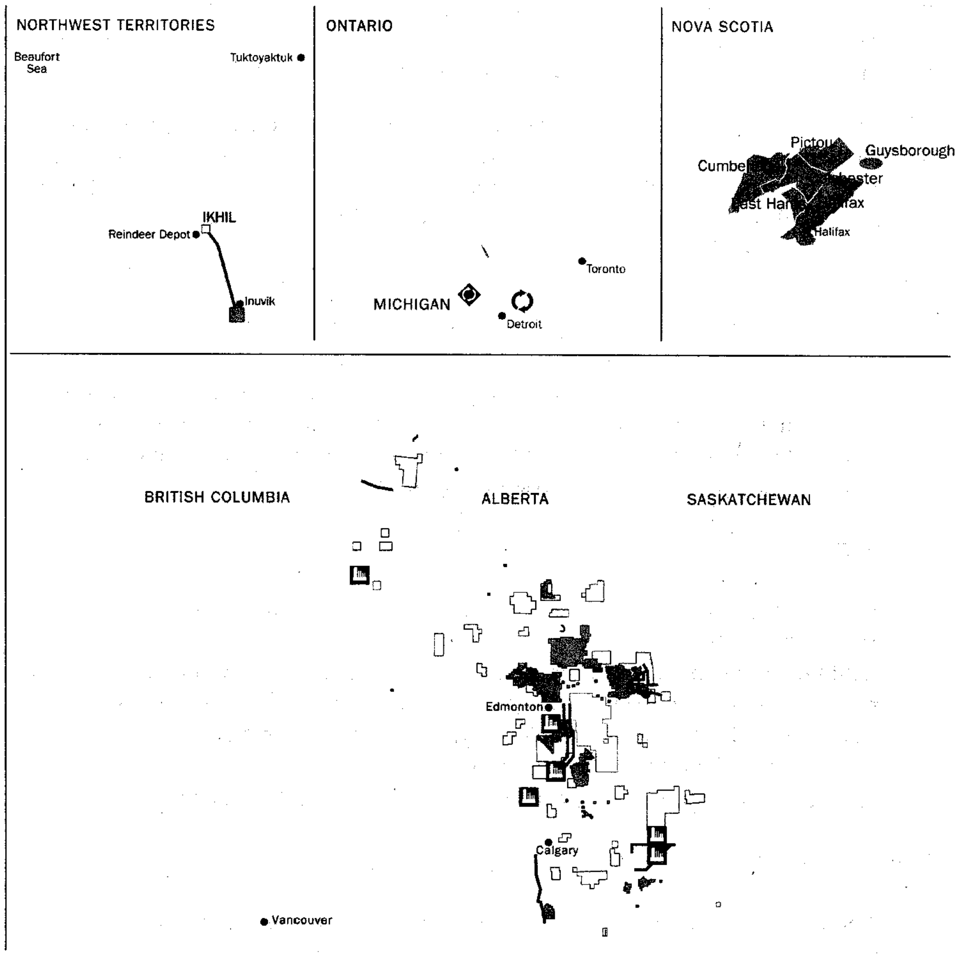
ALTAGAS' GEOGRAPHIC FOOTPRINT

SEC File # 82-34911

Gas

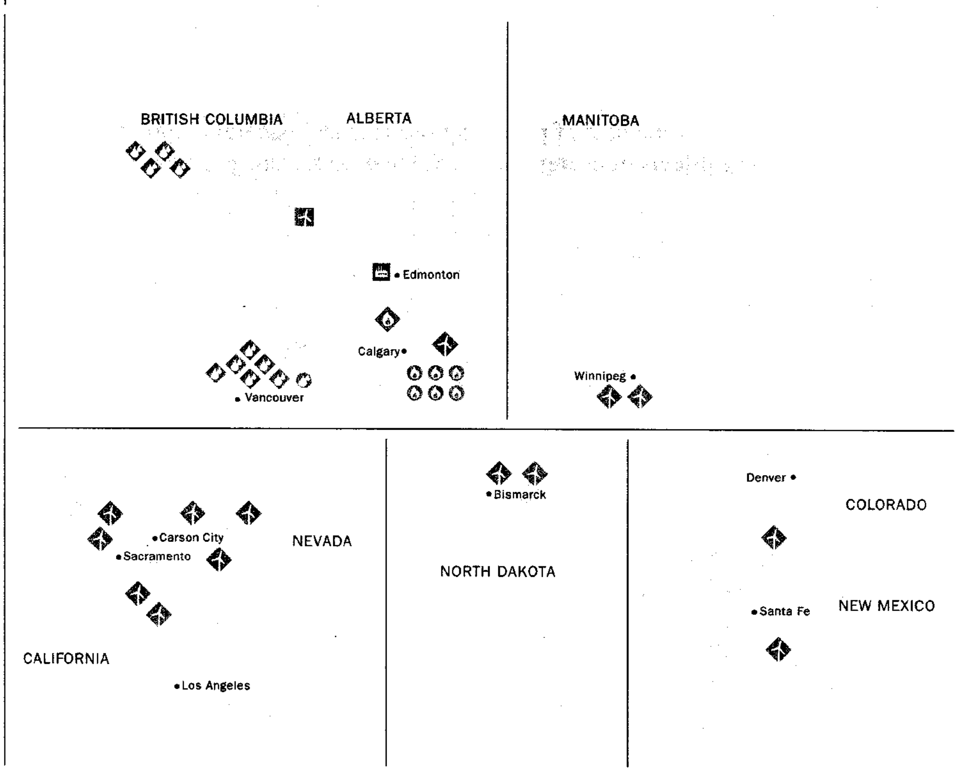


- Extraction Plant
- Transmission Pipeline
- Field Gathering & Processing Area
- Gas Distribution Area
- Storage Facility
- Storage Facility under Development



Power

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



GENERAL DEVELOPMENT OF THE TRUST'S BUSINESS

HISTORICAL DEVELOPMENT

The Trust is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to the Declaration of Trust effected on May 1, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly owned by AltaGas Services.

ASI commenced operations on April 1, 1994 with a founding vision to build a major Canadian natural gas midstream business combining a portfolio of natural gas-related services with long-life assets to grow net income. The concept of a distinct, full-service midstream business was unique in Canada at the time. ASI commenced operations with two major contracts to provide transportation, regulatory and gas management services. The revenue generated from these contracts during 1994 and 1995, together with private placement equity financings, provided the funds for ASI to establish its midstream asset base and make the transition from a consulting services company to a midstream operating company.

Development of the Gas Business

The nature of AltaGas' participation in the midstream industry evolved from holding primarily service contracts and non-operated investments to include fully-operated natural gas facilities of which AltaGas owns 100 percent or in which it has a controlling interest.

In 2006 and 2007 AltaGas invested a total of $76.6 million in growth capital in field gathering and processing assets. These investments included the 20 Mmcf/d Princess sour gas plant, an increased interest in the Pouce Coupe plant, the 10 Mmcf/d Clear Hills sour gas plant, the 15 Mmcf/d Clear Prairie plant, expansion of the Prairie River gas facility, the 10 Mmcf/d Acme CBM processing facility and gathering lines in an area of significant CBM production.

Effective June 1, 2007 AltaGas sold Cedar Energy Partnership to a private energy company for approximately $12 million plus one million warrants of the purchaser with a three-year term ending May 29, 2010. The sale of Cedar Energy Partnership was part of AltaGas' plan to divest non-core oil and gas production assets.

In 2007 AltaGas purchased a 50 percent interest in the Sarnia Airport Storage Pool Project. The 5.3 Bcf Sarnia natural gas storage project represents AltaGas' first investment in natural gas infrastructure in Ontario. The project was completed in mid-2009, on time and under budget.

In 2008 AltaGas invested $55 million to increase natural gas volumes and boost the efficiency at the Harmattan Complex and $12.6 million to upgrade the EDS pipeline. In 2009 AltaGas completed the addition of 10,000 bbls/d of fractionation capacity at the Harmattan Complex for the processing of NGLs brought to the plant by truck.

In 2004 AltaGas significantly expanded its Energy Services business into Ontario and further into British Columbia with the acquisition of substantially all of the assets and liabilities of PremStar Energy Canada Ltd. and its subsidiaries ECNG Inc. and Energistics Group Inc. The businesses of PremStar Energy Canada Ltd. and its subsidiaries were integrated with AltaGas, but the trade names PremStar Energy Limited Partnership and ECNG Energy continued to be used within the Energy Services business. On January 1, 2007 ECNG Limited Partnership changed its name to ECNG Energy L.P., and AltaGas began providing energy management services under the brand name ECNG Energy. In 2008 PremStar Energy Canada Limited Partnership changed its name to AltaGas Energy Limited Partnership.

In 2005 AltaGas further expanded its Energy Services business through the acquisition of substantially all of the assets and liabilities of iQ2 Power Corp. As a result of the acquisition of this business, AltaGas purchases power and gas for resale to agricultural, industrial and commercial customers in Alberta.

On November 29, 2007 the Trust, indirectly through AltaGas LP #1, offered to acquire all of the outstanding limited partnership units of Taylor NGL Limited Partnership. On January 10, 2008 AltaGas LP#1 completed the acquisition of Taylor for the aggregate purchase price of $593.6 million, including $256.3 million of cash and 7.7 million Trust units valued at $198.9 million for all the outstanding limited partnership units of Taylor not previously owned by AltaGas and assumed debt of $132.5 million and $5.9 million in transaction costs. The Taylor acquisition increased extraction capacity by 1,040 Mmcf/d, added 140,000 Bbls/d in transmission capacity, doubled extraction volumes produced to approximately 45,000 Bbls/d and increased the Field Gathering and Processing business capacity by 150 Mmcf/d.

On August 17, 2009 AltaGas, indirectly through AltaGas Holdings #3 Inc., offered to acquire the remaining outstanding common shares of Utility Group not already owned by AltaGas and its affiliates by way of a take-over bid for $9.05 per common share. On September 21, 2009 the offer was amended, increasing the cash consideration payable under the Offer from $9.05 per common share to $10.50 per common share. On October 9, 2009 AltaGas Holdings #3 Inc.

completed the acquisition of Utility Group for a purchase price of $75.2 million for the outstanding common shares of Utility Group, excluding those previously held by AltaGas or its affiliates and assumed $123.8 million in debt and $5.0 million in transaction costs. After the acquisition, Utility Group shares were delisted from the TSX. The Utility Group acquisition added three regulated businesses with more than 72,000 customers and infrastructure of over 20,000 km of pipelines. Utility Group holds an interest in the Ikhil Joint Venture which produces and supplies natural gas in Inuvik, Northwest Territories

In November 2009, AltaGas indirectly through AltaGas Utility Holdings (Nova Scotia) Inc., completed the acquisition of 75.1 percent of the common shares not already owned by AltaGas and shareholder debt of Heritage Gas for $111.0 million including closing costs, bringing AltaGas' ownership of Heritage Gas to 100 percent. Based in Dartmouth, Nova Scotia, Heritage Gas serves 2,435 customers in Amherst and Cumberland County, Dartmouth, Halifax and the Halifax International airport through its 234 km system.

Development of the Power Business

In 2001 ASI entered the power business by purchasing 353 MW of power output from two coal-fired power generation units in the province of Alberta under long-term PPAs. In 2004, 25 MW of gas-fired peaking capacity was acquired under a long-term capital lease arrangement.

In 2007 AltaGas acquired an additional 14 MW of gas-fired power generation capacity which was installed at the Bantry and Parkland field gathering and processing sites in 2008 with access to natural gas supply and the electrical grid.

In July 2006 AltaGas announced that BMWLP's Bear Mountain Wind Park had been selected as a successful bidder in the BC Hydro Fiscal 2006 Open Call for Power. Located near Dawson Creek, British Columbia, the 102-MW wind park comprises 34 turbines. In 2007 BMWLP signed an agreement with Enercon GmbH, a leading turbine manufacturer based in Germany, to provide and install the turbines for the wind park under a fixed-price engineering, procurement and construction contract and to operate and maintain the turbines under a long-term service agreement. In addition, AltaGas purchased Aeolis Wind Power Corporation's interest in BMWLP and as a result is the sole owner of BMWLP. Construction of the wind park began in December 2007, tower foundations were completed in 2008 and the turbines were installed in 2009. As B.C.'s first wind park, the facility made history when it was commissioned on October 24, 2009 at a cost of approximately $200 million.

As part of the Taylor acquisition, AltaGas acquired an effective 25 percent ownership interest in the 7-MW Boston Bar Limited Partnership power plant and a further 20 MW of hydroelectric generation under development.

In 2008 AltaGas acquired four run-of-river hydro development projects ranging from 6.5 MW to 24 MW for $4.5 million. The total potential from these projects is approximately 50 MW. In 2008 AltaGas acquired NovaGreen for approximately $38.5 million. NovaGreen's name was changed to AltaGas Renewable Energy Inc. in December 2008.

In 2008 AltaGas acquired the remaining 45 percent interest in GreenWing for $12.3 million. GreenWing changed its name to AltaGas Renewable Energy Limited Partnership in December 2008.

In 2009 AltaGas acquired the 100-MW Glenridge wind development project located near Medicine Hat, Alberta for $2.2 million. With the acquisition of GreenWing and Glenridge, AltaGas has a portfolio of 1,500 MW of mature and early development wind projects in western Canada and the northern and western United States.

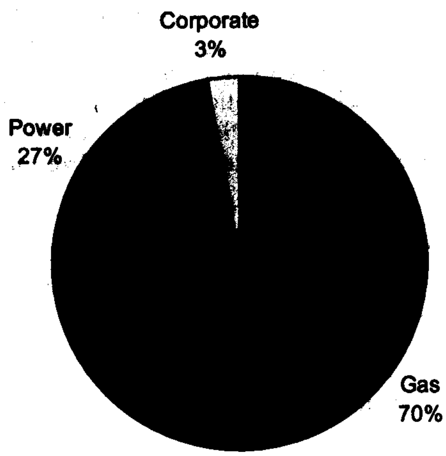
In January 2009 AltaGas invested $10 million to acquire approximately a five percent equity position in Magma Energy Corporation, a company focused on the exploration, development and operation of geothermal energy projects. AltaGas also received the right to acquire a direct interest in certain future geothermal projects developed or acquired by the company. In July 2009 Magma Energy Corporation completed its initial public offering and began trading on the TSX. AltaGas invested an additional $6.2 million to acquire common shares in the offering and maintained an approximate five percent ownership interest in Magma Energy Corporation. Magma Energy Corporation currently owns and operates an 8-MW geothermal energy plant in Nevada as well as a portfolio of geothermal exploration and development projects in the western United States and South America.

AltaGas is developing a portfolio of run-of-river hydroelectric projects in B.C., including the NW Projects which are three projects in Northwest B.C. - Forrest Kerr, McLymont Creek and Volcano Creek. The NW Projects have a combined generating capacity of approximately 277 MW and are currently the subject of discussions with the Government of British Columbia. These discussions include considerations relating to the announcement by the Government of British Columbia to upgrade and extend the electricity transmission capabilities in B.C.'s Northwest, specifically the Northwest Transmission Line. The Northwest Transmission Line upgrade would extend the British Columbia Transmission Corporation's transmission grid to within 44 km of the NW Projects.

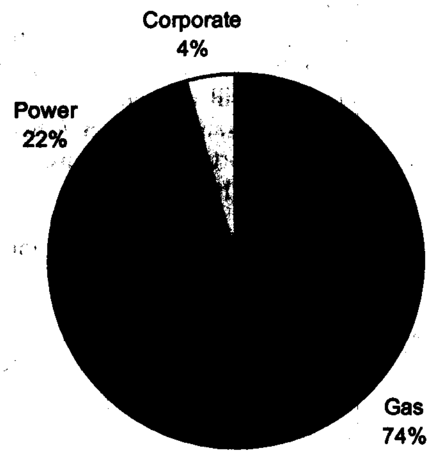
BUSINESS OF THE TRUST

The Trust's net revenue for the 12-month period ended December 31, 2009 was $456.6 million compared to $476.5 million for the 12-month period ended December 31, 2008.

Net Revenue by Segment for 2008 (1)



Net Revenue by Segment for 2009 (1)



Note:

(1) Net revenue is gross revenue less the cost of sales.

OPERATING SEGMENTS

Beginning with 2009, AltaGas has aggregated its business activities into three operating segments; gas, power and corporate. In the gas operating segment, the business activities includes extraction and transmission, field gathering and processing, energy services, and natural gas distribution. The power operating segment consists of conventional coal-fired generation, gas-fired peaking plants generation, wind power generation and hydroelectric generation. The corporate segment consists of opportunistic investments, risk management contract results and revenues and expenses not directly identifiable with the operating segments.

GAS SEGMENT

AltaGas' Gas Segment contributed net revenue of $340.2 million for the year ended December 31, 2009, representing approximately 74 percent of the Trust's total net revenue before intersegment eliminations. At December 31, 2009 there were 648 individuals employed in the Gas Segment's businesses.

GAS SEGMENT – EXTRACTION AND TRANSMISSION

AltaGas' extraction business includes 100 percent ownership of the Harmattan Complex and JEEP, both in central Alberta, as well as interests in two extraction plants at Empress, Alberta, EEEP at Edmonton, Alberta and the Younger Extraction Plant in B.C. Also included in the extraction business is AltaGas' Bantry fractionation facility. AltaGas operates EEEP, JEEP, the Bantry field facility, Harmattan Complex and the Younger Extraction Plant. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin-based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was 1,594 Mmcf/d at December 31, 2009.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and condensate as separate marketable commodities and their value as constituents of the natural gas stream. If the components are not extracted and sold at prices that reflect the value for each of the individual commodities, they are sold as part of natural gas and generate revenue for their heating value at the prevailing natural gas price.

In most cases the NGL recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGL to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGL are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. Ethane is the feedstock for ethylene production.

Extraction - Plant Fee Structures

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the natural gas, or through NGL extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with an export delivery transporter on a natural gas transmission system for the right to extract the ethane and NGL from the transporter's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy content of the shipper's natural gas. The extraction plant owner pays the transporter for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby keeping the transporter whole. This purchased gas is referred to as shrinkage or make-up gas. Based on the results of the ERCB NGL Extraction Inquiry released in February 2009, the convention for obtaining extraction rights will change over the next three years, whereby the entitlement to the NGLs within the common-stream natural gas transported on Alberta-regulated gas transmission pipelines will be transferred to receipt shippers rather than the export delivery transporters. AltaGas is developing a strategy to capitalize on opportunities related to the NGL Extraction Inquiry decision.

Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements. AltaGas' share of all ethane production is sold through long-term, cost-of-service or fixed-fee arrangements that bear no commodity price risk. The sales price received under these contracts provides for a return on and of capital and the recovery of certain operating costs, including shrinkage gas attributable to that production. AltaGas' share of ethane production is sold at the outlet of the plants, with the product purchaser responsible for all downstream transportation and handling. AltaGas' ethane sales provide a stable, predictable cash flow base.

AltaGas' NGL production is sold under a variety of arrangements. At December 31, 2009, approximately 60 percent of AltaGas' NGL production was sold under long-term, fee-for-service arrangements. These volumes do not bear any commodity price risk. The revenue from this portion of NGL sales provides a stable, predictable cash flow base.

On the portion of the extraction production that is not sold under ethane cost-of-service contracts or NGL fee-for-service contracts, performance is subject to frac spread which is the price spread between NGLs extracted and the natural gas purchased to make up the heating value of the NGLs extracted. At December 31, 2009, approximately 40 percent of AltaGas' NGL production (13 percent of total extraction production) was sold under contracts subject to frac spread. If commodity prices or operating costs make NGL extraction uneconomical, the NGLs may be reinjected or the facilities may be turned down or shut-in. If this occurs, the operational flexibility of the commercial contracts translates into a minimal effect on margins.

Extraction – Plant Production

Extraction production is a function of natural gas volume processed, natural gas composition, recovery efficiency of the extraction plant and plant on-line time. The following table represents a summary of AltaGas' capacity and the production associated with extraction and fractionation plants in which AltaGas holds an interest:

Extraction or Fractionation Plant	Interest (%)(1)	AltaGas' Inlet Processing Capacity (Mmcf/d)(1)	2009 Liquids Production (Bbls/d)(2)		2008 Liquids Production (Bbls/d)(2)		Operated or Non-Operated
EEEP	48.667	190	NGLs	2,149	NGLs	1,972	Operated
			Ethane	6,135	Ethane	6,586	
Empress ATCO	7.2	79	NGLs	611	NGLs	671	Non-Operated
			Ethane	623	Ethane	655	
Empress Provident	11.25	135	NGLs	1,488	NGLs	1,119	Non-Operated
			Ethane	2,730	Ethane	1,361	
JEEP	100.0	250	NGLs	1,763	NGLs	977	Operated
			Ethane	4,726	Ethane	2,779	
Younger	56.667	425	NGLs	5,113	NGLs	5,057	Operated
			Ethane	7,698	Ethane	7,351	
Harmattan Complex	100.0	490	NGLs	499	NGLs	434	Operated
			Ethane	5,009	Ethane	5,161	
Bantry	100.0	25	NGLs	157	NGLs	196	Operated
Total(3)		**1,594**	**NGLs**	**11,780**	**NGLs**	**10,426**	
			Ethane	**26,922**	**Ethane**	**23,892**	

Notes:

(1) At December 31, 2009.
(2) Average volumes for the fourth quarter.
(3) Excludes field NGLs.

Extraction - Empress ATCO Extraction Plant

AltaGas' ownership interest in the Empress ATCO extraction plant was 7.2 percent at December 31, 2009. The remaining 92.8 percent interest in the facility is held by nine other owners with varying interests. AltaGas' ownership corresponds to a 79 Mmcf/d share of the plant's 1,100 Mmcf/d of natural gas inlet capacity.

The Empress ATCO plant, located on the Alberta-Saskatchewan border at Empress, Alberta is one of six extraction plants in the area. The Empress ATCO plant has four processing trains which provide the flexibility to easily manage production to reduce operating costs and operational risk, minimizing any downside risk associated with fluctuating production volumes.

In 2009 current firm gas supply under contract was 79 Mmcf/d, of which 24 Mmcf/d was under contract until December 2009 with the remainder being made up of yearly and monthly supply arrangements. AltaGas is currently processing gas under monthly arrangements and is looking at opportunities for long term gas supply agreements through 2010. AltaGas also processes any interruptible gas volumes that are made available to the plant by the Energy Services business and any gas volumes diverted from the shutdown of its other Empress facility. As there are five other extraction plants in the Empress area, there is considerable competition among the owners of the plants for producers' extraction rights.

AltaGas' ethane production is sold under a cost-plus sales arrangement. At December 31, 2009, 100 percent of AltaGas' share of propane plus production at the Empress ATCO plant was sold under one-year evergreen marketing arrangements at the monthly market price. The remaining portion of propane plus production generates revenue subject to a long-term profit and loss arrangement that includes a processing fee and revenue that varies with product pricing.

Extraction - Empress Provident Extraction Plant

AltaGas acquired a 10 percent interest in the Empress Provident extraction plant in April 1998 and increased its share to 11.25 percent in December 2006. The plant, which began operations in September 1996, is located 2 km southeast of the Empress ATCO extraction plant.

The plant is licensed to process 1,200 Mmcf/d of natural gas, of which 135 Mmcf/d is AltaGas' share. AltaGas has managed its gas supply risk at this plant by securing 89 percent of inlet capacity on a long-term basis to ensure that its share of 135 Mmcf/d is fully utilized at all times.

In October 2003 modifications were completed to increase the ethane recovery efficiency. AltaGas' share of the modification costs was $5.5 million and the project more than doubled its ethane production to approximately 2,400 Bbls/d. AltaGas' share of ethane production is sold under a long-term, cost-of-service type contract that provides for the recovery of certain operating costs. Approximately 74 percent of AltaGas' share of propane plus production from this plant generates fixed-fee revenue plus reimbursement of associated operating costs under a long-term processing arrangement. The remainder is sold under a one-year evergreen marketing arrangement at the monthly market price for propane plus.

Extraction - Joffre Extraction Plant

AltaGas owns 100 percent of JEEP which has processing capacity of 250 Mmcf/d of natural gas and is capable of producing up to 10,400 Bbls/d of ethane and NGLs. The plant, which was constructed in 2002 at a net cost to AltaGas of $24.8 million for its initial 50 percent interest, started operations in December 2002. AltaGas operates the facility which is located at Joffre, Alberta.

The plant is adjacent to NOVA Chemicals Corporation's Joffre petrochemical complex and recovers ethane and NGLs from the fuel gas used at the complex. All ethane production from JEEP is sold under a cost-of-service type contract with NOVA Chemicals Corporation that expires in 2031. Under this ethane sales agreement, a small portion of the operating cost risk is borne by AltaGas, based on the ratio of NGLs to total plant production. AltaGas sells its NGL production under a one-year evergreen marketing agreement based on the monthly average market price for NGLs.

JEEP is physically configured such that NGL production can easily be matched to market demand. This ability to step in and out of the NGL market depending on NGL pricing allows AltaGas to fully participate in the market when NGL prices are strong, while minimizing exposure during times of unfavourable pricing.

Extraction – Edmonton Ethane Extraction Plant

AltaGas acquired a 48.67 percent interest in EEEP in August 2004 for $48.2 million, including an environmental liability of $5.0 million, for a net cash outlay of $43.2 million. The remaining interest in the plant is held by ATCO Midstream Ltd. AltaGas operates the plant. EEEP is directly connected to the Alberta Ethane Gathering System, and to BP Canada Energy Resources' Co-Ed NGL pipeline, providing safe and reliable outlets for the plant products.

The plant has a licensed gross inlet capacity of 390 Mmcf/d of natural gas and gross production capacity of specification ethane of 23,000 Bbls/d and NGLs of 7,500 Bbls/d.

A long-term gas supply contract provides a secure feedstock supply to EEEP. The processed gas from the facility supplies end-use markets in the city of Edmonton, Alberta. AltaGas' share of the plant products is sold under long-term contracts through cost-of-service or cost-plus sales arrangements.

Extraction – Younger Extraction Plant

AltaGas owns a 56.7 percent interest in the Younger Extraction Plant. The remaining interest is held by Provident. The Younger Extraction Plant, located at Taylor, British Columbia, processes natural gas transported on the Spectra Energy transmission system and Canadian Natural Resources Limited's Stoddart transmission system to recover NGLs.

The Younger Extraction Plant has 750 Mmcf/d of natural gas processing capacity. AltaGas' share of the natural gas processing capacity is 425 Mmcf/d and Provident's share is 325 Mmcf/d. AltaGas owns 100 percent of the facilities related to fractionation, storage, loading, treating or terminalling of NGLs. AltaGas operates the Younger Extraction Plant.

All of AltaGas' NGL production from the Younger Extraction Plant is sold to Provident under a long-term NGL purchase agreement which consists of a return on capital, recovery of operating costs, shrinkage make-up and a profit-share component. Provident sources all gas supply to the Younger Extraction Plant as part of the NGL purchase agreement. AltaGas' ethane production is sold to Dow Chemicals under a long-term, fixed fee-for-service contract.

Extraction - Harmattan Complex

AltaGas owns a 100 percent interest in the Harmattan Complex located 100 km north of Calgary, Alberta. Harmattan has natural gas processing capacity of 490 Mmcf/d consisting of sour gas treating, NGL extraction and 35,000 Bbls/d of

NGL fractionation and terminalling. Harmattan also has a 450 Bbls/d capacity frac oil processing facility, a 200 tonnes/d capacity industrial grade CO_2 facility and a 10,000 Bbls/d capacity NGL truck offload facility.

The Harmattan Complex extracts NGLs from the raw natural gas delivered for processing, fractionates the recovered NGLs into specification ethane, propane, butane and condensate, and provides storage and terminalling services for each product. The terminalling options for each product are:

Ethane – The Harmattan Complex is connected to the Alberta Ethane Gathering System by an interconnecting pipeline that is owned by AltaGas. All ethane produced at the Harmattan Complex is delivered to the Alberta Ethane Gathering System.

Propane – Producers may have their propane loaded onto either rail or truck. The propane truck and rail loading facilities, which are located at Didsbury, Alberta, are connected by pipeline to the main complex.

Butane and Condensate – Producers may have their butane and condensate delivered to either the Rangeland or Cremona pipeline or loaded onto trucks at the Harmattan Complex.

At the Harmattan Complex, natural gas processing services are provided to approximately 60 producers under contracts with a variety of commercial arrangements and terms. Fee-for-service revenues are generated from the raw natural gas processing, NGL extraction, fractionation and terminalling, and custom NGL processing. Fee-for-service means that fees are charged to the customer for the service provided on a per unit volume basis.

Approximately 35 percent of the natural gas volume processed at the Harmattan Complex is done under the terms of the Rep Agreements which have life-of-reserves dedications. In addition to the natural gas processed under the Rep Agreements, a further 25 percent of the natural gas currently being processed at the Harmattan Complex is committed for over three years with annual minimum volume obligations. The balance of the raw natural gas processed at the Harmattan Complex is processed under contracts with terms varying from one month to life-of-reserves. The majority of the contracts provide for fee escalation based on the Canadian Consumer Price Index.

Under the terms of many of the raw natural gas processing agreements, a component of the compensation received by AltaGas for providing services to the producers is derived by AltaGas having the right to purchase a portion of the producers' ethane, propane, butane and condensate for a price equal to the value of the equivalent natural gas. This commercial arrangement is known as product-in-kind.

The profitability of product-in-kind arrangements is a function of the difference between the value of specification ethane, propane, butane and condensate and the value of NGLs if they remain in the natural gas. The ethane acquired by AltaGas under the product-in-kind arrangements is sold under a long-term contract for a price that includes full recovery of the cost of acquiring the ethane from the producers plus a premium. The propane, butane and condensate volumes acquired by AltaGas are sold into the Alberta market at prevailing prices.

AltaGas has applied to the ERCB to construct the Harmattan Co-Stream Project which, if approved, would allow the extraction of NGLs from gas in the TransCanada system using unused capacity in the NGL recovery units at Harmattan. AltaGas has entered into a Memorandum of Understanding with NOVA Chemicals related to liquids extraction at Harmattan as part of the proposed Co-Stream project. The Memorandum of Understanding provides that the definitive agreements between AltaGas and NOVA Chemicals would be for an initial term of 20 years. AltaGas would deliver all liquids or co-stream gas products on a full cost-of-service basis to NOVA Chemicals and would provide that all capital expenditures and operating costs related to the proposed project will be fully recovered through fees under normal operations. The Memorandum of Understanding is subject to normal conditions precedent, including execution and delivery of mutually satisfactory definitive agreements between AltaGas and NOVA Chemicals and a favourable decision on the Harmattan Co-Stream application currently before the ERCB.

Extraction - Bantry Field Fractionation Facility

AltaGas purchased the Bantry natural gas processing plant in May 2000 and expanded it in 2001. The plant, operated by AltaGas, is equipped with fractionation facilities capable of producing up to 400 Bbls/d of specification propane, butane and pentanes-plus for sale to local markets at market prices. Fractionation services at Bantry are provided at a rate per m^3 of product processed.

Extraction – Competition

AltaGas' extraction assets are well positioned to operate in a competitive environment and take advantage of their strategic locations and contract terms in order to compete in the NGL industry.

Competition exists for AltaGas' Empress ATCO and Empress Provident extraction facilities as there are six extraction plants in the Empress area, resulting in significant competition for natural gas supply. AltaGas' Empress plants mitigate this risk by utilizing long-term natural gas supply contracts and by accessing gas supply through its Energy Services business.

AltaGas' JEEP and EEEP facilities are strategically located and take advantage of the gas consumption by the petrochemical industry and the City of Edmonton, respectively.

The Younger Extraction Plant processes natural gas produced in the Fort St. John basin located in northeast British Columbia. This facility is strategically located as the only straddle extraction plant in this area of British Columbia. While the Younger Extraction Plant is the only straddle extraction plant in the area, the Alliance pipeline competes for local natural gas supply.

The Harmattan Complex is well-positioned as the high-volume, low-cost processing facility in its service area.

Transmission – Business Description

AltaGas owns five natural gas transmission systems with transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity 151,600 Bbls/d.

The following table provides a summary of the gross capacity of AltaGas' transmission pipelines at December 31, 2009. The majority of the transmission pipeline transportation contracts are fixed-fee or transport-or-pay and are generally unaffected by volumes delivered.

Transmission Pipeline	Product	Area	Ownership (percent)	Operating Capacity	Length (km)	Operated/ Non-operated(1)
Battle Lake	natural gas	Central Alberta	100.0	15 Mmcf/d	16	Operated
Cold Lake	natural gas	East central Alberta	99.2	80 Mmcf/d	253	Operated
Kahntah	natural gas	Northeast British Columbia	100.0	35 Mmcf/d	55	Operated
Suffield	natural gas	Southeast Alberta	100.0	400 Mmcf/d	243	Operated
Summerdale	natural gas	Central Alberta	100.0	24 Mmcf/d	18	Operated
Porcupine Hills	NGL	Southwest Alberta	100.0	11,600 Bbls/d	164	Operated
EDS	NGL	Central Alberta	100.0	90,000 Bbls/d	180	Operated
JFP	NGL	Central Alberta	100.0	50.000 Bbls/d	180	Operated

Note:

(1) AltaGas operates the Cold Lake pipeline and has subcontracted out the operator function at its other pipelines.

Transmission – Suffield

The Suffield natural gas transmission system consists of two natural gas pipelines which transport natural gas produced in and around the Suffield military block in southeastern Alberta to the TransCanada Pipelines mainline at Burstall, Saskatchewan. The Suffield system is regulated by the National Energy Board and rates on the system are based on a market-based tolling methodology. The two pipelines have 400 Mmcf/d of combined transmission capacity. The south Suffield pipeline is a 147-km pipeline of six to 16-inch diameter pipe and the north Suffield pipeline is 96 km of 16-inch diameter pipe.

The majority of the Suffield system's capacity is currently contracted by EnCana Oil and Gas Partnership (now Cenovus Energy Inc.) through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter. Volume commitments are expected to increase annually from approximately 390,000 GJ/d in 2009 to approximately 406,000 GJ/d in 2010 and decline thereafter. On the Suffield system, EnCana pays AltaGas based on a daily contract quantity. To the extent that annual volumes shipped are less than the annualized daily contract quantity, AltaGas does not refund the shipper for payments made under the daily contract quantity but posts the shortfall quantity to a shortfall account as a credit until such time as the shipper reduces the shortfall by delivering excess quantities or until the shortfall amounts expire.

Transmission – EDS and JFP

The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan areas of Alberta. The EDS is a 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. The JFP is a 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d.

The EDS transportation agreement has an initial term of 12 years to 2016 with provisions for extensions thereafter. The payments made to AltaGas by NOVA Chemicals for transportation services are the sum of a fixed, transport-or-pay fee plus the full recovery of actual costs incurred in operating EDS. The fixed-fee is subject to an interest rate adjustment in 2010, and every three years thereafter, based on then-current interest rates. The EDS transportation agreement also contains provisions that define the incremental fees that will be charged to NOVA Chemicals in the event that additional capital is invested by AltaGas in the system. The termination of the EDS transportation agreement at the end of the initial 12-year term requires five years' notice by NOVA Chemicals. After the initial term, the notice period to terminate is three years. NOVA Chemicals has the option to purchase the pipeline after the initial term on three years' notice at a price based on a 30-year straight-line depreciation, subject to a floor price. NOVA Chemicals cannot selectively renew only the EDS transportation agreements; the termination of the EDS transportation agreement requires the termination of the JFP transportation agreement. The terms of the JFP transportation agreement are essentially identical to the terms in the EDS agreement. NOVA Chemicals cannot selectively renew only the JFP transportation agreement; the termination of the JFP transportation agreement requires the termination of the EDS transportation agreement.

AltaGas invested a total of approximately $12.6 million to upgrade the EDS pipeline. The upgrade was completed in 2009 and included replacing approximately 12 km of 12-inch diameter pipeline with thicker-walled pipe to meet regulatory requirements associated with an increase in adjoining residential population density. AltaGas receives a fixed, transport-or-pay fee and will have full cost recovery in operating the upgrade under cost-of-service arrangements similar to existing arrangements for the EDS pipeline.

A six-inch diameter portion of the EDS system was segregated in 2008 and leased to Keyera Energy Partnership for butane delivery for an initial term of 24 months.

Transmission – Porcupine Hills

The Porcupine Hills pipeline in southwest Alberta is a single-shipper condensate pipeline. The Porcupine Hills condensate pipeline delivers condensate from the Shell Waterton plant to the Town of Turner Valley for Shell Canada. The Porcupine contract, which expires on June 30, 2010, is expected to be extended on similar terms.

Transmission – Cold Lake, Kahntah, Summerdale and Battle Lake

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The majority of the capacity on the Cold Lake system is contracted to AltaGas' Energy Services business which markets or exchanges most of the gas on the Cold Lake system. The Kahntah pipeline transports natural gas from British Columbia to Alberta and is contracted on an annual basis to a single shipper. Due to lower producer volumes and reduced drilling activity in the area, the Kahntah transportation agreement is expected to terminate March 31, 2010. AltaGas is investigating opportunities to extend the life of this asset. The Summerdale pipeline capacity is contracted to AltaGas' Energy Services business to enable that business to optimize marketing and exchange opportunities. The Battle Lake pipeline capacity is contracted to several shippers under agreements that are extended annually.

Transmission – Competition

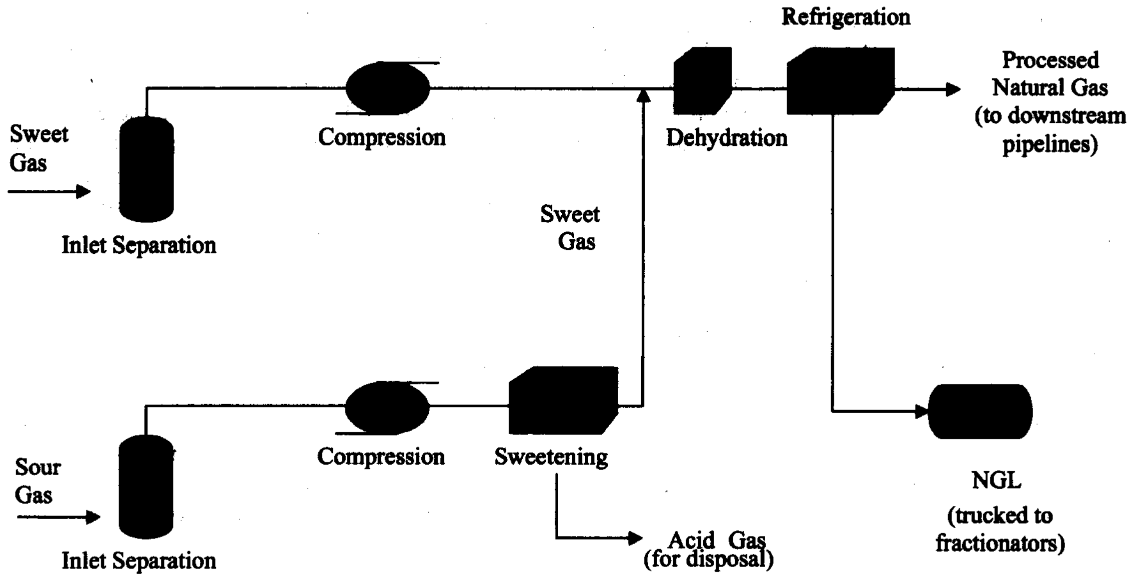
AltaGas competes with other midstream entities operating in the WCSB. AltaGas' transmission assets are well positioned to operate in a competitive environment and take advantage of their strategic locations and contract terms in order to compete with others.

GAS SEGMENT – FIELD GATHERING AND PROCESSING

The Field Gathering and Processing business consists of 76 gathering and processing facilities in 30 operating areas located in western Canada and approximately 6,600 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets. AltaGas has a total gross licensed processing capacity of 1.2 Bcf/d, of which one-third is capable of processing sour gas capacity. AltaGas operates 73 of its 76 facilities.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. Field Gathering and Processing's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie-ins, reactivations, recompletions, well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

Field Gathering and Processing – Typical Field Gas Processing Plant



Raw natural gas produced at the wellhead is a mixture of methane and other hydrocarbon components and impurities, including water vapour, carbon dioxide and hydrogen sulphide. Raw gas with amounts of hydrogen sulphide in excess of downstream pipeline specifications is considered sour. All other gas is considered sweet. Sour gas goes through more extensive processing – known as sweetening – in order to remove the hydrogen sulphide and ensure that the gas meets pipeline specifications. All natural gas must be processed through a natural gas plant to remove impurities and the various hydrocarbon components before the natural gas is delivered via downstream pipelines for ultimate sale and consumption. The amount and complexity of processing required before the raw gas is of saleable quality is a function of the quantity of NGLs and impurities present in the raw gas stream.

The raw natural gas is first gathered from the wellhead through natural gas gathering systems, and then delivered to and processed through a natural gas processing plant. The design of a natural gas processing plant is determined by the composition of the raw gas that it is intended to process. Natural gas that contains minimal or no amounts of NGLs or other elements will bypass certain processes within a typical natural gas plant configuration.

Raw natural gas entering the natural gas plant is subject to inlet separation where free water and any free NGLs are separated from the natural gas stream. If the natural gas is sour, it is sweetened by the removal of hydrogen sulphide. The natural gas is then usually dehydrated to remove any remaining water. If significant NGLs are still present in the sweet gas they are removed to meet downstream pipeline specifications. NGLs generally have greater value if extracted in liquid form and additional NGL recovery beyond downstream pipeline specifications may be carried out in order to capture the value of the NGLs. This additional recovery process can be done at field gas plants or at large-scale extraction plants. See "Extraction". AltaGas has NGL extraction capability at 30 of its natural gas field processing facilities.

The remaining processed gas exiting the natural gas plant is delivered to the downstream transportation pipeline for eventual distribution to end-use markets. NGLs must be further processed (fractionated) into their individual components: propane, butane and pentanes-plus. The NGLs may be fractionated on site or trucked or pipelined to fractionation facilities.

Field Gathering and Processing - Facilities

AltaGas' Field Gathering and Processing business generates revenue from fees for volumes of natural gas processed at a processing facility or gathered through a gathering system.

AltaGas strives for continued improvement, operational excellence, and maximum utilization of all facilities over which it has operational control and to consistently exceed WCSB average utilization rates. Volume additions at facilities, which come from new well tie-ins and from reactivations, re-completions and well optimizations performed by producers, are offset by natural production declines. The focus on skid-mounted facilities allows AltaGas to redeploy these assets in response to producer processing requirements, thereby increasing processing volumes, profitability and utilization.

Field Gathering and Processing Facility Capacity and Throughput

	2009	2008
Capacity (gross Mmcf/d)(1)(3)	1,172	1,172
Throughput (gross Mmcf/d)(2)(3)	423	521
Throughput (gross annual Mmcf/d)(3)	453	541
Capacity utilization (%)	39	46

Notes:

(1) As at December 31.
(2) Fourth quarter average.
(3) Gross numbers are before and are not adjusted to reflect AltaGas' working interest.

Natural gas demand resulted in an estimated 5,079 gas well completions and approximately 14.7 Bcf/d of marketable production in the WCSB during 2009, according to Ziff Energy Group. The Field Gathering and Processing business connected 151 wells in 2009, compared to 319 wells tied-in during 2008. Average facility utilization declined to 39 percent in 2009 from 46 percent in 2008. AltaGas experienced declining throughput primarily due to lower drilling activity and natural declines. Producer activity was impacted by low commodity prices and tight capital markets. AltaGas expects demand for gathering and processing facilities will grow in 2010 as natural gas prices have strengthened and producers are expected to have greater access to capital.

Field Gathering and Processing - Significant Operating Areas

AltaGas' facilities are often physically linked, creating facility complexes that offer delivery options and revenue continuity in the event that one of the plants in a complex shuts down. With 76 processing facilities in 30 operating areas, AltaGas' Field Gathering and Processing business is not dependent on any one facility or operating area.

Field Gathering and Processing - Customers

In 2009 AltaGas conducted business with more than 260 customers in its operating areas, with no customer representing more than 7 percent of Field Gathering and Processing net revenue. The Field Gathering and Processing business's top 10 customers represented approximately 8 percent of consolidated net revenue for 2009.

Field Gathering and Processing - Contracts

AltaGas gathers and processes natural gas under contracts with natural gas producers. There are approximately 1,100 active gathering and processing contracts. These contracts, in general:

- Establish fees for the gathering and processing services offered by AltaGas;
- Define the producers' access rights to gathering and processing services;
- Establish minimum throughput commitments with producers and use appropriate fee structures to recover invested capital early in the life of the contract where capital investment is required by AltaGas;
- Define the terms and conditions under which future production is processed at an AltaGas facility; and
- Assist in mitigating volume risk.

The amount of capital that AltaGas commits to acquiring or developing gathering and processing facilities is linked to AltaGas' assessment of the production available to be processed at the facility, reserves in the area, the extent of the reserve dedication and the processing fees to be paid by producers for its services. When a facility is acquired, AltaGas conducts an independent review of the natural gas reserves and production in the area surrounding each facility using, among other sources, ERCB production data and reserve estimates and producers' reserve reports for the area. AltaGas also conducts a review of the physical plant and equipment and the operating and maintenance costs for each facility.

Fee Structure

In determining appropriate contractual provisions, including a reasonable payback period on its invested capital, AltaGas seeks to align its interests with the financial and business objectives of its producer customers. The vast majority of

AltaGas' gathering and processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput. Volumetric fee structures may include a provision for recovery of actual operating costs, which further mitigates the financial risk related to volume variability. Operating costs recovery in 2009 was approximately 40 percent compared with 41 percent in 2008. In addition, approximately 78 percent of contracts in place at December 31, 2009 were subject to annual price escalation related to changes in the Consumer Price Index. This toll-for-service structure (as opposed to the commodity spread-based price structures predominantly used by midstream companies in the U.S.) avoids exposure to commodity price risk as revenue is a function of volumes processed. AltaGas' investment is generally protected by the life of reserves behind the facility, since producing wells typically remain connected to a gathering and processing system for their entire productive lives.

AltaGas may underpin capital commitments through the use of one or more of the following contractual provisions:

Take-or-Pay: Take-or-pay arrangements are designed to ensure AltaGas recovers its invested capital in a relatively short period of time. This is achieved by producers providing minimum volume or capital recovery commitments to AltaGas. With minimum volume commitments the producer must process a specified volume at a rate per Mcf over a specified period of time or pay any revenue shortfall. The sum of the processing revenue provides AltaGas with a return on and of capital within a specified period. Risk is limited to counterparty creditworthiness. In recent years, AltaGas' strategy has shifted to minimum monthly volume commitments to decrease credit risk and lead to predictable cash flow.

Capital and Operating Cost Recovery: The producer pays two distinct fees to AltaGas, one to provide a return of and on capital and the other to cover AltaGas' operating costs. Return of and on capital is made more certain by reducing the risk of unexpected operating costs. Risk is largely limited to the timing of production.

Area of Mutual Interest: When AltaGas acquires a facility the vendor is typically the largest producer using that facility. As a result, AltaGas is usually entitled to gather and process the majority of the natural gas production associated with the facilities it acquires due to its reserve dedication contracts, thus reducing the possibility of competitive plants being built in the same area. Risk is largely limited to the timing of production. The contract terms also ensure any future production brought on stream in a specified area must flow to an AltaGas facility. Future natural gas throughput is generally secured by contractually committing the vendor of the facility to dedicate any future production from specified reserves or future areas of development surrounding the facility.

Geographic Franchise with Economic Out: Contractual provisions allow AltaGas to terminate or renegotiate a contract if it is not economical to continue processing. Risk is largely limited to the timing of production and operating cost efficiencies.

Length of Term

Where natural gas reserves have been dedicated under contract, the contract normally extends beyond one year and up to the life of the reserves, depending on the amount of capital AltaGas has invested in the facility. Where reserves have not been dedicated under contract or AltaGas has not made a significant capital investment, the contracts are normally subject to termination by either party upon one to three months notice. As mentioned previously, producing wells typically remain connected to a gathering and processing system for their entire productive lives.

Type of Service

In general, producers have access to either firm service or interruptible service. Firm service offers producers priority to have their natural gas processed at the applicable AltaGas facility subject to industry standard maintenance and force majeure. Interruptible service is available only if the applicable AltaGas facility has capacity available after all firm service commitments with respect to such facility have been satisfied. Firm service is normally provided to a producer when the producer's natural gas reserves have been dedicated to an AltaGas facility.

Field Gathering and Processing - Operating and Maintenance Expenses

Operating and maintenance expenses for gathering and processing facilities generally include: (i) labour costs for operations and maintenance staff; (ii) materials consumed in processing or maintenance, including chemicals and lubricants; (iii) land lease costs; (iv) property taxes; (v) fuel and power costs; and (vi) other overhead costs. For the plants operated by AltaGas, the most significant expenses are labour, utilities, property taxes and repairs and maintenance. Repairs and maintenance are scheduled, where possible, to minimize down time and coordinate with producers' well maintenance activities. One of AltaGas' strategies is to increase the number of contracts with flow-through operating costs provisions.

Field Gathering and Processing - Competition

AltaGas competes with other midstream entities operating in the WCSB. In 2009 AltaGas processed an average of 453 Mmcf/d, which was approximately 4 percent of volumes produced in the WCSB. The majority of processing capacity generally continues to be provided by the upstream natural gas exploration and production companies.

The field gathering and processing marketplace continues to evolve and the competitive environment also continues to change. AltaGas believes that its field gathering and processing strategies and competitive advantages will continue to allow it to effectively compete in the midstream marketplace. AltaGas also believes that its operational skills and market penetration make it a preferred business partner for many exploration and production companies.

GAS SEGMENT – NATURAL GAS DISTRIBUTION

The Trust acquired this business effective October 9, 2009.

Regulated Businesses

AUI and Heritage Gas operate in regulated marketplaces where, as franchise holders, they are allowed the opportunity to earn regulated rates that provide for recovery of costs and a return on capital from the franchise capital investment base. Return on rate base comprises regulatory allowed financing costs and return on common equity. Inuvik Gas operates a natural gas distribution franchise in a "light-handed" regulatory environment where delivery service and natural gas pricing are market based.

Regulatory Process

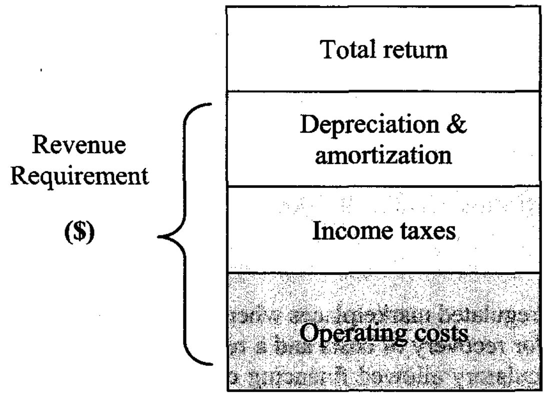
The distribution of natural gas in Alberta, Nova Scotia and the Northwest Territories is regulated by the AUC, the NSUARB and the NWTPUB respectively. The AUC and the NSUARB's jurisdiction includes the approval of a distribution tariff for regulated distribution utilities which includes the rates charged and the terms and conditions on which service is to be provided by those utilities. For Inuvik Gas, rates are set by the utility to be market competitive. Inuvik Gas is regulated on a complaint basis and is required to file annual financial statements and quarterly comparisons to local alternative fuels with the NWTPUB.

The following description of the regulatory process applies to AUI and Heritage Gas. The AUC and the NSUARB approve distribution rates based on a cost-of-service regulatory model. Under this model, the AUC and the NSUARB seek to provide the distribution utility with an opportunity to recover all prudently incurred operating, depreciation, income tax, and financing costs, and to earn a reasonable return on equity. The AUC and the NSUARB attempt to ensure that tariffs are just and reasonable, provide incentives for investments, and are not unduly preferential, arbitrary, or unjustly discriminatory. The natural gas delivered to the end consumer may be purchased from a retail gas supplier at contract prices or from the utility as the default supplier, at a regulated rate based on the current cost of gas to the utility.

The regulatory process usually proceeds through two phases. In the first phase (Phase 1) the distribution utility's total revenue requirement is determined. In the second phase (Phase 2) specific rates to be charged to different classes of consumers and the terms and conditions of service are determined. Phase 1 and Phase 2 may be applied for in a single application or in separate applications at different times. In general, a full Phase 1 and Phase 2 process may take over a year from original application to final decision by the AUC, or up to six months by the NSUARB.

Phase 1

The principal components comprising an approved Phase 1 revenue requirement are as follows (the diagram does not necessarily represent the relative size of such principal components comprising an approved revenue requirement):

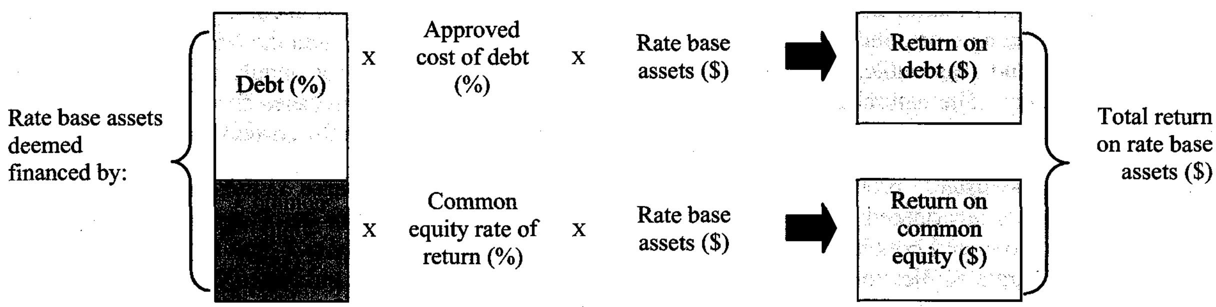


Rate Base

Rate base is the approved investment in plant, property and equipment, less accumulated depreciation, plus allowance for working capital. Net rate base excludes from the rate base no-cost capital, which consists of unamortized customer-contributions and grants from governments and customers. Working capital generally includes an allowance for delays in receipt of cash and average balance for other deferred or prepaid expenses.

Total Return

Total return is the return on the capital invested by the distribution utility in its approved rate base, financed through a deemed capital structure comprised of debt and equity, calculated, as a matter of general practice, on the following basis (the diagram does not necessarily represent all the components, or the relative size of such components, within an approved revenue requirement total return on rate base assets).



Depreciation and Amortization

Depreciation and amortization is an allowance for a return of capital and is the depreciation on the rate base assets that is determined based on depreciation studies filed by a distribution utility, and approved by the AUC or NSUARB. It is net of any customer contribution amortization.

Income Taxes

Income taxes are the allowance for the recovery of income taxes paid in respect of the regulated operations of the distribution utility.

Operating Costs

Operating costs are the operating costs associated with operating a distribution utility that are determined to be prudent by the regulator.

Other revenue generated by the utility through its regulated operations reduces the total regulated revenue requirement collected through rates, from end-users or customers.

The following table summarizes the actual gross and net mid-year rate base for AUI and Heritage Gas for the years 2009, 2008, and 2007:

($ millions)	2009	2008	2007
AUI			
Gross rate base	177.7	166.0	156.0
Less: CIAC	54.7	52.9	50.8
Net rate base	123.0	113.1	105.2
Heritage Gas (1)			
Gross rate base	139.4	117.2	89.5
Less: CIAC	2.0	2.0	2.0
Less: Province of Nova Scotia Loan	5.6	5.6	5.6
Net rate base	131.8	109.6	81.9

Note:

(1) All figures shown in this section are for an ownership interest in Heritage Gas of 100 percent. Prior to November 18, 2009, Utility Group owned a 24.9 percent interest in Heritage Gas.

The following table summarizes AUI's and Heritage Gas' approved allowed rate of return on equity and cost of debt:

Operating year	Capital Structure Debt/Equity (%)	Allowed Rate of Return on Equity (%)	Cost of Debt (%)
AUI			
2009	57/43	9.00	4.02
Heritage Gas			
2007-2011	55/45	13.0	8.75

Phase 2

An approved Phase 2 rate structure results in rate schedules applicable to different customer classes as well as terms and conditions governing the services provided to customers. The determination of rate structure is complex, typically involving the allocation of the Phase 1 revenue requirement to customer classes using the principle of cost causation. Rates are based on a set of rate design principles, with the primary principle being to collect revenue from a customer class equal to the costs to serve the class.

Delivery charge billing determinants are either fixed or vary with the volume of gas delivered. The fixed billing determinants do not vary with energy deliveries and as such provide some revenue stability and moderate the impact on revenue of fluctuations in gas volumes delivered.

AUI

AUI has operated as a provincially regulated natural gas distribution utility in Alberta since 1954. Its head office is located in Leduc, Alberta. AUI delivers natural gas to residential, farm, commercial and industrial consumers in more than 90 communities throughout Alberta. AUI also owns transmission facilities, including high-pressure pipelines that deliver natural gas from gas sources to the distribution systems. AUI's primary objective and responsibility is to recover its costs and earn a return of, and return on, capital while maintaining high operating standards to ensure safe, dependable, cost-effective and secure natural gas supply and delivery for its customers.

AUI operates in a mature market and has achieved nearly 100 percent saturation within its franchise areas, with the exception of those few consumers choosing alternate fuel sources or those living in more remote areas where natural gas service has been cost-prohibitive. The Alberta natural gas distribution market is dominated by a major distributor that serves approximately 85 percent of natural gas consumers. AUI serves approximately 6 percent of Alberta customers, with the remainder of the market served by member-owned natural gas cooperatives and municipally owned systems.

Within its existing franchise areas AUI averaged annual growth of 2.0 percent in the years 2000 through 2005, 3.5 percent in the years 2006 and 2007, and 3.0 percent in 2008. In 2009, the rate of growth in the number of customers returned to a level of 1.8 percent as a result of the general slowdown in the Alberta new housing market. AUI expects annual growth in new service sites of approximately 2.0 percent for 2010 and thereafter.

AUI aggressively pursues opportunities to develop service areas that are not currently served with natural gas. In recent years, these expansion opportunities have typically come with the extension of gas service to small aboriginal communities in northern Alberta. Expansion opportunities that currently exist represent relatively minor asset growth, but AUI remains committed to its strategy of pursuing expansion projects that meet management's target return on investment.

AUI's cash expenditures for capital for the years ended December 31, 2009, 2008, and 2007 are shown in the following table:

Cash expenditures for capital

($ millions)	2009	2008	2007
New business	8.0	10.6	9.1
System betterment and gas supply	5.1	5.7	5.2
General plant	8.4	7.6	3.1
	21.5	23.9	17.4
Less: CIAC	2.3	3.5	4.1
Total	19.3	20.4	13.3

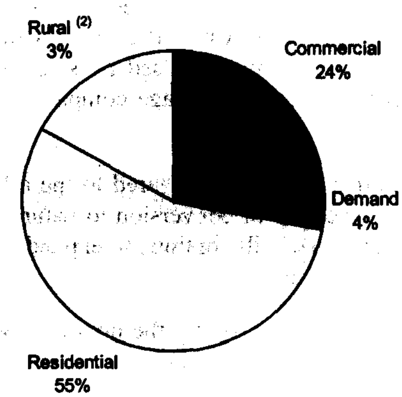
Operations

AUI's distribution system consists of 20,060 km of pipeline, operating at pressures ranging from 200 kilopascals to 8,755 kilopascals. AUI uses steel, aluminium and composite pipe to transport natural gas at pressures greater than 690 kilopascals, while natural gas at lower pressures is transported primarily by steel and plastic pipe. There are 738 small and mid-sized metering and pressure regulating stations throughout AUI's distribution network. AUI operates its gas distribution systems through a network of 16 district offices.

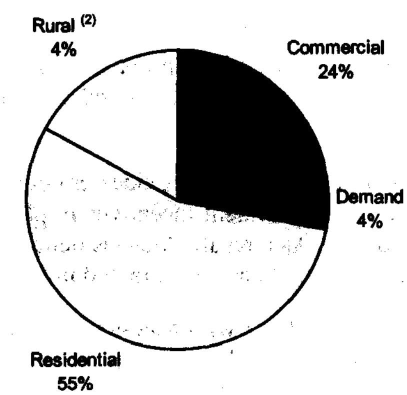
In 2009, the total throughput of natural gas transported for three producers and delivered to 69,370 end consumer service sites had a total energy value of approximately 22.9 PJ.

AUI's market consists primarily of residential and small commercial consumers located in smaller population centres or rural areas of Alberta. New service sites added totalled 1,241 in 2009, 2,056 in 2008 and 3,074 in 2007. Of the 22.9 PJ of natural gas AUI delivered through AUI's system in 2009, 13.3 PJ was attributed to 68,482 non-demand service sites that received default gas supply under the regulated rate, 1.5 PJ to 836 non-demand service sites that received gas supply from natural gas retailers, 3.1 PJ to 52 demand-based service sites and 6.0 PJ for three producer transporters. Producer transportation revenues are primarily derived from capacity charges and do not vary significantly with changes in energy transported. While producer transportation throughput comprises a significant percentage of total throughput, this service produces significantly less revenue than that derived from distribution services.

AUI Revenue by Service Type for 2008 (1)



AUI Revenue by Service Type for 2009 (1)



Notes:

(1) Excludes revenue from producer transportation service.
(2) Rural customers are located outside of incorporated areas and consist primarily of farms, irrigation pumps, grain dryers and greenhouses.

AUI provides service to designated areas in Alberta under the authority granted by franchise agreements or other agreements granted as permits or approvals issued pursuant to applicable statutes. As of December 31, 2009, AUI held a total of 78 such franchises and agreements: 49 municipal distribution franchises granted pursuant to the *Municipal Government Act* (Alberta), nine permits granted on four First Nations by Indian and Northern Affairs Canada under the authority of the *Indian Act* (Canada) and 20 rural franchise approvals issued under the authority of the *Gas Distribution Act* (Alberta). Four of the rural franchises cover Métiš settlements, each of which have a separate operating agreement.

Franchises/Permits	# of Agreements	% of Total Service Sites	Average Remaining Term
Municipal Government Act Franchises	49	64.2	4.2 years
Indian and Northern Affairs Canada Permits	9	1.5	Varying
Gas Distribution Act Franchises	16	33.2	Perpetual
Métis Settlement Operating Agreements	4	1.1	2.6 years

The three largest municipalities served by AUI (City of Leduc, Town of Beaumont and Town of Drumheller) accounted for approximately 21 percent of AUI's total net revenue and 20 percent of energy delivered in 2009.

Seasonality

The natural gas distribution business in Alberta is highly seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Natural gas delivered during the winter season typically accounts for approximately two-thirds of annual natural gas deliveries, resulting in profitable first and fourth quarters and net losses in the second and third quarter. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates are set based on the 20-year rolling average heating Degree Days expected for the application period. Variations from expected deliveries are for the account of the shareholders.

	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	1,950	140	644	2,403	1,774	203	593	2,233
Degree Days - normal	1,767	206	542	2,172	1,752	204	535	2,168

Heritage Gas

Heritage Gas is a greenfield natural gas distribution utility in Nova Scotia. Heritage Gas' franchise was granted on February 7, 2003 and gives it the exclusive right to distribute natural gas to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality until December 31, 2028. Heritage Gas' head office is located in Dartmouth, N.S.

As a greenfield operation, Heritage Gas has relatively small proportion of the Nova Scotia energy end-use market. The dominant energy source for space heating is oil, with over 50 percent of the market share. Most major industrial and institutional consumers use Bunker C heavy fuel oil, while smaller commercial and residential consumers use No. 2 fuel oil. Electricity, primarily used by residential consumers, has the second largest market share, with over 25 percent of the market share. This is followed by propane and wood fuel, which are mainly used by smaller residential customers. Natural gas is fifth in market share. Natural gas has a competitive price advantage compared to all alternative energy sources.

Natural gas is more efficient and provides environmental advantages when compared to the other forms of fuel in the market and there are government incentives in place to reduce the cost of conversion to natural gas for residential and commercial customers. As a result, AltaGas believes that Heritage Gas will continue to expand its customer service base within the franchise areas it has been granted in the Nova Scotia market.

Potential customers are those with access to natural gas service, thereby having the opportunity to switch heating fuel sources, mainly from oil or electricity, to natural gas. At the end of 2009 there were approximately 8,555 potential customers of which 3,380 were commercial energy consumers and approximately 5,175 were residential energy consumers with access to the Heritage Gas distribution system in the Halifax Regional Municipality and in the Town of Amherst and Cumberland County. Of the 8,555 potential customers, Heritage Gas had installed service lines to 2,781 customers over its years of operations, of which 2,435 were activated by December 31, 2009.

In 2009, Heritage Gas connected 550 new customers, compared to 672 in 2008. Heritage Gas expects a growth in activations in 2010 as a result of the higher cost of heating oil compared to natural gas and customer awareness of the environmental benefits of natural gas. In 2010, Heritage Gas expects to expand its services to areas such Fairview, Clayton Park, Bayer's Lake and Bedford in the Halifax Regional Municipality.

Capital expenditures by Heritage Gas for the years ended December 31, 2009, 2008, and 2007 are shown in the following table:

Capital Expenditures

	Year ended December 31,		
($ millions)	**2009**	**2008**	**2007**
New business	15.1	18.0	25.5
General plant	0.2	0.2	0.1
Total	15.3	18.2	25.6

In 2009 Heritage Gas invested $15.3 million to continue expanding in each of its franchise markets. The major focus in 2009 was the continuing development of the Halifax Peninsula market.

Operations

On December 31, 2009, Heritage Gas' distribution system consisted of approximately 234 km of pipeline infrastructure, 180 of which are in the Halifax Regional Municipality and approximately 54 km of pipeline infrastructure in Amherst.

At the end of 2009 Heritage Gas had installed service lines to 2,781 customers, of which 2,435 were activated by year-end. In addition, Heritage Gas had signed commitments for service from an additional 1,429 customers in the Halifax Regional Municipality and Amherst. At the end of 2009 there were approximately 3,380 commercial energy consumers and 5,175 residential consumers with access to the Heritage Gas distribution system. Although the current size of the market is relatively small, Heritage Gas is contemplating numerous future development projects throughout its franchise area. Heritage Gas fully expects to pursue these and other future growth opportunities that are contiguous to its current operations. In 2009 the total peak-day capacity of the Heritage Gas system was 124,000 GJ per day, excluding the Burnside facility.

Heritage Gas purchases gas sourced from offshore Nova Scotia under a negotiated contract with a wholesale gas marketer. The current contract expires on October 31, 2010. The cost of gas purchased is flowed through to the distribution customers and does not impact net income. The natural gas received into the Heritage Gas system is delivered from Maritimes & Northeast Pipeline laterals.

In awarding the franchise to Heritage Gas in 2003, the NSUARB found that there is adequate gas supply to meet both the immediate and long-term needs of Nova Scotia natural gas customers. However, the offshore Nova Scotia gas supply area has not been developed to the extent that was initially envisioned and the level of current reserves estimates has been reduced and there is speculation that current production levels will sustain natural gas demand for a shorter period than previously expected. Heritage Gas has access to gas supply from the western part of the North American pipeline system, which management believes will ensure that Heritage Gas has sufficient gas supplies to serve all its customers as it grows.

Inuvik Gas

Inuvik Gas is a corporation equally owned by AltaGas, the Inuvialuit Petroleum Corporation, and ATCO Midstream NWT Ltd.

On December 1, 1997 Inuvik Gas signed an exclusive franchise agreement with the Town of Inuvik to distribute and sell natural gas within the town. The 15-year initial term of the franchise began with the commencement of deliveries in August 1999 and can be renewed by mutual agreement for a further 10-year period. The Ikhil Gas Project comprises three components, the producing wells, the gas producing facilities and the natural gas distribution system, each governed separately from the other. Inuvik Gas owns the natural gas distribution system and provides residents and businesses in the Town of Inuvik with a secure supply of natural gas for power and heating.

Inuvik Gas is regulated by the NWTPUB and is presently exempt from full regulation as a public utility. The NWTPUB is satisfied that competition for alternative fuels in Inuvik is sufficient to negate the need for full regulation. Inuvik Gas reviews the rates charged to customers regularly, and since its rates are market-based, as opposed to the more traditional cost of service, Inuvik Gas has the opportunity to earn a higher return in times of high alternative fuel prices and, conversely, may not recover its cost of operations in periods of low alternative fuel prices.

The Inuvik Gas distribution system, consisting of 47 km of pipe within the Town of Inuvik, was the first of its type to be buried in permafrost conditions. The total number of customers using natural gas service was 905 at December 31, 2009, up from 862 at December 31, 2008 and 821 at December 31, 2007.

Inuvik Gas purchases gas for resale from Ikhil under a gas purchase agreement through to 2014, at a price adjusted annually on August 1 based on the change in the average price of high sulphur diesel at Edmonton. This arrangement is the sole source of Inuvik Gas' gas supply. Should the Mackenzie Gas Project proceed, Inuvik Gas would expect to have access to natural gas supply from that project during and beyond the life expectancy of the two wells currently servicing the Town of Inuvik.

Ikhil Joint Venture

The Ikhil joint venture owns and operates two gas wells, a processing facility and a pipeline that delivers natural gas to Inuvik Gas and NWTPC. The joint venture partners and their respective ownership interests are as follows: AltaGas (33.3335 percent), Inuvialuit Petroleum Corporation (33.3335 percent) and ATCO Midstream NWT Ltd. (33.333 percent).

The Ikhil gas reserves are the sole gas supply for the Inuvik Gas distribution business and for the gas-fired generation of NWTPC in Inuvik. The wells produce an average of approximately 1.8 Mmcf/d (0.6 Mmcf/d net to AltaGas) of sweet dry gas into a field processing facility that cools the gas and delivers it to the town of Inuvik. The Ikhil reservoir had remaining recoverable gas of approximately 8.6 Bcf (2.9 Bcf net to AltaGas) as at December 31, 2009. Pipeline infrastructure is currently not in place to utilize other natural gas reserves discovered in the area. The supply contract to Inuvik Gas and NWTPC ends in 2014, approximately 14 years prior to the end of the expected life of the natural gas reserves. The sales price is adjusted annually on August 1 based on the price of high sulphur diesel at Edmonton.

GAS SEGMENT – ENERGY SERVICES

The Energy Services business consists of two main components: an energy management business and a gas services business.

Energy Management

The energy management business consists of providing energy consulting and supply management services and arranging natural gas and power supply for non-residential end-users. AltaGas' energy management services are provided under the brand name ECNG Energy and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Vancouver, British Columbia.

The majority of the energy management fee-for-service revenue is based on one-to-three-year evergreen contracts. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides natural gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-use customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Gas Services

One of the key functions of the Energy Services business is to support AltaGas' infrastructure businesses. The gas services group contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas' transmission pipelines and provides natural gas control services to balance natural gas flows. Gas services markets natural gas for Field Gathering and Processing customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. Gas services also contracts and manages natural gas for AltaGas' gas-fired peaking plants.

In addition to supporting the other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell natural gas, market natural gas for producers and exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions in compliance with AltaGas' credit and commodity risk policies. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into eastern Canadian markets and within Alberta in the form of gas exchange arrangements. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has achieved positive margins while providing improved netbacks for producers.

The gas services business manages AltaGas' 50 percent share of Sarnia Airport Storage Pool Limited Partnership, which owns 5.3 Bcf of gas storage capacity. This facility became commercially operational on June 26, 2009. Storage in the pool is marketed on a fee-for-service basis to credit-worthy third parties. Market Hub Partners Management Inc., an affiliate of Spectra Energy Corp., has been contracted to manage the general partner of the limited partnership and operate the facility.

Energy Services - Customers

AltaGas has more than 1,400 energy management and gas service contracts. Customer retention rates are over 92 percent. These customers are commercial, industrial, agricultural and institutional end-users in Ontario, Alberta, British Columbia, Quebec, New Brunswick, Nova Scotia and Manitoba. The AltaGas energy management business arranges natural gas and electricity supply on behalf of its customers through an array of qualified suppliers, including AltaGas.

In its gas services business, AltaGas buys natural gas from a wide array of suppliers including wholesale marketing companies and producers and sells natural gas to other wholesale marketing companies and commercial and industrial end-users.

No Energy Services customer represented more than 8 percent of consolidated revenue during 2009.

Energy Services - Competition

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies. The primary source of competition is the marketing arms of large oil and gas producers.

POWER SEGMENT

AltaGas' Power Segment contributed net revenue of $102.6 million for the year ended December 31, 2009, representing approximately 22 percent of the Trust's total net revenue before intersegment eliminations. At December 31, 2009 there were 38 individuals employed in the Power Segment.

At December 31, 2009, AltaGas had 494 MW of installed power capacity, comprised of 353 MW of power generation capacity through a 50 percent ownership interest in the Sundance B PPAs, a capital lease for 25 MW of gas-fired peaking capacity, another 14 MW of gas-fired peaking capacity and 102 MW of wind power generation capacity sold under a 25 year Energy Purchase Agreement with BC Hydro. Bear Mountain Wind Park is the first wind generation facility in British Columbia. At December 31, 2009, AltaGas' 392 MW of installed power capacity in Alberta served approximately 5 percent of Alberta's power demand. AltaGas also has an effective 25 percent interest in a 7-MW run-of-river hydroelectric generation facility in British Columbia. The Power business is engaged in the sale of electricity and ancillary services in the Alberta wholesale market and the sale of electricity in British Columbia to BC Hydro.

Additional growth in the Power business is expected to occur by advancing AltaGas' significant and growing portfolio of renewable energy projects. AltaGas has approximately 1,900 MW of wind and run-of-river hydroelectric projects under development. The renewable power portfolio consists of 1,500 MW of wind projects, 500 MW in Canada and 1,000 MW in the northern and western United States. The hydroelectric portfolio under development consists of 297 MW in British Columbia.

Power Purchase Arrangements - Alberta

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output.

ASTC Power Partnership

AltaGas and TransCanada are partners in the ASTC Partnership. Each partner owns a 50 percent share of ASTC Partnership and contributed 50 percent of the $223.1 million required for the ASTC Partnership to purchase the two Sundance B PPAs from Enron Canada Power Corporation on December 28, 2001. There are two Sundance B PPAs, one for each of Units 3 and 4 at the Sundance Plant. The ASTC Partnership holds the Sundance B PPAs as partnership property, with both partners having an equal interest in each PPA.

The indirect 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to 353 MW of coal-fired generation capacity, as well as to ancillary services from Sundance Units 3 and 4, until December 31, 2020.

The ASTC Partnership started dispatching power effective December 29, 2001. AltaGas maintains the books and records of the ASTC Partnership, including providing accounting services. TransCanada manages daily operations, including the dispatch of power into the Pool. AltaGas and TransCanada are each responsible for managing the market risk associated with their individual shares of the power generation capacity.

The Sundance B Plant

TransAlta owns the coal-fired Sundance Plant, which is located approximately 70 km west of Edmonton, Alberta. The Sundance Plant consists of Units 1 through 6. An auction conducted on August 24, 2000 grouped the units into three plants: Sundance A Plant - Units 1 and 2, Sundance B Plant - Units 3 and 4, and Sundance C Plant - Units 5 and 6. Sundance B Plant has been operating since 1976 (Unit 3) and 1977 (Unit 4).

The Sundance Plant is connected to the Alberta Interconnected Electric System, which allows access to markets in Alberta, British Columbia, Saskatchewan and the United States.

The Sundance B Plant - Power Sales

Revenue from the sale of power is largely driven by target availability, hedge prices (for the portion of capacity that is hedged) and Pool prices (for the portion of capacity that is not hedged). The inter-relationship of production, Pool prices and cost of sales is specified in the PPAs. Generally, the ASTC Partnership will be compensated when power production is less than target levels, at a rate based on the previous 30-day average Pool price, as described in more detail later in this section. AltaGas recognizes its share of revenue based on target production levels, with any increase or decrease relative to target credited or charged to operating expenses.

Under the Sundance B PPAs, the ASTC Partnership holds the rights to the power capacity and ancillary services from Units 3 and 4 of the Sundance Plant. Day-to-day operation requires the ASTC Partnership to communicate the volume of power available and the price of the power to the AESO. The ASTC Partnership is obligated to pay TransAlta a price which is intended to cover TransAlta's capital and operating costs as determined by formulas in the Sundance B PPAs. The majority of the ASTC Partnership's cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Pool trading charges.

Each of Units 3 and 4 has a contracted capacity of 353 MW. In September 2007, TransAlta increased the capacity of Unit 4 by 53 MW pursuant to their rights under the PPA. TransAlta provided all of the capital, is responsible for all operating costs and is entitled to all benefits associated with this increased capacity, although ASTC earns a fee associated with the administration of the agreement. The Sundance B PPAs recognize that the plants will not produce at

100 percent capacity all of the time. TransAlta is obligated to provide AltaGas financial compensation if actual generation of electricity from Units 3 and 4 falls below a specified target level, which was 86 percent of contracted capacity in 2009. This is accomplished by a monthly payment based on the difference between actual availability and target availability, multiplied by RAPP. Similarly, if Units 3 and 4 produce above target, then ASTC is obligated to pay TransAlta based on the difference between actual availability and target availability, multiplied by RAPP. ASTC pays transmission charges based on actual power delivered. During these under or over-generation periods AltaGas has financial exposure to the difference between the Alberta spot price and RAPP on the difference between volumes generated and target availability. The financial exposure may be positive or negative depending on the difference between the current Pool price and RAPP.

TransAlta is an experienced operator of coal-fired electrical generation facilities and has financial incentives to operate the Sundance B plant efficiently and at high levels of electricity generation. The plant uses coal from the adjacent Highvale Mine, which is anticipated to have sufficient reserves for the expected fuel requirements of the Sundance B Plant beyond the life of the Sundance B PPAs. The coal price formula, which is pre-defined in the PPAs, is subject to inflationary indices and is not linked to current market prices for coal.

Gas-Fired Peaking Capacity

On September 1, 2004 AltaGas entered into a long-term capital lease with Maxim Power Corp. for 25 MW of gas-fired peaking capacity on four sites in southern Alberta. The capital lease has a 10-year term that commenced September 1, 2004 and includes an option at the end of the initial term to extend the term for 15 years or to purchase the assets. The capital lease requires AltaGas to pay a monthly capacity fee. The operations and maintenance services contract that previously dealt with the peaking facilities expired March 15, 2007 and AltaGas assumed responsibility for operation of the facilities. AltaGas retains 100 percent of the ancillary services and merchant peaking sales revenue.

In 2007, AltaGas purchased an additional 14 MW of gas fired peaking generation which was installed in 2008 at the Bantry and Parkland field gathering and processing facilities and is now fully integrated into the business operations.

In Alberta, gas-fired peaking capacity generally provides energy during times of high prices or supplies operating reserves that can be used during system contingencies. AltaGas manages the gas requirement and dispatches the units. This gas-fired power capacity provides fuel diversity to AltaGas' power business, provides increased operational flexibility and partial backstopping to outages at Sundance.

Wind Power Generation

In October 2009, AltaGas completed construction of the 102-MW Bear Mountain Wind Park near Dawson Creek in British Columbia. The Bear Mountain Wind Park consists of 34 turbines, a substation and transmission and collector lines. It is connected to the British Columbia Transmission Corporation's transmission grid. The turbine manufacturer, Enercon GmbH of Germany, provides operating and maintenance services to BMWLP under a long term service agreement.

All of the power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year Electricity Purchase Agreement at a set price which increases annually by 50 percent of Canadian Consumer Price Index. BMWLP has retained the green attributes and renewable energy credits and intends to sell them to provide an additional revenue stream.

Bear Mountain Wind Park is owned 100 percent by AltaGas. There are royalty agreements in place with Peace Energy Cooperative (a community-based group) and Aeolis Wind Power Corporation for a total of 0.912 percent of the project revenues and for 28.5 percent of any revenues from the sale of greenhouse gas credits above a cumulative threshold amount.

In August 2008 AltaGas acquired the remaining 45 percent interest in GreenWing with its portfolio of mature and early development wind projects and changed the name in December 2008 to AltaGas Renewable Energy Limited Partnership. In 2009 AltaGas acquired the 100-MW Glenridge wind development project near Medicine Hat, Alberta. This is a strategic asset that, once operational, will add fuel diversity to AltaGas' power generation portfolio and is expected to generate Alberta based environmental attributes that can be used to offset environmental costs associated with the Sundance B PPA. With these acquisitions, AltaGas now has a portfolio of 1,500 MW of wind power, 500 MW in Canada and 1,000 MW in the northern and western United States. The AltaGas wind portfolio is diverse geographically and its assets are located in regions that have strong support for renewable energy mandated through renewable portfolio standards and utility-sponsored PPA auctions. AltaGas believes these assets will generate further growth for the power infrastructure business.

AltaGas has two projects, Reston and Yellowhead, located in Manitoba totalling 400 MW. These projects are mature projects that are eligible for future calls for power with Manitoba Hydro. The Glenridge project in Alberta has completed most of the Environmental Assessment and has received an Interconnection Approval with the AESO. Power from the Glenridge project will be sold into the Alberta merchant market and is expected to be integrated into the existing AltaGas Alberta power portfolio to optimize sales. The 1,000 MW of wind development projects in the United States is comprised of properties at Walker Ridge, Soledad, Ghost Town and Mojave in California, Chateau Hills in New Mexico, Roughrider in North Dakota, Vinegar Peak, Rhyolite and Spanish Flats in Nevada and Burlington in Colorado. AltaGas intends to continue development of these projects by erecting meteorological towers and conducting transmission, wind resource and environmental studies at these sites.

Hydroelectric Generation

In January 2008 AltaGas acquired an effective 25 percent interest in Boston Bar Limited Partnership which owns a 7-MW run-of-river hydroelectric facility on Scuzzy Creek, near Boston Bar, British Columbia and which is under a 20-year electricity purchase agreement with BC Hydro until 2015. At the same time, AltaGas acquired two 10-MW run-of-river plants in development near Boston Bar, British Columbia: Log Creek and Kookipi Creek. Both the Log Creek and Kookipi Creek projects are supported by 40-year electricity purchase agreements with BC Hydro. Development efforts at Log Creek and Kookipi Creek are now focused on the acquisition of the required regulatory permits as well as the completion of detailed engineering. Subject to necessary approvals, construction on Log and Kookipi is expected to be underway in 2011 with commercial operations targeted for 2013.

In February 2008 AltaGas announced the acquisition of four potential run-of-river hydro projects in British Columbia ranging from 6.5 MW to 24 MW for $4.5 million. The projects remain under review and provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia.

In July 2008 AltaGas acquired NovaGreen with its portfolio of northwest B.C. run-of-river hydroelectric development projects and changed the name to AltaGas Renewable Energy Inc. in December 2008. The NovaGreen development team responsible for the assets joined AltaGas and this team is responsible for leading all of AltaGas' hydroelectric initiatives.

AltaGas is developing a portfolio of run-of-river hydroelectric projects in B.C., including three projects in northwest BC; Forrest Kerr, McLymont Creek and Volcano Creek. The projects have a combined generating capacity of approximately 277 MW and are currently the subject of discussions with the Government of British Columbia. These discussions include considerations relating to the announcement by the Government of B.C. to upgrade and extend the electricity transmission capabilities in B.C.'s Northwest, specifically the Northwest Transmission Line. The Northwest Transmission Line upgrade would extend the British Columbia Transmission Corporation's transmission grid to within 44 km of the projects.

Risk Mitigation

The main risk faced in the power business is the fluctuation in the margin between power revenue and the cost for power. This is generally created through changes in power prices, increases in operating costs, changes in transmission rates and reductions in power available for sale mainly due to outage and force majeure events. AltaGas mitigates this risk through disciplined power hedging strategies and portfolio diversity. AltaGas uses hedges to fix the selling prices on a significant portion of its available capacity prior to the beginning of any calendar year. Hedge contracts tend to have terms ranging from one to 36 months. AltaGas also satisfies its own electrical demand requirements of approximately 11 MW and supplies approximately 40 MW to the Energy Services business, which sells to Alberta power retail customers, for terms of up to 8 years.

During 2009 the average monthly Pool price ranged from a low of $31.53/MWh in April to a high of $92.97/MWh in January. The average all-hours Pool price for 2009 was $47.84/MWh, compared to $89.94/MWh for 2008. The average sales price received by AltaGas for 2009 was $68.97/MWh, compared to $84.51/MWh during 2008. AltaGas has sold almost two-thirds of its power forward for 2010 and a small portion for 2011 through 2015.

The following chart provides a summary of power prices and volumes for the last two years.

Power Prices and Volumes	2009	2008
Volume of power sold (GWh)	2,726	2,623
Average price received on the sale of power ($/MWh)[(1)]	69.37	84.51
Alberta Power Pool average spot price ($/MWh)[(1)]	47.84	89.95

Note:

(1) Annual average.

In the event of any force majeure related to the Sundance B PPAs that results in permanent destruction of the units, ASTC is entitled to a termination payment from the Balancing Pool equal to its portion of the net present value of the amortized Sundance B PPAs' purchase price to that date. AltaGas has further minimized the risk of a force majeure event by diversifying its supply over two independent baseload Sundance B units, acquiring gas-fired peaking capacity and executing independent backstopping arrangements with external counterparties to supply electricity in the event of a force majeure. In addition, delivery obligations for certain hedges are suspended during outages.

A part of AltaGas' business portfolio risk mitigation strategy is geographic and fuel type diversification. The Bear Mountain Wind Park in British Columbia has a capacity of 102 MW. In addition, it is also pursuing development of wind power and run-of-river hydroelectric projects in western Canada and the United States through AltaGas Renewable Energy.

Competition

All of the power produced in Alberta is currently sold into the Pool, which operates an open market for the exchange of electricity and is run by the AESO. The AESO establishes the power price based on offers from Pool participants using a uniform pricing model whereby the marginal unit establishes the price for all generators. AESO system controllers sort the offers by price into a merit order beginning with the lowest priced offer, thereby defining a supply curve for each hour. By matching energy supply with demand, the Pool establishes a uniform hourly market price, which is published on the AESO's website.

In Alberta, coal-fired electrical generation, which is generally produced at a lower cost than gas-fired electrical generation, is a baseload source of supply, while gas-fired units tend to set the marginal price. Management is not aware of any significant increases in power generation capacity in Alberta in the next several years that would alter the tendency for natural gas-fired electricity to continue to influence the marginal price in Alberta.

The Sundance plant is one of the lowest-cost power producers in Alberta and therefore among the lowest in the dispatch merit order. AltaGas does not expect this situation to change with the addition of new capacity on the grid. Power prices have been under pressure since early 2009 due to a combination of reduced demand growth, low gas prices and the addition of new generation capacity to the grid. Management does not believe that the current market environment is sustainable over the long-term and remains confident in the ongoing profitability of its power generation assets.

CORPORATE SEGMENT

AltaGas makes investments where it considers it to be prudent to do so and where it sees an opportunity to create value. The resulting investments and related revenues and expenses not directly identifiable with the operating segments are reported in the Corporate segment. The Corporate segment contributed net revenue of $18.6 million for the year ended December 31, 2009, representing approximately 4 percent of the Trust's total net revenue before intersegment eliminations. At December 31, 2009 there were 173 individuals employed in the Corporate Segment.

AltaGas holds shares of Magma Energy Corporation, which were initially acquired on January 14, 2009. Magma Energy Corporation began trading on the TSX on July 7, 2009 at which time AltaGas increased its ownership. AltaGas held approximately five percent of the common shares of Magma Energy Corporation on December 31, 2009. Magma Energy Corporation is accounted for on an equity basis.

DESCRIPTION OF THE TRUST

The Trust is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to the Declaration of Trust. See "AltaGas Income Trust" and "Declaration of Trust and Description of Units". The Trust's operations and activities are restricted but include among other things: acquiring, investing in, holding, transferring, disposing of and otherwise dealing with securities of whatever nature or kind of, or issued by, Holding Trust, the General Partner, AltaGas Ltd. or any associate or affiliate of any thereof, or of, or issued by, any other corporation, partnership, trust or other person involved, directly or indirectly, in the business of, or the ownership, lease or operation of assets or property in connection with, gathering, processing, transporting, extracting, buying, storing or selling petroleum, natural gas, NGLs or other related products, power or other forms of energy and related businesses and such other investments as the Trustee may determine, and to borrow funds and issue debt securities, directly or indirectly, for that purpose and enter into hedging arrangements in relation thereto; engaging in all activities ancillary or incidental to any of these activities; and undertaking such other activities or taking such actions including investing in securities as shall be approved by the Trustee from time to time, provided that the Trust shall not, in any event, undertake any activity, take any action, or make any investment which would result in the Trust not being considered a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

MANAGEMENT OF THE TRUST

THE TRUSTEE

The following is a summary which does not purport to be complete of the material provisions of the Declaration of Trust as they relate to the Trustee. Reference is made to the Declaration of Trust for the full text of its provisions and a complete description, a copy of which has been filed on SEDAR at www.sedar.com.

The Declaration of Trust provides that the assets and affairs of the Trust are subject to the power, control and authority of the Trustee. Computershare Trust Company of Canada is the Trust's Trustee and also acts as transfer agent and registrar for the Trust units. The Trustee's initial appointment was until the third annual meeting of unitholders following the effective date of the Arrangement. The Trustee was reappointed at such meeting by the unitholders for a further three-year term expiring in 2010. Thereafter, the unitholders shall reappoint or appoint a successor to the Trustee every three years following the reappointment or appointment of the successor to the Trustee.

The Trustee may be removed by notice in writing delivered by AltaGas Ltd. or the General Partner to the Trustee in certain circumstances. The Trustee may also be removed by ordinary resolution of the unitholders with or without cause.

Powers of the Trustee

Without in any way limiting the general power and authority over the assets and affairs of the Trust granted to the Trustee, the Trustee has the following specific powers and authorities to do the following or to cause the same to be done, among other things: (a) supervise the activities and manage the investments and conduct the affairs of the Trust; (b) maintain records and provide reports to Trust unitholders; (c) effect payment of distributions to Trust unitholders; (d) invest funds of the Trust; (e) where reasonably required, engage or employ on behalf of the Trust any persons as agents, representatives, administrators, employees or independent contractors in one or more capacities; (f) arrange for the procedures regarding the limitations on non-resident ownership as described under the heading "Declaration of Trust and Description of Units – Limitation on Non-Resident Ownership", (g) except as prohibited by applicable law, delegate any of the powers and duties of the Trustee in relation to the Trust as provided in the Declaration of Trust or otherwise to any one or more agents, representatives, administrators, officers, employees, independent contractors or other persons (including but not limited to the General Partner or AltaGas Ltd.) without liability to the Trustee, except as provided in the Declaration of Trust, and may, from time to time, with the consent of the General Partner, change the administrator of the Trust; (h) enter into or perform the obligations of the Trust under and in respect of any and all agreements to which the Trust becomes a party; and (i) without limit as to amount, issue any type of debt securities or convertible debt securities and borrow money or incur any other form of indebtedness for the purpose of carrying out the purposes of the Trust or for other expenses incurred in connection with the Trust; and exercise all powers which are necessary or useful to carry on the purpose and activities of the Trust, to promote any of the purposes for which the Trust is formed and to carry out the provisions of the Declaration of Trust.

The Trustee is required to act honestly and in good faith with a view to the best interests of the Trust and in connection therewith to exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The Trustee has delegated to the General Partner, pursuant to the Delegation Agreement, the power, authority and responsibility of the Trustee in respect of those matters referred to in the Delegation Agreement. See "Management of the Trust - Delegation Agreement". In addition, the Trustee has contracted to AltaGas Ltd. to provide management, administrative and operating support pursuant to the Administration Agreement. See "Management of the Trust - Administration Agreement".

Restrictions on Trustee's Powers

Notwithstanding any of the Trustee's power and authority, the Trustee may not under any circumstances: vote the Holding Trust units, the Trust's securities of the General Partner or, where applicable, the Holding Trust Notes; or vote the Trust's securities of, or permit Holding Trust or the General Partner to vote their interests in, AltaGas LP #1 or AltaGas LP #2; or AltaGas LP #1 to vote its interests in AltaGas LP #2; or AltaGas LP #2 to vote its securities of AltaGas Ltd., to authorize:

(a) any sale, lease or other disposition of all or substantially all of the assets of the General Partner, Holding Trust, AltaGas LP #1, AltaGas LP #2 or AltaGas Ltd., except in conjunction with an internal reorganization or a pledge to secure indebtedness incurred in carrying out the purposes of the Trust;

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving Holding Trust, AltaGas LP #1, AltaGas LP #2 or AltaGas Ltd., except in conjunction with an internal reorganization;

(c) any material amendment to the Holding Trust Note Indenture, other than an amendment which is not prejudicial to the Trust;

(d) the winding-up, liquidation or dissolution of the General Partner, Holding Trust, AltaGas Ltd. or (unless all of such limited partnership interests therein are owned directly or indirectly by the Trust) AltaGas LP #1 or AltaGas LP #2 prior to the end of the term of the Trust; or

(e) any material amendment to the Holding Declaration of Trust, the AltaGas LP #1 limited partnership agreement, the AltaGas LP #2 limited partnership agreement, or the articles of the Holding Trust Trustee, the General Partner or AltaGas Ltd., in a manner prejudicial to the Trust,

without the approval of the unitholders by special resolution at a meeting of unitholders called for that purpose. In addition, except as part of an internal reorganization of the direct or indirect assets of the Trust as a result of which the Trust has the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization, the Trustee has no power to:

(a) sell or otherwise dispose of any securities of the General Partner, Holding Trust units or Holding Trust Notes, except pursuant to a pledge pursuant to the Declaration of Trust or an in specie redemption; or

(b) sell all or substantially all of the Trust's assets or cause Holding Trust to sell all or substantially all of its assets, or cause Holding Trust to cause any subsidiary thereof to sell all or substantially all of the direct or indirect assets of the Trust, in each case in a single transaction or a series of related transactions, without the approval of the unitholders by special resolution.

Compensation of the Trustee

The Trustee shall be paid by the Trust such fees as may be agreed upon in writing from time to time by the General Partner and the Trustee. As part of the expenses of the Trust, the Trustee may pay or cause to be paid all reasonable fees, costs and expenses incurred in connection with the discharge of any of the duties in the Declaration of Trust, including, without limitation, fees, costs and expenses of AltaGas Ltd. pursuant to the Administration Agreement, auditors, accountants, lawyers, appraisers and other agents, consultants, professional advisors employed by or on behalf of the Trust and the cost of reporting or giving notices to unitholders, including remuneration of the Trustee for services rendered to the Trust in any other capacity (including as transfer agent or Depository).

Liability of Trustee

Except in the event of a breach of the standard of care, diligence and skill required of the Trustee, the Trustee shall not be liable to any unitholder for any action taken in good faith in reliance on any documents that are, prima facie, properly executed; for any depreciation of, or loss to, the Trust incurred by reason of the sale of any security; for the loss or disposition of monies or securities; or for any other action or failure to act including, without limitation, the failure to compel in any way any former trustee to redress any breach of trust or any failure by Holding Trust to perform obligations or pay monies owed to the Trust. If the Trustee has retained an appropriate expert or advisor with respect to any matter connected with its duties under the Declaration of Trust, the Trustee may act or refuse to act based on the advice of such expert or advisor and, notwithstanding any provision of the Declaration of Trust, including, without limitation, the standard of care, diligence and skill required of the Trust, the Trustee shall not be liable for any action or refusal to act based on the advice of any such expert or advisor which it is reasonable to conclude is within the expertise of such expert or advisor to give.

Subject to the standard of care required of the Trustee, neither the Trustee nor any officer, director, employee or agent thereof shall be subject to any liability whatsoever in tort, contract or otherwise, in connection with the Trust assets or the affairs of the Trust, including, without limitation, in respect of any loss or diminution in value of any Trust assets to the Trust or to the unitholders or to any other person for anything done or permitted to be done by the Trustee. The

Trustee shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust arising out of anything done or permitted or omitted to be done in respect of the execution of the duties of the office of Trustee for or in respect of the affairs of the Trust. No property or assets of the Trustee, owned in its personal capacity or otherwise, will be subject to any levy, execution or other enforcement procedure with regard to any obligations under the Declaration of Trust or under any other related agreements. No recourse may be had or taken, directly or indirectly, against the Trustee in its personal capacity. The Trust shall be solely liable therefore and resort shall be had solely to the Trust assets for payment or performance thereof.

DELEGATION AGREEMENT

The following is a summary which does not purport to be complete of the material provisions of the Delegation Agreement and the Declaration of Trust. Reference is made to the Delegation Agreement and Declaration of Trust for the full text of its provisions and a complete description, a copy of which has been filed on SEDAR at www.sedar.com.

Pursuant to the Declaration of Trust and the Delegation Agreement the Trustee is authorized to, and may, delegate to the General Partner the power, authority and responsibility to make all decisions required to be made by the Trustee from time to time in relation to the Trust including, without limitation the power, authority and responsibility for any and all matters referred to in the Delegation Agreement.

Pursuant to the terms of the Delegation Agreement, the Trustee has delegated to the General Partner the responsibility for, among other things: (a) undertaking responsibility to make all determinations, and take, or cause to be taken, all such actions as relate to (i) the determination of distributions, (ii) redemption of Trust units, (iii) compliance with the Declaration of Trust with respect to non-resident ownership of Trust units, (iv) the acquisition of Trust assets by the Trust; (v) any offering of Trust units or other securities; (b) securing bank financing or refinancing; (c) approving the financial statements of the Trust; (d) approving all information to which unitholders are entitled; (e) undertaking and performing all acts and making all decisions as would be required by applicable law or desirable of an audit committee or other applicable committee of the Trust; (f) undertaking all matters in connection with any take-over bid, merger, amalgamation, arrangement, reorganization, recapitalization, purchase or repurchase of any securities or assets of any person, any business combination, or any other similar transaction involving the Trust; and (g) doing all such other acts and things as may be incidental to or required in connection with the foregoing.

The Delegation Agreement continues in full force and effect until such time as the first of the following occurs: (a) the Trust or the General Partner terminates the Delegation Agreement by notice to the other parties to the Delegation Agreement, with termination to become effective 30 days after the receipt of such notice by the last of the parties; (b) the parties mutually agree in writing to terminate the Delegation Agreement; or (c) the Trust is terminated pursuant to the Declaration of Trust.

Expenses

Pursuant to the Delegation Agreement, generally, all costs, charges and expenses reasonably incurred by the General Partner and the Board of Directors in carrying out the General Partner's obligations and duties under the Delegation Agreement in connection with the provision and performance of the services delegated thereunder (including, without limitation, salary, wages, and other forms of compensation paid to employees engaged in rendering the services to be provided thereunder and/or management fees paid to management entities which might be engaged to provide such services) shall be payable by the Trust out of the Trust's assets.

ADMINISTRATION AGREEMENT

The following is a summary which does not purport to be complete of the material provisions of the Administration Agreement and the Declaration of Trust. Reference is made to the Administration Agreement and Declaration of Trust for the full text of their provisions and a complete description, a copy of which has been filed on SEDAR at www.sedar.com.

The Trustee has delegated to AltaGas Ltd. certain powers and duties expressly provided for in the Declaration of Trust and in the Administration Agreement, including the power to further delegate administration of the Trust. Generally, AltaGas Ltd. provides administrative and support services to, and is responsible for the management and general administration of, the affairs of the Trust, and pursuant to the Administration Agreement, among other things: (a) undertakes any matters required to be performed by the Trustee not otherwise delegated and provides all services as may be necessary or as requested by the Trustee for the administration of the Trust; (b) prepares all documents and makes all necessary determinations necessary for the discharge of the Trustee's obligation; (c) retains and monitors organizations serving the Trust; (d) authorizes and pays operation expenses and negotiates contracts with service providers; (e) provides office space and related equipment and services; (f) subject to the direction and approval of the General Partner, (i) deals with banks and other lenders, (ii) prepares and provides financials statements and tax information to unitholders, (iii) computes, determines and makes distributions to unitholders and administers reinvestment and similar plans, (iv) prepares such disclosure documents as are required under applicable securities legislation in respect of offers to acquire or responses thereto and (v) provides all information to which unitholders are entitled; (g) ensures compliance by the Trust with all agreements and applicable securities legislation; (h) submits all tax returns and filings; (i) provides investor relations services to the Trust; (j) ensures the Trust takes appropriate steps to remain a "mutual fund trust"; (k) calling and holding meetings of unitholders; (l) takes all steps necessary to issue securities of the Trust, as directed by the General Partner; (m) attends to all administrative and other matters in connection with redemptions of Trust units; (n) obtaining and maintaining liability insurance for certain directors and officers; (o) undertakes, manages and prosecutes all proceedings in respect of governmental authorities under the direction of the General Partner; (p) prepares any documents to qualify the sale of securities of the Trust, subject to the approval of the General Partner; and (q) promptly notifies the Trust of any event that might have a material adverse effect on the affairs of the Trust.

AltaGas Ltd. provides similar administrative services to the foregoing to each of Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2 pursuant to the Administration Agreement, modified as necessary to take into account the nature of the entity and the terms, conditions and limitations of the Holding Declaration of Trust, the constating documents of the General Partner, AltaGas LP #1 Limited Partnership Agreement and AltaGas LP #2 Limited Partnership Agreement, respectively.

In the conduct of its duties pursuant to the Administration Agreement, AltaGas Ltd. has full right, power and authority to execute and deliver all contracts, leases, licenses and other documents and agreements, to make applications and filings with governmental authorities and take such other actions as it considers appropriate in connection with the business of the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2, respectively.

AltaGas Ltd. must exercise the powers and discharge the duties conferred under the Administration Agreement honestly, in good faith and in the best interests of the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2 and exercise the degree of care, diligence and skill that a reasonably prudent administrator in Canada having responsibilities of a similar nature would exercise in comparable circumstances.

Expenses

Pursuant to the Administration Agreement, AltaGas Ltd. is reimbursed by each of the Trust, Holding Trust, AltaGas LP #1, AltaGas LP #2 and the General Partner, without duplication, for such of the expenses (including, without limitation, salary, wages and other forms of compensation paid to employees engaged in rendering services under the Administration Agreement, and out-of-pocket expenses) incurred by AltaGas Ltd. as are, in the opinion of AltaGas Ltd., acting reasonably, reasonably allocable respectively thereto.

DECLARATION OF TRUST AND DESCRIPTION OF UNITS

The following is a summary which does not purport to be complete of the material attributes and characteristics of the Trust units and special voting units and certain provisions of the Declaration of Trust. Reference is made to the Declaration of Trust for the full text of its provisions and a complete description of the Trust units and special voting units, a copy of which has been filed on SEDAR at www.sedar.com.

TRUST UNITS

An unlimited number of Trust units may be created and issued pursuant to the Declaration of Trust. Each Trust unit entitles the holder thereof to one vote at any meeting of the unitholders or in respect of any written resolution of unitholders and represents an equal undivided beneficial interest in any distribution from the Trust (whether of income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All Trust units shall rank among themselves equally and rateably without discrimination, preference or priority, whatever may be the actual date or terms of issue thereof. Each Trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust units held by such holder. See "Declaration of Trust and Description of Units – Trust Unit Redemption Right".

SPECIAL VOTING UNITS

The Declaration of Trust allows for the creation of special voting units which enables the Trust to provide voting rights to holders of exchangeable securities. A Special Voting Unit was issued pursuant to the Arrangement to enable the holders of Exchangeable units issued by AltaGas LP #1 and AltaGas LP #2 to vote at meetings of unitholders. The Special Voting Unit created and issued pursuant to the Arrangement was issued to the Voting and Exchange Trustee. The holder of a special voting unit, including in respect of the Special Voting Unit, the Voting and Exchange Trustee, is not entitled to any interest or share in the distributions or net assets of the Trust and is only entitled to such number of votes at meetings of unitholders as is equal to the number of Trust units into which the exchangeable securities to which such special voting unit relates are exchangeable or convertible.

Under the terms of the Voting and Exchange Trust Agreement, the Trust has issued the Special Voting Unit to the Voting and Exchange Trustee for the benefit of every person who received Exchangeable units pursuant to the Arrangement. The Voting and Exchange Trustee is obligated to vote the Special Voting Unit at meetings of unitholders pursuant to the instructions of the holders of Exchangeable units. However, if no instructions are provided by the holders of Exchangeable units, the votes associated therewith in the Special Voting Unit will be withheld from voting.

The special voting units will be subject to such other rights and limitations as may be determined by the Trustee at the time of issuance of the special voting unit. The Declaration of Trust provides that upon the exchange of Exchangeable units for Trust units, the entitlement to vote pursuant to the Special Voting Unit will be eliminated in respect of those Exchangeable units.

EXCHANGEABLE UNITS

AltaGas LP #1 is authorized to issue an unlimited number of AltaGas LP #1 B units. Similarly, AltaGas LP #2 is authorized to issue an unlimited number of AltaGas LP #2 B units. AltaGas LP #1 and AltaGas LP #2 issued AltaGas LP #1 B units and AltaGas LP #2 B units, respectively, to eligible AltaGas Services' securityholders in consideration for their common shares in the capital of AltaGas Services pursuant to the Arrangement.

Each Exchangeable unit is exchangeable for a Trust unit on a one-for-one basis at any time at the option of the holder, entitles the holder thereof to receive non-interest bearing loans from AltaGas LP #1 or AltaGas LP 2, as the case may be, in an amount in cash equal to the cash distributions made by the Trust on a Trust unit, entitles the holder thereof to direct the Voting and Exchange Trustee to vote the Special Voting Unit at all meetings of unitholders, entitles the holder thereof to vote separately as a class in respect of proposals to add to, change or remove any right, privilege, restriction or condition attaching to the Exchangeable units or in respect of any other amendment to the applicable limited partnership agreement which will have an adverse impact on the holders of such Exchangeable units, will not be transferable except to eligible transferees, and AltaGas LP #1 or AltaGas LP #2, as the case may be, will be entitled to acquire all of the Exchangeable units in exchange for Trust units in certain specified circumstances, including there being outstanding fewer than 750,000 AltaGas LP #1 B units or 1,000,000 AltaGas LP #2 B units or in the event of certain transactions which may involve a change of control of the Trust.

ISSUANCE OF UNITS

The Declaration of Trust provides that Trust units, including exchangeable securities, rights, warrants, options or other securities convertible into or exchangeable for Trust units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee may determine. The Declaration of Trust also provides that the Trustee may authorize the creation and issuance of any type of debt securities or convertible debt securities of the Trust from time to time on such terms and conditions to such persons and for such consideration as the Trustee may determine.

DISTRIBUTIONS

Pursuant to the Declaration of Trust, the Trust is required to make cash distributions to unitholders each calendar month (or such other periods as may be determined by the Trustee) of all or any part of the Cash Flow of the Trust. Cash received by the Trust from its subsidiaries will be managed by the General Partner, giving consideration to the consolidated net income of the Trust, the consolidated growth and maintenance capital requirements of the Trust, the consolidated debt repayment requirements of the Trust and other factors. The intent of the General Partner is to maximize the cash received by the Trust from its subsidiaries giving consideration to these various factors.

Distributions in respect of a month will be paid to unitholders of record as at the close of business on each determined distribution record date. The distribution for any month will be paid on the determined distribution payment date. In addition, the Declaration of Trust provides that, if necessary, on December 31st of each year, the Trust will distribute an additional amount such that the Trust will not be liable for ordinary income taxes for such year.

PURCHASE OF UNITS

The Trust may from time to time purchase for cancellation some or all of the Trust units (or other securities of the Trust which may be issued and outstanding from time to time) in the market, by private agreement or upon any recognized stock exchange on which such Trust units are traded or pursuant to tenders received by the Trust upon request for tenders addressed to all holders of record of Trust units, provided in each case that the Trustee has determined that such purchases are in the best interests of the Trust. Any such purchases may constitute an "issuer bid" under Canadian provincial securities legislation and must be conducted in accordance with the applicable requirements thereof. A unitholder will not have the right at any time to require the Trust to purchase such unitholder's Trust units.

TRUST UNIT REDEMPTION RIGHT

Trust units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of a duly completed and properly executed notice requesting the Trust to redeem Trust units. Upon receipt of the notice to redeem Trust units by the Trust, the holder thereof shall thereafter cease to have any rights with respect to the Trust units tendered for redemption (other than to receive the redemption payment therefor unless the redemption payment is not made as required) including the right to receive any distributions thereon which are declared payable on a date subsequent to the day of receipt by the Trust of the notice requesting redemption.

Cash Redemption

Upon receipt by the Trust of the notice to redeem Trust units, the tendering unitholder will thereafter be entitled to receive the Market Redemption Price, which is equal to the lesser of: (a) 90 percent of the Market Price per Trust unit on the principal stock exchange on which the Trust units are listed (or, if the Trust units are not listed on any such exchange, on the principal market on which the Trust units are quoted for trading) during the period of the last 10 trading days immediately prior to the date on which the Trust units were tendered for redemption; and (b) 100 percent of the Closing Market Price on the principal stock exchange on which the Trust units are listed (or, if the Trust units are not listed on any such exchange, on the principal market on which the Trust units are quoted for trading) on the date that the Trust units were tendered for redemption.

The aggregate Market Redemption Price payable by the Trust in respect of the Trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment within five business days after the end of the calendar month in which the Trust units were tendered for redemption.

Trust unitholders will not receive cash upon the redemption of their Trust units if:

(a) The total amount payable by the Trust in respect of such Trust units and all other Trust units tendered for redemption in the same calendar month exceeds $50,000; provided that the Trustee may, in its sole discretion, waive such limitation in respect of all Trust units tendered for redemption in any calendar month. If this limitation is not so waived, the Trust units tendered for redemption in such calendar month shall be redeemed for cash based on the Market Redemption Price and, unless any applicable regulatory approvals are required, by a distribution in specie of the Trust's assets, based on the in specie Redemption Price (as defined below), which may include Series 3 Notes issued by Holding Trust (Series 3 Notes) or other assets held by the Trust, on a pro rata basis. See "Holding Trust – Holding Trust Notes";

(b) At the time such Trust units are tendered for redemption, the outstanding Trust units are not listed for trading on the TSX or traded or quoted on any stock exchange or market which the Trustee considers, in its sole opinion, provides representative fair market value prices for the Trust units;

(c) The normal trading of the Trust units is suspended or halted on any stock exchange on which the Trust units are listed for trading or, if not so listed, on any market on which the Trust units are quoted for trading, on the date that such Trust units tendered for redemption were tendered to the Trust for redemption or for more than five trading days during the 10-day trading period prior to the date on which such Trust units were tendered for redemption; or

(d) The redemption of Trust units will result in the delisting of the Trust units on the principal stock exchange on which the Trust units are listed.

In Specie Redemption

If a cash redemption is not available for Trust units tendered for redemption by a unitholder, then such unitholder will, instead of the Market Redemption Price per Trust unit, be entitled to receive a price per Trust unit (the in specie Redemption Price) equal to the fair market value of a Trust unit as determined by the Trustee in its sole discretion. The in specie Redemption Price will, subject to all necessary regulatory approvals, be paid and satisfied by way of a distribution in specie of Trust assets, which may include Series 3 Notes or other assets held by the Trust (other than Holding Trust units), as determined in the sole discretion of the Trustee.

The aggregate in specie Market Redemption Price payable by the Trust in respect of the Trust units surrendered for redemption during any calendar month shall be paid by the transfer, to or to the order of the Trust unitholder who exercised the right of redemption within five business days after the end of the calendar month in which the Trust units were tendered for redemption, of Trust assets.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust units to dispose of their Trust units. Series 3 Notes which may be distributed in specie to Trust unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Series 3 Notes. Series 3 Notes will not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

MEETINGS OF UNITHOLDERS

The Declaration of Trust provides that meetings of unitholders must be called and held for, among other matters, the election of the Board of Directors, the appointment or removal of the auditors of the Trust, the approval of amendments to the Declaration of Trust (except as described under "Declaration of Trust and Description of Units - Amendments to the Declaration of Trust"), the sale of all or substantially all of the Trust's assets, the dissolution or termination of the Trust and the appointment or removal of the Holding Trust Trustee. Meetings of unitholders will be called and held annually for, among other things, the election of the Board of Directors and the appointment of the auditors of the Trust.

A meeting of unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 5 percent of all votes entitled to be voted at a meeting of unitholders (including the votes attached to Exchangeable units by virtue of the Special Voting Unit) by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Subject to the Voting and Exchange Trust Agreement, only unitholders of record may attend and vote at all meetings of unitholders either in person or by proxy and a proxyholder need not be a unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5 percent of the votes attaching to all outstanding Trust units and the Special Voting Unit shall constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the Special Voting Unit shall be regarded as representing outstanding Trust units equivalent in number to the number of Exchangeable units represented by proxy by the Voting and Exchange Trustee at such meeting.

The Declaration of Trust contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of unitholders in accordance with the requirements of applicable laws.

LIMITATION ON NON-RESIDENT OWNERSHIP

In order to ensure that the Trust qualifies as a "mutual fund trust" under the Tax Act, the Declaration of Trust provides, in part, that:

(a) The General Partner shall: (i) prior to the consummation of any transaction involving the acquisition by the Trust of any properties or assets other than securities of the General Partner or Holding Trust; (ii) prior to any material modification to the Trust other than as contemplated by (i); (iii) promptly following any proposed amendment to paragraph 132(7)(a) of the Tax Act or the publication of any administrative bulletin or other notice of interpretation relating to the interpretation or application of such section; or (iv) otherwise at any time when requested by the Trustee, obtain an opinion of counsel confirming whether the Trust is, at the date thereof and following such transaction or event (which in the case of (iii) shall mean the coming into effect of the amendment or change of interpretation), entitled to rely on paragraph 132(7)(a) of the Tax Act (or any successor provision thereto) for purposes of qualifying as a "mutual fund trust" under the Tax Act;

(b) If at any time the Board of Directors determines, in its sole discretion, or becomes aware, pursuant to (a) above or otherwise, that the Trust's ability to continue to rely on paragraph 132(7)(a) of the Tax Act (or any successor provision thereto) for purposes of qualifying as a "mutual fund trust" thereunder is in jeopardy, then forthwith after such determination:

    (i) The Trust shall not be maintained primarily for the benefit of non-residents and it shall be the sole responsibility of the General Partner to monitor the holdings by non-residents; and

    (ii) The General Partner shall take such steps as are necessary or desirable to ensure that the Trust is not maintained primarily for the benefit of non-residents;

(c) The General Partner may, at any time and from time to time, in its sole discretion, request that the Trustee make reasonable efforts, as practicable in the circumstances, to obtain declarations as to beneficial ownership of Trust units, perform residency searches of Trust unitholders and holders of Exchangeable units and beneficial Trust unitholders and holders of Exchangeable units mailing address lists and take such other steps specified by the General Partner, at the cost of the Trust, to determine or estimate as best possible the residence of the beneficial owners of Trust units; and

(d) If at any time the Board of Directors, in its sole discretion, determines that it is in the best interest of the Trust, the General Partner, notwithstanding the ability of the Trust to continue to rely on subsection 132(7)(a) of the Tax Act for the purpose of qualifying as a "mutual fund trust" under the Tax Act or otherwise, may:

(i) Require the Trustee to refuse to accept a subscription for Trust units from, or issue or register a transfer of Trust units to, a person unless the person provides a declaration to the Trust that the Trust units to be issued or transferred to such person will not when issued or transferred be beneficially owned by a non-resident;

(ii) To the extent practicable in the circumstances, send a notice to registered holders of Trust units which are beneficially owned by non-residents, chosen in inverse order to the order of acquisition or registration of such Trust units beneficially owned by non-residents or in such other manner as the General Partner may consider equitable and practicable, requiring them to sell their Trust units which are beneficially owned by non-residents or a specified portion thereof within a specified period of not less than 60 days. If the Trust unitholders receiving such notice have not sold the specified number of such Trust units or provided the General Partner with satisfactory evidence that such Trust units are not beneficially owned by non-residents within such period, the General Partner may, on behalf of such registered Trust unitholders, sell such Trust units and, in the interim, suspend the voting and distribution rights attached to such Trust units and make any distribution in respect of such Trust units by depositing such amount in a separate bank account in a Canadian chartered bank (net of any applicable taxes). Any sale shall be made on any stock exchange on which the Trust units are then listed and, upon such sale, the affected holders shall cease to be holders of Trust units so deposited of and their rights shall be limited to receiving the net proceeds of sale, and any distribution in respect thereof deposited as aforesaid, net of applicable taxes and costs of sale, upon surrender of the Trust Certificates representing such Trust units;

(iii) Delist the Trust units from non-Canadian stock exchanges; and/or

(iv) Take such other actions as the Board of Directors determines, in its sole discretion, are appropriate in the circumstances that will reduce or limit the number of Trust units held by non-resident Trust unitholders to ensure that the Trust is not maintained primarily for the benefit of non-residents.

AMENDMENTS TO THE DECLARATION OF TRUST

The Trustee may, without the consent, approval or ratification of any of the unitholders, amend the Declaration of Trust at any time:

(a) For the purpose of ensuring the Trust's continuing compliance with applicable laws, regulations or policies of any governmental authority having jurisdiction over the Trustee or the Trust;

(b) In a manner which, in the opinion of the Trustee, provide additional protection for the unitholders;

(c) In a manner which, in the opinion of the Trustee, is necessary or desirable as a result of changes in Canadian tax laws;

(d) To remove any conflicts or inconsistencies in the Declaration of Trust or to make minor corrections which are, in the opinion of the Trustee, necessary or desirable and not prejudicial to the unitholders; or

(e) To change the situs of, or the laws governing, the Trust which, in the opinion of the Trustee is desirable in order to provide unitholders with the benefit of any legislation limiting their liability.

TERM OF THE TRUST

The unitholders may vote by special resolution to terminate the Trust at any meeting of the unitholders duly called for that purpose, following which the Trustee shall commence to wind-up the affairs of the Trust (and shall thereafter be restricted to only such activities).

Unless the Trust is earlier terminated or extended by vote of the unitholders, the Trustee shall commence to wind up the affairs of the Trust on such date as may be determined by the Trustee, being not more than two years prior to the earlier of March 24, 2104 and the date which is one day prior to the date, if any, the Trust would otherwise be void by virtue of any applicable rule against perpetuities then in force in Alberta. In the event that the Trust is wound up, the Trustee will sell and convert into money the assets of the Trust in one transaction or in a series of transactions at public or private sales and do all other acts appropriate to liquidate the property of the Trust, and shall in all respects act in accordance with the directions, if any, of the unitholders (in respect of termination authorized pursuant to a special resolution). After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall, subject to obtaining all necessary regulatory approvals, distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of Trust's assets pro rata among the unitholders.

TAKE-OVER BIDS

The Declaration of Trust contains provisions to the effect that if a take-over bid, as defined under the *Securities Act* (Alberta), is made for the Trust units and not less than 90 percent of the Trust units (including Trust units issuable upon the conversion, exercise or exchange of any securities exchangeable into Trust units but not including any Trust units held at the date of the take-over bid by or on behalf of, or issuable to, the offeror or an affiliate or associate of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust units and exchangeable securities held by unitholders who did not accept the take-over bid on the terms offered by the offeror.

HOLDING TRUST

The Holding Declaration of Trust contains provisions substantially similar to those of the Declaration of Trust relating to the Trust, however reference is made to the Holding Declaration of Trust and the Declaration of Trust for the full text of their respective provisions copies of which have been filed on SEDAR at www.sedar.com.

GENERAL

Holding Trust is an unincorporated investment trust established under the laws of Alberta pursuant to the Holding Declaration of Trust. Its activities are restricted but include specifically, among other things: acquiring, investing in, holding, transferring, disposing of and otherwise dealing with securities of whatever nature or kind of, or issued by, AltaGas LP #1, AltaGas LP #2, AltaGas Ltd. or any associate or affiliate of any thereof, or of, or issued by, any other corporation, partnership, trust or other person involved, directly or indirectly, in the business of, or the ownership, lease or operation of assets or property in connection with, gathering, processing, extracting, transporting, buying, storing or selling of petroleum, natural gas, natural gas liquids, and other related products, power or other forms of energy, and related businesses, and such other investments as the Holding Trust Trustee may determine, and borrowing funds and issuing debt securities for such purposes and entering into hedging arrangements in relation thereto; and engaging in all activities ancillary or incidental to any of the foregoing activities and undertaking such other activities or taking such actions including investing in securities as shall be approved by the Holding Trust Trustee from time to time.

As at the date of this Annual Information Form, Holding Trust does not intend to hold securities of any entities other than AltaGas LP #1.

REDEMPTION RIGHT

The right of redemption conferred upon a holder of trust units of Holding Trust by the Holding Declaration of Trust may only be exercised after the holder of trust units of Holding Trust has received written notice from the Holding Trust Trustee that it may exercise that right, such that holders of Holding Trust trust units will not be entitled to redeem their Holding Trust trust units on demand.

CASH DISTRIBUTIONS

Holding Trust makes monthly cash distributions to the Trust of its net monthly cash flow, after satisfaction of its interest obligations on the Holding Trust Notes, if any, and less any estimated cash amounts required for expenses, costs and other obligations of Holding Trust. Such distributions are paid on the day which is the same as the Trust's distribution payment date to enable the Trust to pay its distributions.

If the Holding Trust Trustee determines that Holding Trust does not have cash in an amount sufficient to make payment of the full amount of any distribution, the payment may include the issuance of additional Holding Trust trust units or Holding Trust Notes having a value equal to the difference between the amount of such distribution and the amount of cash which has been determined by the Holding Trust Trustee to be available for the payment of such distribution. The value of each Holding Trust trust unit so issued will be the redemption price thereof and the value of each Holding Trust Note so issued will be the redemption amount thereof as determined pursuant to the Holding Trust Note Indenture.

Any Holding Trust trust units transferred to unitholders pursuant to a distribution in specie may be subject to resale and transfer restrictions and cannot be resold or transferred except as permitted by applicable securities law.

LIMITATION ON NON-RESIDENT OWNERSHIP

Notwithstanding any other provision of the Holding Declaration of Trust, no Holding Trust trust unit may be issued to, held by or transferred to a non-resident.

RESTRICTIONS ON TRANSFER OF HOLDING TRUST UNITS

Notwithstanding any other provision of the Holding Declaration of Trust, no transfer of any Holding Trust trust unit will be made without the consent of the Holding Trust Trustee, which consent may be withheld by the Holding Trust Trustee for any reason.

HOLDING TRUST NOTES

The following is a summary which does not purport to be complete of the material attributes and characteristics of the Holding Trust Notes and certain provisions of the Holding Trust Note Indenture. Reference is made to the Holding Trust Note Indenture for the full text of its provisions and a complete description of the Holding Trust Notes, a copy of which has been filed on SEDAR at www.sedar.com.

The Holding Trust Note Indenture authorizes the creation and issuance of three series of Holding Trust Notes in Canadian Currency: Series 1 Notes; Series 2 Notes; and Series 3 Notes. Each series of Holding Trust Notes consists of an unlimited aggregate principal amount, is issuable in denominations of $10 and integral multiples of $10, represents an unsecured debt obligation of Holding Trust and is redeemable pursuant to the provisions of the Holding Trust Note Indenture. The specific characteristics unique to each series of Holding Trust Note are as set forth in the Holding Trust Note Indenture.

Payment Upon Maturity

On maturity, Holding Trust will repay the Holding Trust Notes by paying to the Note Trustee under the Holding Trust Note Indenture in cash an amount equal to the principal amount of the outstanding Holding Trust Notes which have then matured, together with accrued and unpaid interest thereon.

Redemption

The Holding Trust Notes are redeemable at the option of Holding Trust prior to maturity.

Subordination/Security

The Holding Trust Notes rank *pari passu* with one another. However the payment of the principal amount and interest on any of the Holding Trust Notes is expressly subordinated in right of payment to the prior payment in full of all senior indebtedness, being all indebtedness, liabilities and obligations of Holding Trust which, by the terms of the instrument creating or evidencing the same, is not expressed to rank in right of payment in subordination to or *pari passu* with the indebtedness evidenced by the Holding Trust Note Indenture. In addition, any liens held by the Note Trustee or holders of Holding Trust Notes, as well as the rights, remedies and recourses granted to the Note Trustee or holders of Holding Trust Notes, are completely subordinated to any and all liens held at present or in the future by the holders of senior indebtedness notwithstanding any ranking that might otherwise be established by law.

The Holding Trust Note Indenture provides that upon any distribution of the assets of Holding Trust in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to Holding Trust, or in the event of any proceedings for voluntary liquidation or termination or other winding-up of Holding Trust, the holders of all such senior indebtedness will be entitled to receive payment in full (of principal, premium or penalty, if any, and interest) before the holders of the Holding Trust Notes are entitled to receive any payment.

Default

The Holding Trust Note Indenture provides that any of the following shall constitute an event of default:

(a) If default is made in the payment of any principal due on any of the Holding Trust Notes of any series when the same becomes due under any provision of the Holding Trust Note Indenture or of the Holding Trust Notes as required under Holding Trust Note Indenture and such default shall have continued for a period of 10 business days; or

(b) If default is made in the payment of any interest due on any of the Holding Trust Notes and such default shall have continued for a period of 15 business days; or

(c) If default is made in the performance or breach by Holding Trust of any other covenant or agreement under the provisions of the Holding Trust Notes or the Holding Trust Note Indenture which shall continue for 30 days after written notice specifying such default and requiring such default to be remedied shall have been given to Holding Trust by the Note Trustee; or

(d) If there occurs with respect to any issue or issues of indebtedness of Holding Trust having an outstanding principal amount of $100 million or more an event of default that has caused the holder thereof to declare such indebtedness to be due and payable prior to its maturity and such indebtedness has not been discharged in full or such acceleration has not been rescinded or annulled within 30 days of such acceleration; or

(e) If a proceeding or action shall be commenced against Holding Trust, except in certain circumstances, in any court of competent jurisdiction, seeking (i) its reorganization, liquidation, termination or winding-up, or the composition or readjustment of its debts, (ii) the appointment of a receiver, custodian, liquidator or the like of Holding Trust or all or any substantial part of its property, or (iii) similar relief in respect of Holding Trust under any law relating to bankruptcy, insolvency, reorganization, winding up or composition or adjustment of debts, and such proceeding or action shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of 60 or more days, or an order for relief against Holding Trust shall be entered in an involuntary case under the Bankruptcy Act; or

(f) If Holding Trust shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, examiner, liquidator or the like of itself or of all or any substantial part of its property, (ii) make a general assignment for the benefit of its creditors, (iii) commence a voluntary case under the Bankruptcy Act or any other similar foreign statute, (iv) institute any proceeding or file a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, liquidation, termination, winding up or composition or readjustment of debts, (v) fail to contest in a timely and appropriate manner, or acquiesce in writing to, any petition filed against it in an involuntary case under the Bankruptcy Act or any other similar foreign statute, or (vi) take any action for the purpose of effecting any of the foregoing; or

(g) If a creditor shall have taken possession of all or substantially all of the assets of Holding Trust.

Holding Trust Unit Certificates

As Holding Trust trust units are not intended to be issued or held by any person other than the Trust, registration of interests in, and transfers of, the Holding Trust trust units will not be made through the book entry system administered by the Canadian Depository for Securities Limited. Rather, holders of Holding Trust trust units will be entitled to receive certificates therefore.

MEETINGS OF HOLDING TRUST UNITHOLDERS

An annual meeting of holders of Holding Trust trust units shall be called on a day on or before June 30 in each year, at such time and place as shall be prescribed for the purpose of presenting the audited financial statements of Holding Trust, appointing the auditors of Holding Trust for the ensuing year and transacting such other business as the Holding Trust Trustee may determine or as may properly be brought before the meeting. Notwithstanding the foregoing, a resolution in writing executed by holders of Holding Trust trust units holding more than 66 2/3 percent of the votes attached to Holding Trust trust units at any time will be valid and binding for all purposes.

 SEC File # 82-34911

Pursuant to the Delegation Agreement, the General Partner is delegated certain of the Trustee's powers and duties in respect of the business and affairs of the Trust and pursuant to the Unanimous Shareholder Agreement the General Partner is entitled to exercise the powers of the directors of AltaGas Ltd. and any other entities as determined to manage, or supervise the management of, the business and affairs of AltaGas Ltd. See "Management of the Trust – Delegation Agreement" and "Declaration of Trust and Description of Units – Meetings of Unitholders".

The General Partner is the general partner of AltaGas LP #1, AltaGas LP #2, AltaGas Limited Partnership, PremStar Energy Canada Limited Partnership and ECNG Energy LP. The General Partner is also a party to the Administration Agreement pursuant to which AltaGas Ltd. provides certain administrative services to the General Partner. See "Management of the Trust – Administration Agreement".

DIRECTORS AND OFFICERS

The number of directors of the General Partner is to be determined from time to time by resolution of the Board of Directors. The number of directors currently comprises nine, of which eight are independent directors.

The term of office of any director continues until the annual meeting of shareholders of the General Partner next following the director's election or appointment or (if an election or appointment of a director is not held at such meeting or if such meeting does not occur) until the date on which the director's successor is elected or appointed, or earlier if the director dies or resigns or is removed or disqualified, or until the director's term of office is terminated for any other reason in accordance with the constating documents of the General Partner. Pursuant to the Declaration of Trust, the unitholders will annually be entitled to direct the Trustee as to the persons to be elected to the Board of Directors.

The names, municipalities of residence, positions with the General Partner, principal occupations within the last five years of the current directors and officers of the General Partner and respective holdings of Trust units and Trust options are set out below.

Name of Director, Municipality of Residence and Position with the General Partner	Principal Occupation During the Past Five Years	Director Since	Securities Beneficially Owned or Controlled[(1)]
David W. Cornhill [(3)(9)] Calgary, Alberta, Canada Chairman and Chief Executive Officer	Mr. Cornhill is a founding member of AltaGas Services Inc., predecessor to the Trust. He has served as Chairman and Chief Executive Officer since AltaGas Services Inc.'s inception on April 1, 1994 and was appointed as a Director of the General Partner on May 1, 2004. Prior to forming AltaGas Services Inc., Mr. Cornhill served in the capacities of Vice President Finance and Administration, and Treasurer of Alberta and Southern Co. Ltd. from 1991 to 1993 and as President and Chief Executive Officer until March 31, 1994.	May 1, 2004 Director of AltaGas Services from March 28, 1994 to April 30, 2004	1,128,479 Trust units 325,000 Trust options
Allan L. Edgeworth [(2)(3)(4)] Calgary, Alberta, Canada Director	Mr. Edgeworth has been the President of ALE Energy Inc., a private consulting company, since January 2005 and is a Commission Member of the Alberta Securities Commission. Mr. Edgeworth was the President and Chief Executive Officer of Alliance Pipeline Ltd. from 2001 until December 2004. Mr. Edgeworth joined Alliance Pipeline Ltd. in 1998 as Executive Vice President and Chief Operating Officer.	March 2, 2005	5,695 Trust units 60,000 Trust options
Hugh A. Fergusson[(2)(3)(4)] Calgary, Alberta, Canada Director	Mr. Fergusson is an independent businessman. Mr. Fergusson is currently President of Argyle Resources Inc., a private petrochemical and energy consulting organization. He retired in 2004 as Vice President Hydrocarbons and Energy after over 25 years of service with The Dow Chemical Company, an international chemicals company listed on numerous stock exchanges.	May 7, 2008	7,310 Trust units 45,000 Trust options

Name of Director, Municipality of Residence and Position with the General Partner	Principal Occupation During the Past Five Years	Director Since	Securities Beneficially Owned or Controlled[1]
Denis C. Fonteyne[2][3][5] Calgary, Alberta, Canada Director	Mr. Fonteyne is the President of Dendon Resources Ltd., a private consulting company, has been a natural gas industry consultant since 1997 and brings over 40 years of industry experience to the board of directors. Mr. Fonteyne has held a number of senior executive positions in the oil and gas industry, including eight years with CanStates Gas Marketing Ltd. prior to his retirement as Executive Vice-President in 1996.	May 1, 2004 Director of AltaGas Services from September 1, 1998 to April 30, 2004	38,200 Trust units 40,000 Trust options
Daryl H. Gilbert [2][4][5][8] Calgary, Alberta, Canada Director	Mr. Gilbert joined JOG Capital Inc. in May 2008 as a Managing Director and Investment Committee Member. Prior thereto, Mr. Gilbert was an Independent businessman since January 2005. Prior to that, Mr. Gilbert was President and Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., an engineering consulting firm.	May 1, 2004 Director of AltaGas Services from May 4, 2000 to April 30, 2004	900 Trust units 40,000 Trust options
Robert B. Hodgins [2][4][6] Calgary, Alberta, Canada Director	Mr. Hodgins has been an Independent businessman since November 2004. Prior to that, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Corporation from 2002 to 2004. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited 1998 to 2002 and was Chief Financial Officer of TransCanada Pipelines Limited from 1993 to 1998.	March 2, 2005	2,000 Trust units 60,000 Trust options
Myron F. Kanik [2][5][6][7] Calgary, Alberta, Canada Director	Mr. Kanik has been the President of Kanik and Associates Ltd., an energy industry consulting company, since 1999. Mr. Kanik was President of the Canadian Energy Pipeline Association from 1993 to 1999, and prior thereto was with the Alberta Department of Energy where he served in various capacities, including Deputy Minister.	May 1, 2004 Director of AltaGas Services from June 1, 2001 to April 30, 2004	43,960 Trust units 40,000 Trust options
David F. Mackie [2][5][6] Houston, Texas, United States Director	Mr. Mackie is a U.S.-based natural gas industry consultant and venture capital investor. Mr. Mackie brings a broad range of experience to the board of directors, having spent more than 32 years in various executive capacities, primarily with El Paso Natural Gas Co. and Transco Energy Co. Mr. Mackie also has extensive consulting experience with many senior energy companies, including the Maritimes and Northeast Pipeline Project.	May 1, 2004 Director of AltaGas Services from January 12, 1995 to April 30, 2004	1,265,091 Trust units 40,000 Trust options
M. Neil McCrank, Q.C., P.Eng. [2][3][6] Calgary, Alberta, Canada Director	Mr. McCrank is Counsel to the Calgary office of Borden Ladner Gervais LLP. Mr. McCrank was Chairman of the Alberta Energy and Utilities Board from July 1998 until his retirement on March 31, 2007. Prior thereto, Mr. McCrank was with the Alberta Department of Justice, serving in various capacities, including Deputy Minister of Justice from 1989 to 1998. He currently serves as Chairman of the Canadian Energy Research Institute of Canada and Chairman of the Canadian Association of the World Petroleum Council, and is a consultant to all provincial and territorial governments in Canada with respect to justice issues.	December 10, 2007	7,000 Trust units 45,000 Trust options

Notes:

(1) References to Trust units in this column includes both Trust units and Exchangeable units beneficially owned, directly or indirectly, or over which control or direction is exercised by each director and officer as at February 26, 2010.
(2) Independent director.
(3) Member of the Environment, Occupational Health and Safety Committee.

(4) Member of the Audit Committee.
(5) Member of the Human Resources and Compensation Committee.
(6) Member of the Governance Committee.
(7) Lead director.
(8) Mr. Daryl H. Gilbert, a director of the General Partner, has been a director of Globel Direct, inc. ("Globel") since December, 1998. Globel was the subject of cease trade orders issued by the Alberta Securities Commission ("ASC") on November 22, 2002 and the British Columbia Securities Commission ("BCSC") on November 20, 2002 for failure to file certain financial statements. Globel filed such financial statements and the cease trade orders were removed on December 20, 2002 and December 23, 2002, respectively. On June 12, 2007, Globel was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the *Companies' Creditors Arrangement Act*, which protection expired on December 7, 2007, following which the monitor was discharged on December 12, 2007 and a receiver/manager was appointed. Subject to the completion of matters relating to the wind-up of the administration of the receivership, the receiver was discharged on September 3, 2008. Globel has ceased operations, and as a result became the subject of cease trade orders issued by the ASC on September 24, 2008 and the BCSC on September 30, 2008 for failure to file certain disclosure documents.
(9) Mr. Cornhill is not considered to be an independent director as he is an executive officer of the General Partner.

Name of Officer, Municipality of Residence and Position with the General Partner	**Principal Occupation During the Past Five Years**	**Officer Since**	**Securities Beneficially Owned or Controlled[(1)]**
David W. Cornhill Calgary, Alberta, Canada Chairman and Chief Executive Officer	Chairman and Chief Executive Officer 2004. Chairman and Chief Executive Officer of AltaGas Services from 1994 to 2004.	March 26, 2004	1,128,479 Trust units 325,000 Trust options
Richard M. Alexander Calgary, Alberta, Canada President and Chief Operating Officer	President and Chief Operating Officer from January 2008. Executive Vice President Chief Operating Officer and Chief Financial Officer January 2007 to January 2008. Senior Vice President Finance and Chief Financial Officer from May 2006 to January 2007. Vice President Finance and Chief Financial Officer Niko Resources Ltd. October 2003 to April 2006. Vice President Investor Relations and Communications of Husky Energy Inc. from July 2001 to September 2003. Treasurer Husky Energy Inc. August 2000 to July 2001.	May 1, 2006	82,665 Trust units 225,000 Trust options
Dennis A. Dawson Calgary, Alberta, Canada Vice President, General Counsel and Corporate Secretary	Since 2005, Vice President General Counsel and Corporate Secretary. Vice President General Counsel and Corporate Secretary of AltaGas Ltd. from May 1, 2004. Vice President General Counsel and Corporate Secretary of AltaGas Services since 1998.	March 16, 2005	95,561 Trust units 45,000 Trust options
Deborah S. Stein Calgary, Alberta, Canada Vice President Finance and Chief Financial Officer	Vice President Finance and Chief Financial Officer from January 2008. Vice President Finance from January 2007 to January 2008. Vice President Controller from October 2005 to January 2007. Vice President Corporate Risk from January to October 2005. Manager Investor Relations TransCanada Pipelines Limited from 2001 to 2005.	January 21, 2008	11,907 Trust units 55,000 Trust options
David R. Wright Executive Vice President Strategy and Corporate Development	Executive Vice President Strategy and Corporate Development from January 2008. Executive Vice President from January 2007 to January 2008. Executive consultant 2005 to January 2007. Executive Vice President General Counsel and Corporate Secretary EPCOR Utilities Inc. from 2001 to 2005. Prior thereto Partner with Borden Ladner Gervais LLP and Howard Mackie.	January 16, 2007	26,697 Trust units 92,500 Trust options

Note:

(1) References to Trust units in this column includes both Trust units and Exchangeable units beneficially owned, directly or indirectly, or over which control or direction is exercised by each director and officer as at February 26, 2010.

As at February 26, 2010 the directors and executive officers of the General Partner and AltaGas Ltd., as a group, owned beneficially, directly or indirectly, or exercised control or direction over 2,715,465 of the outstanding Trust units and Exchangeable units, or approximately 3.36% percent of the outstanding Trust units and Exchangeable units. As at

February 26, 2010 certain of the directors and officers also had been granted Trust options to acquire an aggregate of 1,112,500 Trust units.

Audit Committee Mandate

See attached Schedule A for the Audit Committee Mandate.

Composition of the Audit Committee

The Committee is currently comprised of Allan L. Edgeworth, Daryl H. Gilbert, Hugh A. Fergusson and Robert B. Hodgins. Robert B. Hodgins is the chair of the Committee. All of the members of the Committee are independent and financially literate as defined under Canadian securities law.

Relevant Education and Experience

Allan L. Edgeworth has been the President of ALE Energy Inc. since January 2005. Mr. Edgeworth was the President and Chief Executive Officer of Alliance Pipeline from 2001 until December 2004. Mr. Edgeworth joined Alliance Pipeline in 1998 as Executive Vice President and Chief Operating Officer. Prior to that, Mr. Edgeworth spent almost 20 years with Westcoast Energy where he held various positions including Vice President of Pipeline Operations and Senior Vice President of Regulatory Affairs.

Hugh A. Fergusson has been President of Argyle Resources Inc., a private energy consulting organization, since 2004. Mr. Fergusson was employed for over 25 years with Dow Chemical Company, an international chemicals company. Prior to his retirement from Dow Chemical Company in 2004, Mr. Fergusson was Vice President, Hydrocarbons and Energy.

Daryl H. Gilbert has been an independent businessman since January 2005. Prior to 2005, Mr. Gilbert had a 26-year career with Gilbert Laustsen Jung Associates Ltd., a reservoir engineering company, most recently as President and Chief Executive Officer for 11 years.

Robert B. Hodgins has been an independent businessman since November 2004. Prior to that, Mr. Hodgins was Chief Financial Officer at Pengrowth Energy Trust from 2002 to 2004. Mr. Hodgins was Vice President and Treasurer at Canadian Pacific Limited from 1998 to 2002 and Chief Financial Officer of TransCanada PipeLines Limited from 1993 to 1998. Mr. Hodgins has an Honours Degree in Business from the Richard Ivey School of Business at the University of Western Ontario and is a Chartered Accountant in Ontario and Alberta.

Pre-Approval Policies and Procedures

As set forth in the Committee's charter, the Committee must pre-approve all non-audit services provided by the external auditor and has direct responsibility for overseeing the work of the external auditor.

External Auditor Service Fees by Category

The fees billed by Ernst & Young LLP (E&Y), the Trust's external auditors, for 2008 and 2009 were as follows:

Category of External Auditor Service Fee	2009	2008
Audit Fees	$1,075,936	$721,392
Audit-Related Fees(1)	$-	$52,907
Tax Fees(2)	$11,708	$-
All Other Fees(3)	$287,670	$369,539
TOTAL	$1,375,313	$1,143,838

Notes:

(1) Represent the aggregate fees billed by E&Y for assurance and related services that were reasonably related to the performance of the audit or review of the Trust's financial statements and were not reported under "Audit Fees". The nature of the services was for accounting advice.

(2) Represent the aggregate fees billed by E&Y for professional services for tax compliance, tax advice and tax planning. The nature of the services was tax services and tax planning.

(3) Represent the aggregate fees billed by E&Y for products and services, other than those reported with respect to the other categories of service fees. The nature of the services was for translation services and non-audit/tax related fees.

UNANIMOUS SHAREHOLDER AGREEMENT

Pursuant to the Unanimous Shareholder Agreement, the General Partner was granted the powers of the directors of AltaGas Ltd. to manage, or supervise the management of, the business and affairs of AltaGas Ltd., including without limitation in respect of the following matters:

(a) The appointment of the board of directors of AltaGas Ltd., as determined by the Board of Directors in its sole discretion; and

(b) The appointment, mandates and compensation of the executive officers of AltaGas Ltd.

ALTAGAS LTD.

AltaGas Ltd. is the resultant corporation from the amalgamation of ASI, certain of its subsidiaries and an electing shareholder pursuant to the Arrangement. As a result, AltaGas Ltd. owns, directly or indirectly, all of the assets that ASI owned, directly or indirectly, prior to conversion of the business of ASI to the Trust. AltaGas Ltd. retained certain of the liabilities of ASI, including liabilities relating to corporate and income tax matters.

In accordance with the Administration Agreement, AltaGas Ltd. provides all the management, administrative and operating services to the Trust. At December 31, 2009 AltaGas Ltd. and its subsidiaries employed a total of 859 individuals.

DIRECTORS AND OFFICERS

The names, municipality of residence and position of each of the current executive officers of AltaGas Ltd. are as follows:

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
David W. Cornhill Calgary, Alberta, Canada Chairman and Chief Executive Officer and Director	Chairman and Chief Executive Officer from 2004. Chairman and Chief Executive Officer of AltaGas Services from 1994 to 2004.
Richard M. Alexander Calgary, Alberta, Canada President and Chief Operating Officer and Director	President and Chief Operating Officer from January 2008. Executive Vice President Chief Operating Officer and Chief Financial Officer from January 2007 to January 2008. Senior Vice President Finance and Chief Financial Officer from May 2006 to January 2007. Vice President Finance and Chief Financial Officer Niko Resources Ltd. October 2003 to April 2006. Vice President Investor Relations and Communications of Husky Energy Inc. from July 2001 to September 2003. Treasurer Husky Energy Inc. August 2000 to July 2001.
Gregory A. Aarssen Chatham, Ontario, Canada Vice President Corporate Affairs	Vice President Corporate Affairs from January 2008. Divisional Vice President Energy Management from January 2007 to January 2008. Vice President Retail Services PremStar October 2004 to January 2007. Vice President PremStar Energy Canada Ltd. January 1998 to October 2004.
Nancy A. Anderson Calgary, Alberta, Canada Vice President Renewable Energy Wind	Vice President Renewable Energy Wind from December 2008. Vice President Business Development since June 2005. Divisional Vice President Power Services from 2002 to 2005. Senior Vice President El Paso Merchant Energy Canada from 1999 to 2001.
Jeremy R. Baines Calgary, Alberta, Canada Vice President Treasurer	Vice President Treasurer from September 2009. Treasurer from July 2005 to August 2009. Manager Corporate Finance Agrium Inc. from 2002 to 2005. Treasury Manager Agrium Inc. from 1999 to 2002.
James B. Bracken Calgary, Alberta, Canada Senior Vice President Major Projects	Senior Vice President Major Projects from June 2007. Senior Vice President Energy Services and Power March 2006 to June 2007. Senior Vice President Energy Services from June 2005 to March 2006. Divisional Vice President Gas Services from 2004 to 2005. Managing Director Advisory Services for Acres Management Consulting from 2002 to 2004. Principal with PA Consulting Group from 2000 to 2001.

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
Douglas H. Brown Bellingham, Washington, U.S.A. Divisional Vice President Renewable Energy Hydro	Divisional Vice President Renewable Energy Hydro from July 2008. Prior thereto Vice President Business Development for NovaGold Resources Inc. from June 2003.
Dennis A. Dawson Calgary, Alberta, Canada Vice President General Counsel and Corporate Secretary and Director	Vice President General Counsel and Corporate Secretary since 1998.
Massimiliano Fantuz Chatham, Ontario, Canada Executive Vice President	Executive Vice President from January 2008. Vice President January 2007 to January 2008. Divisional Vice President Gas Services from 2005 to January 2007. President PremStar Energy Canada Limited Partnership from 2004. President PremStar Energy Canada Ltd. from 1998 to 2004.
Michael J. Kilby Chatham, Ontario, Canada Divisional Vice President Gas Services	Divisional Vice President Gas Services from January 2007. Vice President Operations PremStar from October 2004 to January 2007. Vice President Marketing and Operations PremStar Energy Canada Ltd. from February 1998 to October 2004.
Bradley G.H. Mattson Calgary, Alberta, Canada Vice President and Corporate Controller	Vice President and Corporate Controller from January 2008. Prior thereto, Chief Financial Officer, Taylor Gas Liquids Ltd.
Marilyn A. Pfaefflin Calgary, Alberta, Canada Divisional Vice President Transmission	Divisional Vice President Transmission since June 2005. Treasurer from 1998 to June 2005.
Deborah S. Stein Calgary, Alberta, Canada Vice President Finance and Chief Financial Officer	Vice President Finance and Chief Financial Officer from January 2008. Vice President Finance from January 2007 to January 2008. Vice President Controller from October 2005 to January 2007. Vice President Corporate Risk from January to October 2005. Manager Investor Relations TransCanada Pipelines Limited from 2001 to 2005.
Kent E. Stout Calgary, Alberta, Canada Vice President Corporate Resources	Vice President Corporate Resources since 2002. Director Human Resources from 1999 to 2002.
Randy W. Toone Calgary, Alberta, Canada Divisional Vice President Field Gathering and Processing and Energy Services	Divisional Vice President Field Gathering and Processing and Energy Services since October 2009. Divisional Vice President Field Gathering and Processing since February 2009. Divisional Vice President Extraction and Transmission from January 2007 to February 2009. Operations Manager Extraction and Transmission from November 2004 to January 2007. Senior Operations Engineer November 2003 to November 2004. Plant Engineer Williams Energy Canada January 2002 to November 2003.
David R. Tulk Calgary, Alberta, Canada Divisional Vice President Extraction and Transmission	Divisional Vice President Extraction and Transmission from November 2009. Vice President of NGLs for NOVA Chemicals from 2006 until August 2009. Mr. Tulk was employed for twenty-seven years with the NOVA group of companies in a variety of commercial, business development and engineering roles.

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
David R. Wright Calgary, Alberta, Canada Executive Vice President Strategy and Corporate Development and Director	Executive Vice President Strategy and Corporate Development from January 2008. Executive Vice President from January 2007 to January 2008. Executive consultant 2005 to January 2007. Executive Vice President General Counsel and Corporate Secretary EPCOR Utilities Inc. from 2001 to 2005. Prior thereto Partner with Borden Ladner Gervais LLP and Howard Mackie.

RISK FACTORS

RISKS RELATING TO THE TRUST AND THE UNITS OF THE TRUST

A security holder should consider carefully the risk factors set out below. In addition, prospective security holders should carefully review and consider all other information contained in this Annual Information Form before making an investment decision and consult their own experts where necessary.

Capital Markets

As a result of the weakened global economic situation, the Trust may have restricted access to capital and increased borrowing costs. Although the Trust's business and asset base have not changed materially, the lending capacity of all financial institutions has diminished and risk premiums have increased. As the Trust's future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Trust's ability to do so is dependent on, among other factors, the overall state of capital markets and investor demand for investments in the energy industry and the Trust's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Trust's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result.

Based on current funds available and expected cash from operations, the Trust believes it has sufficient funds available to fund its projected capital expenditures. However, if cash flow from operations is lower than expected or capital costs for these projects exceed current estimates, or if the Trust incurs major unanticipated expenses related to development or maintenance of its existing assets, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Trust's capital expenditure plans may result in a delay in the Trust's capital program or a decrease in distributions.

Nature of Trust Units

The Trust units do not represent a traditional investment in the diversified energy services business and should not be viewed by unitholders as shares in AltaGas. The units represent a fractional interest in the Trust. As holders of units, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust's sole assets are the shares of the General Partner, the units of the Holding Trust, Holding Trust Notes and other investments in securities.

Cash distributions of the Trust are not guaranteed and the price per Trust unit is a function of anticipated distributions, the underlying assets of the Trust and management's ability to effect long-term growth in the value of AltaGas and other entities now or hereafter owned directly or indirectly by the Trust. The market price of the Trust units will be sensitive to a variety of market conditions including, but not limited to, interest rates, electricity prices and natural gas and NGL prices. Changes in market conditions may adversely affect the trading price of the Trust units.

The Trust units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Potential Sales of Additional Trust Units

The Trust may issue additional Trust units in the future to directly or indirectly fund capital expenditure requirements of entities now or hereafter owned directly or indirectly by the Trust, including to finance acquisitions by those entities. Such additional Trust units may be issued without the approval of unitholders. Unitholders will have no pre-emptive rights in connection with such additional issues. The Board of Directors has discretion in connection with the price and the other terms of the issue of such additional Trust units.

Nature of Distributions

Unlike interest payments on an interest-bearing security, cash distributions by income trusts on Trust units (including those of the Trust) are, for Canadian tax purposes, composed of different types of payments (portions of which may be fully or partially taxable or may constitute non-taxable returns of capital). The composition for tax purposes of those cash distributions may change over time, thus affecting the after-tax return to unitholders. Therefore, a unitholder's rate of return over a defined period may not be comparable to the rate of return on a fixed-income security that provides a return on capital over the same period. This is because a unitholder may receive cash distributions that constitute a return of capital (rather than a return on capital) to some extent during the relevant period. Subject to the "SIFT Rules" (as defined and described below), returns on capital are generally taxed as ordinary income or as dividends in the hands of a unitholder while returns of capital are generally non-taxable to a unitholder (but reduce a unitholder's adjusted cost base in the Trust unit for tax purposes). The Trust expects that prior to January 1, 2011, substantially all of the cash distributions to unitholders will be taxed as ordinary income. See "Declaration of Trust and Description of Units – Distributions". Unitholders are advised to consult their own tax advisors with respect to the implications of the distinction discussed above in their own circumstances.

Variability of Distributions

The Cash Flow of the Trust available for distribution to unitholders is a function of numerous factors, including AltaGas' financial performance, the impact of interest rates, electricity prices, natural gas and NGL prices, debt covenants and obligations, working capital requirements and future capital requirements. Distributions may be reduced or suspended entirely depending on the operations of AltaGas and the performance of its assets.

The market value of the Trust units may deteriorate if the Trust is unable to meet its distribution targets in the future, and that deterioration may be material.

Changes in Legislation

Environmental and applicable operating legislation may be changed in a manner which adversely affects AltaGas through the imposition of restrictions on its business activities or by the introduction of regulations that increase AltaGas' operating costs thereby indirectly affecting the Trust and potentially reducing distributions to unitholders.

Income tax laws relating to the Trust, such as the status of mutual fund trusts, may be changed in a manner which adversely affects unitholders.

Federal Government Changes to Taxation of Income Trusts

On October 31, 2006 the Minister of Finance (Canada) ("Finance") announced proposed changes to the taxation of certain publicly-traded trusts and partnerships and their unitholders. These changes (the "SIFT Rules"), were enacted and became law on June 22, 2007. Technical amendments to the SIFT Rules were subsequently announced and became law on March 12, 2009. The SIFT Rules apply, in the case of trusts, to a trust that is resident in Canada for purposes of the Tax Act, holds one or more "non-portfolio properties", and the units of which are listed on a stock exchange or other public market (a specified investment flow-through trust, or "SIFT trust"). In the case of a SIFT trust the units of which were publicly traded on October 31, 2006, which includes the Trust, the SIFT Rules generally will not take effect until January 1, 2011, provided the trust does not exceed "normal growth" before then. On December 15, 2006 Finance issued guidelines (the "Guidelines") with respect to what would be considered "normal growth" for this purpose, which Guidelines were effectively incorporated by reference into the Tax Act when the SIFT Rules were enacted.

Under the SIFT Rules, commencing January 1, 2011, the Trust, in its current structure, will become subject to tax on its income from non-portfolio properties and taxable capital gains from dispositions of non-portfolio properties, that is paid or payable to Unitholders, at a rate equal to the then prevailing federal corporate income tax rate (currently set at 16.5 percent for 2011 and 15 percent for 2012 and subsequent years) plus an additional amount in lieu of provincial tax which would be calculated with reference to the general provincial corporate income tax rate of each province in which the Trust has a permanent establishment. Distributions of such income to Unitholders would be treated as dividends paid by a taxable Canadian corporation. The trust units of Holding Trust and the Holding Trust Notes constitute "non-portfolio properties" of the Trust under the SIFT Rules, with the result that virtually all of the Trust's income would be subject to the new tax, and distributions of such income by the Trust to its Unitholders would be treated as eligible dividends paid by a taxable Canadian corporation. Returns of capital by the Trust to its Unitholders would not be affected by the SIFT Rules and would continue to be taxed in the same manner as currently.

It is not expected that the Trust will become subject to the SIFT Rules until 2011. However, when the SIFT Rules commence to apply to the Trust, such rules are expected to result in adverse tax consequences to the Trust and certain Unitholders (in particular, Unitholders that are tax exempt or non-residents of Canada) and may impact cash distributions from the Trust.

In light of the foregoing, the SIFT Rules may reduce the value of the Units, which would be expected to increase the cost to the Trust of raising capital in the public capital markets. While technical amendments that facilitate the conversion of a SIFT trust into a corporation were enacted and became law on March 12, 2009, there can be no assurance that the Trust will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the SIFT Rules.

As noted above, the Trust could become subject to the SIFT Rules before 2011 if it experiences growth, other than "normal growth", before that time. Under the Guidelines, the Trust will be considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust units and debt that is convertible into Trust units, but does not include non-convertible debt) do not exceed a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the value of the Trust's issued and outstanding publicly-traded Trust units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately $1.5 billion. Before the revisions to the Guidelines, announced on December 4, 2008, the intervening periods and their respective safe harbour amounts were as follows:

(a) November 1, 2006 to December 31, 2007 – 40 percent of the Trust's market capitalization as of October 31, 2006;

(b) January 1, 2008 to December 31, 2008 – 20 percent of the Trust's market capitalization as of October 31, 2006;

(c) January 1, 2009 to December 31, 2009 – 20 percent of the Trust's market capitalization as of October 31, 2006;

(d) January 1, 2010 to December 31, 2010 – 20 percent of the Trust's market capitalization as of October 31, 2006.

On December 4, 2008, Finance announced changes to the Guidelines to allow a SIFT trust to accelerate the utilization of the SIFT trust's annual permitted expansion amount for each of 2009 and 2010 so that the amount is available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for a SIFT trust, but it allows a SIFT trust to use its normal growth room remaining as of December 4, 2008 in a single year, rather than staging a portion of the normal growth room over the 2009 and 2010 years.

While these Guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to maintain and to grow its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

Loss of Mutual Fund Trust Status

The General Partner intends that the Trust will continue to qualify as a mutual fund trust (and thus also as a registered investment) for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements to maintain its mutual fund trust status. See "Changes in Legislation" above. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and unitholders. Some of the significant consequences of losing mutual fund trust status are listed below.

(a) If the Trust were to cease to be a mutual fund trust, it may, as a consequence of ceasing to be a mutual fund trust, also cease to be a registered investment. In that event, unless the Trust units continued to be listed on a designated stock exchange (which includes the TSX), Trust units would cease to be qualified investments for Exempt Plans effective January 1st of the second calendar year following the year in which the Trust ceases to be a registered investment. If, at the end of any month, an Exempt Plan (other than a registered disability savings plan or a tax-free savings account) holds Trust units that are not qualified investments, the plan must pay a tax equal to 1 percent of the fair market value of the Trust units at the time the Trust units were acquired by the Exempt Plan. A registered retirement savings plan, registered retirement income fund or tax-free savings account holding Trust units that are not qualified investments would be subject to taxation on income attributable to the Trust units, including the full amount of any capital gain from a disposition of such Trust units. If a registered disability savings plan or tax-free savings account holds Trust units that become a non-qualified investment, the holder of the registered disability savings plan or tax-free savings account, as the case may be, would be liable to pay a special tax equal to 50 percent of the fair market value of the Trust units at the time they became a non-qualified investment. If a registered education savings plan holds units that are not qualified investments, it may have its registration revoked by the Canada Revenue Agency.

(b) Units held by non-resident unitholders would immediately become taxable Canadian property. Non-resident unitholders would be subject to Canadian income tax and reporting requirements on any gains realized on a disposition of units held by them.

(c) The Trust would be taxed on certain types of income distributed to unitholders (apart from under the SIFT Rules). Payment of this tax may have adverse consequences for some unitholders, particularly unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

(d) The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.

(e) The Trust would no longer be exempt from the application of the alternative minimum tax provisions of the Tax Act.

In addition, the Trust may take certain measures in the future to the extent it believes necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain unitholders, particularly non-residents. See "Risks Associated With the Level of Foreign Ownership" below.

Risks Associated With the Level of Foreign Ownership

The Declaration of Trust contains a number of provisions designed to protect the status of the Trust as a "mutual fund trust" under the Tax Act which, inter alia, requires that a mutual fund trust cannot be established or maintained primarily for the benefit of non-residents. There is no indication that the mutual fund trust status of the Trust currently is in jeopardy. If, in the future, the General Partner determines that any such risk exists, it is entitled to take a number of actions under the Declaration of Trust, including requiring unitholders that it believes are non-residents to sell their Trust units, which actions may have an adverse effect on the market price of the Trust units. In addition, there can be no assurances that the Tax Act will not be amended in the future in a manner that would have a material adverse impact on the mutual fund trust status of the Trust.

Distribution of Holding Trust Notes or Other Securities on Redemption or Termination of the Trust

It is anticipated that the redemption right will not be the primary mechanism for unitholders to liquidate their investment. Holding Trust Notes which may be received as a result of a redemption of units will not be listed on any stock exchange and no market for Holding Trust Notes is expected to develop. In addition, there may be resale restrictions imposed by applicable law upon the recipients of Holding Trust Notes pursuant to the redemption right. The Holding Trust Notes will not be qualified investments for Exempt Plans. On termination of the Trust, the Trustee may distribute securities directly to unitholders, subject to obtaining all of the necessary regulatory approvals. The Holding Trust Notes will not be guaranteed by any other party, and the provisions of the Holding Trust Note Indenture governing events of default and the remedies available thereunder will not provide protection to the holders of Holding Trust Notes which would be comparable to the provisions generally found in debt securities issued to the public.

Debt Service

The Trust or its affiliates may, from time to time, finance a significant portion of their operations through debt. Amounts paid in respect of interest and principal on debt incurred by these entities may impair the ability to satisfy any obligations under its indebtedness held by the Trust or indirectly by the Trust. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Ultimately, this may result in lower levels of Cash Flow of the Trust and could reduce distributions to unitholders.

Loans to the Trust or its affiliates are subject to customary covenants and financial tests which may in certain circumstances restrict the Trust's ability to make distributions to unitholders or AltaGas' ability to make distributions to AltaGas LP #2 and ultimately to unitholders.

Structural and Contractual Subordination

In the event of a bankruptcy, liquidation or reorganization of AltaGas LP #1, AltaGas or AltaGas Operating Partnership, holders of their respective indebtedness and trade payables will generally be entitled to payment of their claims from the assets of AltaGas or AltaGas Operating Partnership, as applicable, before any assets are made available for distribution to the Trust. The Trust units are therefore effectively junior to indebtedness and most other liabilities (including trade payables) of AltaGas, AltaGas LP #1 and AltaGas Operating Partnership. Neither AltaGas nor AltaGas Operating Partnership is limited in its ability (except pursuant to restrictive covenants contained in debt agreements) to incur secured or unsecured indebtedness.

AltaGas distributes a substantial portion of its cash flow to AltaGas LP #2 pursuant to an interest bearing loan agreement. Payments by AltaGas under this loan agreement are expressly subordinated to the prior payment in full of all indebtedness of AltaGas to third parties. Upon a default under certain indebtedness, AltaGas may be prevented from distributing cash to AltaGas LP #2 thereby ultimately reducing cash available for distribution to unitholders.

Refinancing Risk

Each of the credit facilities has a maturity date, on which date absent replacement, extension or renewal, the indebtedness under the respective credit facility becomes repayable in its entirety. To the extent any of the credit facilities are not replaced or extended on or before their respective maturity dates or are not replaced, extended or renewed for the same or similar amounts or on the same or similar terms, the Trust's ability to fund ongoing operations and distribute cash could be impaired.

Dependence on Operating Entities

The Trust is entirely dependent upon the success of the operations of affiliates. Accordingly, the distributions to the unitholders will be dependent on the ability of these entities to generate cash flow.

Taxation of Corporate Entities

Income fund structures often involve significant amounts of inter-entity debt, generating substantial interest expense, which serves to reduce earnings and therefore income tax payable. The Board of Directors expects this to be the case in respect of AltaGas Ltd. and its interest expense on its subordinated debt. There can be no assurance that taxation authorities will not seek to challenge the amount of interest expense deducted. If such a challenge were to succeed against AltaGas Ltd. it could have a material adverse affect on the Cash Flow of the Trust available for distribution to unitholders.

Unitholder Limited Liability

The Declaration of Trust provides that no unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Declaration of Trust, the Trust will indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a unitholder resulting from or arising out of such unitholder not having such limited liability. There is no assurance that at the relevant time the Trust will have sufficient assets to be able to satisfy such indemnity.

The Declaration of Trust provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that obligations under those instruments will not be binding upon unitholders personally. Personal liability may however arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The operations of the Trust will be conducted, upon the advice of counsel to the Trust, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the unitholders for claims against the Trust, including by obtaining appropriate insurance, where available and to the extent commercially feasible.

On July 1, 2004, the *Income Trusts Liability Act* (Alberta) came into force, which provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the Trustee that arises after the particular provision of such legislation comes into force.

Deductibility of Expenses

Although the General Partner is of the view that all expenses to be claimed by the Trust, Holding Trust, AltaGas LP #1 and AltaGas LP #2 will be reasonable and deductible, there can be no assurance that the Canada Revenue Agency will agree. If the Canada Revenue Agency successfully challenges the deductibility of any such expenses, the return to unitholders may be adversely affected.

Potential Conflicts of Interest

Circumstances may arise where directors and officers of AltaGas and the General Partner are directors or officers of other entities that are in competition to the interests of AltaGas and the Trust. The General Partner owes a fiduciary duty to AltaGas and the Trust. While the General Partner has agreed to indemnify the Trust in certain circumstances, the General Partner may not have sufficient assets to honour such indemnification.

RISKS INHERENT IN THE TRUST'S OPERATING ENTITIES

The following are the primary risks associated with the business and affairs of the Trust's operating affiliates and should be considered carefully in light of the fact that the Trust will depend entirely on the operations and assets of these entities for its cash flow, and thereby its ability to pay distributions to unitholders. These risks are applicable to AltaGas' current operations and AltaGas' expected future operations.

Operating Risk

As the Trust continues to grow and diversify its energy infrastructure businesses, the risk profile of the Trust may change. Operating entities may enter into or expand business segments where there is greater economic exposure and more "at risk" capital. The Trust's expectation of higher returns from these businesses justifies the level of risk. In addition the Trust enters into these businesses on the basis that these risks can be actively managed.

Current operations are subject to the risks normally associated with the operation and development of natural gas and power systems and facilities, including mechanical failure, physical degradation, operator error, manufacturer defects, sabotage, terrorism, failure of supply, weather, wind or water resource deviation, catastrophic events and natural disasters. The occurrence or continuation of any of these events could increase AltaGas' costs and reduce its ability to process, transport or deliver natural gas or generate or deliver power.

The Trust believes that operational risk is best managed by maintaining control over the timing of capital expenditures, operational decisions and costs by becoming the operator of the facilities in which it invests. At the end of 2009 AltaGas operated 73 of its 76 field gathering and processing facilities, all of its transmission facilities, EEEP, JEEP, the Younger Extraction Plant, the Harmattan Complex, Bear Mountain Wind Park and the gas-fired peaking units. AltaGas does not operate the power plant from which power is generated under the PPAs. Failure by the operators of these facilities to operate at the cost or in the manner projected by AltaGas could negatively affect the Trust's results.

Facility Throughput

AltaGas' extraction and field gathering and processing facilities process natural gas from the WCSB and its transmission facilities transport natural gas, ethane and NGLs from the WCSB. Throughput at these facilities is dependent on a number of factors, including the level of exploration and development activity within the WCSB, the long-term supply and demand dynamics for natural gas, ethane and NGLs and the regulatory environment for market participants. These factors may result in AltaGas being unable to maintain throughput at its facilities. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas, ethane and NGL throughput and from rising operating costs.

Market Risk

AltaGas is exposed to market risks resulting from movements in commodity prices and interest rates. AltaGas seeks to manage its exposure to these risks through the use of various physical and financial instruments.

AltaGas' Commodity Risk Management Policy details the parameters used to measure, monitor and report commodity price risks. It also includes risk management guidelines and objectives, risk tolerance and approved products. This policy prohibits the use of physical and financial instruments for speculative purposes.

Composition Risk

The extraction business is influenced by the composition of natural gas produced in the WCSB and processed at AltaGas' facilities. The composition of the gas stream has the potential to vary over time due to factors such as the level of processing done at plants upstream of AltaGas' facilities and the composition of the natural gas produced from reservoirs upstream of AltaGas' facilities.

Electricity Prices

AltaGas' revenue from sales related to PPAs and Alberta peaking plant generation are subject to Alberta electricity market factors such as fluctuating supply and demand, which may be affected by weather, customer usage, economic activity and growth. AltaGas reduces its exposure to floating electricity prices by locking in margins with financial instruments out as far as 36 months and signing fixed-price sales arrangements with end-use customers for terms of up to 8 years. All of the power from the Bear Mountain Wind Park is contracted to BC Hydro under a 25-year Electricity Purchase Agreement at a set price which increases annually by 50 percent of the Canadian Consumer Price Index.

Interest Rates

The Trust is exposed to interest rate fluctuations on variable rate debt. The Trust monitors its level of fixed to variable rate debt and from time to time enters into interest rate swaps. The Trust's target is to have approximately 70 to 75 percent of its debt at fixed interest rates.

Regulatory

The Trust's businesses are subject to regulation in the jurisdictions in which they carry on business. Changes in the regulatory environment may be beyond the Trust's control and may significantly affect the Trust's businesses, results of operations and financial conditions. Pipelines and facilities can be subject to common carrier and common processor applications and to rate setting by the regulatory authorities in the event an agreement on fees or tariffs cannot be reached with producers. Power facilities are also subject to regulatory approvals and regulatory changes in tariffs, market structure and penalties.

Counterparty and Credit Risk

The Trust is exposed to credit-related losses in the event that counterparties to contracts fail to fulfill their present or future obligations to AltaGas. AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas seeks to reduce counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits on clients, both prior to providing products or services and on a recurring basis. In addition, AltaGas seeks to include credit mitigation clauses in its contracts which allow for 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 has credit risk relating to numerous industrial, commercial and institutional counterparties. AltaGas seeks to contract with diversified counterparties to avoid excessive concentration of risk associated with any particular industry or counterparty.

Collateral

AltaGas is able to obtain unsecured credit limits from its counterparties in order to lock in baseload electricity margins and also to procure natural gas supply and services for its energy services business. If counterparties' credit exposure to AltaGas exceeds the unsecured credit limits granted, AltaGas may have to provide collateral in the form of letters of credit. AltaGas mitigates this risk through negotiation of contractual terms with counterparties related to unsecured credit, and diversification of electricity sales and natural gas purchases among a number of counterparties. Through accepted industry practices, AltaGas performs sensitivity analysis to ensure the Trust has sufficient bank lines of credit available to withstand commodity price movements that may require AltaGas to provide counterparties with letters of credit.

REP Agreements

If AltaGas becomes insolvent or is in material default under the terms of the Rep Agreements for an extended period, effective ownership of the natural gas processing plant within the Harmattan Complex can be claimed by the original Harmattan Complex owners for a nominal fee. Accordingly, under these circumstances, AltaGas could lose its investment in the natural gas processing plant, excluding the Caroline Pipeline and various ancillary facilities that are owned 100 percent by AltaGas.

Harmattan Complex - Environment

Management has identified environmental issues associated with the prior activities of the Harmattan Complex. There are indications of significant groundwater and soil contamination resulting from the Harmattan Complex's prior activities. There is a risk that the costs of addressing these environmental issues could be significant. An environmental allocation agreement is in place with the former operator which allocates the liability. This agreement significantly reduces the soil contamination liability and eliminates the groundwater contamination liability to AltaGas.

Labour Relations

The operations and maintenance staff at the Younger Extraction Plant and some employees of AUI are members of the Communications, Energy and Paperworkers' Union of Canada. Labour disruptions could restrict the ability of the

Younger Extraction Plant to process natural gas and produce NGLs and therefore affect AltaGas' cash flow, net income and cash available for distribution. Labour disruptions at AUI could impact AUI's ongoing operations.

Aboriginal Land Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of the lands in western Canada. Such claims, if successful, could have a significant adverse effect on natural gas production and power development and generation in Alberta and British Columbia which could have a materially adverse effect on the volume of natural gas processed at AltaGas' facilities, the power produced by AltaGas facilities or on development of new facilities for gathering and processing, power generation or extraction and transmission.

Crown Duty to Consult First Nations

The federal and provincial governments in Canada have a duty to consult and, where appropriate, accommodate aboriginal people where the interests of the aboriginal peoples may be affected by a Crown action or decision. Accordingly, the Crown's duty may result in regulatory approvals being delayed or not being obtained.

Construction and Development

The development, construction and future operation of natural gas and power facilities can be affected adversely by changes in government policy and regulation, environmental concerns, increases in capital and construction costs, construction delays, increases in interest rates and competition in the industry. In the event that any one of these factors emerges, the actual results may vary materially from projections, including projections of costs, natural gas facility utilization or throughput, power production, future revenue and earnings.

The construction and development of AltaGas' natural gas and power projects and their future operations are subject to changes in the policies and laws of both Canadian and U.S. federal, provincial and state governments, including regulatory approvals and regulations relating to the environment, land use, health, culture, conflicts of interest with other parties and other matters beyond the direct control of AltaGas.

Weather and Long Term Wind or Hydrology Data

AltaGas' run-of-river power projects once built may be subject to significant variations in the stream flow necessary for power generation. AltaGas relies on hydrological studies and data to confirm that sufficient water flow is available to generate sufficient electricity to determine the economic viability of its projects. There can be no assurance that the long-term historical water availability will remain unchanged or that no material hydrologic event will impact the hydrologic conditions that exist within the watersheds. Annual and seasonal deviations from the long-term average can be significant.

AltaGas' wind power projects once built may be subject to significant variations in wind which could affect the amount of power generated. AltaGas relies on wind studies and data to confirm that sufficient wind flows are available to generate sufficient electricity to determine the economic viability of its projects. There can be no assurance that the long-term historical wind patterns will remain unchanged. Annual and seasonal deviations from the long-term average can be significant.

The natural gas distribution business is highly seasonal, with the majority of natural gas demand occurring during the winter heating season, the length of which varies in each jurisdiction. Natural gas distribution revenue during the winter typically accounts for the largest share of annual natural gas distribution revenue.

ENVIRONMENTAL REGULATION

The natural gas industry and the power generation industry are subject to environmental regulation pursuant to local, provincial, state, territorial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. Due to the highly toxic and corrosive nature of sour gas, numerous extra regulatory precautions are applied to sour gas wells, processing facilities and pipelines. Environmental legislation can affect the operation of facilities and limit the extent to which facility expansion is permitted. In addition, provincial, territorial and federal legislation requires that facility sites and pipelines be abandoned and reclaimed to the satisfaction of provincial authorities and local landowners. A breach of such legislation may result in the imposition of fines, the issuance of clean-up orders or the shutting down of facilities and pipelines. It is possible that increasingly strict environmental laws, regulations and enforcement policies, and potential claims for damages and injuries to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future.

AltaGas takes its responsibility to protect the environment in which it operates very seriously. Its mandate is to fully comply with all environmental laws and regulations and to immediately and efficiently deal with any environmental incidences.

On April 26, 2007, the federal government proposed a plan entitled *"Turning the Corner"* for addressing greenhouse gas emissions. Elaboration on this plan was released March 10, 2008. Under this plan, facilities with greenhouse gas emissions exceeding a threshold level will be required to reduce their net greenhouse gas emissions intensity by 18 percent (relative to 2006 levels) by 2010. Compliance options include making operating improvements, participating in domestic emissions trading, buying a domestic offset to apply against the emission total, buying a Certified Emissions Reductions credit through the Kyoto Protocol's Clean Development Mechanism up to a prescribed maximum amount or contributing to an independent, third-party-administered fund that will invest in technology to reduce greenhouse gas emissions in Canada. Until the relevant legislation and regulations are enacted, AltaGas is not in a position to accurately determine the impact of any federal requirement to reduce greenhouse gas emission levels on its financial position.

On March 8, 2007 the Alberta government introduced the *Climate and Emissions Management Amendment Act* and the Specified Gas Emitters Regulation. The act came into force April 20, 2007 and the Specified Gas Emitters Regulation took effect July 1, 2007. The regulation applies to large emitter facilities producing a minimum of 100,000 tonnes of annual greenhouse gas emissions. Large emitters with 8 or more years of commercial operation must achieve annual emissions intensity reductions of 12 percent relative to a baseline emissions intensity established for the facility December 31, 2007. Annual emissions intensity reduction targets are phased in for newer facilities. Compliance options include making operating improvements, buying or developing an Alberta-based offset to apply against the emission total or contributing to the Alberta Government's new Climate Change and Emissions Management Fund that will invest in technology to reduce greenhouse gas emissions in the province. Owners of facilities that do not achieve the necessary reduction through operating improvements or offsets must pay $15 per tonne into the Climate Change and Emissions Management Fund or they may be subject to fines and penalties.

AltaGas has completed an assessment program of its field gathering and processing facilities to quantify the current levels of greenhouse gas emissions. Only the Harmattan Complex is subject to the Alberta regulation as its greenhouse emissions are above 100,000 tonnes per year. Management's initial calculations for emission intensity for 2009 indicate that the emissions from the Harmattan Complex are below its target intensity and therefore will not be subject to any penalty, but will qualify for credits.

AltaGas has completed an assessment of its facilities that do not qualify as large emitters under the Specified Gas Emitters Regulation and identified several opportunities to create offsets which could be used to mitigate some of the costs associated with greenhouse gas emissions from the Sundance B facility. Offsets from these facilities were used to reduce compliance costs for the 2008 reporting period and are expected to be available again for 2009, pending the formal verification and documentation process which is currently underway.

The Sundance B Plant is a large emitter and TransAlta, as the facility owner, must ensure that facility complies with the Regulation. The Sundance B PPAs require TransAlta to take all reasonable steps as agreed to by ASTC, and at the cost of ASTC, to minimize any decrease in revenues or increase in the fixed or variable costs resulting from a Change in Law as that term is defined in the PPAs. AltaGas' share of the cost of compliance in 2009 was approximately $3.7 million.

On February 6, 2006 the Alberta government passed a regulation under the Alberta *Environmental Protection and Enhancement Act* related to control of mercury emissions from coal-fired power plants. Holders of approvals to operate a coal-fired power plant were required to submit a proposal in accordance with the regulation for a mercury emissions control program at their coal-fired plant prior to April 1, 2007.

TransAlta submitted a mercury emission control program for the Sundance generating station to Alberta Environment on March 29, 2007. Based on discussions with Alberta Environment, TransAlta submitted a revised Proposal on April 3, 2009 that addressed Alberta Environment comments. TransAlta has now selected Activated Carbon Injection technology to meet the required 70% reduction in mercury emissions by January 1, 2011. In addition, TransAlta will install a Continuous Emission Monitoring System to ensure that the reductions are meeting the targeted levels. TransAlta has provided ASTC frequent updates as to the progress of the program (and its associated costs) and AltaGas expects that it will be in place to meet the regulatory compliance obligations by the target date.

DISTRIBUTIONS

The Trust and AltaGas LP #1 pay cash distributions on or about the 15th day of each month, or if that date is not a business day then the following business day, to unitholders of record on the 25th day of the previous month, or if that day is not a business day the following business day.

Distribution levels are reviewed periodically by the Board of Directors, giving consideration to the ongoing sustainable distributable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of the Trust. The Trust targets to pay substantially all of its ongoing sustainable distributable cash through regular monthly distributions made to unitholders.

The Trust's distributions may be limited by its debt covenants under its credit agreements if a default or event of default exists or would be reasonably expected to exist upon or as a result of making such distribution, or if such distribution would cause the aggregate distributions made during the 12-month period ending on the date of such distribution to exceed the cumulative distributable cash for such period.

In addition, the Declaration of Trust provides that, if necessary, on December 31 of each year, the Trust will distribute an additional amount such that the Trust will not be liable for ordinary income taxes for such year. For income tax purposes, 78.83 percent of the cash distributions declared in 2009 will be taxed as other income (investment income), 0.19 percent as dividend income, 3.98 percent as capital gain and the remaining 17.00 percent classified as return of capital.

The following table summarizes the monthly cash distributions of the Trust during 2007, 2008 and 2009. On September 17, 2007 all unitholders received a special distribution of one share of AltaGas Utility Group Inc. for every 100 Trust units held on August 27, 2007, for additional value of $0.076 per unit.

Record Date	Payment Date	Distribution per Unit
January 26, 2009	February 17, 2009	$0.180
February 25, 2009	March 16, 2009	$0.180
March 25, 2009	April 15, 2009	$0.180
April 27, 2009	May 15, 2009	$0.180
May 25, 2009	June 15, 2009	$0.180
June 25, 2009	July 15, 2009	$0.180
July 27, 2009	August 17, 2009	$0.180
August 25, 2009	September 15, 2009	$0.180
September 25, 2009	October 15, 2009	$0.180
October 26, 2009	November 16, 2009	$0.180
November 25, 2009	December 15, 2009	$0.180
December 29, 2009	January 15, 2010	$0.180
Total 2009 Cash Distributions Declared		**$2.16**
January 25, 2008	February 15, 2008	$0.175
February 25, 2008	March 17, 2008	$0.175
March 25, 2008	April 15, 2008	$0.175
April 25, 2008	May 15, 2008	$0.175
May 26, 2008	June 16, 2008	$0.175
June 25, 2008	July 15, 2008	$0.175
July 25, 2008	August 15, 2008	$0.175
August 25, 2008	September 15, 2008	$0.180
September 25, 2008	October 15, 2008	$0.180
October 27, 2008	November 17, 2008	$0.180
November 25, 2008	December 15, 2008	$0.180
December 29, 2008	January 15, 2009	$0.180
Total 2008 Cash Distributions Declared		**$2.125**
January 25, 2007	February 15, 2007	$0.170
February 26, 2007	March 15, 2007	$0.170
March 26, 2007	April 16, 2007	$0.170
April 25, 2007	May 15, 2007	$0.170
May 25, 2007	June 15, 2007	$0.170
June 25, 2007	July 16, 2007	$0.170
July 25, 2007	August 15, 2007	$0.170
August 27, 2007	September 17, 2007[(1)]	$0.175
September 25, 2007	October 15, 2007	$0.175
October 25, 2007	November 15, 2007	$0.175
November 26, 2007	December 17, 2007	$0.175
December 27, 2007	January 15, 2008	$0.175
Total 2007 Cash Distributions Declared		**$2.065**

Note:

(1) Distributions paid in September 2007 do not include $0.076 per unit paid to unitholders in the form of shares of Utility Group as a special distribution.

DISTRIBUTION REINVESTMENT PLAN

The Trust has adopted a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan for holders of Trust units and holders of Exchangeable units.

The Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan, as may be amended from time to time, provides eligible holders of Trust units and Exchangeable units with the opportunity to reinvest the cash distributions paid by the Trust or AltaGas LP #1 on their units towards the purchase of new Trust units at a 5 percent discount to the Average Market Price of the Trust units, as defined below, on the applicable distribution payment date (the distribution reinvestment component of the Plan) or to elect to exchange such Trust units for a cash payment equal to 102 percent of such distributions on such date (the premium distribution component of the Plan). The Trust unitholder Plan also provides Trust unitholders who are enrolled in either the distribution reinvestment component or the premium distribution component of the Plan with the opportunity to purchase new Trust units at the Average Market Price (with no discount) on the applicable distribution 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 Trust units in certain events.

The "Average Market Price", in respect of a particular distribution payment date, refers to the arithmetic average (calculated to four decimal places) of the daily volume weighted average trading prices of Trust units on the TSX for the trading days on which at least one board lot of Trust units is traded during the period beginning on the later of the 21st business day preceding a distribution payment date and the second business day following the record date applicable to such distribution payment date and ending on the second business day preceding such distribution payment date. Such trading prices will be appropriately adjusted for certain capital changes (including Trust unit subdivisions, Trust unit consolidations, certain rights offerings and certain distributions).

No brokerage commissions will be payable in connection with the purchase of Trust units under the distribution reinvestment component of the plan or optional unit purchase component of the plan and all administrative costs under the Plan are borne by the Trust. Proceeds received by the Trust upon the issuance of additional Trust units under the Distribution Reinvestment Plan will be used by AltaGas for future acquisitions, capital improvements and working capital. Unitholders resident outside of Canada are not entitled to participate in the Plan. Upon ceasing to be a resident of Canada, unitholders will be required to terminate their participation in the Plan.

On August 1, 2007 the Trust announced that it had suspended the Premium component of the Distribution Reinvestment Plan effective with the August 15, 2007 distribution payment. The regular component of the Distribution Reinvestment Plan remained in effect.

MARKET FOR SECURITIES

The following chart provides the reported high and low trading prices and volume of Trust units traded by month from January to December 2009 as reported by the TSX:

Month	High	Low	Volume
January	$18.85	$16.45	4,396,777
February	$16.52	$12.25	9,861,861
March	$14.71	$12.51	5,370,312
April	$15.49	$13.93	4,525,237
May	$16.79	$14.52	4,872,620
June	$17.50	$15.55	7,095,498
July	$16.35	$15.55	6,777,304
August	$17.24	$16.36	5,542,824
September	$17.70	$16.60	7,349,020
October	$19.09	$17.18	8,099,281
November	$18.95	$17.75	5,918,666
December	$19.07	$17.19	6,167,026

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following table summarizes selected financial information for the last three financial years:

Year ended and as at December 31 *($ millions unless otherwise indicated)*	2009	2008	2007
Revenue			
Gas	1,142.4	1,643.2	1,300.5
Power	188.5	223.5	182.5
Corporate	18.7	12.9	6.2
Intersegment Eliminations	(81.3)	(62.8)	(60.8)
	1,268.3	1,816.8	1,428.4
Net revenue			
Gas	340.2	334.2	215.7
Power	102.2	129.0	104.2
Corporate	18.6	12.9	6.2
Intersegment Elimination	(4.4)	0.4	(2.1)
	456.6	476.5	324.0
EBITDA	248.4	256.4	173.7
- per unit (basic)	$3.16	$3.73	$3.03
Net income	141.3	163.6	108.8
- per unit (basic)	$1.80	$2.38	$1.90
Cash from operations	184.1	205.2	183.3
- per unit (basic)	$2.34	$2.98	$3.19
Funds from operations	202.3	216.8	162.9
- per unit (basic)	$2.58	$3.15	$2.84
Total assets	2,629.1	2,132.3	1,172.7
Total debt	1,014.7	565.3	220.8

CREDIT AND STABILITY RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity and willingness of a company to meet its financial commitment on an obligation in accordance with the terms of an obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an income trust's distribution stream when compared to other rated Canadian income trusts.

S&P and DBRS are rating agencies that provide credit ratings. These rating agencies' ratings for debt instruments range from a high of AAA to a low of D and for stability ratings range from a high of SR-1 (S&P) / STA-1 (DBRS) to a low of SR-7 (S&P) / STA-7 (DBRS). S&P also assigns a corporate rating which ranges from a high of AAA to a low of D.

On April 21, 2009 S&P upgraded its rating for the Trust from BBB- to BBB with a Stable outlook. S&P cited the Trust's increased exposure to long-term contracted gas infrastructure business, prudent financial practices and effective strategy execution for the upgrade in rating.

On October 16, 2009, DBRS raised its rating for the Trust from BBB (low) with a positive trend to BBB with a stable trend. DBRS cited AltaGas's business-risk profile, and the addition of low-risk regulated natural gas distribution assets in Alberta, for the upgrade in rating.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present 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 stability rating of STA-3 is considered to have good stability and sustainability of distributions per unit. The stability rating is further separated into high, middle and low to indicate where within the ratings category the trust falls. Seven areas are reviewed and assigned a ranking of superior, moderate or weak in determining the overall stability rating. The areas reviewed are operating and industry characteristics, asset quality, financial flexibility, diversification, size and market position, sponsorship and governance, and growth.

According to the S&P rating system, an obligor rated BBB has 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 commitments. 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 stability rating of SR-3 indicates that the Trust has a high level of distributable cash flow generation stability relative to other income funds in the Canadian marketplace.

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.

Except as set forth above, neither DBRS nor S&P has announced that it is reviewing or intends to revise or withdraw the ratings on the Trust.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Trust within the most recently completed financial year, or before the most recently completed financial year but which are still material and are still in effect, are the following:

- Declaration of Trust. See "Declaration of Trust and Description of Units";
- Holding Trust Note Indenture. See "Holding Trust – Holding Trust Notes";
- Administration Agreement. See "Management of the Trust – Administration Agreement";
- Delegation Agreement. See "Management of the Trust – Delegation Agreement";
- Voting and Exchanging Trust Agreement. See "Declaration of Trust and Description of Units – Special Voting Units";
- Unanimous Shareholders' Agreement. See "Unanimous Shareholder Agreement";
- Support Agreement. See "Management of The Trust – Administration Agreement";
- $75,000,000 Extendible Revolving Term Credit Facility Credit Agreement. This is an unsecured three-year extendible revolving letter of credit facility with The Bank of Nova Scotia maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowing on the facility bear fees and interest at rates relevant to the nature of the draw made;
- $375,000,000 Extendible Revolving Term Credit Facility Credit Agreement, which was increased from $300,000,000 in January 2008. This is an unsecured extendible revolving three-year credit facility with Royal Bank of Canada, Canadian Imperial Bank of Commerce, Bank of Montreal, The Bank of Nova Scotia, Alberta Treasury Branches and National Bank of Canada maturing on September 30, 2010. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made;
- Trust Indenture between the Trust and Computershare Trust Company of Canada dated May 12, 2005 related to the issuance and sale of debentures pursuant to the Trust's medium-term note program;
- $250,000,000 Revolving Term Credit Facility, put in place March 9, 2009 which was reduced to $150,000,000 on July 9, 2009, with The Toronto Dominion bank, Royal Bank of Canada, The Bank of Nova Scotia, Canadian Imperial Bank of Commerce, National Bank of Canada, HSBC Bank Canada, Canadian Western Bank and Alberta Treasury Braches, maturing on August 13, 2010. Borrowings on the facility can be made by way of prime loans or bankers' acceptances; and
- Utility Group $130 million Extendible Revolving Term Credit Facility with a syndicate of Canadian chartered banks, maturing November 17, 2010. Borrowings on the facility can be made by way of prime loans, U.S. base rate loans, letters of credit, bankers' acceptances or LIBOR loans.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The General Partner and AltaGas Ltd. are not aware of any material interest, direct or indirect, of any director or officer of the General Partner or AltaGas Ltd., any director or officer of a corporation that is an insider or subsidiary of the Trust, or any other insider of the Trust, or any associate or affiliate of any such person, in any transaction since the commencement of the Trust's last three completed financial years, or in any proposed transaction, that has materially affected or would materially affect the Trust or any of its subsidiaries.

LEGAL PROCEEDINGS

AltaGas Ltd. is not aware of any material legal proceedings to which the Trust or its affiliates is a party or to which their property is subject.

INTERESTS OF EXPERTS

The auditors of the Trust are Ernst & Young LLP, Chartered Accountants, 1000, 440-2nd Ave. S.W., Calgary, Alberta T2P 5E9. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including directors and officers remuneration and indebtedness, principal holders of the Trust's securities, options to purchase the Trust's securities, and interests of insiders in material transactions, where applicable, is contained in the Trust's 2010 Information Circular, which is expected to be filed on or about May 7, 2010 in connection with the Annual and Special Meeting of unitholders to be held June 3, 2010.

Additional financial information is contained in the Trust's consolidated financial statements for the year ended December 31, 2009 and management's discussion and analysis contained in the 2009 Annual Report of the Trust.

The Trust routinely files all required documents through the SEDAR system and on its own website. Internet users may retrieve such material through the SEDAR website www.sedar.com. The Trust's website is located at www.altagas.ca, but the Trust's website is not incorporated by reference into this Annual Information Form.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent for the Trust units and Exchangeable units is Computershare Trust Company of Canada, 600, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

The registrar and trustee for the Trust's medium-term notes is Computershare Trust Company of Canada, 710, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

EFFECTIVE DATE

Unless otherwise specifically herein provided, the information contained in this Annual Information Form is stated as at December 31, 2009.

SCHEDULE A: AUDIT COMMITTEE MANDATE

I. Constitution

The Board of Directors (the "Board") of AltaGas General Partner Inc. (the "General Partner" or the "Corporation") in accordance with the Delegation Agreement among the Trust, the General Partner and the Trustee, has established an Audit Committee (the "Committee") to serve as the Audit Committee of the Trust. Such Committee shall be in compliance with the guidelines for corporate governance of The Toronto Stock Exchange ("TSX") and any regulatory or legal authority having jurisdiction over the Trust.

The Committee shall supervise the audit of the Trust's financial records and will ensure the adequacy and effectiveness of its policies and procedures regarding the Trust's financial reporting, internal accounting, financial controls, management information and risk management.

II. Membership

Following each annual meeting of unitholders of the Trust, the Board shall elect from its Members, not less than three (3) Directors to serve on the Committee (the "Members"). The Members and the Chair of the Committee are nominated and elected by the Board. Every Audit Committee Member must be:

- A Director of the Corporation;
- Independent; and
- Financially literate.

No Member of the Committee shall be an officer or employee of the Corporation or any other subsidiary or affiliate of the Trust. Any Member may be removed or replaced at any time by the Board and shall cease to be a Member upon ceasing to be a Director of the Corporation. Each Member shall hold office until the Member resigns or is replaced, whichever first occurs.

The Board will appoint a Member as Chair of the Committee on an annual basis.

The Corporate Secretary of AltaGas Ltd. shall be secretary to the Committee unless the Committee directs otherwise.

III. Meetings

The Committee shall convene no less than four times per year at such times and places designated by its Chair or whenever a meeting is requested by a Member, the Board, or an officer of the Corporation or of AltaGas Ltd. A minimum of twenty-four (24) hours notice of each meeting, plus a copy of the proposed agenda, shall be given to each Member. The Corporate Secretary and Members of management shall attend whenever requested to do so by a Member.

A meeting of the Committee shall be duly convened if two Members are present. Where the Members consent, and proper notice has been given or waived, Members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a Member participating in such a meeting by any such means is deemed to be present at that meeting.

In the absence of the chair of the Committee, the Members may choose one (1) of the Members to be the chair of the meeting.

The external auditor will be given notice of and be provided the opportunity to attend every meeting of the Committee.

The Audit Committee will hold in camera sessions with management, the internal and external auditors as may be deemed appropriate by the Members.

Minutes shall be kept of all meetings of the Committee by the Corporate Secretary or designate of the Corporate Secretary.

IV. Duties and Responsibilities

The Committee shall, as permitted by and in accordance with the requirements of the *Canada Business Corporations Act*, the Delegation Agreement, the Articles and By-Laws of the Corporation and any legal or regulatory authority having jurisdiction, periodically assess the adequacy of procedures for the public disclosure of financial information and review on behalf of the Board and report to the Board the results of its review and its recommendation regarding all material matters of a Financial Reporting and Audit nature, including, but not limited to the following main subject areas:

(a) Financial Statements, including Managements Discussion and Analysis;

(b) Reports to Unitholders and others;

(c) Annual and Interim Press releases regarding financial results;

(d) Internal controls;

(e) Audits and reviews of financial statements of the Trust and its subsidiaries;

(f) Filings to securities regulators;

(g) Review and approval of issuer's hiring policies re: current and former partners and employees of the external auditor;

(h) Pre-approve non-audit work undertaken by the external audit firm;

(i) Accounting and Auditing Irregularity Reporting Policy; and

(j) Commodity risk management and related policies.

The Committee shall ensure satisfactory procedures for receipt, retention and resolution of complaints and for the confidential, anonymous submission by employees regarding any accounting, internal accounting controls or auditing matters.

The full Board will be kept informed of the Committee's activities by a report at each regular meeting of the Board.

The Committee will review the relevance and adequacy of this Mandate on at least an annual basis and will provide recommendations to the Governance Committee of the Board.

V. External Auditor

The Audit Committee shall recommend the appointment of the external auditor annually. Once appointed by the Unitholders, the external auditor shall report directly to Audit Committee.

The Audit Committee shall pre-approve all non-audit services provided by the external auditor, and shall have direct responsibility for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services, including the resolution of disagreements between the external auditor and management.

VI. Relations with Management

The Committee will ensure that it coordinates its activities with the Chief Financial Officer on audit and financial matters and will:

- Meet regularly with Management to discuss areas of concern;
- Review and assess the quality of the executives involved in financial reporting process; and
- Ensure Management provides adequate funding to the Committee so that it may independently engage and remunerate the Auditor and any advisors.

VII. Committee Timetable

The major activities of the Committee will be outlined in an annual Schedule.

SEC File # 82-34911

AltaGas

AltaGas Income Trust
1700, 355 - 4th Avenue S.W.
Calgary, AB T2P 0J1
Tel: 403-691-7575
Fax: 403-691-7576
www.altagas.ca

AltaGas **NEWS RELEASE**

ALTAGAS FILES 2009 YEAR-END FINANCIAL DISCLOSURE DOCUMENTS

Calgary, Alberta (March 2, 2010) – AltaGas Income Trust (AltaGas or the Trust) (TSX: ALA.UN)) today announced that its audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2009, as well as the related Management's Discussion and Analysis, are now available online at www.altagas.ca. All documents have been filed with the relevant securities regulators and are posted on the Canadian Securities Administrators' website at www.sedar.com.

Summary year-end disclosure was provided on February 26, 2010 in the fourth quarter and year-end news release and during a conference call held that same day. The transcript for that conference call and the webcast replay are available on the Trust's website.

The print version of the 2009 Annual Report will be available in late March. The materials for AltaGas' annual and special meeting, including the Notice of Meeting and Management Proxy Circular, will be mailed to AltaGas unitholders in May. AltaGas' annual and special meeting will be held at 3:00 p.m. MDT on Thursday, June 3, 2010 at The Petroleum Club in Calgary, Alberta.

Tax information for cash distributions declared by the Trust in 2009 is now available on the AltaGas website, www.altagas.ca, by selecting "Investors" and then "Tax Information".

AltaGas Income Trust is one of Canada's largest and fastest growing energy infrastructure organizations. The Trust creates value by acquiring, growing and optimizing gas and power infrastructure, including a focus on renewable energy sources.

AltaGas Income Trust's units are listed on the Toronto Stock Exchange under the symbol ALA.UN. The Trust is included in the S&P/TSX Composite Index, the S&P/TSX Income Trust Index and the S&P/TSX Capped Energy Trust Index.

This news release contains forward-looking statements. When used in this news release, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. 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 the Trust's 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, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this news release, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in, or incorporated by reference in this news release, should not be unduly relied upon. Such statements speak only as of the date of this news release. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

For further information contact:

Media
Adrianne Lovric
(403) 691-9873
adrianne.lovric@altagas.ca

Investment Community
Sheena McKellar
(403) 691-9855
sheena.mckellar@altagas.ca

Website: www.altagas.ca
Investor Relations
1-877-691-7199
investor.relations@altagas.ca

CERTIFICATE OF COMPLIANCE

TO: **The Securities Commission or other Securities Regulatory Authority in each of the Provinces of Canada**

RE: **Annual Undertaking Pursuant to National Policy 41-102 "Income Trusts and Other Indirect Offerings" to be filed Concurrently with the Annual Financial Statements**

AltaGas Ltd. ("**AltaGas**"), in its capacity as the administrator of AltaGas Income Trust (the "**Trust**"), hereby certifies for and on behalf of the Trust that the Trust has complied with the undertaking dated June 3, 2004, given by the Trust in relation to the offering of trust units by way of a short form prospectus of the Trust dated June 3, 2004, except any references therein to Ontario Securities Commission Rule 61-501 and Quebec Policy Statement Q-27 should be read as references to Multilateral Instrument 61-101 "Protection of Minority Security Holders in Special Transactions", from and after February 1, 2008 .

DATED March 2, 2010.

ALTAGAS INCOME TRUST, by its administrator, ALTAGAS LTD.

By: (signed) *"David W. Cornhill"*

David W. Cornhill
Chairman and Chief Executive Officer

FORM 13-502F1

CLASS 1 REPORTING ISSUERS -- PARTICIPATION FEE

Reporting Issuer Name: **ALTAGAS INCOME TRUST**

End date of last completed fiscal year: **December 31, 2009**

Market value of listed or quoted securities:

Total number of securities of a class or series outstanding as at the end of the issuer's last completed fiscal	(i)	78,231,948
Simple average of the closing price of that class or series as of the last trading day of each month in the last completed fiscal year (See clauses 2.7(a)(ii)(A) and (B) of the Rule)	(ii)	16.47
Market value of class or series	(i) X (ii) =	(A) 1,288,480,183
(Repeat the above calculation for each class or series of securities of the reporting issuer that was listed or quoted on a marketplace in Canada or the United States of America at the end of the last completed fiscal year)		(B)

Market value of other securities at end of the last completed fiscal year:

(See paragraph 2.7(b) of the Rule) (Provide details of how value was determined)		(C)
(Repeat for each other class or series of securities to which paragraph 2.7(b) of the Rule applies)		(D)

Capitalization for the last completed fiscal year

(Add market value of all classes and series of securities) (A) + (B) + (C) + (D) = **1,288,480,183**

Participation Fee **$29,700**

(From Appendix A of the Rule, select the participation fee beside the capitalization calculated above)

Late Fee, if applicable

(As determined under section 2.5 of the Rule)

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 Income Trust (AltaGas or the Trust) as at and for the year ended December 31, 2009 compared to 2008. This MD&A dated March 2, 2010 should be read in conjunction with the accompanying Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2009.

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 the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements are set forth under: "Strategy"; "Gas - Description of Assets - Capitalizing on Opportunities"; "Gas Outlook"; "Power - Description of Assets - Capitalizing on Opportunities"; "Power Outlook"; "Global Capital Market Conditions"; "Growth Capital" and "Corporate Outlook".

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material facts 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 the Trust's public disclosure documents.

Many factors could cause the Trust's or any of its segment's actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust 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 the Trust, including its annual MD&A and Consolidated Financial Statements, Annual Information Form, Information Circular, Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's Website or directly through the SEDAR system at www.sedar.com.

2009 Highlights

Completed two major capital projects: the 102-MW Bear Mountain Wind Park in northeast B.C. and the 5.3 Bcf Sarnia storage facility in Ontario (AltaGas owns 50 percent).

Acquired ownership in three natural gas distribution businesses serving more than 72,000 customers in Alberta, Nova Scotia and the Northwest Territories. These acquisitions enhanced fourth quarter results.

Weak gas prices combined with volatility in the capital markets impacted drilling activity in the Western Canada Sedimentary Basin, prompting some producers to shut in gas wells.

Completed several financing initiatives – $100 million equity issue, $250 million credit facility and $300 million in medium-term notes – and received credit rating upgrades from both S&P and DBRS.

SEC File # 82-34911

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership, AltaGas Pipeline Partnership, Taylor NGL Limited Partnership (Taylor), AltaGas Utility Group Inc. (Utility Group), as well as AltaGas Energy Limited Partnership and ECNG Energy L.P. (collectively, the operating subsidiaries). The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is predominantly derived from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the unitholders, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

VISION

AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the northern and western United States. To achieve its vision, AltaGas capitalizes on its solid base business, operational expertise and financial strength and focuses on increasing the value and profitability of its existing assets and growing and diversifying its business. With more than $2 billion in organic growth projects under development over the next five years, AltaGas is well on its way to realizing its vision.

OVERVIEW OF THE BUSINESS

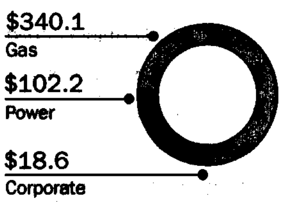
AltaGas is a natural gas and power infrastructure business with physical and economic links along the energy value chain. AltaGas' efficient, reliable and profitable assets, market knowledge and financial discipline have resulted in the creation of long-term value for its investors. AltaGas focuses on maximizing the profitability of its assets, providing services that are complementary to its existing business, and growing through the acquisition and development of additional energy infrastructure.

AltaGas' gas infrastructure touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing transmission, distribution and storage. The power infrastructure includes conventional power generation in Alberta and renewable power generation in British Columbia.

STRATEGY

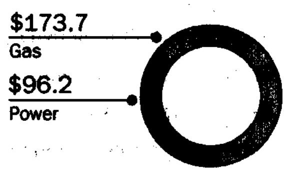
AltaGas' strategy is to increase unitholder value through the delivery of sustainable and increasing earnings and cash flow from its existing assets, as well as from the growth of its business through acquisition and construction of new gas and power infrastructure with long economic lives. Investments are diversified revenue source, fuel source, contractual term, exposure to industry cycle and location. The Trust expects growth in its business to be evenly split between gas and power over the long term through investments in Canada and the northern and western United States. The Trust has a strong track record of employing its operational expertise, energy market knowledge and financial discipline and strength to deliver sustainable

$456.6
million
Net Revenue



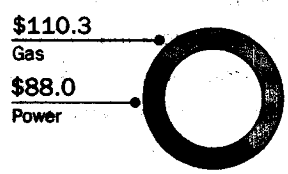
Before intersegment eliminations

$248.4
million
EBITDA



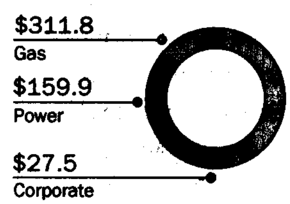
Excluding Corporate Segment

$174.2
million
Operating Income



Excluding Corporate Segment

$499.2
million
Invested Capital



returns to its investors. The Trust positions its services along the energy value chain, linking energy production to energy users. The sound long-term supply and demand fundamentals for gas and power form the foundation for AltaGas' strategy.

As part of its growth strategy, AltaGas plans to acquire and construct both gas and power infrastructure assets. In executing this growth strategy for new construction projects, AltaGas employs project management processes and disciplines. Engineering design is performed by outside engineering firms selected on the basis of best fit for a given project. For large projects, construction management is also provided by outside experts with specific experience in the execution of similar projects. AltaGas project management processes coordinate the contracting and deployment of internal and external expertise to manage execution risk.

AltaGas identifies, evaluates and pursues growth opportunities that offer strong financial returns and earnings and cash flow accretion, as well as providing the appropriate balance between risk and return. AltaGas remains open to opportunities and may deploy capital in gas and power infrastructure not currently represented within its portfolio.

AltaGas differentiates itself from its peers and competitors by linking its operating experience, gas and power market knowledge and business and financial expertise and by capitalizing on the natural hedges within its business and its strong risk management expertise.

ALTAGAS 2009 HIGHLIGHTS

- Connected the 102-MW Bear Mountain Wind Park to the B.C. power grid and met the conditions of Commercial Operation Date (COD) in order to receive the firm price under the 25-year energy purchase agreement (EPA) with BC Hydro. Owned and operated by AltaGas, the $200 million project was completed ahead of schedule and on budget and is B.C.'s first fully operational wind park;
- Acquired all the outstanding common shares of Utility Group not previously held by AltaGas for $204.5 million including assumed debt;
- Acquired the 75.1 percent it did not already own of the outstanding shareholder loans and common shares of Heritage Gas Limited (Heritage Gas) for $111.0 million;
- Completed the Sarnia Storage project on June 25, 2009; it was constructed on schedule and under budget;
- Completed two issues of senior unsecured medium-term notes. The $200 million April issue carries a coupon rate of 7.42 percent and matures on April 29, 2014. The $100 million June issue carries a coupon rate of 6.94 percent and matures on June 29, 2016;
- Entered into a Memorandum of Understanding (MOU) with NOVA Chemicals related to liquids extracted at the Trust's Harmattan Complex, as part of the Harmattan Co-stream Project. The MOU provides that the definitive agreements between AltaGas and NOVA Chemicals would be for an initial term of 20 years. AltaGas submitted its application for the project to the Alberta Energy Resources Conservation Board (ERCB) in April;
- Received an upgrade from both credit rating agencies. Dominion Bond Rating Services (DBRS) increased the Trust's credit rating from BBB(low) with a Positive trend to BBB with a Stable trend. Standard & Poor's (S&P) increased the Trust's rating from BBB- to BBB with a Stable outlook;
- Generated net income of $141.3 million ($1.80 per unit) compared to $163.6 million ($2.38 per unit) in 2008;
- Reported EBITDA[1] of $248.4 million ($3.16 per unit), down from $256.4 million ($3.73 per unit) in 2008;
- Generated cash from operations of $184.1 ($2.35 per unit) in 2009 compared to $205.2 million ($2.98 per unit) in 2008; and
- Generated funds from operations[1] of $202.3 million ($2.58 per unit) compared to $216.8 ($3.15 per unit) in 2008.

1 Includes financial measures not included under Canadian generally accepted accounting principles. Please see discussion in Non-GAAP Financial Measures.

Gas

DESCRIPTION OF ASSETS

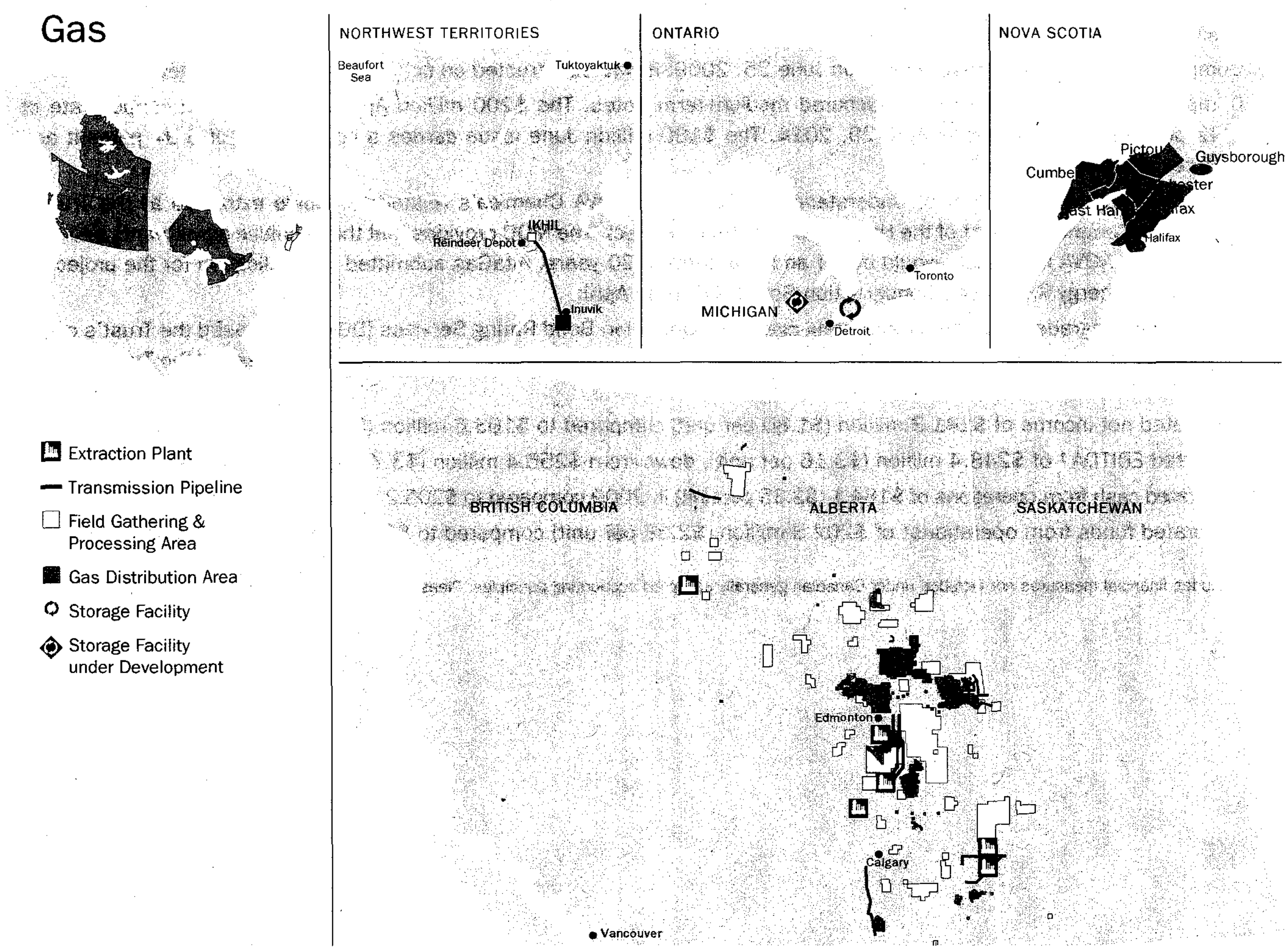
AltaGas' gas infrastructure touches more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, transmission, distribution and storage. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are 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 natural gas liquids (NGLs). AltaGas owns 1.6 Bcf/d of extraction processing capacity and 1.2 Bcf/d of raw gas processing capacity.

Transmission pipelines deliver natural gas and NGLs to distribution systems, end users or other downstream pipelines. With the 2009 acquisition of Utility Group and Heritage Gas, AltaGas owns and operates natural gas distribution (NGD) assets that deliver natural gas to end users. These regulated assets are located in Alberta, Nova Scotia and the Northwest Territories. AltaGas uses its market knowledge and expertise to create value. It provides energy consulting and supply management services to non-residential end users, buys and resells energy, provides gas transportation and storage, and markets gas for producers.

AltaGas' Gas Segment includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1,594 Mmcf/d. Current throughput at these facilities is 841 Mmcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin-based revenues;
- Five natural gas transmission systems with combined transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d;
- More than 70 gathering and processing facilities in 30 operating areas in western Canada and a network of 6,500 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;

Gas



- Ownership in three natural gas distribution businesses serving more than 72,000 customers, including 100 percent of both AltaGas Utilities Inc. (AUI) and Heritage Gas and 33.335 percent ownership of Inuvik Gas Ltd. (Inuvik Gas) and the Ikhil Joint Venture. The businesses were acquired in fourth quarter 2009 through the purchase of 80.2 percent of Utility Group not already owned by AltaGas and 75.1 percent of Heritage Gas not already owned by AltaGas; and
- 50 percent partnership interest in Sarnia Storage Pool Limited Partnership (Sarnia Storage), which owns 5.3 Bcf of gas storage capacity that became operational in second quarter 2009. Storage in the pool is marketed on a fee-for-service basis to credit-worthy third parties.

In addition to the segment's physical assets, AltaGas offers gas procurement, management and optimization services, which help enhance the asset base. Energy Services provides support for the infrastructure-based businesses by contracting supply and shrinkage gas for the extraction facilities, contracting and reselling capacity on the transmission pipelines and providing gas control services to balance gas flows. Energy Services also markets gas for Field Gathering and Processing (FG&P) customers, earning margins, managing credit exposure and providing additional value-added services to AltaGas' customers. In addition, it contracts and manages gas for AltaGas' gas-fired power-peaking plants. AltaGas also provides energy procurement services for large industrial and utility gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

Capitalizing on Opportunities

AltaGas pursues opportunities in this segment to enhance long-term unitholder value. The Trust's objectives are to:

- Increase throughput and utilization of existing facilities;
- Manage costs and improve reliability and efficiencies;
- Increase returns and mitigate volume risk by directly recovering operating costs from customers;
- Acquire and develop new gas infrastructure assets to meet customer demand;
- Enter into commercial arrangements that have long-term fixed-fee or cost-of-service components; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration with other business segments.

The Trust's Gas Segment provides safe and reliable gathering, processing, extraction, transportation, storage and distribution services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share and redeploying assets to capitalize on increased exploration and drilling activities in the Western Canada Sedimentary Basin (WCSB). AltaGas also focuses on increasing long-term, fixed-fee and cost-of-service contracts.

While the WCSB is considered to be a maturing basin, 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 basin and a return to stronger gas prices. The emergence of unconventional gas plays in the WCSB, such as Montney and Horn River, as well as increased focus on horizontal multi-frac technology are expected to provide renewed life to the basin.

Growth opportunities in the Trust's Gas Segment are expected to arise from plant modifications to increase product recoveries or throughput at facilities and by increasing interests in existing plants, acquiring facilities and constructing new facilities in emerging markets or with growing demand.

The natural gas supply to all extraction plants 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, propane heating and Canadian oil and gas industries. AltaGas' Empress extraction plants rely on Alberta supply of natural gas for natural gas export to the NOVA Gas Transmission Ltd. (NGTL) eastern gate, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. The Harmattan Complex is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Stream Project is also expected to increase processing capability at the plant. Overall, the diverse nature of its extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

Due to the integrated nature of AltaGas' businesses, 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 market demands.

AltaGas 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 dedicating to non-core activities such as processing. AltaGas also expects there to be opportunities to increase volumes by tying in new wells and building or purchasing adjoining facilities and systems to create larger franchise areas to capture operating synergies. Based on its existing infrastructure, the Trust expects to capitalize on growing natural gas production in northeast B.C. and northwest Alberta, as well as unconventional sources of gas, such as shale and coal bed methane. In addition, most of the gas compression and processing units are skid-mounted. AltaGas is able to relocate units quickly and cost-effectively to respond to the changing processing needs of its customers.

The acquisition of NGD assets in 2009 is an example of AltaGas' strategy at work. The low-risk, long-life energy infrastructure is underpinned by regulated returns and cost-of-service recovery that provide stable and predictable cash flows. The addition of Utility Group's investments, people and growth opportunities expands, diversifies and strengthens the Gas Segment. AltaGas plans to grow its existing NGD business through infill and expansion of services within current franchise areas and by developing systems in new market areas. Heritage Gas offers strong growth potential in its franchise areas, such as the 2010 planned expansion to Bedford within the Halifax Regional Municipality and through ongoing conversion of customers with existing access to natural gas. In addition, AltaGas is actively pursuing the prudent acquisition of other utility-type infrastructure and related businesses.

The Energy Services business provides gas control and gas supply contracting services to the Gas and Power segments, as well as gas storage. AltaGas pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure-based businesses. These include increasing margins earned in transmission, maintaining the cost-effective flow of gas through extraction plants and increasing services provided to producers. Energy Services also shares gas and electricity market knowledge across all AltaGas businesses and enhances the energy value chain to more effectively serve customers across Canada.

Gas Outlook

In 2010 the Gas Segment is expected to deliver stronger results compared to 2009. This increase is largely due to the addition of NGD assets in fourth quarter 2009. AltaGas expects to invest more than $56 million into property, plant and equipment to grow its average mid-year rate base by roughly $47 million or more than 18 percent in 2010. AltaGas also expects stronger results due to higher producer activity in the FG&P business along with expansions at AltaGas' existing Pouce Coupe, Ante Creek and Acme gas processing plants, a full year of Sarnia Storage and the expiration of a gas marketing contract. These increases will be partially offset by non-recurring items that provided uplift in 2009, such as the reduction of liabilities related to natural gas transactions and the decrease of Suffield revenue deferral.

In 2010, the Trust expects to invest $5.0 million in its Acme processing facility to increase capacity by 8 Mmcf/d. In addition, the Trust expects to invest approximately $11.0 million to increase capacity by 8 Mmcf/d at the Ante Creek facility. The Pouce Coupe expansion is expected to be completed in 2010, cost approximately $24.5 million and increase capacity at the facility by 18 Mmcf/d. All three projects are expected to be completed and contributing to operating income by third quarter 2010.

Based on management's analysis of historical NGL prices along with NGL published commodity prices and the current forward curve for 2010, management expects NGL frac spread prices averaging approximately $22/Bbl.

In 2010, the Trust estimates that 13 percent of extraction volumes will be exposed to frac spread. Approximately 50 percent of the exposure has been hedged at an average price of $21/Bbl.

Gas Segment Risk Management

AltaGas' gas infrastructure assets process and transport natural gas and NGLs produced in the WCSB. Utilization of these facilities is dependent on a number of factors, including natural gas supply and demand, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the long-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for market participants. The extraction business is influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes-plus as separate marketable commodities versus their value in a heat content basis within the natural gas stream.

In the energy management business, AltaGas competes with other consulting firms. In the gas services business, AltaGas' competitors range from single-person operations to large marketing and aggregation companies. The most significant risk in the Energy Services business is counterparty credit risk. The credit-intensive nature of this business requires balance sheet support to enable the execution of fixed-price natural gas purchase and sale agreements.

AltaGas manages its exposure to financial risk in the Gas Segment using the strategies outlined in the following table:

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term volume declines	
• Contract provisions underpin capital commitments. • Long-term contracts independent of throughput, such as take-or-pay, area of mutual interest, geographic franchise with economic out.	• In 2009, 30 percent of extraction ethane production sold under long-term cost-of-service contracts. • 99 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed fee. • New field gathering and processing facilities and expansions underpinned by take-or-pay contracts.
• Increase market share by expanding existing facilities or acquiring or constructing new facilities.	• Completed expansion of NGL fractionation facilities at Harmattan to increase capacity for processing of trucked-in NGL mix from additional locations. • Signed contract to expand Pouce Coupe and Ante Creek facilities to serve growing production in northeast B.C. and northwest Alberta. Currently these projects are under construction. • Completed the construction and first year of operation for the Sarnia Airport Storage Pool.
• Increase geographical and customer diversity to reduce exposure to individual customer or area of the WCSB. • Strategically locate facilities to provide secure access to gas supply.	• Approximately 260 customers, with no customer representing more than 7 percent of FG&P net revenue during 2009. • Top 10 FG&P customers represented 8 percent of consolidated net revenues in 2009. • 76 FG&P facilities in 30 operating areas in three provinces within the WCSB. • Interest in six of Canada's 10 NGL extraction facilities. • Sarnia Storage in Ontario provides opportunity to capitalize on eastern gas markets.
• Collaborate with other AltaGas businesses to increase volumes through the extraction facilities.	• Empress extraction facilities maintained high-capacity utilization through gas contracted by gas services business.
Increasing operating costs	
• Acquire large working interests to control and optimize operations and maximize efficiencies. • Contractual provisions provide for recovery of operating costs.	• 40 percent of FG&P's operating costs were recovered directly from customers in 2009 and 45 percent of Extraction and Transmission (E&T) operating costs were recovered through contract provisions in 2009. • Operate 73 of 76 FG&P facilities. • Operate all transmission assets. • Operate four of six extraction facilities. • Average FG&P working interest of 93 percent and average E&T working interest of 82 percent. • Maintenance management and field purchasing programs ensure tight cost controls and equipment reliability.
Commodity price fluctuation	
• Contracting terms, processing and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions. • Employ hedging practices to reduce exposure to frac spread volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility. • Commodity Risk Policy prohibits transactions for speculative purposes. • Have strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems, natural gas and NGL markets.	• Less than 14 percent of total extraction production was exposed to frac spreads in 2009. • Most ethane production sold under long term, cost-of-service or fee-for-service. • 60 percent of NGL production under long-term, fixed-fee arrangements. • The transmission business is not directly affected by commodity price fluctuations. • Hedged 74 percent of volumes exposed to frac spread for 2009 and 47 percent for 2010. • NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce. • Majority of FG&P contracts are volumetric service-fee structures, based on a rate per Mcf of throughput reducing direct commodity price risk compared to a percentage of price arrangement. • All gas service transactions are back to back with locked-in margins. • In majority of energy management business, AltaGas acts as agent, taking no direct commodity price risk

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Counterparty risk	
• Strong credit policies. • Continual review of counterparty credit. • Establish credit thresholds using conservative credit metrics. • Closely monitor exposures and impact of price shocks on liquidity. • Build a diverse customer and supplier base. • Base business model in energy management on agency arrangements whereby counterparty credit risk for commodity is between the supplier and end user. • Active accounts receivable monitoring and collections processes in place. • Credit mitigates included in gas processing contracts.	• Over 260 FG&P customers, with no customer representing more than 7 percent of FG&P net revenue during 2009. • Majority of the exposures are to investment-grade counterparties. • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees. • No Energy Services customer represented more than 8 percent of consolidated revenues during 2009. • In 2009 AltaGas added customers in key sectors nationwide. • AltaGas purchases natural gas from a wide array of investment-grade suppliers. • No additional allowance for doubtful accounts was required in 2009 for gas processing customers. • Liens placed on natural gas volumes owned by customers, but processed by AltaGas to collect accounts receivable in accordance with contractual terms, if necessary.
Construction risk	
• Appropriate internal management structure and processes. • Major Projects group manages and monitors significant construction projects. • Strong project control and management framework. • Engage specialists in designing and building major projects. • Contractual arrangements to recover cost overruns.	• Practised effective procurement policies and procedures and vendor selection, resulting in few overruns in 2009. • Fixed-price quotes for most major equipment components. • Redeploying equipment from underutilized plant. • Sarnia Storage completed on time and under budget.
Community support	
• Maintain active corporate and regulatory affairs department.	• Held several events to inform and educate the communities in which AltaGas is constructing and developing projects.
Regulatory risk	
• Regulatory and commercial personnel monitor and react to regulatory issues. • Proactive government relations group.	• AltaGas continued active participation in industry committees and regulatory forums in 2009.
Environment and safety risk	
• Strong safety and environmental management systems, which AltaGas continually strives to improve.	• Audits resulted in AltaGas maintaining its Certification of Recognition from Alberta Human Resources and Employment. • Performed annual third-party safety and environmental audits to ensure continued compliance and improvement. • Participated in industry programs, including the annual Safety Stand Down.
Rate-regulated environment	
• Skilled regulatory department retained. • Strong relationship with regulators maintained. • Use of expert consultants when needed.	• Alberta Utilities Commission (AUC) increased AUI's return on equity to 9 percent and its equity thickness by 200 basis points. • Nova Scotia Utility and Review Board (NSUARB) granted Heritage Gas' requested rate increases.

Power

DESCRIPTION OF ASSETS

The Power Segment includes conventional power generation in Alberta and renewable power generation in British Columbia.

Conventional Power

The conventional power business comprises 392 MW of total power generation capacity in Alberta. AltaGas owns 50 percent of the Sundance B power purchase arrangements (PPAs), giving it the rights to power output and ancillary services from 353 MW of coal-fired base-load generation until December 31, 2020. PPAs were established in 1999 under Alberta's program of power industry deregulation in order to separate ownership of the physical power generation assets from marketing of output.

In addition, AltaGas has 39 MW of gas-fired power-peaking capacity in southern Alberta. This 39 MW of gas-fired peaking capacity provides fuel diversity to AltaGas' conventional power business and partial backstopping to outages at Sundance. Due to their quick ramp-up capability, the peaking plants also provide revenue from the sale of energy and ancillary services.

Renewable Power

AltaGas' renewable power generation includes the 102-MW Bear Mountain Wind Park near Dawson Creek, British Columbia, and a 25 percent interest in a 7-MW run-of-river hydroelectric generation facility.

Bear Mountain Wind Park achieved commercial operations in October 2009. The wind park is backstopped by a 25-year electricity purchase agreement with BC Hydro. AltaGas retained the green attributes and renewable energy credits related to the project. In addition, Bear Mountain has qualified for the Federal Government of Canada's ecoEnergy renewable initiative (eRPI), which grants $10/MWh generated by the Bear Mountain Wind Park for 10 years beginning on October 31, 2009. AltaGas has entered into a long-term service agreement with Enercon GmbH to operate and maintain the wind turbines.

Capitalizing on Opportunities

AltaGas pursues opportunities in this segment to enhance long-term unitholder value. The Trust's objectives are to:

- Execute power hedge strategies as appropriate to increase earnings stability and growth from the Sundance B PPAs;
- Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy sales and ancillary services;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Capitalize on internal synergies and integration efforts with other operating lines;
- Acquire and develop power infrastructure backstopped by long-term power sales arrangements or supported by strong power supply and demand fundamentals;
- Diversify power generation portfolio by geography and fuel source;
- Develop operating capability in other energy sources; and
- Capitalize on increasing demand for clean power by investing in renewable power projects across Canada and the northern and western U.S.

AltaGas' strategy is to expand its power infrastructure to ensure the long-term sustainability of this business and offset the expiration of the Sundance B PPAs on December 31, 2020. Growth is focused on clean and renewable sources of energy.

The demand for renewable and clean generating capacity continues to be strong across North America, as industry prepares to address climate change legislation and utilities are faced with renewable portfolio standards. The poor economic environment has resulted in reduced demand for power, and in Alberta specifically, average power demand has remained essentially unchanged since 2008, notwithstanding the fact that new peak demand records were set in December 2009. AltaGas expects power demand growth to follow suit with a broader economic recovery, which will subsequently lead to a recovery in power prices. Based on broker reports published February 11, 2010, forward prices in Alberta are unsustainably low, in the high $40s/MWh. AltaGas expects that any significant new generation project that is not already committed to will be deferred until forward prices recover. The Sundance B facility is among the lowest-cost producers of power in the province, uniquely positioning AltaGas to maintain profitable operations during difficult economic conditions. The power generated by the Bear Mountain Wind Park is sold to BC Hydro at a fixed price with 50 percent CPI escalators for 25 years and is therefore not exposed to fluctuations in the market value of power.

Opportunities to develop and own additional power generation are likely to arise due to the growing North American demand for cleaner energy sources, such as natural gas, hydroelectric and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, Alberta may prompt additional growth opportunities to develop new clean power generation capacity. The 102-MW Bear Mountain Wind Park, which commenced commercial operations October 24, 2009, is an example of a clean energy project and of AltaGas' strategy in action.

AltaGas has approximately 1,900 MW of renewable power under development, including 1,500 MW of wind power developments and 400 MW of run-of-river hydroelectric developments. The wind projects are geographically dispersed in western North America, with 500 MW in Canada and 1,000 MW in the northern and western United States, while the run-of-river projects are focused in British Columbia.

Power Outlook

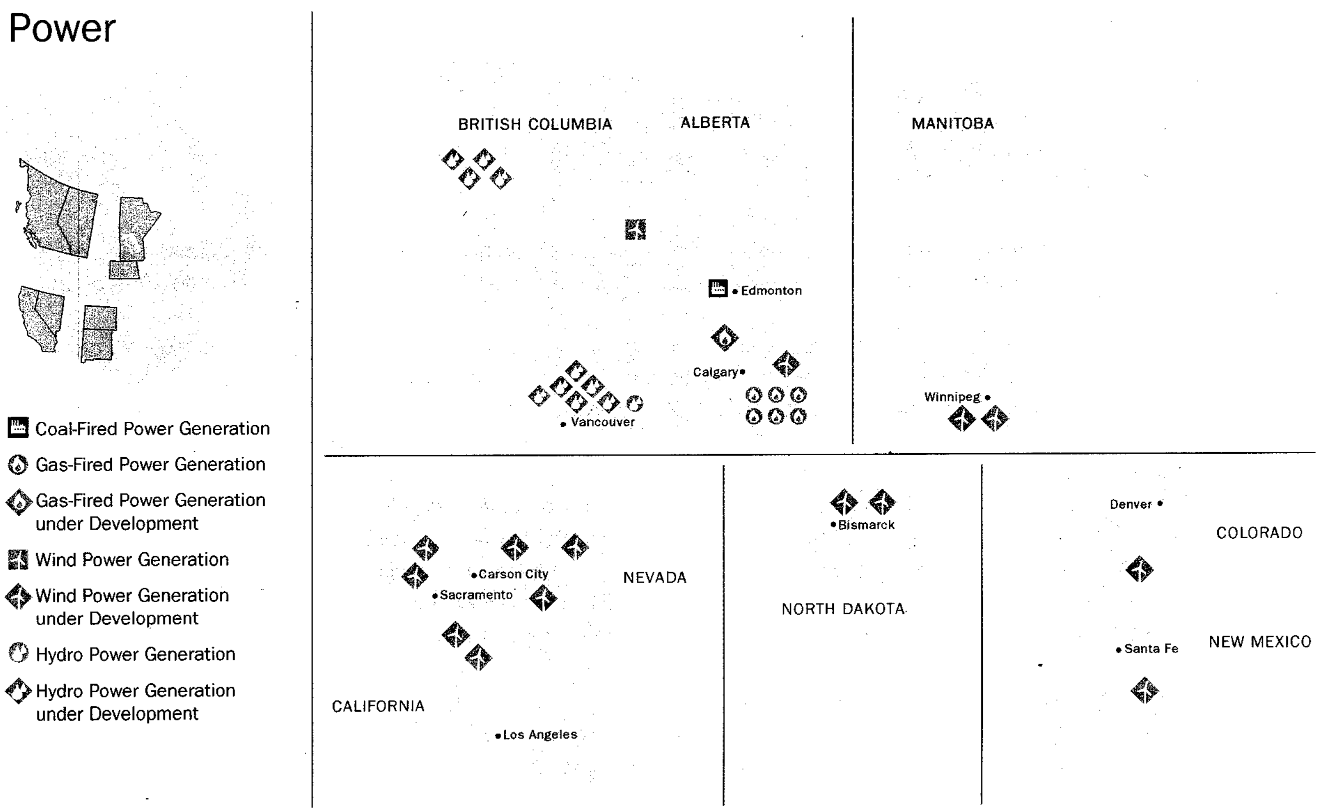
In 2010 almost two-thirds of the power delivered to the Alberta Power Pool from the Sundance Plant is hedged at a price of $72, slightly lower than the average hedge price in 2009. Current forward prices, as published in daily broker reports, are in the high $40's/MWh for the balance of 2010. This reflects a temporary oversupply situation in the Alberta Power market that management does not believe is sustainable over the long term. According to the Alberta Electric System Operator (AESO), if the demand for power and the rate of growth in Alberta continues as forecast, the addition of up to 3,800 MW of new generation may be required by 2016. A large coal unit in Alberta is expected to be retired during 2010, resulting in a reduction of supply that will not be fully replaced in the near term, and improved economic conditions are expected to bring increased power demand to the province. Offsetting weakness in the spot market will be the impact of a full-year contribution from Bear Mountain Wind Park, as well as the anticipated addition of the Harmattan Co-generation facility, currently expected to be on-line in the fourth quarter of 2010.

AltaGas is constructing a 13-MW gas-fired co-generation facility at its Harmattan Complex, which is expected to cost approximately $22 million. The co-generation facility will deliver power to the Alberta electrical grid and use steam to provide process heat to the Harmattan Complex. This is a highly efficient process of generating power and will reduce greenhouse gas emissions. It also adds further diversity to AltaGas' portfolio of generation assets and will provide another source of capacity to backstop the Sundance B PPAs. The facility is expected to be commissioned in fourth quarter 2010.

Risk Management

The main risks faced in the Power Segment are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risks related to the deregulation of power, market regulation and environmental legislation. Power results are generally driven by volumes of power generated, hedge prices, spot power prices and the cost of power and transmission.

Power



Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth. The cost of power is driven by operating costs, changes in transmission rates and power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table:

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Power price volatility	
• Disciplined hedging strategy with hedge targets approved by the Board of Directors. • Monitor hedge transactions through Risk Management Committee. • In-depth Alberta power market knowledge and experience. • Hedge own electrical demand requirements. • Own and operate gas-fired peaking capacity to backstop PPAs and sell energy and ancillary services.	• Financial hedge contracts generally have terms ranging from one month to three years. • Average sales price received in 2009 was $69.37/MWh, compared to average monthly Alberta Power Pool price range of $31.53/MWh to $92.97/MWh. • Supplied approximately 14 MW for own use in 2009. • Supplied approximately 60 MW to Alberta power retail customers under one- to five-year contracts. • Peaking plants contributed $4.1 million to net revenue in 2009 through sales of ancillary services and energy.
Volume of power generation	
• PPAs include specified target availability levels. • Diversification of fuel sources and geography. • Hedging strategy to balance price and operating risk. • Reciprocal backstopping agreements with another generator to supply power at a fixed price during force majeure events.	• The operator of the Sundance B plant is obligated to provide AltaGas financial compensation for shortfalls below the specified target availability level, which was 86 percent of rated capacity in 2009. Payment is based on the difference between actual and target availability multiplied by the 30-day rolling average power price (RAPP). • 39 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs. • Wind and hydro power projects under development. • Bear Mountain Wind Park in commercial service. • Power delivered from a total of 67 independent generation sources.
Cost of power	
• Hedge power costs. • Avoid commodity price exposure on electricity energy sources.	• Cost of power from the coal-fired generation based on PPA indices not market price of coal. • Modest decrease in cost of power from Sundance PPAs in 2009.
Counterparty risk	
• Strong credit policies. • Continual review of counterparty credit. • Establish credit thresholds using conservative credit metrics. • Closely monitor exposures and impact of price shocks on liquidity.	• All relevant policies and processes were maintained in 2009. • All financial hedge counterparties are investment-grade. • No counterparty defaults in 2009. • Alberta retail credit risk has little impact on hedge portfolio on an individual basis. In the event of a default, AltaGas can sell the power on the spot market.
Construction risk	
• Major Projects group manages and monitors significant construction projects. • Strong project control and management framework.	• Completed Bear Mountain Wind Park ahead of schedule and on budget.
Community support	
• Active corporate and regulatory affairs departments.	• Held several events to inform and educate the communities in which AltaGas is constructing and developing projects.
Regulatory risk	
• Appropriate human resources deployed on regulatory issues. • Build risk mitigation into contracts where possible.	• AltaGas' Sundance B PPAs have provisions for financial relief in the event that policies and regulations render PPAs uneconomic. • AltaGas personnel participate in industry policy and oversight committees.

Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Environment and safety risk	
• Strong safety and environmental management systems, which AltaGas continually strives to improve. • Focus on mitigating the impact of the Alberta Specified Gas Emitters Regulation (SGER).	• Bear Mountain Wind Park generates emission credits. • Bantry and Parkland gas-fired peaking plants compress natural gas to drive the peaking plant starter motors. The compressed gas is then captured and cycled through the peaking plants rather than vented into the environment. • Potentially generate offsets and emissions performance credits from existing AltaGas operating facilities. • Possible offset of Alberta SGER costs through higher Alberta Power Pool prices.

CONSOLIDATED RESULTS

Years ended December 31

($ millions)	2009	2008	2007
Revenue	1,268.3	1,816.8	1,428.4
Unrealized gain (loss) on risk management	3.7	11.0	1.1
Net revenue [1]	456.6	476.5	324.0
EBITDA [1]	248.4	256.4	173.7
EBITDA before unrealized gain (loss) on risk management [1]	244.7	245.4	172.6
Operating income [1]	174.2	188.0	126.6
Net income	141.3	163.6	108.8
Net income before tax-adjusted unrealized gain (loss) on risk management [1]	139.7	158.0	109.3
Total assets	2,629.1	2,132.3	1,172.7
Total long-term liabilities	719.1	851.6	313.5
Net additions of capital assets	486.5	808.0	21.8
Distributions declared [2,3]	170.2	147.1	118.6
Cash flows			
Cash from operations	184.1	205.2	183.3
Funds from operations [1]	202.3	216.8	162.9

($ per unit except as noted)			
EBITDA [1]	3.16	3.73	3.03
EBITDA before unrealized gain (loss) on risk management [1]	3.12	3.57	3.01
Net income	1.80	2.38	1.90
Net income per diluted unit	1.79	2.36	1.89
Net income before tax-adjusted unrealized gain (loss) on risk management [1]	1.78	2.30	1.90
Distributions declared [2,3]	2.160	2.125	2.065
Cash flows			
Cash from operations	2.34	2.98	3.19
Funds from operations [1]	2.58	3.15	2.84
Units outstanding (millions)			
Weighted average number of units outstanding for the year (basic)	78.5	68.8	57.4
Weighted average number of units outstanding for the year (diluted)	79.4	69.7	57.4
End of year	80.3	71.9	58.1

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

2 Distributions declared of $0.180 per unit per month commencing August 2008, $0.175 per unit per month from August 2007 to July 2008. From August 2006 to July 2007, distributions of $0.170 per unit per month were declared. From March 2006 to July 2006, distributions of $0.165 per unit per month were declared. From August 2005 to February 2006, distributions of $0.160 per unit per month were declared.

3 Excludes special distribution of AltaGas Utility Group Inc. shares in September 2007, providing an additional non-cash distribution of $0.076 per unit.

2009 CONSOLIDATED FINANCIAL REVIEW

Net income for 2009 was $141.3 million compared to $163.6 million in the same period in 2008, which included a one-time tax recovery of $13.8 million. Excluding this recovery, net income for 2008 was $149.8 million or $8.5 million higher than the current period. Net income was $1.80 per basic unit for 2009 compared to $2.38 per basic unit for 2008.

During 2009, the Gas Segment performed well due to a reduction of liabilities related to natural gas transactions, higher extraction volumes, the addition of NGD assets in fourth quarter 2009, no major extraction turnarounds and a one-time adjustment to transmission revenues previously deferred. These increases were partially offset by lower processing volumes at FG&P facilities as producers reduced drilling activities and shut-in production in response to weak gas prices and lower realized frac spreads. The Power Segment reported lower results primarily due to declines in realized power prices but benefited from lower transmission and environmental costs as well as contributions from Bear Mountain Wind Park, which commenced commercial operations in fourth quarter 2009. The Corporate Segment benefited from higher investment income offset by lower unrealized gains on risk management contracts compared to 2008. The Trust reported higher interest expense in 2009 compared to 2008 due to higher average debt balances and a higher average borrowing rate. Income tax expense was higher in 2009 due to a one-time tax recovery of $13.8 million in 2008, partially offset by the tax impact for financial instruments and lower income subject to tax.

On a consolidated basis, net revenue for 2009 was $456.6 million compared to $476.5 million in 2008. In the Gas Segment, net revenue increased due to the addition of the NGD assets in fourth quarter 2009, higher extraction volumes, adjustments to liabilities, previously deferred transmission revenues, contribution from Sarnia Storage and expanded transmission business. These increases were partially offset by lower throughput in most FG&P areas, lower frac spreads and lower operating cost recoveries. In the Power Segment, net revenue decreased due to lower spot power prices in Alberta, the gain on assets sold in 2008 and lower contribution from gas-fired peaking plants, partially offset by strong hedge prices and lower PPA and transmission costs. The Corporate Segment reported higher net revenue due to investment income, partially offset by lower unrealized gains on risk management contracts.

Operating and administrative expense for 2009 was $208.2 million, down from $221.5 million in 2008. The decrease was largely due to fewer turnarounds compared to prior year, when approximately $7.4 million of turnaround costs were recorded. The decrease is further explained by a $2.6 million charge for project development costs in 2008. Cost control measures have also resulted in a decline in administrative costs. These decreases were partially offset by incremental costs associated with the growth of the Trust, including the addition of NGD assets.

Amortization expense for 2009 was $74.1 million compared to $67.0 million last year. The increase was due to the growth in AltaGas' asset base from acquisitions and construction activities.

Interest expense in 2009 was $31.8 million compared to $27.4 million in 2008. The increase was due to higher average debt balances of $691.5 million compared to $581.0 million in 2008. The average borrowing rate was 5.6 percent in 2009 compared to 5.3 percent in 2008.

Income tax expense in 2009 was $1.2 million compared to a recovery of $1.6 million in 2008. The increase was largely due to a one-time $13.8 million recovery of future income taxes in third quarter 2008 as a result of legal entity ownership changes within the Trust structure, partially offset by the tax impact for financial instruments and lower income subject to tax.

2008 CONSOLIDATED FINANCIAL REVIEW

Financial results for 2008 reflect the strong operating performance of AltaGas' energy infrastructure assets. In 2008 the Trust increased its assets by approximately $600 million as a result of the Taylor acquisition. The Trust also completed approximately $50 million of growth and enhancement initiatives in late 2008 at the Harmattan Complex. Net income increased by 50 percent year-over-year. The Gas and Power Segments each reported year-over-year operating income increases of 75 percent and 25 percent, respectively. The Gas Segment reported strong results despite turnarounds at four extraction facilities in 2008, which resulted in lost revenues of $3.7 million, operating costs of $4.3 million and a major turnaround at one field processing facility, which resulted in $1.0 million in lower operating income. The Power Segment reported strong results due to higher power prices realized on both spot and hedged sales as well as higher contributions from the gas-fired peaking plants. The Trust recorded higher interest costs mainly due to the increased debt balances as a result of the Taylor acquisition and lower taxes primarily as a result of changes within the Trust's legal structure.

Net income in 2008 was $163.6 million ($2.38 per unit – basic) compared to $108.8 million ($1.90 per unit – basic) in 2007. Excluding a $13.8 million reduction in future tax liability related to changes in the Trust structure and a $5.6 million after-tax gain on risk management contracts, net income was $144.2 million ($2.10 per unit – basic). Excluding the Specified Investment Flow-Through (SIFT) tax of $5.4 million and a $6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in 2007, net income in 2007 was $108.1 million ($1.88 per unit – basic).

Operating income across all segments increased by 50 percent to $188.0 million in 2008 compared to $126.6 million in 2007.

Operating income from the Gas Segment was $103.6 million in 2008 compared to $59.3 million in 2007. In the Power Segment, operating income was $117.9 million in 2008 compared to $94.6 million in 2007. In 2008 operating income from the Gas and Power Segments was 47 percent and 53 percent, respectively, of total business operating income compared to 39 percent and 61 percent, respectively, for 2007. The improved balance between the Gas and Power Segments reflects the impact of the Trust's strategy to have a more balanced portfolio of assets.

In the Gas Segment, operating income increased mainly due to the larger energy infrastructure asset base as a result of the Taylor acquisition, higher rates and other revenues in FG&P and higher frac spreads, partially offset by lower throughput due to declines, planned and unplanned downtime in certain FG&P areas and lower volumes processed at the extraction plants owned prior to January 2008. The Gas Segment reported strong results despite approximately $10 million impact of five extraction plant turnarounds, planned and unplanned downtime at some field processing facilities and a fire at the Harmattan Complex.

In the Power Segment, operating income increased due to higher average power prices, higher contributions from the peaking plants, a deferral account settlement from the AESO and a gain on the sale of one of the Trust's power development projects, partially offset by a more favourable RAPP in 2007, higher transmission costs and higher environmental compliance costs.

The operating loss in the Corporate Segment increased primarily due to higher costs to support the growth of the Trust, general cost escalations and lower investment income, partially offset by the unrealized gain reported on risk management contracts.

Consolidated net revenue for 2008 was $476.5 million compared to $324.0 million in 2007. In the Gas Segment, net revenue increased due to the addition of extraction, processing and transmission facilities, higher operating cost recoveries, higher rates and other revenues in FG&P and higher frac spreads. These increases were partially offset by lower throughput in certain FG&P areas, the sale of non-core assets in mid-2007, lower fixed-price gas and transport sales and lower volumes processed at the extraction plants owned prior to the acquisition of the Taylor extraction facilities. In the Power Segment, net revenue increased due to higher average price realized on the sale of power, higher contributions from the peaking plants, a deferral account settlement from the AESO and the gain on sale of a power development project, partially offset by a higher RAPP in 2007, higher transmission and environmental compliance costs.

Operating and administrative expense for 2008 was $221.5 million compared to $150.3 million in 2007. The increase was due to costs related to new facilities, turnaround costs and higher compensation and administrative costs.

Operating costs included approximately $8.0 million related to turnaround costs incurred during the year. Approximately 36 percent was recovered. Administrative costs included approximately $2.0 million in non-recurring technology costs.

Amortization expense for 2008 was $67.0 million compared to $47.1 million in 2007. The increase was primarily due to new and expanded facilities in the Gas Segment, partially offset by the disposition of non-core assets in the second quarter of 2007. Administrative costs include approximately $2.0 million in non-recurring technology costs.

Interest expense in 2008 was $27.4 million compared to $11.9 million in 2007. The increase was primarily due to higher average debt balances of $581.0 million in 2008 compared to $234.9 million in 2007. The average borrowing rate for 2008 was 5.3 percent, which was consistent with 2007.

Income tax recovery for 2008 was $1.6 million compared to income tax expense of $5.9 million in 2007. Income tax expense was lower as a result of certain tax planning initiatives undertaken by management in 2008. The income tax expense was lower by $11.8 million as a result of applying a lower tax rate to the future income tax liability that arose from changes in the legal entity structure of the Trust. This internal reorganization had the added benefit of reducing income tax expense by $13.3 million through use of higher intercompany interest offset by income taxes of $12.0 million due to higher operating income. The lower 2008 income tax expense was partially offset by $2.3 million in current taxes from the sale of a power project, $1.7 million due to higher mark-to-market gains on risk management contracts and $1.5 million due to an adjustment for the estimated tax asset basis of the Trust. For comparative purposes, the enactment of the SIFT tax during 2007 increased income tax expense by $5.3 million. Later in the same year, income tax expense was reduced by $5.4 million due to the federal income tax rate reductions.

GLOBAL CAPITAL MARKET CONDITIONS

Although uncertainty in global financial markets persisted in 2009, AltaGas' financial position and ability to generate cash from its operations in the short and long terms have remained strong.

Throughout 2009, the Trust demonstrated its ability to access capital markets. In February AltaGas completed an equity offering that generated gross proceeds of approximately $100 million, and in March the Trust secured a new $250 million credit facility with a syndicate of eight banks. AltaGas also completed two issuances of medium-term notes (MTN) in second quarter 2009 for total proceeds of $300 million.

The Trust's liquidity position remains sound, underpinned by highly predictable cash flow from operations, as well as revolving bank lines of $816.0 million, of which $262.2 million was available as at December 31, 2009 and strong participation in the distribution reinvestment plan (DRIP).

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2010 to be approximately $225 million, 70 percent for gas and 30 percent for power. To date, approximately $80 million of capital has been committed for 2010. Growth capital is funded through AltaGas' cash from operations, DRIP proceeds and credit facilities. The following projects have an expected in-service date post-2010.

Harmattan Co-stream Project

On April 23, 2009, AltaGas submitted its application for the Harmattan Co-stream Project to the ERCB. The project, as currently designed, is expected to cost in the range of $100 to $120 million. The project will allow 250 Mmcf/d of rich, sweet natural gas sourced from the NGTL Western Alberta System to be processed using spare capacity at the Harmattan Complex to recover ethane and NGL. AltaGas expects a favourable decision from the ERCB in the near future and expects the project to commence operations in late 2011.

On July 6, 2009, AltaGas entered into a Memorandum of Understanding (MOU) with NOVA Chemicals Corporation (NOVA Chemicals). The MOU provides that the definitive agreements between AltaGas and NOVA Chemicals would be for an initial term of 20 years, AltaGas would deliver all liquids or co-stream gas products on a full cost-of-service basis to NOVA Chemicals and would provide that all capital expenditures and operating costs related to the proposed project be fully recovered through fees under normal operations. The MOU is subject to normal conditions precedent, including execution and delivery of mutually satisfactory definitive agreements between AltaGas and NOVA Chemicals, a favourable decision on the Harmattan Co-stream application currently under review by the ERCB and approval by the boards of directors of AltaGas and NOVA Chemicals.

Alton Gas Storage Project

AltaGas has made an offer to acquire Landis Energy Corporation, which is a developer of underground natural gas storage facilities. The most advanced project under development by Landis is the Alton natural gas storage project, located near Truro, Nova Scotia, which is expected to serve customers seeking to manage natural gas supply requirements in eastern Canada and the northeast United States.

Walker Ridge Project

AltaGas is developing the 70-MW Walker Ridge wind project in northern California. AltaGas has selected the turbines and a preliminary layout and has completed the preliminary engineering studies. The project is located near existing transmission lines and requires limited system upgrades to interconnect. It is located in Lake Colussa County, close to San Francisco load. This project is proceeding with the environment and land permitting process, and AltaGas is actively seeking bilateral agreements for sale of the power output.

Glenridge Project

AltaGas is developing the 100 MW Glenridge wind project in southeast Alberta. AltaGas has secured a 17,000 acre land package and has applied to the Federal Government of Canada for eRPI funding. AltaGas has completed its AESO transmission system impact study and expects to submit its AUC application and begin the facilities study in first quarter 2010. AltaGas is actively seeking a market for its prospective green credits. Once in service, the project will use these green credits to offset compliance costs associated with the Trust's Sundance B PPA.

Roughrider Project

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

AltaGas continues to advance its early-stage wind development projects by setting up meteorological towers to collect wind data, and initiating permit applications and transmission studies.

Hydroelectric

AltaGas is developing a portfolio of run-of-river hydroelectric projects in the province of British Columbia (B.C.), including three projects in northwest B.C.: Forrest Kerr, McLymont Creek and Volcano Creek (collectively, NW Projects). The NW projects have a combined generating capacity of approximately 277 MW and are currently the subject of discussions with the Government of B.C. These discussions include considerations relating to the announcement by the Government of B.C. to upgrade and extend the electricity transmission capabilities in B.C.'s northwest, specifically the Northwest Transmission Line (NTL). The NTL upgrade would extend the British Columbia Transmission Corporation's (BCTC) transmission grid to within 44 km of the NW Projects.

Log and Kookipi Creek Run-of-River Projects

AltaGas is advancing engineering studies, preparing comprehensive environmental submissions and engaging with First Nations to support the development of the Log and Kookipi Creek projects. Located in southern British Columbia, these two 10-MW capacity run-of-river projects have 40-year electricity sales agreements with BC Hydro. Subject to successful conclusion of permitting and other activities, construction of these two projects is expected to begin in 2011 with an in-service in 2013.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (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. All of the measures have been calculated to be consistent with previous disclosures. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and its capacity to fund distributions, capital expenditures and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to net revenue, operating income, EBITDA, EBITDA before unrealized gain (loss) on risk management, net income before tax-adjusted unrealized gain (loss) on risk management, net income before tax and funds from operations throughout this document have the meanings as set out in this section.

Net Revenue

Years ended December 31 ($ millions)	2009	2008	2007
Net revenue	456.6	476.5	324.0
Add:			
Cost of sales	811.7	1,340.3	1,104.4
Revenue (GAAP financial measure)	1,268.3	1,816.8	1,428.4

Net revenue, which is revenue 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 natural gas and power affect both revenue and cost of sales.

Operating Income

Years ended December 31 ($ millions)	2009	2008	2007
Operating income	174.2	188.0	126.6
Add (deduct):	(31.8)	(27.4)	(11.9)
Interest			
Foreign exchange gain	-	1.4	–
Income taxes	(1.2)	1.6	(5.9)
Net income (GAAP financial measure)	141.3	163.6	108.8

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. The measure is used by management to assess the operating performance of the business segments since it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization.

EBITDA

Years ended December 31 ($ millions)	2009	2008	2007
EBITDA	248.4	256.4	173.7
Add (deduct):			
Amortization and goodwill impairment	(74.1)	(67.0)	(47.1)
Interest	(31.8)	(27.4)	(11.9)
Income taxes	(1.2)	1.6	(5.9)
Net income (GAAP financial measure)	141.3	163.6	108.8

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to accounting for how these activities are financed, assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

EBITDA Before Unrealized Gains on Risk Management

Years ended December 31 ($ millions)	2009	2008	2007
EBITDA before unrealized gains on risk management	244.7	245.4	172.6
Add (deduct):			
Unrealized gains on risk management	3.7	11.0	1.1
Amortization and goodwill impairment	(74.1)	(67.0)	(47.1)
Interest	(31.8)	(27.4)	(11.9)
Income taxes	(1.2)	1.6	(5.9)
Net income (GAAP financial measure)	141.3	163.6	108.8

EBITDA before unrealized gain on risk management is a measure of the Trust's operating profitability without the impact of the change in fair value of risk management contracts. EBITDA before unrealized gain on risk management reports the results of the Trust's principal business activities on a realized basis and prior to how business activities are financed, assets are amortized or how the results are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, and therefore evaluates company performance excluding unrealized gain from risk management activities. EBITDA before gains or losses on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gain (loss) on risk management less operating and administrative expenses.

Net Income Before Tax-Adjusted Unrealized Gains on Risk Management

Years ended December 31 ($ millions)	2009	2008	2007
Net income before tax-adjusted unrealized gains on risk management	139.7	158.0	109.3
Add (deduct):			
Unrealized gains on risk management	3.7	11.0	1.1
Income tax expense on risk management	(2.1)	(5.4)	(1.6)
Net income (GAAP financial measure)	141.3	163.6	108.8

Net income before tax-adjusted unrealized gain on risk management is a better reflection of actual performance than net income, since changes related to risk management are based on unrealized estimates relating to commodity prices, interest rates and foreign exchange rates over time. AltaGas enters into financial instruments to manage risk, not as a principal business activity, and therefore evaluates performance prior to accounting for the unrealized gain from risk management activities. Net income before tax-adjusted unrealized gain on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net income adjusted for unrealized gain on risk management and its related income tax expense.

Funds from Operations

Years ended December 31 ($ millions)	2009	2008	2007
Funds from operations	202.3	216.8	162.9
Add (deduct):			
Net change in non-cash working capital and asset retirement obligations settled	(18.2)	(11.6)	20.4
Cash from operations (GAAP financial measure)	184.1	205.2	183.3

Funds from operations is used to assist management and investors in analyzing financial performance without regard to changes in the Trust's non-cash working capital in the period. 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 is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement obligations.

RESULTS OF OPERATIONS BY SEGMENT

Operating Income

Year ended December 31 ($ millions)	2009	2008
Gas	110.3	103.6
Power	88.0	117.9
Corporate	(24.1)	(33.5)
	174.2	188.0

GAS

SEC File # 82-34911

Operating Income

Year ended December 31 ($ millions)	2009	2008
E&T	88.6	83.8
FG&P	6.3	20.4
NGD	7.4	–
Energy Services	8.0	(0.6)
Total Gas operating income	110.3	103.6

Operating income from the Gas Segment was $110.3 million in 2009 compared to $103.6 million in 2008. In 2009, the Gas Segment focused on integrating both acquired and constructed assets. Operating income generated from both the new NGD assets and Sarnia Storage contributed to the increase in operating income. The Trust also focused on optimizing its existing business units to improve operating income, including a positive adjustment to transmission revenues that were previously deferred and liabilities related to natural gas transactions, higher NGL volumes, higher contracted volumes in the transmission business and higher extraction volumes processed in part due to no major turnarounds in 2009. These increases to operating income were partially offset by lower throughput in most FG&P areas due to lower producer activity and gas well shut-ins during 2009. Lower realized frac spreads received, lower fixed-price natural gas transportation sales and one turnaround in the FG&P business also contributed to lowering operating income.

Net revenue in the Gas Segment for 2009 was $340.1 million compared to $334.2 million in 2008. Net revenue increased $9.4 million from a reduction of liabilities related to natural gas transactions, $6.0 million due to higher NGL volumes, $4.5 million due to increased transmission revenues, which included a one-time adjustment of $3.3 million for revenues that were previously deferred and increased contracted volumes, $3.9 million as a result of the 2008 capital program at the Harmattan Complex and $3.8 million due to the addition of Sarnia Storage. Net revenue also increased $7.4 million due to the acquisition of NGD assets in fourth quarter 2009. These increases were partially offset by $12.7 million in lower realized frac spreads, $12.4 million in lower volumes processed at FG&P facilities, $4.3 million due to lower fixed-price natural gas transportation sales, $3.2 million from lower facility service revenues and $1.0 million due to a gas marketing contract that expired in fourth quarter 2009.

Operating and administrative expense for 2009 was $166.4 million, down from $173.2 million in 2008. The decrease was largely due to fewer turnarounds than 2008, when approximately $7.4 million of turnaround costs were recorded. The decrease is further explained by a $2.6 million charge for project development costs in 2008. Cost control measures have also resulted in a decline in administrative costs. These decreases were partially offset by incremental costs associated with the addition of new assets and businesses acquired by the Trust during the second half of 2008 and fourth quarter 2009.

Amortization expense for 2009 was $63.4 million compared to $57.3 million in 2008. The increase was due to the growth in AltaGas' asset base from acquisition and construction activities.

Extraction and Transmission (E&T) Variance Analysis

Operating income in the E&T business for 2009 was $88.6 million compared to $83.8 million in 2008. Operating income increased $6.0 million due to higher NGL volumes, $4.5 million from increased transmission revenues, of which $3.3 million was a one-time adjustment for revenues previously deferred and increased contracted transmission volumes, $3.9 million as a result of the 2008 Harmattan Complex capital program, lower operating costs of $2.9 million and $1.3 million due to the EDS upgrade and increased transmission cost-of-service fees. These increases were partially offset by $12.7 million in lower realized frac spreads, $2.7 million of higher amortization related to 2008 capital programs and $0.6 million due to lower fees-for-service revenues in the extraction business.

Field Gathering and Processing (FG&P) Variance Analysis

Operating income from the FG&P business was $6.3 million in 2009 compared to $20.4 million in 2008. Operating income decreased by $12.4 million due to lower throughput, $3.2 million due to lower facility service revenues and $1.0 million due to higher amortization. These decreases were partially offset by $2.5 million from lower operating costs and $1.0 million due to lower turnaround costs in 2009 compared to 2008.

Natural Gas Distribution Variance (NGD) Analysis

Operating income for the NGD business has been included in 2009 with the acquisition of Utility Group effective October 8, 2009 and the remaining 75.1 percent of Heritage Gas effective November 18, 2009. The results of NGD assets are highly seasonal, with the majority of natural gas deliveries occurring during the winter heating season. For 2009, the NGD business contributed $7.4 million to operating income.

Energy Services Variance Analysis

Operating income in the Energy Services business was $8.0 million for 2009 compared to an operating loss of $0.6 million for 2008. Operating income increased approximately $9.4 million as a result of the reduction of liabilities related to natural gas transactions, $3.2 million from Sarnia Storage and $1.0 million loss in 2008 as a result of a gas marketing contract that expired in early fourth quarter 2009. These increases were partially offset by $4.3 million in lower fixed-price natural gas and transportation sales and a one-time loss of $0.8 million for risk management contracts.

GAS OPERATING STATISTICS

Year ended December 31	2009	2008
E&T		
Extraction inlet gas processed (Mmcf/d) [1]	841	801
Extraction ethane volumes (Bbls/d) [1]	26.817	24,795
Extraction NGL volumes (Bbls/d) [1]	13.236	12,242
Total extraction volumes (Bbls/d) [1]	40,053	37,037
Frac spread – realized ($/Bbl) [1,2]	23.46	26.97
Frac spread – average spot price ($/Bbl) [1]	19.51	28.79
Transmission volumes (Mmcf/d) [1,3]	324	379
FG&P		
Processing capacity (Mmcf/d) [4]	1.172	1,172
Processing throughput (gross Mmcf/d) [1]	453	541
Capacity utilization (%) [4]	39	46
Average working interest (%) [4]	93	92
NGD		
Natural gas deliveries – end-use (PJ) [5,6]	6.62	–
Natural gas deliveries – transportation (PJ) [5,6]	0.55	–
Service sites at year-end [7]	72.717	–
Degree day variance (%) [8]	9.9	–
Energy Services		
Energy management service contracts [9]	1.748	1,711
Average volumes transacted (GJ/d) [10]	354.513	302,392

1 Average for the period.
2 Indicative frac spread or NGL margin, expressed in dollars per barrel of NGL and derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.
3 Excludes NGL pipeline volumes.
4 As at the end of the reporting period.
5 Petajoule (PJ) is one million gigajoules (GJ).
6 Deliveries reflect Utility Group as of October 8, 2009, when the Trust obtained control, and 100% of the deliveries of Heritage Gas as of November 18, 2009.
7 Service sites reflect all of the service sites of AUI, Heritage Gas and Inuvik Gas.
8 Degree days relate to AUI's service area. A degree day is the cumulative extent to which the daily mean temperature falls below 15°C. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations.
9 Active energy management service contracts at the end of the reporting period.
10 Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

Average ethane and NGL volumes in the extraction business increased by 2,022 Bbls/d and 994 Bbls/d, respectively, in 2009 compared to 2008 due to the completion of projects that attracted approximately 25 Mmcf/d of incremental natural gas at the Harmattan Complex for the full year compared to two months in 2008 and higher throughput at Younger, Harmattan and Joffre due to no turnarounds in 2009. The increases were partially offset by intermittent curtailment of inlet gas at other extraction plants in response to lower frac spreads in early 2009. Natural gas volumes transported in the transmission business in 2009 decreased from 2008 due to lower volumes moved on the Suffield system. However, in the transmission business, pipeline throughput has minimal impact on the financial results due to cost-of-service and take-or-pay contractual arrangements in place.

In FG&P, throughput in 2009 averaged 453 Mmcf/d compared to 541 Mmcf/d in 2008. Approximately 65 percent (57 Mmcf/d) of the decline was due to lower producer activity not offsetting natural declines, approximately 20 percent was due to producers shutting-in natural gas production due to low commodity prices in the latter half of the year and the remainder was due to planned and unplanned downtime. Utilization reported in 2009 was 39 percent compared to 46 percent in 2008, primarily due to lower throughput at most facilities. In response to low natural gas prices, several of AltaGas' customers temporarily shut-in production at some facilities during the latter half of 2009.

POWER

Operating income in the Power Segment in 2009 was $88.0 million compared to $117.9 million in 2008. During 2009, the Power Segment was focused on the completion of Bear Mountain Wind Park, which reached commercial operation ahead of schedule and on budget. Contributions from Bear Mountain and a strong hedging program were more than offset by lower spot power prices.

Net revenue for 2009 was $102.2 million compared to $129.0 million for 2008. Net revenue decreased $26.8 million due to lower spot prices in Alberta, which averaged $47.84/MWh in 2009 compared to an average of $89.95/MWh in 2008. Net revenue was also lower due to a $1.6 million gain on the sale of a power project under development reported in 2008. The peaking plants reported $2.4 million lower net revenue due primarily to lower power prices in Alberta and $1.2 million higher PPA costs. These decreases were partially offset by lower transmission costs of $7.0 million, $3.0 million due to the commencement of commercial operations at Bear Mountain and $2.3 million of lower environmental costs.

Operating and administrative expense was $6.1 million for 2009 compared to $3.7 million for 2008. The increase was due to costs related to the development of renewable energy projects and increased costs related to the gas-fired peaking plants commissioned in late 2008 and the commencement of commercial operations at Bear Mountain.

Amortization expense was $8.2 million in 2009 compared to $7.4 million in 2008. The increase was due to the gas-fired peaking plants commissioned in late 2008.

POWER OPERATING STATISTICS

Year ended December 31	2009	2008
Volume of power sold (GWh) [1]	2.726	2,623
Average price realized on the sale of power ($/MWh) [1]	68.97	84.51
Alberta Power Pool average spot price ($/MWh) [2]	47.84	89.95

1 Average for the period.
2 Includes only Alberta volumes and prices realized on the sale of power.

CORPORATE

Description of Corporate Assets

The Corporate Segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity and return on capital without the impact of the volatility in commodity prices, interest rates and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity since risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate Segment.

Corporate Variance Analysis

The operating loss for 2009 was $24.1 million compared to $33.5 million for 2008. The decreased loss was mainly due to realized and unrealized gains from investments, higher investment income and last year's charge for project development costs. These decreases were partially offset by lower unrealized gains on risk management contracts.

Net revenue was $18.6 million in 2009 compared to $12.9 million in 2008. Net revenue increased $13.4 million due to increased investment income, partially offset by $7.7 million in lower unrealized gains on risk management contracts.

Operating and administrative expense was $40.1 million in 2009 compared to $44.1 million in 2008. Increased expenses were incurred to support regulatory requirements and growth of the Trust but were more than offset as a result of several initiatives to reduce general and administrative expenses. The overall decrease was primarily due to these cost-controlling efforts.

Amortization expense was $2.5 million in 2009 compared to $2.2 million in 2008.

Corporate Outlook

Excluding the impact of mark-to-market accounting, the operating loss for 2010 is expected to be higher than the loss reported in 2009. Operating and administrative expenses are expected to be higher than 2009 as a result of the growth of the Trust as well as the cost of converting to a corporation and meeting new financial reporting requirements. The Corporate Segment is also expected to report lower earnings from equity investments since Utility Group is no longer reported as an equity investment.

The effects of risk management contracts are based on estimates relating to commodity prices, interest rates and foreign exchange rates over time. The actual amounts will vary based on these drivers, and management is therefore unable to predict the impact of financial instruments. However, the impact of the accounting standards is expected to be relatively low as the Trust uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked-in margins. The Trust does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2009, AltaGas acquired capital assets, long-term investments and other assets for $499.2 million compared to $824.8 million in same quarter 2008.

Net Invested Capital – Investment Type

Year ended December 31, 2009 ($ millions)	Gas Segment	Power Segment	Corporate Segment	Total
Invested capital:				
Capital assets	324.0	160.3	3.2	487.5
Long-term investments and other assets	(12.3)	(0.4)	24.4	11.7
	311.7	159.9	27.6	499.2
Disposals:				
Capital assets	(0.2)	(0.7)	(0.1)	(1.0)
Net invested capital	311.5	159.2	27.5	498.2

Net Invested Capital - Investment Type

Year ended December 31, 2008 ($ millions)	Gas Segment	Power Segment	Corporate Segment	Total
Invested capital:				
Capital assets	675.1	141.7	6.6	823.4
Long-term investments and other assets	–	0.7	0.7	1.4
	675.1	142.4	7.3	824.8
Disposals:				
Capital assets	(10.2)	(5.2)	–	(15.4)
Long-term investments and other assets	–	–	(48.2)	(48.2)
Net invested capital	664.9	137.2	(40.9)	761.2

The Trust categorizes its invested capital into maintenance, growth and administration.

Growth capital of $490.1 million was expended in 2009 (2008 – $813.5 million). In the Gas Segment, growth capital comprised $259.1 million for the acquisition of NGD assets, $17.6 million for the Harmattan fractionation project, $14.2 million for the completion of Sarnia Storage, $8.9 million for various E&T projects and $8.4 million for FG&P projects. Within the Power Segment, growth capital projects included $145.6 million for the completion of Bear Mountain Wind Park, $7.9 million for renewable power development projects and $6.4 million related to the Harmattan Cogeneration project. The Corporate Segment growth capital of $22.0 million was related to the acquisition of shares in Magma Energy Corporation. Administrative and maintenance capital expenditures in 2009 were $5.8 million and $3.3 million, respectively (2008 – $7.6 million and $3.7 million, respectively).

Invested Capital - Use

Year ended December 31, 2009 ($ millions)	Gas Segment	Power Segment	Corporate Segment	Total
Invested capital:				
Maintenance	3.3	–	–	3.3
Growth	308.2	159.9	22.0	490.1
Administrative	0.3	–	5.5	5.8
Invested capital	311.8	159.9	27.5	499.2

Invested Capital - Use

Year ended December 31, 2008 ($ millions)	Gas Segment	Power Segment	Corporate Segment	Total
Invested capital:				
Maintenance	3.7	–	–	3.7
Growth	669.0	142.4	2.1	813.5
Administrative	2.4	–	5.2	7.6
Invested capital	675.1	142.4	7.3	824.8

FINANCIAL INSTRUMENTS

The Trust 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 2009, the Trust had positions in the following types of derivatives, which are also disclosed on Note 15 to the Consolidated Financial Statements:

Commodity Forward Contracts

The Trust 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 business transacts primarily on this basis.

Commodity Swap Contracts

The Trust 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's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0.10/MWh to $999.99/MWh in 2009 and $0.00/MWh to $999.99/MWh in 2008. The average spot price was $47.84/MWh in 2009 (2008 – $89.95/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 the Trust was $68.97/MWh in 2009 (2008 – $84.51/MWh). In 2010, almost two-thirds of the power delivered to the Alberta Power Pool from the Sundance Plant is hedged at a price of $72.00/MWh.

NGL Frac Spread Hedges

The Trust executes fixed-for-floating NGL frac spread swaps to manage its NGL frac spreads. The E&T business' results are affected by fluctuations in NGL frac spreads. In the fourth quarter, the Trust had NGL frac spread agreements for 3,900 Bbls/d for the October to December 2009 period at an average price of approximately $25.17/Bbl. The average spot NGL frac spread for 2009 was $19.51/Bbl (2008 – $28.79/Bbl). The average NGL frac spread realized in 2009 was $23.46/Bbl (2008 – $26.97/Bbl). The Trust has also hedged an average of 2,390 Bbls/d, or approximately 50 percent of volumes that are exposed to spot prices for 2010, at a price of approximately $21/Bbl. In addition, the Trust has hedged 700 Bbls/d, or approximately 15 percent of volumes that are exposed to spot prices for 2011, at a price of approximately $20/Bbl.

Interest Rate Forward Contracts

The Trust enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2009 the Trust had interest rate swaps for $185 million with varying terms to maturity until March 31, 2012. At December 31, 2009, the Trust had fixed the interest rate of 68 percent of its debt including MTNs and capital leases.

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.

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 the interest rate derivatives used quoted market rates.

The Trust does not speculate on commodity prices and therefore does not engage in any 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 has a risk management group that reviews commodity and credit risk on a daily basis and has created and adheres to a conservative risk policy and hedging program.

LIQUIDITY

At this time AltaGas does not expect any currently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash. MTN offerings during 2009 and credit rating upgrades by DBRS and S&P in 2009 are indications of the Trust's strong financial position and capacity to access financing. Each of the Trust's credit facilities has a maturity date, on which date and absent replacement, extension or renewal, the indebtedness under the respective credit facility becomes repayable. The earliest maturity date for the Trust's credit facilities is August 2010.

Cash Flows

Year ended December 31 ($ millions)	2009	2008
Cash from operations	184.1	205.2
Investing activities	(464.1)	(432.7)
Financing activities	265.4	233.4
Change in cash	(14.6)	5.9

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $184.1 million in 2009 compared to $205.2 million in 2008. The decrease in cash from operations was the result of lower net income, no future income tax recovery and gains on sale of assets in 2009 compared to 2008 and less equity income. These decreases were partially offset by higher unrealized investment income and lower non-cash working capital.

Working Capital

Year ended December 31 ($ millions except current ratio)	2009	2008
Current assets	331.8	363.9
Current liabilities	861.1	323.2
Working capital	(529.3)	40.7
Current ratio	0.39	1.13

Working capital was $529.3 million at December 31, 2009 compared to $40.7 million at December 31, 2008. The working capital ratio was 0.39 at the end of 2009 compared to 1.13 at the end of 2008. The change is mainly due to the classification of the current portion of long-term debt maturing in 2010 as a current liability.

As of December 31, 2009, the Trust's current portion of long-term debt was $591.9 million. The Trust's management expects to align the timing of the renewal of its credit facilities with the timing of its conversion to a corporation, expected in the second half of 2010. The Trust has begun discussions with current and potential members of the syndicate and does not expect any issues with renewing or increasing its credit facilities.

Investing Activities

Cash used for investing activities in 2009 was $464.1 million compared to $433.0 million in 2008. The increase was due to the acquisition of short-term investments and capital assets. A description of the acquisitions and investments related to long-term assets is in the Invested Capital section of this MD&A. Cash used for investing activities reflects the actual cash disbursed for investing activities and may not agree with the amounts in the invested capital sections of the MD&A due to the timing of the actual disbursement of funds and the fact that some acquisitions may be non-cash transactions.

Financing Activities

Cash used for financing activities was $265.4 million in 2009 compared to $233.4 million in 2008. The increase in cash was due to the issuance of long-term and revolving debt, distributions paid to unitholders and redemption of convertible debentures.

CAPITAL RESOURCES

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. At December 31, 2009 AltaGas had total debt outstanding of $1,014.7 million, up from $582.0 million as at December 31, 2008. At December 31, 2009 the Trust had $500.0 million in MTNs outstanding and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances and letters of credit through bank lines amounting to $816.0 million. At December 31, 2009 the Trust had drawn bank debt of $502.0 million and letters of credit outstanding of $51.8 million against the extendible revolving-term letter of credit facility and the demand operating facilities.

As of December 31, 2009, the Trust's current portion of long-term debt was $591.9 million. The Trust's management expects to align the timing of the renewal of its credit facilities with the timing of its conversion to a corporation, expected in the second half of 2010. The Trust has begun discussions with current and potential members of the syndicate and does not expect any issues with renewing or increasing its credit facilities.

On September 16, 2009, AltaGas redeemed its $16.6 million of outstanding 5.85 percent convertible debentures. The debentures were redeemed at $1,000.96 for each $1,000.00 of principal outstanding. The redemption amount was equal to the principal and all accrued and unpaid interest thereon.

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 Trust's earnings interest coverage for the rolling 12 months ended December 31, 2009 was 4.49 times.

Subsequent to the acquisition of Utility Group in fourth quarter 2009, AltaGas increased its target debt-to-total-capitalization ratio from 40 to 45 percent to 45 to 50 percent. The increase is a result of the addition of stable, rate-regulated natural gas distribution assets to the Trust's portfolio of energy infrastructure assets. The Trust's debt-to-total-capitalization ratio at December 31, 2009 was 49.2 percent, up from 37.8 percent at December 31, 2008.

On June 5, 2009, AltaGas filed a Short Form Base Shelf Prospectus to facilitate the issuance of trust units or unsecured debt securities. This shelf has a life of 25 months and permits the Trust to issue up to an aggregate of $500 million of securities. On June 22, 2009, the Trust filed a prospectus supplement establishing AltaGas' MTN program and allowing AltaGas to access the Canadian MTN market when appropriate. As of December 31, 2009, AltaGas had utilized approximately $100 million of the original $500 million available.

Credit Facilities

($ millions)	Borrowing capacity	Drawn at December 31 2009	Drawn at December 31 2008
Demand operating facility	86.0	16.3	2.8
Letter of credit facility	75.0	56.7	68.1
Syndicated credit facility [1]	150.0	-	100.0
Syndicated operating credit facility [2]	375.0	350.8	253.0
Utility Group revolving term credit facility [3]	130.0	130.0	-
	816.0	553.8	423.9

1 Revolving credit facility maturing August 13, 2010.
2 Revolving credit facility maturing September 30, 2010.
3 Revolving credit facility maturing November 17, 2010.

At December 31, 2009 the Trust held a $75.0 million (December 31, 2008 – $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2009 the Trust had letters of credit of $46.7 million (December 31, 2008 – $68.1 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of $5.1 million (December 31, 2008 – $2.8 million) outstanding against the demand operating facilities.

The Trust expects to renew its credit facilities in 2010.

CONTRACTUAL OBLIGATIONS

December 31, 2009 ($ millions)	Total	Payments due by period Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	1,000.1	594.8	100.0	205.3	100.0
Capital leases	7.5	1.9	3.8	1.8	-
Operating leases	62.3	3.3	6.5	6.6	45.9
Purchase commitments	3.2	3.2	-	-	-
Total contractual obligations	1,073.1	603.2	110.3	213.7	145.9

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power-peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2009 was $7.5 million (December 31, 2008 – $8.8 million), with the balance due in monthly payments comprising principal and interest of $0.2 million.

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

RELATED PARTIES

As of October 8, 2009, the Trust owned 100 percent of the shares of Utility Group. Therefore, commencing fourth quarter 2009, the Utility Group is not considered a related party. During the first three quarters of 2009, the Trust sold $39.0 million of natural gas to, and incurred transportation costs of $0.1 million charged by, Utility Group as part of the Trust's normal course of business. The Trust also paid management fees of $0.1 million to, and received management fees of $0.1 million, from Utility Group for administrative services. In addition, the Trust provided $0.1 million of operating services to Utility Group. The measurement of transactions between AltaGas and Utility Group is exchange value, to which both parties have agreed. The Trust held significant influence over Utility Group given AltaGas' 19.8 percent ownership, and AltaGas' Chairman and Chief Executive Officer was a director of Utility Group prior to the October 8, 2009 acquisition.

The Trust pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is owned by an employee. Payments of $90,540 were made in 2009 (2008 – $88,000), which is the exchange value of the property agreed to by both parties. The lease expires December 2011.

RATING AGENCIES

On October 16, 2009, DBRS raised its rating for the Trust from BBB (low) with a Positive trend to BBB with a Stable trend. DBRS has cited the Utility Group acquisition as improving AltaGas' business risk profile through the addition of low-risk, regulated natural gas distribution assets in Alberta, Nova Scotia and the Northwest Territories.

On April 21, 2009 Standard & Poor's (S&P) upgraded its rating for the Trust from BBB- to BBB with a Stable outlook. S&P cited the Trust's increased exposure to long-term contracted gas infrastructure business, prudent financial practices and effective strategy execution for the rating upgrade.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of repayments and of the capacity and willingness of an entity to meet its financial commitment on an obligation in accordance with the terms of the obligation.

TRUST UNIT INFORMATION

At February 28, 2010 the Trust had 78.8 million trust units and 2.1 million exchangeable units outstanding and a market capitalization of $1.5 billion based on a closing trading price on February 26, 2010 of $18.70 per trust unit. At February 28, 2010 there were 3.8 million options outstanding and 1.2 million options exercisable under the terms of the unit option plan.

DISTRIBUTIONS

AltaGas distributions are determined giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital expenditures and debt repayment requirements of the Trust. AltaGas has been able to sustain its distributions through funds from operations. In 2009, the Trust declared distributions of $170.2 million and had funds from operations of $202.3 million (2008 – $147.1 million and $217.1 million, respectively), or a payout ratio of 84 percent (2008 – 68 percent).

The Board of Directors of AltaGas General Partner Inc., delegate of the Trustee, maintained the Trust's monthly cash distribution at $0.18 per unit ($2.16 per unit annualized) for 2009. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment or record date falls on a weekend or holiday.

The following table summarizes AltaGas' distribution declaration history since 2007:

Distributions

Years ended December 31

($ per unit)	2009	2008	2007
First quarter	0.540	0.525	0.510
Second quarter	0.540	0.525	0.510
Third quarter	0.540	0.535	0.520
Fourth quarter	0.540	0.540	0.525
Distribution of shares [1]	–	–	0.076
Total	2.160	2.125	2.141

1 On September 17, 2007 one share of Utility Group was issued for every 100 trust units and exchangeable units held on August 27, 2007.

Assuming a unit was held throughout 2009, for income tax purposes, the Trust expects 78.8 percent of the total distributions declared in 2009 to be taxed as income, 4.0 percent as capital gains, 0.2 percent as dividend income and 17.0 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their Trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

CORPORATE CONVERSION

AltaGas expects to convert to a corporation in the second half of 2010 in response to the Government of Canada's changes to the tax treatment of income trusts effective January 1, 2011. In 2009, federal legislation was enacted for the conversion of income trusts in which the trust is able to convert to a corporation without triggering adverse tax consequences to the trust or its unitholders.

AltaGas expects to continue to implement its growth strategy, while seeking to provide investors with a balance between income and growth. As a corporation, AltaGas' management expects to pay a dividend between $1.10 and $1.40 per share on an annual basis to support the Trust's growth strategy going forward. At the time of conversion, the Board of Directors will approve the dividend policy subject to economic and financial conditions at that time. Until its anticipated conversion, AltaGas expects to continue to pay a monthly distribution of $0.18 per trust unit.

AltaGas has always executed its strategy as a tax-efficient corporate and focused on key traditional financial metrics such as earnings per unit and return on equity. It does not rely on the trust structure to sustain its business.

NON-MONETARY TRANSACTIONS

AltaGas has entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs will be created through the generation of power at the Bear Mountain Wind Park between 2009 and 2011. The verified emission offsets received by AltaGas were used to offset the costs to comply with SGER in 2009.

SUBSEQUENT EVENT

Warrants

On January 1, 2010 AltaGas issued 180,433 units on exercise of special warrants that were originally issued in February 2008 on a one-for-one basis at $24.94 per special warrant.

Landis Energy Corporation

On February 2, 2010 AltaGas offered to acquire all the outstanding common shares of Landis Energy Corporation (Landis) in exchange for cash of $0.80 per common share. The acquisition is valued at approximately $22 million and, if successful, will be funded through AltaGas' existing credit facilities. The offer is subject to certain conditions, including its acceptance by the holders of at least two-thirds of the outstanding common shares of Landis and regulatory approval. The offer is currently due to expire on March 10, 2010.

CHANGES IN ACCOUNTING POLICIES

Section 3064 Goodwill and Intangible Assets

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new Canadian Institute of Chartered Accountants (CICA) Handbook Section 3064 "Goodwill and Intangible Assets" will replace Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". This section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets, including internally generated intangible assets. The adoption of this standard did not have a material impact on the Consolidated Financial Statements for the year ended December 31, 2009.

EIC-173 - Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

In January 2009, the EIC reached a consensus that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Accordingly, the Trust was required to fair value derivative instruments, at the beginning of the period of adoption, to take into account both own credit risk and counterparty credit risk. Any resulting difference has been recorded as an adjustment to retained earnings with the exception of cash flow hedges, which have been recorded in accumulated other comprehensive income.

In accordance with CICA Handbook Section 3863 "Financial Instruments – Presentation", the Trust changed its presentation of derivative financial assets and financial liabilities to report the net amount in the balance sheet where AltaGas has a legally enforceable right to offset the recognized amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously. Accordingly, the Trust's comparative balances have been reclassified to reflect the change in accounting policy. For the impact on the Trust's financial statements on adopting EIC-173, see note 2 to the interim Consolidated Financial Statements for the year ended December 31, 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

The Accounting Standards Board (AcSB) confirmed in February 2009 that IFRS will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

AltaGas commenced a process to transition from Canadian GAAP to IFRS in April 2008. AltaGas has established a project team that is led by Finance management and includes representatives from various areas of the organization as necessary to plan for and achieve a smooth transition to IFRS. Regular progress reporting to the Audit Committee of the Board of Directors on the status of the IFRS implementation project has been instituted and enacted.

The implementation project consists of six phases, which in certain cases will be in process concurrently as IFRS are applied to specific areas from start to finish:

Scoping phase This phase involves a high-level assessment to identify key areas impacted by the transition to IFRS and to identify the Standards and Interpretations applicable to the Trust. This phase was completed in July 2008.

Diagnostic phase In this phase, each Standard and Interpretation is assessed to identify the changes required in the existing accounting policies, information systems and business processes. An IFRS mock-financial statement has been prepared for further guidance in the conversion process. This phase was completed in December 2008.

Design and planning phase Available alternatives in the accounting policies, elective exemptions and mandatory exceptions are assessed and adopted. Evaluation of the quantitative impact from the IFRS adoption is in progress.

Solution development phase Based on the adopted accounting policies, the project team defines and develops systems, processes and training required for the implementation of the target solutions under IFRS. The evaluation of the quantitative impact from IFRS adoption is in progress.

Implementation phase During the dual reporting period from January 1 until December 31, 2010, changes in accounting policies and procedures are executed and tested. Financial information in accordance with IFRS is collected, enabling the comparative reporting in 2011. Where possible, the CEO/CFO certification will start and the risk control assessment matrix will be updated accordingly. Training is provided at different levels with emphasis on the areas more impacted by IFRS adoption.

Post-implementation phase IFRS financial statements are produced for each reporting period. External auditors are requested to provide their opinion on the compliance of the financial statements with IFRS requirements. CSOX certification process is fully deployed for the IFRS conversion in compliance with the disclosure controls and procedures (DC&P). The achieved results are compared with the target objectives, including enhancing the effectiveness of financial reporting, to confirm whether the project has been successful and consequently can be closed.

There are currently no delays anticipated to AltaGas' project plan to meet IFRS reporting requirements in 2011.

Financial Statements Adjustments

IFRS 1 "First time adoption of International Financial Reporting Standards" provides entities adopting IFRS for the first time with a number of elective exemptions and mandatory exceptions, in certain areas, to the general requirement for a full retrospective application of IFRS. Similarly, other Standards provide for an accounting choice that has been assessed and elected prospectively from January 1, 2010, the transition date to IFRS. AltaGas is in the process of evaluating the standards and policy choices.

Key Performance Metrics

Compensation arrangement Incentive schemes shall be tested under IFRS financial results during the transition period to verify any impacts. If necessary, compensation arrangements will be renegotiated before the end of 2010.

Disclosure Controls and Procedures and Internal Control Framework

- A risk assessment on disclosure controls and procedures and internal control framework has been initiated during 2010.
- The alignment between the IFRS conversion and the certification processes started during the design and planning phase and is considered a test for the quality and completeness of the IFRS implementation.

Accounting Changes

The Trust will monitor the changes in the standards throughout the dual reporting period for adopting, where necessary, amendments to the implementation plan. According to the International Accounting Standards Board (IASB) work plan, the following changes are foreseen to be issued in the near future:

- Joint arrangements (Q1 2010)
- Liabilities and provisions (Q3 2010)
- Emission trading schemes (Q1 2011)
- Fair value measurement guidance (Q3 2010)
- Impairment financial instruments (Q4 2010)
- Hedge accounting (Q3 2010)
- Derecognition financial instruments (Q3 2010)
- Rate-regulated activities (Q2 2010)
- Leases (Q1 2011)
- Consolidation (Q3 2010)

Contingency plans have been developed to track and incorporate subsequent changes as a result of changes in accounting standards. Where permitted by the standards and appropriate, these changes will be effective from January 1, 2010.

Project Status

AltaGas had initiated discussions with the external auditors around the IFRS opening balances and the timing and review of these values. It is expected that the timing will be confirmed early in 2010 after the year-end has been completed and any final entries required for the opening balances finalized.

At this time, it is not possible to reasonably quantify the effects of IFRS to the Trust's Consolidated Financial Statements. AltaGas will provide additional disclosures of the key elements of the plan and progress of the project as the information becomes available.

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 Trust's 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 amortization expense, asset retirement obligations, asset impairment assessment, income taxes, pension and rate-regulated assets and liabilities. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. 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. 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 also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that the Trust recognizes from period to period.

Asset Retirement Obligations and Other Environmental Costs

The Trust 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 (most are estimated between 2045 and 2060), requiring the Trust 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 the Trust's 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 an impairment may be material to the Trust's 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 Trust and its Canadian subsidiaries are (in addition to local tax rules applicable to their foreign subsidiaries) subject to a regime of specialized rules prescribed under the Income Tax Act (Canada) for purposes of determining the amount of the Trust's and its subsidiaries' income that will be subject to tax in Canada. Accordingly, the determination of the Trust's and its subsidiaries' provision for income taxes involves the application of these complex rules in respect of which alternative interpretations may arise. Management of the Trust and its subsidiaries recognize that interpretations they may make in connection with tax filings may ultimately differ from those made by the tax authorities. Tax planning may allow the entities to record lower income taxes in the current year, and, as well, income taxes recorded in prior years may be adjusted in the current year to reflect management's best estimates of the overall adequacy of the provisions.

Substantial future income tax assets are recognized in the Consolidated Financial Statements of the Trust. The recognition of future tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the future 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 local 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 12 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 22 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.

Rate Regulation

AltaGas acquired AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas) in the acquisition of AltaGas Utility Group Inc. (Utility Group) (note 3), which also owns one-third of Inuvik Gas Ltd. (Inuvik Gas). AUI and Heritage Gas and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC) and the Nova Scotia Utility and Review Board (NSUARB) and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC 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 AUC 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 GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light-handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

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

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust 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. The Trust 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 with the Trust.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Trust is responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of the Trust's employees, DC&P to provide reasonable assurance that material information relating to the Trust is made known to them and information required to be disclosed by the Trust in its annual filings, interim filings and other documents filed or submitted under securities legislation are recorded, processed, summarized and reported within the time periods specified in securities legislation.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of the Trust's employees, the effectiveness of the Trust's DC&P and, based on that evaluation, have concluded that the Trust's DC&P was effective at December 31, 2009.

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of the Trust's employees, ICFR to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with Canadian GAAP.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of the Trust's employees, the effectiveness of the Trust's ICFR based on the framework established by the Committee of Sponsoring Organizations (COSO) and have concluded that the Trust's ICFR was effective at December 31, 2009 based on that evaluation.

During 2009 there were no changes made to the Trust's ICFR that materially affected, or are reasonably likely to materially affect, the Trust's ICFR.

FOURTH QUARTER HIGHLIGHTS

Net income for fourth quarter 2009 was $32.1 million compared to $39.6 million in the same period in 2008. Net income was $0.40 per basic unit for fourth quarter 2009 compared to $0.55 per basic unit for the same period in 2008.

Fourth quarter 2009 was a successful quarter for AltaGas due to the completion of the Utility Group and Heritage Gas acquisitions (natural gas distribution assets) and Bear Mountain Wind Park commencing commercial operations. All of these achievements immediately contribute to the Trust's operating income.

During the quarter, the Gas Segment performed well due to the addition of the NGD assets, contributions from Sarnia Storage, adjustment to transmission revenues previously deferred, higher fee-for-service revenues and the expiry of a legacy gas marketing contract. These increases were partially offset by lower processing volumes at FG&P facilities as producers reduced drilling activities and shut-in production in response to weak gas prices and lower realized frac spread prices. The Power Segment reported lower results primarily due to higher volumes sold at low spot power prices but benefited from lower transmission and environmental costs, as well as contributions from Bear Mountain Wind Park, which commenced commercial operations in fourth quarter 2009. Higher investment income offset operating costs in the Corporate Segment. The Corporate Segment reported unrealized losses on risk management contracts compared to unrealized gains in fourth quarter 2008. The Trust reported higher interest expense in fourth quarter 2009 compared to the same period in 2008 due to higher average debt balances, partially offset by a lower average borrowing rate. Income tax expense was lower in fourth quarter 2009 due to the impact for financial instruments and lower income subject to tax.

On a consolidated basis, net revenue for fourth quarter 2009 was $115.4 million compared to $125.8 million in same period 2008. In the Gas Segment, net revenue increased due to the acquisition of NGD assets, higher fee-for-service revenues, contributions from Sarnia Storage, increased rates, expiry of a legacy gas marketing contract, higher frac spreads and NGL volumes and higher transmission fees. These increases were partially offset by lower throughput in most FG&P areas and lower operating cost recoveries. In the Power Segment, net revenue decreased due to lower revenue from the sale of power in Alberta at spot power prices, which were lower than the same period last year, the gain on assets sold in 2008 and lower contribution from gas-fired peaking plants, partially offset by the contribution from Bear Mountain Wind Park, strong hedge prices and lower PPA costs. The Corporate Segment reported higher net revenue due to investment income, partially offset by unrealized losses on risk management contracts.

Operating and administrative expense for fourth quarter 2009 was $56.4 million, up from $56.1 million for same period 2008. The increase was due to the addition of NGD assets partially offset by lower costs within the Corporate Segment.

Amortization expense for fourth quarter 2009 was $20.3 million compared to $16.8 million in the same period 2008. The increase was due to the growth in AltaGas' asset base from acquisitions and construction activities.

Interest expense in fourth quarter 2009 was $9.3 million compared to $8.1 million for the same period 2008. The increase was due to higher average debt balances of $945.3 million compared to $581.6 million for the same period in 2008. The average debt balance was higher due to the Utility Group and Heritage Gas acquisitions in the fourth quarter. The increase was partially offset by a lower average borrowing rate. The average borrowing rate was 4.9 percent in fourth quarter 2009 compared to 6.3 percent in fourth quarter 2008.

In fourth quarter 2009, an income tax recovery of $2.9 million was reported compared to an expense of $6.4 million in fourth quarter 2008. The decrease was due to the impact for financial instruments and lower income subject to tax.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2009 net income:

Factor share	Increase or decrease	Increase or decrease in net income per unit
Gathering and processing volumes	5 Mmcf/d	0.012
Gathering and processing operating margin per Mcf	1¢/Mcf	0.022
Alberta electricity prices [1]	$1/MWh	0.006
Natural gas liquids fractionation spread [2]	$1 per Bbl	0.008
Interest rates	25 bps	0.008
Degree days [3]	5 percent	0.006

1 Based on 70 percent of PPA volumes being hedged.

2 Based on 60 percent of frac spread exposed NGL volumes being hedged.

3 Degree day variance is a measure of the temperature of the geographic areas in which AUI operates, over the applicable period expressed in relation to normal degree days in that period. A degree day is the cumulative extent to which the day mean temperature falls below 15°C. Normal degree days are based on a 20-year rolling average.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS

	2009				2008			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	336.4	291.4	285.8	354.6	424.6	460.7	487.1	444.5
Net revenue [1]	115.4	114.7	114.3	112.1	125.8	122.7	117.3	110.7
Operating income [1]	38.8	45.4	45.5	44.7	54.1	50.7	37.0	47.6
Net income	32.1	34.7	36.9	37.5	39.6	53.5	32.9	37.6

	2009				2008			
($ per unit)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net income								
Basic	0.40	0.44	0.47	0.50	0.55	0.75	0.49	0.58
Diluted	0.40	0.43	0.46	0.49	0.56	0.75	0.49	0.57
Distributions declared	0.54	0.54	0.54	0.54	0.54	0.535	0.525	0.525

1 Non-GAAP financial measure. See Non-GAAP Financial Measures.

Identifiable trends in AltaGas' business in the past eight quarters reflect the organization's internal growth, acquisitions, generally increasing power prices in Alberta until 2009, higher NGL frac spreads through most of 2008, increased volatility in commodity prices in recent quarters and asset dispositions.

Significant items that impacted individual quarterly earnings were as follows:

- In fourth quarter 2007, a $6.1 million non-cash future income tax benefit was recorded as a result of the substantive enactment of a reduction in the federal corporate income tax rates.
- In first quarter 2008, the Taylor acquisition was completed for total consideration of $455.2 million, of which $256.3 million was cash consideration and $198.9 million was for units issued. Results in first quarter 2008 increased as a result of the Taylor acquisition.
- In second quarter 2008, operating income was affected by major turnarounds within the gas business and one-time charge to expense project development costs.
- In third quarter 2008, AltaGas recognized an income tax recovery of $13.8 million related to the reduction of future income tax liabilities, which was a result of the reorganization of legal entities within the Trust's structure and required the use of lower effective tax rates.
- In third quarter 2008, operating income was negatively impacted by two extraction plant turnarounds and unplanned outage due to a natural gas heater fire at the Harmattan Complex.
- In latter part of fourth quarter 2008 and during the first half of 2009, prices for power, natural gas and NGLs declined, breaking the historical price trend for these products. Reduced natural gas prices have directly affected the activity of producers within the WCSB.
- In second quarter 2009, the Trust purchased a short-term investment that resulted in an unrealized gain of $4.6 million.
- During 2009, the Trust has adjusted liabilities related to natural gas transaction within Energy Services resulting in a one-time revenue impact of $9.2 million.
- During fourth quarter 2009, Bear Mountain was fully connected to the B.C. power grid and met the conditions for commercial operations in order to receive the firm price under the 25-year energy purchase agreement with BC Hydro.
- Acquired all the outstanding common shares of Utility Group not previously held by AltaGas for $204.5 million including assumed debt.
- Acquired the 75.1 percent it did not already own of the outstanding shareholder loans and common shares of Heritage Gas Limited (Heritage Gas) for $111.0 million.

Consolidated Financial Statements

Management's Responsibility for Financial Statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. The internal controls and systems of AltaGas Income Trust (AltaGas or the Trust) are designed to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine the Consolidated Financial Statements. The 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 Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.

((Signed by))

DAVID W. CORNHILL
Chairman and Chief Executive Officer
of AltaGas General Partner Inc.,
delegate of the Trustee of AltaGas Income Trust

February 25, 2010

((Signed by))

DEBORAH S. STEIN
Vice President Finance and Chief Financial Officer
of AltaGas General Partner Inc.,
delegate of the Trustee of AltaGas Income Trust

February 25, 2010

Auditors' Report

To the Unitholders of AltaGas Income Trust

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2009 and 2008 and the consolidated statements of income and accumulated earnings, comprehensive income and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of AltaGas Income Trust as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

((Signed by))

ERNST & YOUNG, LLP
Chartered Accountants

February 23, 2010
Calgary, Canada

Consolidated Balance Sheets

SEC File # 82-34911

As at December 31 ($ thousands)	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,739	$ 18,304
Short-term investment (note 15)	19,436	–
Accounts receivable	203,673	220,280
Inventory	1,401	775
Restricted cash holdings from customers	27,228	24,017
Regulatory assets (note 4)	2,567	–
Risk management (note 15)	66,271	92,842
Prepaid expense and other current assets	7,505	7,705
	331,820	363,923
Capital assets (note 5)	1,857,095	1,436,686
Energy arrangements, contracts and relationships (note 6)	128,949	138,913
Goodwill (note 7)	201,728	143,840
Regulatory assets (note 4)	60,885	–
Risk management (note 15)	18,132	31,147
Long-term investments and other assets (note 8)	30,487	17,744
	$ 2,629,096	$2,132,253
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$ 158,319	$ 198,232
Distributions payable to unitholders	15,110	12,943
Short-term debt (note 9)	14,626	4,493
Current portion of long-term debt (note 10)	591,944	1,363
Customer deposits	30,678	24,017
Deferred revenue	–	2,777
Regulatory liabilities (note 4)	1,403	–
Risk management (note 15)	34,200	57,423
Other current liabilities	14,830	21,927
	861,110	323,175
Long-term debt (note 10)	408,170	559,412
Asset retirement obligations (note 12)	41,771	41,708
Future income taxes (note 13)	228,596	211,256
Regulatory liabilities (note 4)	16,610	–
Risk management (note 15)	14,491	16,745
Convertible debentures (note 11)	–	16,682
Future employee obligations (note 22)	9,491	5,833
	1,580,239	1,174,811
Unitholders' equity (notes 16, 17 and 18)	1,048,857	957,442
	$ 2,629,096	$2,132,253

Commitments and contingency (notes 9, 10, 15, 20, 22 and 26)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:

((Signed by))

DAVID W. CORNHILL
Director

((Signed by))

ROBERT B. HODGINS
Director

Consolidated Statements of Income and Accumulated Earnings

SEC File # 82-34911

For the years ended December 31

($ thousands except per-unit amounts)	2009	2008
REVENUE		
Operating	$ 1,249,649	$1,803,928
Unrealized gain on risk management (note 15)	3,697	10,986
Other (notes 11 and 15)	14,919	1,881
	1,268,265	1,816,795
EXPENSES		
Cost of sales	811,688	1,340,318
Operating and administrative	208,219	221,500
Amortization:		
Capital assets	64,157	57,075
Energy arrangements, contracts and relationships	9,964	9,903
	1,094,028	1,628,796
Foreign exchange gain (loss)	(1)	1,369
Interest expense		
Short-term debt	1,283	2,632
Long-term debt	30,476	24,767
Income before income taxes	142,477	161,969
Income tax expense (recovery) (note 13)		
Current income tax	981	2,328
Future income tax	187	(3,930)
Net income	141,309	163,571
Accumulated earnings, beginning of year (note 2)	673,736	510,412
Accumulated earnings, end of year	$ 815,045	$ 673,983
Net income per unit (note 19)		
Basic	$ 1.80	$ 2.38
Diluted	$ 1.79	$ 2.36
Weighted average number of units outstanding (thousands) (notes 17 and 19)		
Basic	78,540	68,813
Diluted	79,371	69,704

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income

SEC File # 82-34911

For the years ended December 31

($ thousands)	2009	2008
Net income	$ 141,309	$ 163,571
Other comprehensive income (loss), net of tax		
Unrealized net gain on available-for-sale financial assets	3,877	–
Unrealized net gain on derivatives designated as cash flow hedges	15,088	20,560
Reclassification of available-for-sale financial assets as a result of business acquisition	-	(17,873)
Reclassification to net income of net gain (loss) on derivatives designated as cash flow hedges pertaining to prior periods	(29,309)	1,686
	(10,344)	4,373
Comprehensive income	$ 130,965	$ 167,944
Accumulated other comprehensive income (loss), beginning of year	$ 31,569	$ 27,169
Other comprehensive income (loss), net of tax	(10,344)	4,373
Accumulated other comprehensive income, end of year (note 15)	$ 21,225	$ 31,542

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

SEC File # 82-34911

For the years ended December 31 ($ thousands)	2009	2008
Cash from operations		
Net income	$ 141,309	$ 163,571
Items not involving cash:		
Amortization	74,121	66,978
Accretion of asset retirement obligations (note 12)	3,138	2,302
Unit-based compensation	(195)	387
Future income tax expense (recovery) (note 13)	187	(3,930)
Gain on sale of assets	(28)	(2,045)
Equity income	(158)	(1,388)
Unrealized gain	(9,468)	(10,986)
Goodwill impairment (note 7)	150	100
Other	2,788	1,801
Non-operating investment income	(9,585)	–
Asset retirement obligations settled (note 12)	(384)	(744)
Net change in non-cash working capital (note 21)	(17,729)	(10,891)
	184,146	205,155
Investing activities		
Increase (decrease) in customer deposits	(3,211)	352
Decrease in notes receivable	-	6,500
Capital expenditures	(242,970)	(143,928)
Disposition of capital assets	-	15,618
Investment in regulatory assets	(6,014)	–
Distributions from equity investments	3,236	291
Acquisition of short-term investment	(8,198)	–
Business acquisition (note 3)	(191,277)	(311,493)
Acquisition of long-term investments and other assets	(15,658)	–
	(464,092)	(432,660)
Financing activities		
Repayment of short-term debt	10,133	942
Net issuance of revolving long-term debt	16,132	233,985
Issuance of long-term debt	295,080	–
Repayment of long-term debt	(18,017)	(5,792)
Distributions to unitholders	(168,666)	(144,348)
Net proceeds from issuance of units	130,719	144,071
Net proceeds from issuance of warrants	-	4,500
	265,381	233,358
Change in cash and cash equivalents	(14,565)	5,853
Cash and cash equivalents, beginning of year	18,304	12,451
Cash and cash equivalents, end of year	$ 3,739	$ 18,304

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 dollars unless otherwise indicated.)

1. STRUCTURE OF ALTAGAS INCOME TRUST

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

BASIS OF PRESENTATION

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures, including the Edmonton Ethane Extraction Plant, Empress ATCO Extraction Plant, Empress Provident Extraction Plant, Younger Extraction Plant, Sarnia Airport Storage Pool Limited Partnership, ASTC Power Partnership (ASTC), Inuvik Gas Ltd. (Inuvik Gas) and Ikhil Joint Venture. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009 the Trust adopted Emerging Issues Committee (EIC) 173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities" and the new Canadian Institute of Chartered Accountants (CICA) Handbook accounting requirements for Section 3064 "Goodwill and Intangible Assets". In accordance with the transitional provisions for these new standards, these policies were adopted retrospectively without restatement of prior periods.

Effective October 8, 2009 the Trust adopted the changes to Section 1100 "Generally Accepted Accounting Principles" and Section 3465 "Income Taxes" related to the recognition and measurement of assets and liabilities arising from rate regulation. The Trust adopted these standards as a result of the acquisition of AltaGas Utility Group Inc. (Utility Group) (note 3).

Effective December 31, 2009 the Trust adopted the revisions to Section 3862 "Financial Instruments – Disclosures". This policy was adopted retrospectively.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

In January 2009, the EIC reached a consensus that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Accordingly, the Trust was required to fair value derivative instruments, at the beginning of the period of adoption, to take into account both its own credit risk and counterparty credit risk. Any resulting difference has been recorded as an adjustment to retained earnings with the exception of cash flow hedges, which have been recorded in accumulated other comprehensive income.

In accordance with CICA Handbook Section 3863 "Financial Instruments – Presentation", the Trust changed its presentation of derivative financial assets and financial liabilities to report the net amount in the balance sheet where AltaGas has a legally enforceable right to offset the recognized amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously. Accordingly, the Trust's comparative balances have been reclassified to reflect the change in accounting policy.

The net effect on the Trust's financial statements as at January 1, 2009 resulting from the above-mentioned changes is as follows:

Balance sheet account affected	Increase (Decrease)
Current assets – risk management	(25,772)
Long-term assets – risk management	(5,983)
Current liabilities – risk management	(25,421)
Long-term liabilities – risk management	(5,900)
Future income taxes	(285)
Unitholders' equity – accumulated earnings	(176)
Unitholders' equity – accumulated other comprehensive income	27

The unrealized gains and losses included in accumulated earnings and accumulated other comprehensive income were recorded net of income tax recovery of $287,645 and expense of $2,629, respectively.

Goodwill and Intangible Assets

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2008, the new CICA Handbook Section 3064 replaces Section 3062 "Goodwill and Other Intangible Assets", which included the old Section 3450 "Research and Development Costs" that was transferred in February 2008. This Section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets, including internally generated intangible assets. This new section is effective for the Trust beginning January 1, 2009. There was no financial impact to AltaGas' financial statements as a result of these changes.

Goodwill represents that portion of the purchase price on acquisition that was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the fair value of goodwill is determined. Any excess of the carrying value of goodwill over its fair value is recorded as an impairment charge to income.

Intangible assets are initially recorded at cost, including costs directly attributable to acquiring, creating, producing and preparing the intangible asset to be capable of operating in the manner intended. An intangible asset that is capable of operating in the manner intended is amortized to income on a straight-line basis over the estimated useful life, unless it is determined to have an infinite life. Intangible assets are tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of the intangible asset is determined. Any excess of the carrying value of intangible assets over its implied fair value is recorded as an impairment charge to income.

Financial Instruments – Disclosures

Effective for annual financial statements for fiscal years ending after September 30, 2009, the CICA revised standards under Handbook Section 3862 "Financial Instruments – Disclosures". The revisions require additional disclosure based on a fair value hierarchy that reflects the significance of the inputs used in measuring fair value. Financial assets and financial liabilities with fair value measurement based on quoted prices (unadjusted) in active markets are included in Level 1, inputs other than quoted prices that are observable either directly or indirectly in Level 2 and inputs that are not based on observable market data in Level 3. The disclosure requirements are effective for the Trust beginning December 31, 2009. The additional information to comply with these standards is disclosed in note 16.

Rate-regulated Assets and Liabilities

Effective for the Trust on October 8, 2009, the revisions to CICA Handbook Section 1100 "Generally Accepted Accounting Principles" pertain to the recognition and measurement of assets and liabilities arising from rate regulation. As a result of adopting these changes, the Utility Group, an indirect wholly owned subsidiary of AltaGas, reclassified $16.3 million of reserves for future removal and site restoration costs previously netted against capital assets to non-current regulatory liabilities.

Effective for the Trust on October 8, 2009, the revisions to CICA Handbook Section 3465 "Income Taxes" require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future tax rates and recovered from or paid to future customers. As a result of adopting these changes, Utility Group, an indirect wholly owned subsidiary of AltaGas, recognized $11.3 million of previously unrecognized future income tax liabilities and an offsetting regulatory asset.

SIGNIFICANT ACCOUNTING POLICIES

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method, assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Regulation

AltaGas acquired AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (Heritage Gas) in the acquisition of Utility Group (note 3), which also owns one-third of Inuvik Gas. AUI, Heritage Gas and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the Alberta Utilities Commission (AUC), the Nova Scotia Utility and Review Board (NSUARB) and the Northwest Territories Public Utilities Board (NWTPUB), respectively. The AUC 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 AUC 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 GAAP for entities not subject to rate regulation. Inuvik Gas is subject to light-handed regulation by the NWTPUB, whereby rates are set by Inuvik Gas based on competitive market price. Inuvik Gas is required to file its rates, terms and conditions of service with NWTPUB when they are revised. The NWTPUB can take action should any complaints be received and may review the affairs, earnings and accounts of Inuvik Gas as it deems necessary.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that will 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 to be refunded to customers through the rate-setting process.

See note 4 for a description of the financial statement effects of rate regulation.

Cash and Cash Equivalents

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

Short-term Investment

Short-term investments are highly liquid investments with no contractual maturities. Short-term investments are recorded at fair value based on quoted market prices, with changes in fair value recorded in other revenue.

Inventory

Inventory consists of materials and supplies and natural gas liquid (NGL) product held for sale. All inventories are valued at the lower of cost or net realizable value. Cost is assigned using a weighted average cost formula.

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. Any corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Major renewals or betterments are included in the cost of capital assets while routine repair and maintenance costs are expensed in the period incurred.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets, with the exception of regulated natural gas distribution assets, where amortization is calculated on a straight-line basis or over the contract term of a specific agreement at rates approved by the regulatory authorities.

Gas	
Extraction and transmission (E&T) assets	15–40 years
Field gathering and processing (FG&P) assets	15–25 years
Energy Services assets	19 years
Storage assets	20–50 years
Natural gas distribution assets	0.85–23.82 percent
Other assets	1–32 years
Power	
Assets under capital lease	10 years
Power generation assets	20–30 years
Corporate	
Other assets	1–5 years

Depletion of natural gas properties is provided using the unit of production method based upon estimated proved reserves before royalties.

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. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise, the principal is included as a long-term debt.

Net additions to natural gas distribution assets at AUI and Heritage Gas are not depreciated until the year after they are brought into active service, as required by the respective regulatory authorities.

Energy Arrangements, Contracts, Relationships and Amortization

Energy arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life.

Sundance B power purchase arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18–49 months
Energy Services relationships	15 years
E&T contracts	10–20 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC. ASTC is committed to purchasing all of the power from the two 353-MW capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses thereunder are recorded on a proportionate basis. Acquisition of the Sundance B PPAs required a capital outlay. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded based on target generator availability.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy Services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp., PremStar Energy Canada Ltd. (re-named AltaGas Energy Limited Partnership subsequent to acquisition), ECNG Canada Ltd. and Energistics Group Inc. and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

The E&T contracts were acquired through the acquisition of Taylor NGL Limited Partnership (Taylor) (note 3) and are recorded at fair value and amortized on a straight-line basis over the average expected life of the contracts.

Financial Instruments

All financial instruments, including derivatives, are included on the Consolidated Balance Sheets initially 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 is determined by classification.

Held-for-trading financial assets and liabilities are entered into with the intention of generating a profit and 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. Held-to-maturity financial assets are accounted for at their amortized cost using the effective interest method. The Trust does not have any held-to-maturity financial instruments. 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. 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. The Trust used January 1, 2003 as the transition date for identifying embedded derivatives.

Hedges

As part of its asset and liability management, the Trust uses derivatives to reduce its exposure to commodity price, interest rate and foreign exchange risk. The Trust designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Trust 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. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

The effective portion of changes in the fair value of cash flow hedges is recognized in other comprehensive income (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. The Trust has hedged certain future cash flows over a range of periods to a maximum of seven years.

Comprehensive Income and Equity

The Trust's financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income, which consists of earnings and the effective portion of changes in unrealized gains and losses related to available-for-sale assets and cash flow hedges. In addition, the Trust presents separately in its unitholders' equity note the changes for each of its components of unitholders' equity. Accumulated other comprehensive income and a one-time transition adjustment have been added to the Trust's unitholders' equity as a result of the implementation of this standard.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available-for-sale or held-for-trading. Available-for-sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI. Investments in equity instruments that do not have a quoted market price in an active market will be measured at cost. Held-for-trading assets are initially accounted for at fair value with changes in fair value recorded in other revenue.

Development Costs

The Trust 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 are still 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 and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust 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 operating and administrative expense in the Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income.

No asset retirement obligations have been recorded for certain transmission and distribution assets due to their indeterminate life.

Revenue Recognition

In the Gas Segment, the extraction and transmission, field gathering and processing and Energy Services business recognize revenue at the time the product or service is delivered. The natural gas distribution business 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 regulating authority.

The Power Segment recognizes revenue based on target generator availability in accordance with the Sundance B PPAs and at the time the product or service is delivered for all other power generation.

Realized gains and losses from risk management activities related to commodity prices are recognized in the related segment revenues when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheets. Unrealized gains and losses in respect of fair value changes to the Trust's risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate 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. For financial instruments classified as other than held-for-trading, transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the exchange rate in effect at the balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the average exchange rate applicable to the period.

Recognition Date

AltaGas uses the settlement date for transactions. Any difference in value between the trade and settlement date for third-party transactions will be recognized on the balance sheet and in net income or in OCI as appropriate.

Effective Interest Method

The Trust uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate a shorter period, to the net carrying amount of the financial asset or liability.

Unit-Based Compensation Plans

The Trust follows the fair value method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement of 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 units is recognized in the period the change occurs.

Pension Plans and Post-Retirement Benefits

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, 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 14.8 years and 10.1 years, respectively. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada), and its income that is not paid or payable to the unitholders is taxable in a particular taxation year. Prior to 2007 the Trust allocated all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and met the requirements of the Income Tax Act (Canada) applicable to the Trust. Accordingly, no provision for Canadian income tax expense was made for the Trust.

On June 22, 2007 the Specified Investment Flow-through (SIFT) tax received royal assent, creating a new tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. On December 14, 2007 reduced tax rates were enacted and are to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012, respectively.

Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust had recorded a SIFT future income tax expense and future income tax liability for the year ended December 31, 2007. This non-cash expense had no immediate impact on cash flows. Temporary differences occur when the book carrying value of AltaGas' assets and liabilities for accounting purposes differs from the amounts attributed to these same assets and liabilities for tax purposes. A tax rate of nil was applied to any temporary differences reversing before 2011.

In 2008 the partnership in which the temporary differences for SIFT tax purposes resided was moved under an operating subsidiary, with the result the SIFT future tax liability was replaced by a future tax liability at corporate tax rates.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities and restructuring within the Trust. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the book carrying value and the tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non-routine transactions have been recorded at the exchange amount.

Per-Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the period. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period plus the trust units issuable on conversion of outstanding convertible debentures and warrants. Diluted net income is increased by the interest on the convertible debentures and decreased by the accretion on the convertible debentures. As of September 16, 2009 the Trust redeemed any outstanding convertible debentures.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with 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 amortization, asset impairment, litigation, environmental and asset retirement obligations, financial instruments, pension plans and other post-retirement benefits, unit-based compensation, income taxes 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.

Warrants

Warrants are recorded at fair value, deemed to be the gross proceeds upon issue and are included as part of unitholders' equity.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. Cost is deemed to be the fair value as no active market currently exists for emission credits.

SEC File # 82-34911

FUTURE ACCOUNTING CHANGES

Section 1582 "Business Combinations"

This section applies to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. The new CICA Handbook Section 1582 will replace Section 1581 "Business Combinations", establishing standards for the accounting for a business combination that will more closely resemble those under International Financial Reporting Standards (IFRS). Earlier adoption of this section is permitted. The section is not expected to have a material impact on the Consolidated Financial Statements.

Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-Controlling Interests"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2011, the new CICA Handbook Sections 1601 and 1602 will replace Section 1600 "Consolidated Financial Statements". These sections establish standards for the preparation of consolidated financial statements and accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Earlier adoption of this section is permitted as of January 1, 2010 for the Trust. Management has not fully determined the impact of adopting this standard.

International Financial Reporting Standards (IFRS)

Canadian publicly traded companies will be required to prepare their financial statements in accordance with IFRS as issued by the International Accounting Standards Board, for the financial years beginning on or after January 1, 2011. Effective January 1, 2011, AltaGas will adopt IFRS as the basis for preparing its Consolidated Financial Statements. Financial results for the quarter ended March 31, 2011 shall be prepared on an IFRS basis, with comparative data on an IFRS basis, including an opening balance sheet, as at January 1, 2010. Management has not fully determined the financial impact of adopting IFRS on its financial statements; however, it should be noted that the current financial statements may be significantly different if presented in accordance with IFRS.

3. BUSINESS ACQUISITIONS

AltaGas Utility Group Inc.

On October 8, 2009 AltaGas Holdings No. 3 Inc. (AltaGas Holdings #3), an indirect wholly owned subsidiary of AltaGas, acquired all of the outstanding common shares of Utility Group not already owned by AltaGas and its affiliates.

Utility Group was a publicly traded company holding interests in AUI, Heritage Gas and Inuvik Gas. Utility Group also holds a 33.3335 percent interest in the Ikhil Joint Venture (Ikhil), which produces and supplies natural gas in Inuvik, Northwest Territories.

AltaGas paid Utility Group shareholders $10.50 per common share in cash. The aggregate purchase price was $80.2 million, including $75.2 million of cash for the remaining 81.7 percent of Utility Group and $5.0 million in transaction costs.

Until the date of acquisition, AltaGas accounted for its investment in Utility Group using the equity method. As a result, the Trust's portion of income earned by Utility Group was recorded as other revenue in the Corporate Segment. As of October 8, 2009, the operating results of Utility Group are consolidated with the results of the Trust within the Gas Segment.

AltaGas drew on its available credit facility to finance the cash consideration of $75.2 million for the Utility Group acquisition.

Heritage Gas Limited

On November 18, 2009 AltaGas acquired all of the Heritage Gas common shares and shareholder loans not already owned. Heritage Gas operates a full regulation-class natural gas distribution franchise in Nova Scotia.

AltaGas paid approximately $109.8 million for the remaining 75.1 percent in Heritage Gas. The aggregate purchase price was $111.0 million, including $109.8 million of cash for all of the common shares and shareholder loans not previously owned and $1.2 million in transaction costs.

Until the date of acquisition, AltaGas accounted for its investment in Heritage Gas using the proportional accounting method.

Purchase Price Allocation

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed on October 8, 2009 and November 18, 2009 for Utility Group and Heritage Gas, respectively. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

	Utility Group	Heritage Gas	Total
Cash consideration	$ 75,199	$ 109,828	185,027
Estimated transaction costs	5,000	1,200	6,200
Total consideration			191,227

Purchase price allocation			
Assets acquired			
Current assets	$ 16,743	$ 5,377	
Capital assets	149,371	74,808	
Regulatory assets	16,633	34,509	
Goodwill (note 7)	44,143	13,895	
Long-term investments and other assets	3,267	–	358,746
Less liabilities assumed			
Current liabilities	23,078	8,214	
Long-term debt	101,511	–	
Regulatory liabilities	13,587	–	
Asset retirement obligations	96	–	
Future income taxes	9,113	9,347	
Future employee obligations	2,573	–	167,519
			191,227

In accordance with CICA Handbook Section 1600 "Consolidated Financial Statements", AltaGas accounted for the Utility Group acquisition as a step-by-step purchase resulting from the Trust's original equity accounted investment in Utility Group. Accordingly, the $12.3 million investment was proportionately allocated to identifiable assets and liabilities of Utility Group.

2008

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) acquired all of the outstanding limited partnership units of Taylor (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of NGL extraction plants, natural gas processing assets and two NGL pipelines. It also had an interest in a 7-MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders $11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of $245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, $27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. AltaGas paid $256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at $198.9 million for all the outstanding units not previously owned by AltaGas and $5.9 million in transaction costs. The value of the Trust units issued was determined based on the weighted average market price between two days preceding and two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at January 10, 2008. The allocation of the purchase price is as follows:

Total consideration for 100% of Taylor		
Cost of 8.9% investment in Taylor originally owned by AltaGas		$ 23,156
Purchase price for the remaining 91.1% of Taylor units		
Cash consideration	$ 256,281	
Units	198,861	
Estimated transaction costs	5,884	
Equity portion of Taylor convertible debentures	2,127	463,153
Total consideration		$ 486,309

Purchase price allocation for 100% of Taylor		
Assets acquired		
Current assets	$ 30,584	
Capital assets	592,030	
Energy arrangements, contracts and relationships	53,100	
Goodwill (note 7)	125,680	
Long-term investments and other assets	4,640	806,034
Less liabilities assumed		
Current liabilities	27,549	
Long-term debt	110,423	
Convertible debentures	22,171	
Asset retirement obligations	18,741	
Future income taxes	135,320	
Future employee obligations	2,542	
Risk management	2,979	319,725
		$ 486,309

At the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available-for-sale and was measured at fair value, with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor was included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of $256.3 million for the Taylor acquisition.

Acquisition of Power Projects under Development

On July 31, 2008 AltaGas acquired NovaGreen Power Inc. (re-named AltaGas Renewable Energy Inc.) a wholly owned subsidiary of NovaGold Resources Inc., for $35 million on closing, with an additional $3.75 million on completion of certain conditions. AltaGas Renewable Energy Inc. is developing the Forrest Kerr run-of-river hydroelectric project in northwest B.C., which is expected to have capacity of 195 MW. AltaGas Renewable Energy Inc. is also pursuing three other development projects, all within the same region as Forrest Kerr, with additional potential combined run-of-river hydroelectric capacity of approximately 130 MW.

On August 15, 2008 AltaGas acquired GreenWing Energy Management Ltd.'s 45 percent interest in GreenWing Energy Development Limited Partnership (re-named AltaGas Renewable Energy Limited Partnership) for $12.3 million. As a result, the Trust now owns 100 percent of AltaGas Renewable Energy Limited Partnership. The portfolio of wind assets includes 650 MW in mature-stage development and 850 MW in early-stage development.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

AltaGas accounts for certain transactions in accordance with applicable regulations enforced by the AUC and NSUARB, which may be different in the absence of rate regulations. This results in the creation of regulatory assets and liabilities.

When the AUC or NSUARB issues a decision affecting the financial statements, the effects of the decision are recorded in the period in which the decision is received. However, if in management's judgment a reasonable estimate can be made regarding the impact a pending decision will have on the current year's financial statements, an estimate will be recorded in the current year for the expected impact.

Return on Rate Base

A generic cost of capital proceeding in Alberta during 2009 resulted in an AUC decision setting the return on equity for 2009 and 2010 at 9 percent. The AUC 2009 generic cost of capital decision further set AUI's regulated capital structure at 57 percent debt and 43 percent equity.

Heritage Gas' regulated capital structure is set at 55 percent debt and 45 percent equity with a return on equity of 13 percent. The NSUARB has approved this structure and return until December 31, 2011.

Regulatory Process - Delivery Tariffs

AUI's and Heritage Gas' delivery tariffs are designed to recover AUI's and Heritage Gas' approved cost-of-service and an approved return on equity. Tariffs are determined through a two-phase General Rate or Tariff Application (GTA). Phase 1 establishes the revenue requirement and Phase 2 sets the rates to be charged to various customer classes.

AUI seeks approval of its revenue requirement through a negotiated settlement process with interested parties or through an administrative hearing before the AUC. The AUC monitors the negotiated settlement process, and AUC approval is required for any settlement AUI reaches with interested parties. Factors affecting AUI's revenue requirement include forecasts for rate base, distribution and other revenue, operating costs, depreciation, financing costs, income taxes and return on rate base.

Heritage Gas uses an administrative hearing before the NSUARB for the two phases of the regulatory process.

Although the approved revenue requirement and subsequent approved rates are based on forecasts and actual results can differ from these forecasts, no adjustment is made to either the revenue requirement or rates for actual results varying from forecast. Once the rates are approved for a period, all risks and rewards from differences in actual versus forecast energy units delivered, capital expenditures, number of service sites billed, operating costs, debt servicing costs and taxes are borne by the unitholders. Actual results achieved can therefore differ from allowed returns.

Regulatory Process - Gas Cost Recovery Rate and Third-Party Transportation Rate

The Gas Cost Recovery Rate (GCRR) is charged to consumers for gas supply and is designed to allow AUI and Heritage Gas to recover the market-determined price paid for natural gas without any markup. The AUC and NSUARB have established a framework for AUI and Heritage Gas to file their costs monthly with the AUC and NSUARB, respectively. The AUC reviews AUI's GCRR applications to ensure that only the actual cost of gas is passed on to customers. Once verified by the AUC, interested parties have 30 days to file any objections to the rate. The NSUARB has established that it does not have jurisdiction over setting the GCRR and therefore Heritage Gas advises the NSUARB of the new price for the following month.

The Third-Party Transportation Rate (TPTR) is designed to allow AUI to recover third-party gas transportation service costs without any markup and is administered in an equivalent manner to GCRR. The TPTR applies to customers buying retail gas supply, which is the non-regulated gas supplied by competitive retailers, as well as customers buying default gas supply, since third-party transportation is required by all customers.

Cost of Natural Gas Sales

The cost of natural gas sales included in customer rates is based on the forecast cost of natural gas. As described in the GCRR process above, variances between forecast cost and actual costs of natural gas are deferred for refund to or collection from customers through adjustments to future rates. For both AUI and Heritage Gas, such adjustments generally occur in the following month.

Cost of natural gas sales for Inuvik Gas is based on market rates and there is no cost pass-through mechanism.

Regulatory Assets

Deferred Charges

Certain charges connected with costs of regulation are recorded at cost, deferred and amortized as approved by the regulator. The recovery or settlement period, or likelihood of recovery or settlement, of deferred charges is affected by the ultimate treatment by the regulator in the rate-setting process. There is risk and uncertainty that the regulator may not allow full recovery of recorded regulated assets.

Revenue Deficiency Account

Heritage Gas has approval from the NSUARB to use a Revenue Deficiency Account (RDA). The RDA changes are based on the difference between the actual revenue billed and the revenue required to earn the rates of return approved by the NSUARB. AUI accrues revenue equal to the difference between the revenue requirement expected to be received under its proposed GTA and the sales revenues at current approved rates. When the AUC issues a decision regarding the GTA, AUI bills revenue based on the approved revenue requirement and the revenue forecast to be collected at current approved rates and collects the revenue by way of a deficiency rate rider. The AUI accrual is included in accounts receivable.

AUI accrues revenue associated with the difference between the accrued costs and the funded costs of other retirement benefits. This revenue is recovered from customers in future periods in a manner that is consistent with the underlying rate-setting mechanism as mandated by the regulator.

For entities not subject to rate regulation, GAAP does not provide for the accrual of a revenue deficiency. Revenue would be recognized based on services provided to customers during the period.

Regulatory assets and liabilities recognized in the Consolidated Balance Sheet as at December 31, 2009 are as follows:

Regulatory assets – current	
Deferred cost of gas	$ 2,567
	–
Regulatory assets – non-current	
Deferred charges	474
Future recovery of other retirement benefits	1,416
Deferred depreciation	2,546
Deferred future taxes	22,583
Revenue deficiency account	33,866
	$ 60,885
Regulatory liabilities– current	
Deferred property taxes	70
Deferred cost of gas	72
Deferred regulatory costs	1,261
	$ 1,403
Regulatory liabilities – non-current	
Future removal and site restoration costs	16,610
	$ 16,610

AUI incurred costs to meet CEO/CFO certification requirements as mandated by the Canadian Securities Administrators. For regulatory purposes, differences between forecast and actual costs are held as a regulatory asset until the regulator rules on their final disposition. As directly by the AUC, AUI expensed the remaining deferred charges during the year through operating and administrative expenses. In the absence of regulatory accounting, GAAP would require that actual CEO/CFO certification costs be recognized as an expense when incurred and operating income would have been $0.4 million higher in 2009.

For rate-setting purposes at Heritage Gas and AUI, differences between forecast and actual costs of regulatory proceedings are held as a regulatory asset or liability until the regulator rules on their final disposition. Heritage incurred costs related to regulatory proceedings in 2004, 2006 and 2007. These costs are being amortized on a straight-line basis over a five-year period as approved by the NSUARB. Regulatory costs at AUI are included in 2009 allowed rates on a interim basis using forecast costs. AUI intends to seek and expects to receive the regulator's approval for refund of the year-end 2009 deferred regulatory costs in future rate proceedings. AltaGas expensed $0.3 million deferred charges in 2009 through operating and administrative costs. In the absence of regulatory accounting, GAAP would require that actual regulatory costs be recognized as an expense when incurred, and operating income would have been $0.3 million higher in 2009.

Natural gas and transportation costs are included in the approved tariff on a monthly forecast basis. For rate-setting purposes differences between forecast and actual costs in the month are held for collection or refund in the following months. AltaGas recognizes the cost variances as a regulatory asset or liability based on the expectation that amounts held from one month to the next for regulatory purposes will be approved for collection from or refund to customers in future months. AltaGas expects to recover the outstanding deferred costs in the first quarter of the following year. In the absence of regulatory accounting, GAAP would require that actual costs be recognized as an expense when incurred, and operating results would have been $2.1 million lower in 2009.

Future income taxes expected to be included in future recoveries from customers are deferred in accordance with CICA Handbook Section 3465. In the absence of rate regulation, GAAP would require that future income taxes be recognized in income when incurred and net income would have been $1.5 million lower in 2009.

Property taxes are included in allowed rates on an annual forecast basis. For regulatory purposes, differences between forecast and actual costs in the year are held for collection or refund in the following month. AUI recognizes the cost variances as a regulatory asset or liability based on the expectation that amounts held from one year to the next for regulatory purposes will be approved for collection from or refund to customers in future years. AltaGas expects to refund the December 31, 2009 outstanding deferred costs in 2010. In the absence of regulatory accounting, GAAP would require that actual costs be recognized as an expense when incurred.

Other retirement benefits are accounted for on an accrual basis in accordance with CICA Handbook Section 3461. For regulatory purposes, these other retirement benefit costs are recoverable from customers based on the funding of the costs. The revenue associated with the difference between the accrued costs and the funded costs is accrued and is expected to be recovered from customers in future periods. In the absence of regulatory accounting, GAAP would require that accrued revenue be recognized in the period earned, and operating income would have been $0.1 million lower in 2009.

Pursuant to the NSUARB decision dated February 12, 2009, Heritage Gas was ordered to suspend amortization for regulatory purposes for the 2009–2011 period. As a result of this order, Heritage Gas has set up a regulatory asset equal to the amortization required under GAAP. The effect of this decision for the year ended December 31, 2009 was to record a deferred regulatory revenue accrual of $2.5 million and deferred regulatory asset of $2.5 million. This regulatory deferral amount is expected to be recovered on the same basis as the amended amortization charge over the remaining useful life of related assets commencing in 2012.

Future removal and site restoration costs are included in revenue as allowed by the regulator. AUI recognizes the variance between amounts collected and future removal and site restoration costs incurred as a regulatory asset or liability based on the expectation that amounts held for regulatory purposes will be approved for collection from or refund to customers in future periods. In the absence of rate regulation, GAAP would require that the variance between the amounts collected and incurred be recognized as revenue in the period of collection, and income would have been $0.1 million lower in 2009.

The RDA at December 31, 2009 was $33.9 million. The effect of the RDA accumulation was to increase 2009 revenue by $0.9 million. In the absence of regulatory accounting, GAAP would require that the revenue deficiency account would not be recognized and would have reduced operating income by $0.9 million in 2009.

5. CAPITAL ASSETS

	2009			2008		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas						
E&T assets	$ 896,753	$ (97,998)	$ 798,755	$ 871,042	$ (70,590)	$ 800,452
FG&P assets	629,284	(202,791)	426,493	619,465	(174,797)	444,668
Energy services assets	1,555	(1,343)	212	1,555	(1,173)	382
Storage assets	23,423	(284)	23,139	9,053	–	9,053
NGD assets	271,464	(1,420)	270,044	–	–	–
Other assets	8,303	(5,339)	2,964	7,791	(4,003)	3,788
Power						
Capital lease (note 10)	13,798	(7,358)	6,440	13,798	(6,119)	7,679
Power generation assets	323,118	(1,081)	322,037	158,881	(72)	158,809
Other assets	330	–	330	–	–	–
Corporate						
Other assets	23,270	(16,589)	6,681	25,919	(14,064)	11,855
	$ 2,191,298	$ (334,203)	$ 1,857,095	$ 1,707,504	$ (270,818)	$ 1,436,686

Interest capitalized on long-term capital construction projects for the year ended December 31, 2009 was $7.1 million (2008 – $3.2 million). At December 31, 2009 the Trust had spent approximately $326.8 million (2008 – $188.1 million) on capital projects under construction that were not yet subject to amortization.

Net additions to natural gas distribution assets at AUI and Heritage Gas are not amortized until the year after they are brought into active service, as required by the respective regulating authorities. Natural gas distribution assets not subject to amortization were $18.7 million as at December 31, 2009 (December 31, 2008 – nil).

6. ENERGY ARRANGEMENTS, CONTRACTS AND RELATIONSHIPS

	2009			2008		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Energy services and E&T arrangements and contracts	$ 168,171	$ (54,799)	$ 113,372	$ 168,171	$ (46,228)	$ 121,943
Energy services relationships	20,892	(5,315)	15,577	20,892	(3,922)	16,970
	$ 189,063	$ (60,114)	$ 128,949	$ 189,063	$ (50,150)	$ 138,913

The amortization of the energy services relationships began in 2006, upon expiration of the corresponding short-term marketing contracts.

7. GOODWILL

	2009	2008
Balance, beginning of year	$ 143,840	$ 18,260
Acquisition (note 3)	58,038	125,680
Goodwill impairment	(150)	(100)
Balance, end of year	$ 201,728	$ 143,840

Through its annual goodwill impairment testing in 2009, AltaGas determined that the fair value of an investment was less than the book value and reduced the carrying value by $0.2 million (December 31, 2008 – $0.1 million).

8. LONG-TERM INVESTMENTS AND OTHER ASSETS

		2009		2008 [1]
Equity accounted investments in publicly traded entities	$	–	$	12,660
Investments in publicly traded entities		24,332		–
Equity accounted investments in private entities [2]		3,999		4,366
Warrants		–		286
Accrued pension asset		1,361		–
Other		795		432
	$	30,487	$	17,744

1 Excludes the purchase of Taylor and power projects under development (note 3).
2 The Trust accounts for its investment in Boston Bar Limited Partnership, which has run-of-river hydroelectric operations, using the equity method.

At December 31, 2009 the quoted market value of the holdings of publicly traded entities was $24.3 million (December 31, 2008 – $7.7 million).

Prior to the October 8, 2009 acquisition of the remaining shares of Utility Group, AltaGas accounted for its investment in Utility Group using the equity method. As a result, the Trust's portion of income earned by the Utility Group was recorded as other revenue in the Corporate Segment. As of October 8, 2009, the operating results of the Utility Group are consolidated with the results of the Trust within the Gas Segment.

9. SHORT-TERM DEBT

		2009		2008
Bank indebtedness	$	4,950	$	4,493
$50 million demand operating facility		–		–
$20 million demand operating facility		2,444		–
$15 million demand operating facility		6,960		–
$1.0 million demand operating facility		272		–
	$	14,626	$	4,493

Revolving Operating Credit Facilities

At December 31, 2009 the Trust held a $50.0 million (December 31, 2008 – $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.

On October 8, 2009 the Trust acquired a $20 million unsecured uncommitted demand operating credit facility with a Canadian chartered bank through the acquisition of Utility Group (note 3). Draws on the facility can be by way of prime rate loans, U.S. base rate loans, letters of credit, bankers' acceptances and LIBOR loans. Letters of credit outstanding at December 31, 2009 were $1.0 million.

AltaGas acquired a further $15 million unsecured uncommitted demand operating credit facility with a Canadian chartered bank through the acquisition of Utility Group (note 3). Draws on the facility can be by way of prime rate loans, letters of credit or bankers' acceptance equivalent loans. Letters of credit outstanding at December 31, 2009 were $1.4 million.

On November 18, 2009 the Trust acquired a $1.0 million demand credit facility from a Canadian chartered bank through the acquisition of Heritage Gas (note 3). It is secured by a general security agreement on the property of Heritage Gas and bears interest at prime plus one percent. Draws on the facility are by way of loans bearing interest at the bank's prime rate or by way of letters of credit or letters of guarantee for a fee.

Bank indebtedness bears interest at the lender's prime rate. The prime lending rate at December 31, 2009 was 2.25 percent (December 31, 2008 – 3.50 percent).

10. LONG-TERM DEBT

	2009	2008
Credit facilities	$ 490,518	$ 353,000
Medium-term notes	500,000	200,000
Loan from Province of Nova Scotia	4,272	–
Capital lease obligations	7,484	8,800
Other long-term debt	1,049	1,282
Unamortized deferred financing	(3,209)	(2,307)
	1,000,114	560,775
Less current portion	591,944	1,363
	$ 408,170	$ 559,412

Credit Facilities

At December 31, 2009 the Trust held a $375.0 million (December 31, 2008 – $375.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. On September 30, 2007 AltaGas negotiated the extension of the maturity of this facility to September 30, 2010.

On March 10, 2009 the Trust closed a $250.0 million unsecured 18-month credit facility with a syndicate of Canadian chartered banks that matures on August 13, 2010, replacing the credit facility that was due to mature on September 28, 2009. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances. Borrowings on the facility bear fees and interest rates relevant to the nature of the draw. On April 29, 2009 the Trust issued $200 million of senior unsecured medium-term notes (MTNs). On June 29, 2009 AltaGas issued $100 million of senior unsecured MTNs. In accordance with the terms of the $250 million credit facility, $100 million of the MTN proceeds were used to repay and reduce the facility from $250 million to $150 million on July 9, 2009.

On October 8, 2009 the Trust acquired a $130 million unsecured extendible revolving credit facility through the acquisition of Utility Group (note 3) with a syndicate of Canadian chartered banks with a maturity date of November 17, 2010. Borrowings on the facility can be by way of prime rate loans, U.S. Bank rate, letters of credit, LIBOR or bankers' acceptance equivalent loans.

At December 31, 2009 the Trust had drawn $490.5 million (December 31, 2008 – $353.0 million) against the facilities. The average rate on the Trust's bankers' acceptances at December 31, 2009 was 1.2 percent (December 31, 2008 – 3.1 percent).

Medium-Term Notes

On August 30, 2005 $100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually.

On January 19, 2007 AltaGas issued $100.0 million of 5.07 percent senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012.

On April 29, 2009 AltaGas issued $200 million of 7.42 percent senior unsecured MTNs. The notes carry a coupon rate of 7.42 percent and mature on April 29, 2014.

On June 29, 2009 AltaGas issued $100 million of 6.94 percent senior unsecured MTNs. The notes carry a coupon rate of 6.94 percent and mature on June 29, 2016.

Loan from Province of Nova Scotia

On October 8, 2009 AltaGas acquired a loan from the Province of Nova Scotia through the acquisitions of Utility Group and Heritage Gas (note 3). Heritage Gas, an indirectly wholly owned subsidiary of Utility Group, received $7.6 million from the Province of Nova Scotia in 2005, $2.0 million of which was forgiven on January 1, 2007. The loan is non-interest-bearing until certain revenue targets are achieved, at which time interest will be charged prospectively at 6 percent. On or before July 31, 2011, AltaGas must elect to repay the loan in full on July 1, 2014 or in five equal instalments beginning July 31, 2012. AltaGas may also elect to fully repay the loan at any time with no penalty. The loan is recorded at its amortized cost of $4.3 million. Interest expense is recorded at the effective interest rate of 6 percent. The face value of the loan is $5.6 million as at December 31, 2009.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease for 25 MW of gas-fired power-peaking capacity with an option to extend the term for an additional 15 years. The lease has payment commitments as follows, excluding the extended term option:

2010	$ 1,878
2011	1,878
2012	1,878
2013	1,878
2014	1,254
	8,766
Less imputed interest at 6.85%	1,282
Present value of minimum lease payments	7,484
Less current portion	1,408
	$ 6,076

Interest expense on capital leases was $0.6 million in 2009 (2008 – $0.6 million).

Letter of Credit Facility

At December 31, 2009 the Trust held a $75.0 million (December 31, 2008 – $75.0 million) unsecured three-year extendible revolving-term letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2009 the Trust had letters of credit of $46.7 million (December 31, 2008 – $68.1 million) outstanding against the extendible revolving-term letter of credit facility.

11. CONVERTIBLE DEBENTURES

On September 16, 2009 the Trust redeemed $16.6 million of outstanding convertible debentures at an amount of $1,000.96 for each $1,000.00 principal amount. The redemption amount is equal to the principal plus all accrued and unpaid interest thereon.

The Trust recognized a gain on redemption of convertible debentures of $0.1 million as other revenue and applied $1.6 million to contributed surplus related to the equity portion of the convertible debentures.

12. ASSET RETIREMENT OBLIGATIONS

	2009	2008
Balance, beginning of year	$ 41.708	$ 18,811
Obligations assumed under acquisition (note 3)	95	18,741
New obligations	742	–
Obligations settled	(384)	(744)
Obligations disposed	–	(219)
Revision in estimated cash flow	(3.528)	2,817
Accretion expense	3,138	2,302
Balance, end of year	$ 41,771	$ 41,708

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2009 was $278.2 million (December 31, 2008 – $244.3 million). The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 5.6 and 8.5 percent and are expected to be incurred between 2016 and 2072. No assets have been legally restricted for settlement of the estimated liability.

13. INCOME TAXES

Taxation of the Trust

The Trust has recorded a future income tax expense of $0.2 million for the year ended December 31, 2009 (2008 – recovery of $3.9 million) and an increase in future income tax liability of $17.3 million for the year ended December 31, 2009 (December 31, 2008 – $5.3 million).

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On June 22, 2007 the Specified Investment Flow-through (SIFT) tax received royal assent, creating a new tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. Based on the amount of the Trust's temporary differences that were anticipated to reverse after January 1, 2011, the Trust recorded a future income tax expense of $5.4 million (including $0.1 million expense in respect of financial instruments) and a future income tax liability in the same amount for the year ended December 31, 2007. This non-cash expense related to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities held in partnerships and had no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

In 2008 the partnership in which the temporary differences resided was moved under an operating subsidiary, resulting in the Trust recording a SIFT future tax expense of nil at December 31, 2008 and the SIFT future tax liability being replaced by a future tax liability at corporate tax rates. In 2009 $18.5 million of future income tax liabilities was assumed as a result of the Utility Group acquisition (note 3).

Taxation of the Operating Subsidiaries

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation.

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:

Years ended December 31	2009	2008
Income before taxes – consolidated	$ 142,477	$ 161,969
Financial instruments – net	(3,697)	(10,986)
Income before financial instruments and taxes	138,780	150,983
Income from AltaGas Income Trust distributed to unitholders	(135,119)	(134,849)
Income before income taxes – operating subsidiaries	3,661	16,134
Statutory income tax rate (%)	29.00	29.50
Expected taxes at statutory rates	1,062	4,760
Add (deduct) the tax effect of:		
Financial instruments	187	3,357
Rate reductions applied to future income tax liabilities	262	(11,347)
Permanent differences between accounting and tax basis of assets and liabilities	988	373
Non-taxable portion of capital gains on disposition of assets and investments	(1,798)	–
Other	(436)	1,255
Future income tax on regulated assets	(588)	–
Prior year adjustment	1,491	–
Income tax provision (recovery)		
Current	981	2,328
Future	187	(3,930)
	$ 1,168	$ (1,602)
Effective income tax rate (%)	0.82	(0.99)

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

As at December 31, future income taxes were composed of the following:

December 31	2009	2008
Capital assets	$ 206,742	$ 162,680
Regulatory assets	18,196	–
Deferred debt charges	(7)	(60)
Unit issue costs	(40)	(679)
Partnerships	10,494	37,010
Deferred compensation	(4,942)	(3,890)
Financial instruments	10,711	16,260
Non-capital losses	(12,971)	–
Other	413	(65)
	$ 228,596	$ 211,256

14. CAPITAL DISCLOSURE

The Trust's objective for managing capital is to maintain its investment-grade credit ratings and allow the Trust to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. The Trust considers unitholders' equity (including accumulated other comprehensive income), short-term and long-term debt (including current portion) less cash and cash equivalents to be part of its capital structure. The Trust's overall strategy remains unchanged from 2008.

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. AltaGas' target debt-to-total-capitalization ratio was 40 to 45 percent until third quarter 2009. Subsequent to the acquisition of Utility Group (note 3), the Trust increased its target debt-to-total-capitalization ratio to 45 to 50 percent. The increase is the result of the addition of natural gas distribution assets to the Trust's portfolio of energy infrastructure assets. The Trust's debt-to-total-capitalization ratio as at December 31, 2009 was 49.2 percent (December 31, 2008 – 37.8 percent).

	2009	2008
Debt		
Short-term debt	$ 14,626	$ 4,493
Current portion of long-term debt	591,944	1,363
Long-term debt	408,170	559,412
Convertible debentures	-	16,682
	1,014,740	581,950
Unitholders' equity	1,048,857	957,442
Total capitalization	$ 2,063,597	$ 1,539,392
Debt-to-total-capitalization ratio (%)	49.2	37.8

All of the borrowing facilities have covenants customary for the types of facilities that must be met at the end of each calendar quarter. AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

The debt covenants are based on non-GAAP measures that cannot be recalculated from information provided in the Consolidated Financial Statements.

The following table summarizes the Trust's debt covenants for all credit facilities as at December 31, 2009:

Ratios [1]	Debt Covenant Requirements
Debt-to-capitalization	not greater than 60 percent
Debt-to-EBITDA	not greater than 3.5x
EBITDA-to-interest expense	not less than 2.5x
Debt-to-capitalization (Utility Group)	not greater than 67.5 percent

1 Debt covenant ratios are calculated in accordance with the credit facility agreements including adjustments for business acquisitions and will differ from management's internal calculation due to the definition of certain items in the credit facility agreements.

15. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

In the course of normal operations, the Trust purchases and sells natural gas, natural gas liquids (NGLs) and power commodities and issues short- and long-term debt. The Trust uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Trust does not make use of derivative instruments for speculative purposes.

Fair Values of Financial Instruments

At December 31, 2009 and 2008, all derivatives, other than those that meet the expected purchase, sale or usage requirements exemption, were carried on the Consolidated Balance Sheets at fair value. 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 the interest rate and foreign exchange derivatives used quoted market rates.

The fair value of long-term debt has been estimated based on discounted future interest and principal payments using estimated interest rates. The fair value of the convertible debentures was estimated using a Black-Scholes model.

The carrying amount and fair values of the Trust's financial assets and liabilities were as follows:

Summary of fair values December 31, 2009	Held-for-trading	Cash flow hedges	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents 1	$ 3.739	$ -	$ -	$ -	$ -	$ -	$ 3.739
Short-term investment 1	19.436	-	-	-	-	-	19.436
Accounts receivable 1	-	-	189.458	-	-	14.215	203.673
Restricted cash holdings from customers 1	-	-	27,228	-	-	-	27,228
Risk management assets (current)	36.108	30.163	-	-	-	-	66.271
Prepaid expense and other current assets 1	-	-	1.064	-	-	6,441	7,505
Risk management assets (non-current)	16,673	1,459	-	-	-	-	18,132
Long-term investments and other assets (note 8)	11.327	-	-	13.327	-	5,833	30.487
	$ 87.283	$ 31.622	$ 217.750	$ 13.327	$ -	$ 26.489	$ 376,471
Financial liabilities							
Accounts payable and accrued liabilities 1	$ -	$ -	$ -	$ -	$ 45.190	$ 113,129	$ 158,319
Distributions payable	-	-	-	-	15,110	-	15,110
Short-term debt 1	-	-	-	-	14.626	-	14.626
Current portion of long-term debt 2	-	-	-	-	591.944	-	591.944
Customer deposits 1	-	-	-	-	30.678	-	30.678
Risk management liabilities (current)	31.408	2.792	-	-	-	-	34.200
Other liabilities 1	-	-	-	-	14.162	668	14.830
Long-term debt 3	-	-	-	-	411.380	(3,210)	408.170
Risk management liabilities (non-current)	13.732	759	-	-	-	-	14,491
	$ 45,140	$ 3,551	$ -	$ -	$1,123.090	$ 110.587	$1,282,368

1 Due to the nature and/or short maturity of these financial instruments, the carrying amount approximates the fair value.
2 Fair value of current portion of long-term debt is approximately $591.8 million.
3 Fair value of long-term debt excluding non-financial instruments is approximately $425.7 million.

Summary of fair values December 31, 2008	Held-for-trading	Cash flow hedges	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total
Financial assets							
Cash and cash equivalents [1]	$ 18,304	$ –	$ –	$ –	$ –	$ –	$ 18,304
Accounts receivable [1]	–	–	214,589	–	–	5,691	220,280
Restricted cash holdings from customers [1]	–	–	24,017	–	–	–	24,017
Risk management assets (current)	36,156	56,686	–	–	–	–	92,842
Prepaid expense and other assets [1]	–	–	1,490	–	-	6,215	7,705
Risk management assets (non-current)	13,114	18,033	–	–	–	–	31,147
	$ 67,574	$ 74,719	$ 240,096	$ –	$ –	$ 11,906	$ 394,295
Financial liabilities							
Accounts payable and accrued liabilities [1]	$ –	$ –	$ –	$ –	$ 130,724	$ 67,508	$ 198,232
Distributions payable	–	–	–	–	12,943	–	12,943
Short-term debt [1]	–	–	–	–	4,493	–	4,493
Current portion of long-term debt	–	–	–	–	1,363	–	1,363
Customer deposits [1]	–	–	–	–	24,017	–	24,017
Risk management liabilities (current)	34,824	22,599	–	–	–	–	57,423
Other liabilities [1]	–	–	–	–	18,271	3,656	21,927
Long-term debt [2]	–	–	–	–	561,719	(2,307)	559,412
Risk management liabilities (non-current)	10,038	6,707	–	–	–	–	16,745
Convertible debentures	–	–	–	–	16,682	–	16,682
	$ 44,862	$ 29,306	$ –	$ –	$ 770,212	$ 68,857	$ 913,237

1 Due to the nature and/or short maturity of these financial instruments, the carrying amount approximates the fair value.
2 Fair value of long-term debt is approximately $551 million.

Summary of unrealized gain (loss) on risk management December 31	2009	2008
Natural gas	$ 4,772	$ 5,510
NGL	281	4,997
Power	68	(550)
Heat rate	122	(163)
Interest rate swaps	4,523	(4,896)
Foreign exchange	(6,069)	(6,088)
	$ 3,697	$ 10,986

Summary of unrealized gain (loss) and tax expense (recovery) on derivatives designated as cash flow hedges

December 31	Unrealized gain (loss)	Tax expense (recovery)	2009	Unrealized gain (loss)	Tax expense (recovery)	2008
NGL	$ (2,555)	$ 714	$ (1,841)	$ 35,931	$ (10,352)	$ 25,579
Power	30,622	(8,557)	22,065	5,914	(1,555)	4,359
Bond forward	(2,881)	-	(2,881)	(3,214)	–	(3,214)
Foreign exchange	-	–	–	6,785	(1,967)	4,818
Available-for-sale	4,462	(580)	3,882	–	–	–
	$ 29,648	$ (8,423)	$ 21,225	$ 45,416	$ (13,874)	$ 31,542

Fair Value Hierarchy

The Trust 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 value is based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly held 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, 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-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.

	Level 1	Level 2	Level 3	Total
Financial assets				
Held-for-trading [1]	30,763	52,781	–	83,544
Cash flow hedges	–	31,622	–	31,622
Available-for-sale	13,327	–	–	13,327
Financial liabilities				
Held for trading	–	45,140	–	45,140
Cash flow hedges	–	3,551	–	3,551

1 Excludes cash and cash equivalents as carrying amount approximates fair value.

Long-term Investments and Other Assets

In January 2009 AltaGas purchased common shares of Magma Energy Corp. (Magma) through a private-equity offering for $10.0 million. These shares were classified as available-for-sale. The changes in value for these common shares are reported within OCI, which was $4.5 million as at December 31, 2009. In July 2009, AltaGas purchased additional common shares of Magma as part of its initial public offering. These shares were classified as held-for-trading and included in long-term investments and other assets. As at December 31, 2009, the Trust recognized an unrealized gain of $1.3 million in the Corporate Segment as other revenue.

In October 2009 AltaGas acquired an equity investment in a public company with the acquisition of Utility Group (note 3). The shares are classified as available-for-sale. The changes in value for these common shares are reported within OCI.

Short-term Investment

For the year ended December 31, 2009 the Trust recognized a realized gain of $6.8 million and unrealized gain of $4.5 million in the Corporate Segment as other revenue.

Market Risk on Financial Instruments

The Trust 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

The Trust 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 2014.

The Trust had the following contracts outstanding:

December 31, 2009			Notional volume (GJ)		
Derivative instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$4.55 to $10.01	1–61	127,863,433	–	$ 47,598
Commodity forward	$4.51 to $9.825	1–61	–	127,863,433	$ (40,808)

December 31, 2008			Notional volume (GJ)		
Derivative instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$2.27 to $10.49	1–59	77,195,070	–	$ 27,209
Commodity forward	$2.27 to $10.73	1–59	–	77,195,070	$ (24,720)

NGL

The Trust entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread.

The Trust had the following contracts outstanding:

December 31, 2009			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$0.858 to $1.555 US/gallon	1–12	14,705,000 gallons	–	$ (347)
Butane	$1.100 to $1.870 US/gallon	1–12	4,726,000 gallons	–	$ (231)
WTI	$72.55 to $122.95 US/Bbl	1–12	80,700 Bbls	–	$ 749
USD swaps	$0.995 to $1.154	1–12		$ 38,890	$ 202
Natural gas	$4.79 to $8.88/GJ	1–12	–	3,270,600 GJ	$ (2,375)

December 31, 2008			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$1.380 to $1.800 US/gallon	1–24	36,330,000 gallons	–	$ 40,016
Butane	$1.650 to $2.300 US/gallon	1–24	11,676,000 gallons	–	$ 15,915
WTI	$94.50 to $144.65 US/Bbl	1–24	134,500 Bbls	–	$ 9,531
USD	$0.995 to $1.026	1–24		$ 82,550	$ (17,749)
Natural gas	$7.84 to $9.93/GJ	1–24	–	5,451,000 GJ	$ (11,509)

Power

Under the PPAs AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins 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, 2009 the Trust had no intention to terminate any contracts prior to maturity.

The Trust had the following commodity forward contracts on electrical power outstanding at December 31, 2009 (December 31, 2008 – nil):

December 31, 2009			Notional volume (MWh)		
Derivative instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$45.00 to $72.35	1–37	47,349	–	$ 2,335
Commodity forward	$44.75 to $70.36	1–37	–	47,349	$ (1,597)

The Trust had the following commodity swaps and collars outstanding:

December 31, 2009			Notional volume (MWh)		
Derivative instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Swaps and collars	$46.75 to $81.00	1–12	1,098,336	–	$ 30,118
Swaps and collars	$56.50	1–97	–	210,384	$ (132)

December 31, 2008			Notional volume (MWh)		
Derivative instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Swaps and collars	$60.50 to $88.00	1–24	2,595,105	–	$ 734
Swaps and collars	$56.50 to $75.75	1–108	–	259,520	$ 5,207

The Trust had the following heat rate hedges outstanding:

December 31, 2009			Notional volume (GJ or MWh)		
Derivative instruments	Fixed price (per GJ or MWh)	Period (months)	Sales	Purchases	Fair value
Natural gas (per GJ)	$5.123	1	–	72,000	$ 18
Power (per MWh)	$65.50 to $70.00	1	1,575	–	$ 128

December 31, 2008			Notional volume (GJ or MWh)		
Derivative instruments	Fixed price (per GJ or MWh)	Period (months)	Sales	Purchases	Fair value
Natural gas (per GJ)	$6.07	1	–	14,700	$ (5)
Power (per MWh)	$107.50 to $195.50	1	1,225	–	$ 29

Interest Rate Risk Management

To hedge against the effects of future interest rate movements, the Trust enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. The Trust's target is to have approximately 70 to 75 percent of its debt at fixed interest rates.

The Trust had the following interest rate swaps outstanding:

December 31, 2009	Weighted average interest rate	Period (months)		Notional quantity		Fair value
Swaps	2.756%	1-26	$	185,000	$	(282)

December 31, 2008	Weighted average interest rate	Period (months)		Notional quantity		Fair value
Swaps	3.746%	1–15	$	205,000	$	(4,814)

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, the Trust enters into foreign exchange forwards, swaps and options for U.S. dollars (USD) and euros (EUR).

The Trust had the following contracts outstanding:

December 31, 2009	Fixed price	Period (months)		Notional quantity		Fair value
Swaps (USD)	$1.0164 to $1.2215	1-21	$	16,900	$	248

December 31, 2008	Fixed price	Period (months)		Notional quantity		Fair value
Swaps (USD)	$1.0164 to $1.2925	1–21	$	3,273	$	539
Forwards and options (EUR) [1]	$1.470 to $1.5350	4–9	€	62,700	$	12,651

1 Related to the supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind Project. Obligations are denominated in euros.

In 2009 AltaGas entered into a natural gas storage agreement denominated in U.S. dollars resulting in an embedded derivative. The change in value of the contract is recognized in unrealized gain on risk management. The unrealized gain was $87,057 as of December 31, 2009.

Bond Forward

In April 2009 the Trust issued $200 million of senior unsecured MTNs with a maturity date of April 2014. To partially hedge against the risk of rising interest rates, the Trust 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. The Trust 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, interest rate swap and foreign exchange contract 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, 2009:

Factor share	Increase or decrease [1]	Increase or decrease in net income	Increase or decrease in OCI
Alberta electricity average pool prices	$1/MWh	$ –	$ 951
Natural gas spot price (AECO)	$0.50/GJ	758	–
NGL frac spread:			
Propane	$1/Bbl	152	142
Butane	$1/Bbl	81	–
WTI	$1/Bbl	15	43
Natural gas to replace heat value of NGL	$0.50/GJ	–	1,177
Foreign exchange (USD only)	1%	7	275
Interest rate swaps	25 bps	423	–
Foreign exchange	1%	$ 121	$ –

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 on clients, 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.

The Trust's maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. At December 31, 2009 AltaGas had no concentration of credit risk with a single counterparty.

Accounts Receivable Past Due or Impaired

The Trust had the following past due and impaired receivables:

December 31, 2009			Receivables by period and not impaired			
Accounts receivable	2009	Receivables impaired	Less than 30 days	31-60 days	61-90 days	Over 90 days
Trade receivable	$ 191,797	$ 2,167	$ 170,572	$ 8,379	$ 2,841	$ 7,838
Other receivable	14,043	–	9,974	–	161	3,908
Allowance for credit losses	(2,167)	(2,167)	–	–	–	–
	$ 203,673	$ –	$ 180,546	$ 8,379	$ 3,002	$ 11,746

Allowance for credit losses	
Allowance for credit losses, beginning of year	$ 1,908
Impairment expense	259
Allowance for credit losses, end of year	$ 2,167

December 31, 2008			Receivables by period and not impaired			
Accounts receivable	2008	Receivables impaired	Less than 30 days	31–60 days	61–90 days	Over 90 days
Trade receivable	$ 213,959	$ 1,908	$ 193,012	$ 9,887	$ 3,029	$ 6,123
Other receivable	8,229	–	7,672	–	194	363
Allowance for credit losses	(1,908)	(1,908)	–	–	–	–
	$ 220,280	$ –	$ 200,684	$ 9,887	$ 3,223	$ 6,486

Allowance for credit losses	
Allowance for credit losses, beginning of year	$ 1,765
Impairment expense	143
Allowance for credit losses, end of year	$ 1,908

Liquidity Risk on Financial Instruments

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. The Trust manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. The Trust's objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required (note 15).

At December 31, 2009 the Trust had the following contractual maturities with respect to non-derivative financial liabilities:

		Payments due by period			
	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
Short-term debt	$ 14,626	$ 14,626	$ –	$ –	$ –
Current portion of long-term debt	591,944	591,944	–	–	–
Long-term debt [1,2]	411,380	–	104,858	206,522	100,000
	$ 1,017,950	$ 606,570	$ 104,858	$ 206,522	$ 100,000

1 Comprising operating loans, MTNs and capital lease obligations excluding deferred financing costs (note 10).
2 Credit facilities maturing within the next 12 months are expected to be refinanced on a long-term basis.

16. UNITHOLDERS' EQUITY

December 31	2009	2008
Unitholders' capital (note 17)	$ 982,662	$ 850,992
Contributed surplus (notes 4, 11 and 18)	5,621	4,261
Accumulated earnings	815,045	673,736
Convertible debentures	–	1,600
Warrants	4,500	4,500
Accumulated dividends	(41,114)	(41,114)
Accumulated unitholders' distributions declared [1]	(709,058)	(538,227)
Distributions of common shares of Utility Group	(29,848)	(29,848)
Transition adjustment resulting from adopting new financial instruments accounting standards	(176)	–
Accumulated other comprehensive income	21,225	31,542
	$ 1,048,857	$ 957,442

1 Accumulated unitholders' distributions paid by the Trust as at December 31, 2009 were $694.0 million (as at December 31, 2008 – $525.3 million).

17. UNITHOLDERS' CAPITAL

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas Holding Limited Partnership No. 2 (AltaGas LP No. 2) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange was at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. Since May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust units issued and outstanding	Number	Amount
December 31, 2007	56,057,438	$ 493,866
Units issued for cash on exercise of options	2,150	55
Units issued under DRIP [1]	1,635,937	34,612
Units issued for exchangeable units	60,890	859
Units issued on business acquisition	7,553,174	194,645
Units issued on conversion of convertible debentures	53,439	1,843
Units issued on public offering (net of $5.2 million of issuance costs)	4,398,750	110,077
December 31, 2008	69,761,778	$ 835,957

Exchangeable units issued and outstanding		
December 31, 2007 issued by AltaGas LP #1	2,040,456	$ 11,678
AltaGas LP #1 units redeemed for Trust units	(60,890)	(859)
Units issued on business acquisition	163,607	4,216
December 31, 2008	2,143,173	15,035
Issued and outstanding at December 31, 2008	71,904,951	$ 850,992

Trust units issued and outstanding	Number of units	Amount
December 31, 2008	69,761,778	$ 835,957
Units issued for cash on exercise of options	71,750	1,246
Units issued under DRIP [1]	2,236,266	34,169
Units issued for exchangeable units	59,517	892
Units issued on conversion of convertible debentures	2,637	71
Units issued on public offering (net of $5.4 million of issuance costs and $0.9 million tax benefit) [2]	6,100,000	96,184
December 31, 2009	78,231,948	$ 968,519

Exchangeable units issued and outstanding	Number of units	Amount
December 31, 2008 issued by AltaGas LP #1	2,143,173	$ 15,035
AltaGas LP #1 units redeemed for Trust units	(59,517)	(892)
December 31, 2009	2,083,656	14,143
Issued and outstanding at December 31, 2009	80,315,604	$ 982,662

1 Distribution Reinvestment Program.
2 Net proceeds on issuance of units will not tie to the units issued due to non-cash items, including tax benefits.

Weighted average units outstanding [1]	2009	2008
Number of units – basic	78,539,800	68,812,654
Dilutive equity instruments [2]	830,847	890,744
Number of units – diluted	79,370,647	69,703,398

1 Includes exchangeable units.
2 Includes options, convertible debentures and warrants.

The Trust has an employee unit option plan under which employees and directors are eligible to receive grants. At December 31, 2009, 10 percent of units outstanding were reserved for issuance under the plan. As at December 31, 2009 options granted under the plan generally had a term of 10 years until expiry and vested no longer than over a four-year period.

At December 31, 2009 outstanding options were exercisable at various dates within the next nine years. As at December 31, 2009 the unexpensed fair value of unit option compensation cost associated with future periods was $0.7 million (December 31, 2008 – $0.6 million).

The following table summarizes information about the Trust's unit options:

	Options outstanding					
	2009			2008		
	Number of options		Exercise price	Number of options		Exercise price [1]
Unit options outstanding, beginning of year	2,972,250	$	20.33	1,310,400	$	26.36
Granted	1,024,500		18.04	1,882,250		16.84
Exercised	(71,750)		12.94	(2,150)		17.17
Expired	(117,750)		20.30	(218,250)		26.42
Unit options outstanding, end of year	3,807,250	$	19.86	2,972,250	$	20.33
Unit options exercisable, end of year	1,194,398	$	23.48	602,326	$	25.91

1 Weighted average.

The following table summarizes the employee unit option plan as at December 31, 2009:

	Options outstanding			Options exercisable	
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life	Number exercisable	Exercise price
$5.00–15.25	1,301,250	$ 14.17	8.87	296,500	$ 13.94
$15.26–25.08	1,714,500	20.56	8.95	327,564	24.34
$25.09–29.15	791,500	27.67	6.89	570,334	27.95
	3,807,250	$ 19.86	8.49	1,194,398	$ 23.48

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

	2009	2008
Risk-free interest rate (%)	3.35	3.43
Expected life (years)	10	10
Expected volatility (%)	24.58	23.81
Annual distribution per unit ($)	2.15	2.10

In 2004 AltaGas implemented a unit-based compensation plan, which awards phantom units to certain employees. Beginning in 2008, all employees were eligible to receive phantom units. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2009 in respect of this plan was $7.2 million (2008 – $5.5 million). As at December 31, 2009 the unexpensed fair value of unit-based compensation costs associated with future periods was $26.4 million (December 31, 2008 – $18.4 million).

18. CONTRIBUTED SURPLUS

	2009	2008
Balance, beginning of year	$ 4,261	$ 3,875
Amortization of unit options	376	431
Exercise of unit options	(318)	(18)
Cancellation of unit options	(213)	(27)
Other adjustments [1]	1,515	–
Balance, end of year	$ 5,621	$ 4,261

1 Includes equity portion of convertible debentures redeemed in September 2009 of $1.6 million (note 11).

19. NET INCOME PER UNIT

The following table summarizes the computation of net income per unit:

Years ended December 31	2009	2008
Numerator:		
Numerator for basic net income per unit	$ 141,309	$ 163,571
Numerator for diluted net income per unit	$ 141,998	$ 164,567
Denominator:		
Weighted average number of units	78,540	68,813
Dilutive equity instruments [1]	831	891
Denominator for diluted net income per unit	79,371	69,704
Basic net income per unit	$ 1.80	$ 2.38
Diluted net income per unit	$ 1.79	$ 2.36

1 Includes options, convertible debentures and warrants.

20. COMMITMENTS

Future minimum lease payments under operating leases for office space, office equipment and automotive equipment at December 31, 2009 are estimated as follows:

2010	$ 4,985
2011	4,386
2012	3,602
2013	886
2014	601
	$ 14,460

In 1999 the Trust acquired an agreement to purchase natural gas from specific reserves for $0.05/Mcf for the life of the reserves. The production from these reserves was 841 Mcf/d in 2009 (2008 – 1,239 Mcf/d).

In 2007 AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain Wind Park. The Trust has an obligation to pay a minimum of $0.5 million over the next 12 years.

In 2009 AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. The Trust is obligated to pay approximately $3.3 million per annum over the term of the contract for storage services.

In 2009 AltaGas entered into various purchase agreements with respect to Ante Creek and Pouce Coupe gas processing facilities. In 2010 the Trust is obligated to pay approximately $1.5 million and $1.6 million, respectively, to increase processing capacity at these facilities.

21. NET CHANGE IN NON-CASH WORKING CAPITAL

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

Years ended December 31	2009	2008 [1]
Accounts receivable	$ 41,744	$ 4,803
Inventory	(626)	(645)
Other current assets [2]	200	(4,491)
Regulatory assets	(1,774)	–
Accounts payable and accrued liabilities	(75,057)	(7,878)
Customer deposits	6,661	(352)
Deferred revenue	(2,777)	1,059
Other current liabilities	(7,096)	12,606
	(38,725)	5,102
Add back:		
Increase (decrease) in capital costs payable	20,996	(15,993)
Net change in non-cash working capital related to operations	$ (17,729)	$ (10,891)

1 Specific line items may not agree with the net change in the Consolidated Balance Sheets due to acquisition.
2 Excludes note receivable of $6.5 million included in investing activities in 2008.

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

Years ended December 31	2009	2008
Interest paid	$ 32,328	$ 24,023
Income taxes paid (received)	$ (89)	$ 2,577

22. PENSION PLANS AND RETIREE BENEFITS

SEC File # 82-34911

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was $2.3 million for the year ended December 31, 2009 (2008 – $1.7 million).

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2009 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2008 based on a report dated April 29, 2009, and plan contributions for 2008 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 based upon a report dated March 29, 2006.

As at December 31, 2009 the accrued benefit obligation of the Trust for this plan was $2.2 million (December 31, 2008 – $1.9 million). At December 31, 2009 the plan had an accrued benefit asset recognized in the Consolidated Financial Statements of $3,000 (December 31, 2008 – $10,000).

In 2008 the Trust assumed two defined benefit pension plans with the acquisition of Taylor (note 3). These plans are in relation to the unionized employees at the Younger Extraction Plant (Younger) and certain employees at the Harmattan Complex (Harmattan). Plan contributions for the Younger pension plan and Harmattan pension plan during 2009 were made in accordance with an actuarial valuation for funding purposes as at December 31, 2006 and December 31, 2008, respectively. As at December 31, 2009 the accrued benefit obligation of the Trust for these plans was $9.0 million (December 31, 2008 – $7.7 million). At December 31, 2009 these plans had an accrued benefit liability recognized in the Consolidated Financial Statements of $0.8 million (December 31, 2008 – $1.1 million).

In 2009 the Trust assumed two defined benefit non-contributory pension plans in the acquisition of Utility Group (note 3). The plans are in relation to substantially all full-time employees of AUI. Plan contributions for the AUI pension plans during 2009 were made in accordance with actuarial valuations for funding purposes as at September 30, 2008 based on reports dated March 31, 2009. As at December 31, 2009 the accrued benefit obligation of the Trust for these plans was $19.0 million (December 31, 2008 – nil). At December 31, 2009 the plans had accrued benefit liabilities recognized in the Consolidated Financial Statements of $1.4 million (December 31, 2008 – nil).

For the year ended December 31, 2009 the net pension cost for all defined benefit plans was $0.8 million (2008 – $0.4 million).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan that provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. In 2009, the Trust assumed the liability recorded for the SERP held by Utility Group (note 3). As at December 31, 2009 the accrued benefit obligation of the Trust for this plan was $6.4 million (December 31, 2008 – $3.6 million). At December 31, 2009 the plan had an accrued benefit liability recognized in the financial statements of $6.2 million (December 31, 2008 – $3.7 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

For the year ended December 31, 2009 the net pension expense related to the SERP was $1.2 million (2008 – $1.7 million).

Post-Retirement Benefits

In 2008 the Trust assumed two post-retirement benefit plans for the unionized employees at Younger and Harmattan. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums.

In 2009 the Trust assumed a post-retirement benefit plan for certain employees of AUI providing benefits such as life insurance and health care. These other benefit plans are not funded.

For the year ended December 31, 2009 the net benefit cost for these plans was $0.2 million (2008 – $0.1 million).

The estimates for health care benefits takes into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rate used to measure the expected cost of benefits is 7.83 percent and the ultimate trend rate is 4.50 percent, which is assumed to be achieved by 2029.

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

	Defined benefit 2009	Post-retirement benefits 2009	Defined benefit 2008	Post-retirement benefits 2008
Accrued benefit obligation				
Balance, beginning of year	$ 13,146	$ 563	$ 4,968	$ –
Assumed through acquisition [1,2]	16,910	1,217	10,154	734
Actuarial gain	3,673	617	(3,588)	(235)
Current service cost	2,261	93	1,575	37
Member contributions	-	-	102	–
Past service cost	-	-	294	–
Interest cost	2,249	136	844	41
Benefits paid	(1,628)	(55)	(1,203)	(14)
Balance, end of year	36,611	2,571	13,146	563
Plan assets				
Fair value, beginning of year	8,763	-	1,586	–
Assumed through acquisition [1,2]	14,542	-	8,345	–
Actual loss on plan assets	4,978	-	(1,538)	–
Employer contributions	2,280	55	1,471	14
Member contributions	95	-	102	–
Benefits paid	(1,628)	(55)	(1,203)	(14)
Expected plan expenses	(342)	-	–	–
Fair value, end of year	28,688	-	8,763	–
Funded deficit	(7,923)	(2,571)	(4,383)	(563)
Unamortized transitional obligation	179	181	–	–
Unamortized past service costs	625	-	(810)	–
Unamortized net actuarial loss	1,511	137	389	(235)
Accrued benefit liability recognized in the financial statements	$ (5,608)	$ (2,253)	$ (4,804)	$ (798)

	Defined benefit 2009	Post-retirement benefits 2009	Defined benefit 2008	Post-retirement benefits 2008
Significant actuarial assumptions used as at December 31				
Discount rate (%)	6.20–7.10	6.50–6.70	7.25	7.25
Expected long-term rate of return on plan assets (%)	6.75–7.75	6.75	6.75–7.25	7.25
Rate of compensation increase (%)	4.00–5.50	4.00	3.50–4.00	4.00
Average remaining service life of active employees (years)	14.8	10.1	12.9	9.2
Net benefit plan expense for the year				
Current service cost and expenses	$ 1,519	$ 43	$ 1,575	$ 37
Interest cost	1,262	62	844	41
Actual gain (loss) on plan assets	(2,362)	–	1,538	–
Actuarial gain (loss) on accrued benefit obligation	2,380	209	(3,588)	(235)
Costs arising in the year	2,799	314	369	(157)
Differences between costs arising in the year and costs recognized in the year in respect of				
Actuarial gain (loss) on plan assets	1,498	–	(2,197)	–
Plan amendments	1	–	–	–
Actuarial gain (loss) on accrued benefit obligation	(2,414)	(231)	3,588	235
Amortization of past service costs	77	–	371	–
Transitional obligations	11	7	–	–
Net periodic benefit plan costs recognized	$ 1,972	$ 90	$ 2,131	$ 78

1 Includes the AUI plan acquired in the acquisition of Utility Group (note 3) in 2009.
2 Includes the Younger and Harmattan plans acquired in the acquisition of Taylor (note 3) in 2008.

The assets are invested under balanced fund mandates with a broad mix of fixed income, Canadian equity and foreign equity investments. The collective investment mixes for the plans are as follows as at December 31, 2009:

	Percentage of plan assets
Cash and short-term equivalents	2.4%
Canadian equities	33.78%
Foreign equities	27.74%
Fixed income	36.08%
	100.00%

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 2009:

	Increase	**Decrease**
Service and interest costs	7	(6)
Accrued benefit obligation	310	(249)

23. RELATED PARTY TRANSACTIONS

On October 8, 2009 AltaGas acquired all of the outstanding common shares of Utility Group (note 3) and therefore consolidated the operating results of the Utility Group with the results of the Trust. All intercompany transactions have been eliminated on consolidation.

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts and are as follows:

Years ended December 31	2009	2008
Fees for administration, management and other services paid by		
Utility Group to the Trust [1]	$ -	$ 219
The Trust to Utility Group [1]	$ -	$ 4
Natural gas sales by the Trust to Utility Group subsidiaries [1]	$ -	$ 96,457
Fees for operating services paid by Utility Group subsidiaries [1]	$ -	$ 427
Transportation services provided by Utility Group subsidiaries [1]	$ -	$ 491
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	$ 90	$ 88

1 *Includes transactions up to the date of acquisition of Utility Group (note 3).*

The resulting amounts due from and to related parties are non-interest-bearing and are related to transactions in the normal course of business.

24. JOINT VENTURES

The Trust's proportionate interest in its joint venture arrangements is summarized as follows:

	2009	2008
Proportionate share of operating income for the years ended December 31		
Revenues	$ 238,176	$ 402,006
Expenses	193,807	290,677
	$ 44,369	$ 111,329
Proportionate share of net assets at December 31		
Current assets	$ 31,304	$ 39,517
Capital assets	299,213	283,426
Energy services arrangements, contracts and relationships	82,284	88,893
Long-term investments and other assets	14	1
Current liabilities	(15,644)	(30,622)
Other long-term liabilities	(1,660)	(912)
	$ 395,511	$ 380,303
Proportionate share of cash flows for years ended December 31		
Operating activities	$ 61,613	$ 121,015
Investing activities	(18,497)	(214,624)
Financing activities	(38,309)	96,094
	$ 4,807	$ 2,485

25. NON-MONETARY TRANSACTION

In first quarter 2009 AltaGas entered into a non-monetary transaction with a third party in which it exchanged B.C. Renewable Energy Certificates (RECs) for verified emission offsets that were generated in Alberta. The RECs will be created through the generation of power at the Bear Mountain Wind Park between 2009 and 2011. The verified emission offsets received by AltaGas were used to offset the costs to comply with Alberta's Specified Gas Emitters Regulation in 2009.

26. CONTINGENT LIABILITY

Sundance B Unit 4 Power Outage

The contingent liability related to the Sundance B Unit 4 facility outage in mid-December 2008 due to the failure of an induced fan was settled in August 2009. The terms of the settlement are confidential. No contingent liabilities are outstanding related to power outages.

27. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current financial presentation.

28. SUBSEQUENT EVENT

Warrants

On January 1, 2010 AltaGas issued 180,433 units on exercise of special warrants that were originally issued in February 2008 on a one-for-one basis at $24.94 per special warrant.

Landis Energy Corporation

On February 2, 2010 AltaGas offered to acquire all the outstanding common shares of Landis Energy Corporation (Landis) in exchange for cash of $0.80 per common share. The acquisition is valued at approximately $22 million and, if successful, will be funded through AltaGas' existing credit facilities. The offer is subject to certain conditions, including its acceptance by the holders of at least two-thirds of the outstanding common shares of Landis and regulatory approval. The offer is currently due to expire on March 10, 2010.

29. SEGMENTED INFORMATION

AltaGas is an integrated energy trust with a portfolio of assets and services used to move energy from the source to the end user. The majority of the transactions among the reporting segments are recorded at the market price of the commodities, and the remainder is at the exchange amount. In accordance with the CICA Handbook Section 1700, for the year ended December 31, 2009, AltaGas has changed the composition of its reportable segments as a result of modifications and growth of the enterprise. Comparative periods have been restated based on the current reportable segments. The following describes the Trust's three reporting segments:

Gas	• NGL processing and extraction plants • transmission pipelines to transport natural gas and NGL • natural gas gathering lines and processing facilities • energy consulting and sale of natural gas and electricity • natural gas storage facilities • regulated natural gas distribution assets
Power	• coal-fired and gas-fired power output under power purchase arrangements and other agreements • gas-fired power plants • wind and run-of-river power plants
Corporate	• the costs of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management contracts

The following tables show the composition by segment:

Year ended December 31, 2009	Gas Segment	Power Segment	Corporate Segment	Intersegment elimination	Total
Revenue	$ 1,142,411	$ 188,508	$ 14,919	$ (81,270)	$ 1,264,568
Unrealized gain on risk management	-	-	3,697	-	3,697
Cost of sales	(802,262)	(86,280)	-	76,854	(811,688)
Operating and administrative	(166,433)	(6,069)	(40,133)	4,416	(208,219)
Amortization	(63,427)	(8,167)	(2,527)	-	(74,121)
Foreign exchange gain	-	-	(1)	-	(1)
Interest expense	-	-	(31,759)	-	(31,759)
Income (loss) before income taxes	$ 110,289	$ 87,992	$ (55,804)	-	$ 142,477
Net additions to					
Capital assets [1]	$ 323,779	$ 159,544	$ 3,073	-	$ 486,396
Long-term investment and other assets [2]	$ (12,300)	$ (367)	$ 24,410	-	$ 11,743
Goodwill	$ 201,728	-	-	-	$ 201,728
Segmented assets	$ 2,053,177	$ 425,899	$ 150,020	-	$ 2,629,096

1 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $245,397.

2 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $195,553.

Year ended December 31, 2008	Gas Segment	Power Segment	Corporate Segment	Intersegment elimination	Total
Revenue	$ 1,643,187	$ 223,510	$ 1,882	$ (62,770)	$ 1,805,809
Unrealized gain on risk management	–	–	10,986	–	10,986
Cost of sales	(1,308,989)	(94,518)	–	63,189	(1,340,318)
Operating and administrative	(173,230)	(3,715)	(44,136)	(419)	(221,500)
Amortization	(57,306)	(7,436)	(2,236)	–	(66,978)
Foreign exchange gain	–	–	1,369	–	1,369
Interest expense	–	–	(27,399)	–	(27,399)
Income (loss) before income taxes	$ 103,662	$ 117,841	$ (59,534)	–	$ 161,969
Net additions to					
Capital assets [1]	$ 664,847	$ 136,523	$ 6,592	–	$ 807,962
Energy services arrangements, contracts and relationships	$ 53,000	–	–	–	$ 53,000
Long-term investment and other assets [2]	–	$ 713	$ (47,479)	–	$ (46,766)
Goodwill	$ 143,840	–	–	–	$ 143,840
Segmented assets	$ 1,708,335	$ 268,474	$ 155,444	–	$ 2,132,253

1 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $679,652.

2 Difference in timing of cash flows, non-cash transactions and assets acquired in business acquisitions (note 3), recorded as acquisition of long-term investment on statement of cash flow of $358,259.

AltaGas

NEWS RELEASE

ALTAGAS 2009 FOURTH QUARTER AND YEAR-END RESULTS AND CONFERENCE CALL ADVISORY

Calgary, Alberta (February 18, 2010) – AltaGas Income Trust (AltaGas or the Trust) (TSX: ALA.UN) will announce its 2009 fourth quarter and year-end financial results on Friday, February 26, 2010 before markets open. A conference call and webcast to discuss the results will be held the same day.

Time:	9:00 a.m. MT (11:00 a.m. ET)
Dial-in:	416-695-6616 or toll free at 1-888-952-4972
Webcast:	http://events.digitalmedia.telus.com/altagas/022610/index.php

Shortly after the conclusion of the call, a replay will be available by dialling 416-695-5800 or 1-800-408-3053. The passcode is 5262350. The replay will expire at midnight (Eastern) on March 5, 2010. The webcast will be archived for one year.

AltaGas Income Trust is one of Canada's largest and fastest growing energy infrastructure organizations. The Trust creates value by acquiring, growing and optimizing gas and power infrastructure, including a focus on renewable energy sources.

AltaGas Income Trust's units are listed on the Toronto Stock Exchange under the symbol ALA.UN. The Trust is included in the S&P/TSX Composite Index, the S&P/TSX Income Trust Index and the S&P/TSX Capped Energy Trust Index.

This news release contains forward-looking statements. When used in this news release, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. 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 the Trust's 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, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this news release, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in, or incorporated by reference in this news release, should not be unduly relied upon. Such statements speak only as of the date of this news release. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

For further information contact:

Media	Investment Community	Website: www.altagas.ca
Adrianne Lovric	Sheena McKellar	Investor Relations
(403) 691-9873	(403) 691-9855	1-877-691-7199
adrianne.lovric@altagas.ca	sheena.mckellar@altagas.ca	investor.relations@altagas.ca

AltaGas

NEWS RELEASE

ALTAGAS INCOME TRUST ANNOUNCES MONTHLY DISTRIBUTION

Calgary, Alberta (February 11, 2010) – AltaGas Income Trust (AltaGas or the Trust) (TSX: ALA.UN) today announced that a monthly distribution will be paid on March 15, 2010 to holders of record on February 25, 2010, of Trust Units and limited partnership units that are exchangeable into Trust Units (Exchangeable Units). The amount of the distribution will be $0.18 for each Trust Unit and each Exchangeable Unit.

AltaGas has a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan (the Plan) for eligible Unitholders of AltaGas Income Trust and AltaGas Holding Limited Partnership No. 1. The Premium component of the Plan is currently suspended. Information on the Plan is available on the AltaGas website at www.altagas.ca.

AltaGas Income Trust is one of Canada's largest and fastest growing energy infrastructure organizations. The Trust creates value by acquiring, growing and optimizing gas and power infrastructure, including a focus on renewable energy sources.

AltaGas Income Trust's units are listed on the Toronto Stock Exchange under the symbol ALA.UN. The Trust is included in the S&P/TSX Composite Index, the S&P/TSX Income Trust Index and the S&P/TSX Capped Energy Trust Index.

This news release contains forward-looking statements. When used in this news release, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. 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 the Trust's 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, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this news release, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in, or incorporated by reference in this news release, should not be unduly relied upon. Such statements speak only as of the date of this news release. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

For further information contact:

Media
Adrianne Lovric
(403) 691-9873
adrianne.lovric@altagas.ca

Investment Community
Sheena McKellar
(403) 691-9855
sheena.mckellar@altagas.ca

Website: www.altagas.ca
Investor Relations
1-877-691-7199
investor.relations@altagas.ca