ight states, one wind project under construction in Idaho, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW"), in which our ownership interest is approximately 808 MW.

The following map shows the location of our projects, including joint venture interests, across the United States:

We sell the capacity and power from our projects under PPAs with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2010 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects under steam sales agreements to industrial purchasers. The TSRs we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our projects generally operate pursuant to long-term supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and most of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

We partner with recognized leaders in the independent power business to operate and maintain our projects, including Caithness, Cogentrix and Western. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Atlantic Power Corporation is organized under the laws of the Province of British Columbia. Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia, Canada V6C 2G8 and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. Our website is atlanticpower.com. Information contained on our website is not part of this prospectus.

We completed our initial public offering on the TSX in November 2004. At the time of our initial public offering, or IPO, our publicly traded security was an IPS, each of which was comprised of one common share and Cdn$5,787 principal value of 11% subordinated notes due 2016. On November 17, 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form part of an IPS was exchanged for approximately 0.44 of a new common share. Our shares trade on the TSX under the symbol "ATP" and began trading on the NYSE under the symbol "AT" on July 23, 2010.

History of Our Company

Atlantic Power Corporation is a Canadian corporation that was formed in 2004. The following timeline illustrates significant events in the development of our business since our initial public offering. Further details about these events are included below:

Atlantic Power History

We used the proceeds from our IPO to acquire a 58% interest in Atlantic Power Holdings, LLC (now Atlantic Power Holdings, Inc., which we refer to herein as "Atlantic Holdings") from two private equity funds managed by ArcLight Capital Partners, LLC and from Caithness. Until December 31, 2009, we were externally managed by Atlantic Power Management, LLC, an affiliate of ArcLight. Under this external management arrangement, ArcLight provided administrative and office support services to us and was required to give us the opportunity to pursue investment opportunities that did not fit ArcLight's investment guidelines for its private equity funds. At the time of our IPO, Atlantic Holdings was granted a right of first offer related to ArcLight's interest in 11 power generating projects. Our acquisitions of a 40% interest in the Chambers project in 2005 and the Auburndale project in 2008 were completed under the terms of this right of first offer, which has since expired.

In August 2005, we acquired Epsilon Power Partners, LLC, which owns a 40% interest in the Chambers project, for approximately $63 million in cash and the assumption of $43 million in non-recourse debt.

In September 2006, we acquired 100% of the equity interests in Trans-Elect NTD Holdings Path 15, LLC (Path 15), which has since been renamed Atlantic Path 15 Holdings, LLC, which indirectly owns approximately 72% of the transmission system rights in the transmission line upgrade along the Path 15 transmission corridor located in central California. The purchase price was approximately $78.4 million.

In December 2006, we completed a private placement of 8,600,000 IPSs and Cdn$3.0 million principal amount of separate subordinated notes to three institutional investors. In February 2007, we used the net proceeds of the private placement to increase our ownership in Atlantic Holdings to 100%.

In December 2007, we increased our ownership interest in the Pasco project from 50% to 100%.

In November 2008, we acquired a 100% ownership interest in Auburndale Power Partners, L.P, which owns the Auburndale project for a purchase price of $139.9 million, subject to customary adjustments for working capital. The acquisition was funded with cash on hand, a $55 million borrowing under our credit facility and non-recourse acquisition debt of $35 million. The non-recourse acquisition debt associated with this transaction amortizes fully over the remaining term of the project's power purchase agreement.

In the first quarter of 2009, we transferred our remaining net interest in Onondaga Cogeneration Limited Partnership, at net book value, into a 50% owned joint venture, Onondaga Renewables, LLC, which is engaged in the redevelopment of the Onondaga project into a 40 MW biomass power plant.

In March 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina corporation. Rollcast is a developer of biomass power plants in the southeastern U.S. with five, 50 MW projects in various stages of development. In March 2010, we agreed to invest $2.0 million to increase our ownership interest in Rollcast to 60%. Under the terms of the agreement, $1.2 million of the investment was made in March 2010 and the remaining $0.8 million was made in April 2010. As a result of this additional investment, we began to consolidate our investment in Rollcast beginning March 1, 2010. Pursuant to the terms of our investment in Rollcast, we have the option, but not the obligation, to invest directly in biomass power plants under development by Rollcast.

In October 2009, we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreements with us, satisfied by a payment of $6 million on the termination date of December 31, 2009, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. In connection with the termination of the management agreements, we hired all of the then-current employees of Atlantic Power Management and entered into employment agreements with its officers.

In April 2010, Rollcast entered into a construction agreement for a 53.5 MW biomass project, known as Piedmont Green Power, to be located in Barnesville, Georgia. We are currently in advanced discussions that we expect will lead to our commitment to invest up to $75 million in the Piedmont Green Power project, representing substantially all of the equity interests in the project. We intend to use a sole arranger to syndicate project-level debt financing for Piedmont. Construction on the project is scheduled to begin in the third quarter of 2010. The Piedmont Green Power project has obtained a 20-year PPA with Georgia Power Company which includes an adjustment related to the cost of biomass fuel for the plant.

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("IWP" or "Idaho Wind") for approximately $40 million. IWP recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is currently scheduled to be completed in late 2010 or early 2011. IWP has 20-year fixed-price PPAs with Idaho Power Company. Our investment in IWP was funded with cash on hand and a $20 million borrowing under our senior credit facility. Our investment in IWP will be accounted for under the equity method of accounting.

Our Competitive Strengths

Diversified Projects. Our power generation projects have an aggregate gross electric generation capacity of approximately 1,823 MW, and our net ownership interest in the electric generation capacity of these projects is approximately 808 MW. Our power generation projects are diversified by geographic location, electricity and steam customers, and project operators. These projects are generally located in the deregulated and more liquid electricity markets of New England, New York, Mid-Atlantic, California and Texas, or are located in regions of relatively high electricity demand growth such as Florida and New Mexico.

Our power transmission project, known as the Path 15 project, is an 84-mile, 500-kilovolt transmission line built in order to alleviate north-south transmission congestion in California. It is a traditional rate-base asset whose revenues are regulated by the Federal Energy Regulatory Commission ("FERC") and is operated by Western, a U.S. Federal power agency.

Strong Customer Base. Our customers are generally large utilities, and other parties with investment-grade credit ratings. The largest customers of our power generation projects are Progress Energy Florida, Inc. ("PEF"), Tampa Electric Company ("TECO"), and Atlantic City Electric ("ACE"), which purchase approximately 40%, 15% and 11%, respectively, of the net electric generation capacity of our projects. No other electric customer purchases more than 7% of the net electric generation capacity of our power generation projects.

Leading Third-Party Managers. Our power generation projects rely on a number of different operators for their operation, which are generally recognized leaders in the independent power business. Affiliates of Caithness, Cogentrix and Babcock and Wilcox Power Generation Group, Inc. operate projects representing approximately 49%, 21% and 9%, respectively, of the net electric generation capacity of our power generation projects. No other operator is responsible for the operation of projects representing more than 8% of the net electric generation capacity of our power generation projects.

Stability of Project Cash Flow. Each of our power generation projects has been in operation for over ten years. Cash flows from each project are generally supported by energy sales contracts with investment-grade utilities and other sophisticated counterparties. We believe that each project's combination of PPA(s), fuel supply agreement(s) and/or commodity hedges help stabilize operating margins as fuel prices fluctuate.

Our Objectives and Business Strategy

Our objectives include maintaining the stability and sustainability of dividends to shareholders and to maximize the value of our company. In order to achieve these objectives, we intend to focus on enhancing the operating and financial performance of the projects and on pursuing additional acquisitions primarily in the electric power industry in the U.S. and Canada.

Organic Growth

We intend to enhance the operation and financial performance of our projects through:

- optimization of commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, and operations and maintenance agreements;
- achievement of improved operating efficiencies;
- upgrade or enhancement of existing equipment or plant configurations; and
- expansion of existing projects.

Successfully extending PPAs and fuel agreements may facilitate refinancings that provide capital to fund growth opportunities.

Extending PPAs Following Their Expiration

PPAs in our portfolio have expiration dates ranging from 2010 to 2037. In each case, we plan for expirations by evaluating various options in the market for maximizing project cash flows. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, arrangements with creditworthy energy trading firms for tolling agreements, full service PPAs or the use of derivatives to lock in value. We do not assume that pricing under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs.

Acquisition and Investment Strategy

We believe that new electricity generation projects will be required in the United States and Canada over the next several years as a result of growth in electricity demand, transmission constraints and the retirement of older generation projects due to obsolescence or environmental concerns. There is also a very active secondary market for existing projects. We intend to expand our operations by making accretive acquisitions with a focus on power generation, transmission, distribution and related facilities in the United States and Canada. We may also invest in other forms of energy-related projects, utility projects and infrastructure projects, as well as additional investments in development stage projects or companies where the prospects for creating long-term predictable cash flows are attractive. Since the time of our initial public offering on the TSX in 2004, we have twice acquired the interest of another partner in one of our existing projects and will continue to look for such opportunities.

Our senior management has significant experience in the independent power industry and we believe the experience, reputation and industry relationships of our management team will provide us with enhanced access to future acquisition opportunities.

Acquisition Guidelines

We use the following general guidelines when reviewing and evaluating possible acquisitions:

- each acquisition or investment should result in an increase in cash available for distribution to shareholders;
- in the case of an acquisition of power generation facilities, facilities with long-term PPAs with major electrical utilities or other creditworthy customers will be preferred; and, for facilities without such agreements, market electricity price assumptions used in acquisition evaluations will be obtained from a recognized independent source; and

in the case of an acquisition of a power generation facility, the expected useful life of the facility and associated structures will, with regular maintenance, be long enough to conform with our objective of providing stable long-term dividends to shareholders.

Power Industry Overview

Historically, the North American electricity industry was characterized by vertically-integrated monopolies. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers.

In the independent power generation sector, electricity is generated from a number of sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. According to the North American Electric Reliability Council's Long-Term Reliability Assessment, published in December 2009, summer peak demand within the United States in the ten-year period from 2009 through 2018 is projected to increase 14.8%, while winter peak demand in Canada is projected to increase 8.8%.

The Non-Utility Power Generation Industry

Our 12 power generation projects are non-utility electric generating facilities that operate in the U.S. electric power generation industry. The electric power industry is one of the largest industries in the United States, generating retail electricity sales of approximately $365 billion in 2008, based on information published by the Energy Information Administration. A growing portion of the power produced in the United States is generated by non-utility generators. According to the Energy Information Administration, there were approximately 8,287 non-utility generators representing approximately 471 gigawatts of capacity in 2008, the most recent year for which data is available, (equal to 47% of total generating plants and 43% of nameplate capacity). Non-utility generators sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

Based on our experience in the acquisition market since our IPO, as well as transactions we are currently evaluating for potential investment, we believe that an active secondary market for power generation projects will continue to provide us with meaningful acquisition and growth opportunities.

Our Power Projects

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of August 9, 2010, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

A corporate organizational chart, which includes all our operating and development projects, is included on the following page.

Project Name	Location (State)	Type	Total MW	Economic Interest(1)	Accounting Treatment(2)	Net MW(3)	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	C	155	PEF	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	C	121	PEF	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	C	121	TECO	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	E	89(4)	ACE	2024	BBB
						16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	C	N/A	California Utilities via CAISO(5)	N/A(6)	BBB+ to A(7)
Orlando	Florida	Natural Gas	129	50.00%	E	46	PEF	2023	BBB+
						19	Reedy Creek Improvement District	2013(8)	A(9)
Selkirk	New York	Natural Gas	345	17.70%(10)	E	14	Merchant	N/A	N/R
						47	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	E	59	Fortis Energy Marketing and Trading	2013	A-
						9	Sherwin Alumina	2020	NR
Topsham(11)	Maine	Hydro	14	50.00%	E	7	Central Maine Power	2011	BBB+

Badger Creek	California	Natural Gas	46	50.00%	E	23	Pacific Gas & Electric	2011	BBB+
Rumford	Maine	Coal/Biomass	85	26.40%	E	22	Rumford Paper Co.	2010	N/R
Koma Kulshan	Washington	Hydro	13	49.80%	E	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	E	53	PNM	2020	BB-
Idaho Wind	Idaho	Wind	183	27.56%	E	51	Idaho Power Co.	2030	BBB

(1) Except as otherwise noted, economic interest represents the percentage ownership interest in the project held indirectly by Atlantic Power.

(2) Accounting Treatment: C Consolidated; and E Equity Method of Accounting (for additional details, see Note 2 of the accompanying consolidated financial statements for the year ended December 31, 2009).

(3) Represents our interest in each project's electric generation capacity based on our economic interest.

(4) Includes separate power sales agreement in which the project and ACE share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(5) California utilities pay TACs to CAISO, who then pays owners of TSRs, such as Path 15, in accordance with its FERC approved annual revenue requirement.

(6) Path 15 is a FERC regulated asset with a FERC-approved regulatory life of 30 years: through 2034.

(7) Largest payers of fees supporting Path 15's annual revenue requirement are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements for any participants of A or better unless collateral is posted per CAISO imposed schedule.

(8) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF.

(9) Fitch rating on Reedy Creek Improvement District bonds.

(10) Represents our residual interest in the project after all priority distributions are paid, which is estimated to occur in 2012.

(11) We own our interest in this project as a lessor.

(12) Project currently under construction and is expected to be completed in late 2010 or early 2011.

The following corporate organization chart includes all of our operating and development projects:

Our projects are organized into the following six business segments:

Auburndale	Chambers
Lake	Path 15
Pasco	Other Project Assets

Auburndale Segment

General Description

The Auburndale Segment consists of a 155 MW dual-fired (natural gas and oil), combined-cycle, cogeneration plant located in Polk County, Florida, which commenced operations in July 1994. We own 100% of the Auburndale project, which is a "qualifying facility" (or "QF") under the rules promulgated by FERC. We acquired Auburndale from ArcLight Energy Partners Fund I, L.P. and Calpine Corporation in a transaction that was completed on November 21, 2008.

Auburndale is located on an 11-acre site in the City of Auburndale, Florida. Capacity and energy from the project is sold to PEF under three PPAs expiring at the end of 2013. Auburndale typically operates as a mid-merit generator, which means that it is called upon by PEF to run during periods of peak electricity demand on most weekdays and occasionally during periods of lower electricity demand. Steam is supplied to Florida Distillers Company and Cutrale Citrus Juices USA, Inc. The Florida Distillers steam agreement is renewed annually, and the Cutrale Citrus Juices steam agreement expires in 2013.

Auburndale has non-recourse debt outstanding of $26.6 million as of June 30, 2010 which is required to be fully amortized over the term of its PPAs expiring in 2013. See "Project-Level Debt" on page 61 of this prospectus for additional details. Atlantic Power has provided letters of credit in the total amount of $13.4 million to support certain Auburndale obligations: $5.5 million to support its debt service reserve, $4.4 million to support its PPA, and $3.5 million to support its fuel supply agreement.

Power Purchase Agreement

Auburndale sells electricity to PEF under three PPAs expiring at the end of 2013. Under the largest of the PPAs, Auburndale sells 114 MW of capacity and energy. An additional 17 MW of committed capacity is sold under two identical 8.5 MW agreements with PEF. Revenue from the sale of electricity under the three PPAs consists of capacity payments based on a fixed schedule of prices, and energy payments. Capacity payments under the largest PPA are dependent on the plant maintaining a minimum on-peak capacity factor of 92 percent on a rolling twelve-month average basis. On-peak capacity factor refers to the ratio of actual electricity generated during periods of peak demand to the capacity rating of the plant during such periods. The project has achieved the minimum on-peak capacity factor continuously since commercial operation. Capacity payments under the smaller two agreements are dependent on the project maintaining a minimum on-peak capacity factor of 70 percent. Energy payments under the largest PPA are comprised of a fuel component based on the delivered cost of coal at two PEF-owned coal-fired generating stations and a component intended to recover operating and maintenance costs. Energy payments under the smaller two agreements are based on the lesser of PEF's actual avoided energy cost or an energy price index based on the delivered fuel cost at a specific coal-fired power plant owned by TECO.

Steam Sales Agreement

Auburndale provides steam to Florida Distillers and Cutrale Citrus Juices under two separate steam purchase agreements. The Florida Distillers agreement automatically extends on an annual basis, and can be terminated by either party with 90 days notice. The Cutrale Citrus Juices agreement terminates on December 31, 2013 and contains automatic two-year renewal terms.

Fuel Supply Arrangements

Auburndale receives the majority of its required natural gas through a gas supply agreement with El Paso Merchant Energy, L.P. that expires on June 30, 2012. Under the agreement, El Paso provides a fixed amount of gas on a daily basis. The gas price is based on a fixed schedule of prices that escalate annually and is below current market prices. At historic utilization rates, the gas supplied under the El Paso contract has accounted for approximately 80% of the gas required by the project under its PPA commitments and the remaining required fuel is purchased at spot prices.

The required natural gas for the project is delivered through firm gas transportation agreements with Central Florida Gas Company ("Florida Gas") and Florida Gas Transmission Company and is transported through the gas distribution system owned by Peoples Gas Transmission, Inc. ("Peoples Gas"). The gas transportation agreements are co-terminus with the PPAs, expiring on December 31, 2013.

Operations & Maintenance

The Auburndale project is operated and maintained by an affiliate of Caithness. In 2006, Auburndale entered into a maintenance agreement with Siemens Energy, Inc. for the long-term supply of certain parts, repair services and outage services related to the gas turbine. The term of the maintenance agreement is dependent on the timing of completion of a certain number of maintenance inspections and is expected to expire in late 2012.

Auburndale entered into an agreement with TECO to transmit electric energy from the project to PEF. The agreement expires in 2024, unless extended as provided for in the agreement. Auburndale's cost for these services is based on a contractual formula derived from TECO's cost of providing such services.

Factors Influencing Project Results

Auburndale derives a significant portion of its revenue through capacity payments received under the PPAs with PEF. In the event the project's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward or terminated altogether. Since it began commercial operation, the project has received full capacity payments.

During the term of the gas supply agreement, approximately 80% of the natural gas required to fulfill the project's PPAs is purchased at fixed prices. The remainder of the natural gas is purchased on the spot market. As a result, the project's operating margin is exposed to changes in spot market natural gas prices because the PPAs do not pass through those price changes to PEF. In order to mitigate this risk, Auburndale has entered into a series of financial swaps that effectively fix the price of natural gas to be purchased.

The following table summarizes the hedge position related to natural gas requirements to satisfy Auburndale's PPAs as of August 12, 2010:

	2010	**2011**	**2012**	**2013**
Amount of gas volumes currently hedged:				
Contracted at fixed prices	80%	80%	40%	0%
Financially hedged with swaps	15%	13%	32%	79%
Total	95%	93%	72%	79%
Average price of financially hedged volumes (per Mmbtu)(US$)	$ 6.30	$ 6.68	$ 6.51	$ 6.92

We will continue to periodically analyze whether to execute further hedge transactions intended to mitigate natural gas price exposure at Auburndale through the expiration of the PPAs with PEF.

The energy portion of Auburndale's revenue under the largest PPA with PEF is impacted by changes in the price of coal purchased by two power plants in Florida owned by PEF. Because these power plants purchase a significant portion of their coal through contracts of varying lengths, the price of coal burned at those plants is not directly correlated with changes in spot coal prices. Accordingly, changes in the price of coal procured by these two power plants will impact Auburndale's energy revenue.

Lake Segment

General Description

The Lake Segment consists of a 121 MW dual-fuel, combined-cycle QF cogeneration plant located in Florida, which began commercial operation in July 1993. We own 100% of the Lake project. In late 2007, the existing combustion turbines at the facility were upgraded to increase their efficiency by approximately 4% and output from 110 MW to 121 MW.

The Lake project is located on a 16-acre site at a citrus processing facility in Umatilla, Florida. Lake sells all of its capacity and electric energy to PEF under the terms of a PPA expiring in July 2013. The project is operated as a mid-merit facility typically running during 11 peak hours daily. Steam is sold to Citrus World, Inc. for use at its citrus processing facility and is also used to make distilled water in distillation units.

The Lake project does not have any debt outstanding. Atlantic Power has provided a $4.3 million letter of credit in favor of PEF to support the Lake project's obligations under its PPA.

Power Purchase Agreement

Electricity is sold to PEF pursuant to a PPA that expires on July 31, 2013. Revenues from the sale of electricity consist of a fixed capacity payment and an energy payment. Capacity payments are subject to the project maintaining a capacity factor of at least 90% during on-peak hours (11 hours daily), on a 12-month rolling average basis. Lake is subject to reductions in its capacity payment should it not achieve the 90% on-peak capacity factor. The project generally has achieved the minimum on-peak capacity factor continuously since commercial operation. Energy payments are comprised of a fuel component based on the cost of coal consumed at two PEF-owned coal-fired generating stations, a component intended to recover operations and maintenance costs, a voltage adjustment and an hourly performance adjustment. During off-peak hours, energy payments are made in accordance with a prescribed formula based on the price of natural gas, although Lake usually does not operate during off-peak hours.

Steam Sales Agreement

The Lake project provides steam to Citrus World under a steam purchase agreement that expires in 2013. The project also supplies steam to an affiliate that uses steam to make distilled water, which is sold to unaffiliated third parties.

Fuel Supply Arrangements

The natural gas requirements for the facility are provided by Iberdrola Renewables, Inc. and TECO Gas Services, Inc. ("TGS"). Both the Iberdrola and TGS agreements contain market index based prices, commenced on July 1, 2009 and expire on July 31, 2013.

Natural gas is transported to the project from supply points in Texas, Louisiana and Mississippi to Florida under contracts with Peoples Gas System, Inc.

Operations & Maintenance

The Lake project is operated and maintained by an affiliate of Caithness.

Lake also has a contractual services agreement and a lease engine agreement in place with General Electric (or "GE"). The contractual services agreement provides for planned and unplanned maintenance on the two gas turbines at the plant. The lease engine agreement provides temporary replacement gas turbines to Lake to support operations when the Lake turbines require significant maintenance.

Factors Influencing Project Results

The Lake project derives a significant portion of its operating margin through capacity revenues received under the PPA with PEF. In the event the facility's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward, although the project has rarely experienced such reductions. During the term of the current gas supply agreement, effective July 1, 2009, Lake's operating margins are exposed to changes in natural gas prices through the end of the PEF PPA in 2013. As a result, we have entered into a series of financial swaps that effectively fix the price of natural gas supplied to Lake thereby reducing fuel price risk.

The following table summarizes the volumes hedged relative to natural gas requirements under Lake's PPA as of August 12, 2010:

	2010	2011	2012	2013
Amount of gas volumes currently hedged:				
Contracted at fixed prices	0%	0%	0%	0%
Financially hedged with swaps	80%	78%	90%	65%
Total	80%	78%	90%	65%
Average price of financially hedged volumes (per Mmbtu)(US$)	$ 7.11	$ 6.52	$ 6.90	$ 7.05

We will continue to analyze whether to execute further hedge transactions to mitigate natural gas price exposure at Lake through expiration of the PPA with PEF.

The energy portion of Lake's revenue under the PPA with PEF is impacted by changes in the price of coal used by two of their power plants in Florida. Because these power plants secure a significant portion of their coal through contracts of varying lengths, the price of coal burned at those plants does not move in tandem with changes in spot coal prices.

The energy payment under the PPA includes a performance adjustment. For energy deliveries in excess of contracted capacity to PEF during on-peak periods in which the system price for energy exceeds the PPA energy rate, the project receives the then as-available energy rate, determined according to regulatory methodology. Conversely, when the project is not available and is dispatched by PEF, the project incurs negative performance adjustment charges corresponding to the difference between the then as-available energy rate and the PPA energy rate.

Pasco Segment

General Description

The Pasco Segment consists of the 100% owned Pasco project, a 121 MW dual fuel, combined-cycle, cogeneration plant located in Dade City, Florida, which began commercial operations in 1993 as a QF. With the expiration of the original PPA with PEF in 2008, and the commencement of the tolling agreement with TECO in 2009, Pasco self-certified with the FERC as an exempt wholesale generator and was no longer required to maintain QF status. The project owns the 2.7 acre site approximately 45 miles north of Tampa, Florida.

Power Purchase Agreement

Electricity is sold to TECO pursuant to a tolling agreement that commenced on January 1, 2009 and expires on December 31, 2018. Under the tolling agreement, TECO purchases the project's capacity and conversion services. Pasco converts fuel supplied by a TECO affiliate into electricity. Revenues consist of capacity payments, start-up charges, variable payments based on the amount of electricity generated and heat rate bonus payments based on the actual efficiency of the plant versus the contract efficiency. Atlantic Power has provided a $10 million letter of credit in favor of TECO to support the project's obligations under the tolling agreement.

In exchange for obtaining the right to sell any potential excess emissions allowances from the plant, TECO accepted financial responsibility for any costs associated with additional allowances required and changes to environmental laws, including state or federal carbon legislation.

Fuel Supply Arrangements

Under the terms of the tolling agreement, TECO is responsible for the fuel supply and is financially responsible for fuel transportation to the project.

Operations & Maintenance

The Pasco project is operated and maintained by an affiliate of Caithness.

Pasco also has a services agreement and a lease engine agreement in place with GE. The services agreement provides for discounts for planned and unplanned maintenance on the project's two natural gas turbines, and commits the project to use GE for gas turbine maintenance activities. Under the lease engine agreement, GE rapidly provides temporary replacement natural gas turbines to the project to support operations when the project's turbines are removed from the site for significant maintenance.

Factors Influencing Project Results

The Pasco project derives the majority of its revenues under the tolling agreement with TECO through capacity payments. In the event the project does not maintain certain levels of availability, the capacity payments will be reduced. Based on historical performance, we expect the project to continue to exceed the availability requirement of 93% in the summer and 90% in the winter. A portion of the project's operating margin is based on three variable payments from TECO, consisting of a variable operation and maintenance charge, a start charge and a heat rate bonus. As a result, the project achieves a variable margin during periods of operation; and as a result, the level of variable margin is impacted by how often the plant is called on to produce electricity.

Chambers Segment

General Description

The Chambers Segment consists of our 40% equity investment in the Chambers project, a 262 MW pulverized coal-fired cogeneration facility located at the E.I. du Pont de Nemours and Company Chambers Works chemical complex near Carney's Point, New Jersey, which began commercial operation in March 1994 as a QF. Affiliates of Goldman Sachs Group, Inc. and Energy Investors Funds, an established private equity fund manager that invests in the U.S. energy and electric power sector, in the aggregate hold 60% of the general partner interests. Chambers sells electricity to ACE under two separate power purchase agreements, a "Base PPA" and a power sales agreement. Historically, the project has operated as a baseload plant, however, during periods of low energy market pricing, the facility has run at partial or minimum load. Steam and electricity are sold to DuPont pursuant to an energy services agreement. The project site is leased from DuPont. Under the terms of the ground lease, DuPont has a right to purchase the project within 60 days of the lease expiration in 2024, or upon earlier termination of the lease, at fair market value.

Chambers financed the construction of the project with a combination of term debt due March 31, 2014 and New Jersey Economic Development Authority bonds due July 1, 2021. The term loan is expected to amortize over its remaining term, while the bonds are repayable at maturity. Both are non-recourse to Atlantic Power. Our 40% share of the total debt outstanding at the Chambers project as of June 30, 2010 is $80.6 million. See "Project-Level Debt" on page 61 of this prospectus for additional details.

Epsilon Power Partners, L.P., our wholly-owned subsidiary, directly owns our interest in Chambers. Epsilon has outstanding debt of $37.0 million as of June 30, 2010 which fully amortizes by its final maturity in 2019 and is non-recourse to Atlantic Power. See "Project-Level Debt" on page 61 of this prospectus for additional details.

Power Purchase Agreements

Base PPA

The 30-year term of the Base PPA with ACE expires in 2024. ACE has agreed to purchase 184 MW of capacity and has dispatch rights for energy of up to 187.6 MW during the summer season (May 1 to October 31) and 173.2 MW during the winter season (November 1 to April 30). The project must be available to deliver power to ACE at 90% of the average availability rate of a specific group of mid-Atlantic generating stations. Capacity prices are determined using a fixed price with a capacity factor adjustment. The energy payment under the Base PPA is divided between on-peak and off-peak periods and linked to a coal index that is identical to the project's coal supply contract escalation provisions. Chambers is guaranteed a minimum energy payment equivalent to 3,500 hours of operation per contract year, whether or not it has dispatched that many hours, provided the project is available for energy production for at least 3,500 hours during the course of the contract year.

DuPont Energy Services Agreement

DuPont purchases all its electrical needs for its Chambers Works chemical complex from the Chambers project, subject to a peak requirement of 40 MW, under the energy services agreement. The initial term of the agreement expires in 2024 but will continue thereafter unless terminated by at least 36 months prior written notice. The electricity sold under the agreement contains a fixed price, which is adjusted quarterly by the lesser of either: (i) the price of coal delivered to the facility; and (ii) the change in ACE's average retail rate.

In December 2008, Chambers filed suit against DuPont for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In the event the dispute cannot be resolved through settlement, a trial is expected in the second half of 2010. We do not believe that the outcome of this litigation will have a material impact on Atlantic Power.

Power Sales Agreement

Energy generated at the Chambers project in excess of amounts delivered to ACE under the Base PPA and to DuPont is sold to ACE under a separate power sales agreement. Under this agreement, energy that ACE does not find economically attractive at the Base PPA's energy rate, but which may be cost effective to sell into the spot market ("Undispatched Energy"), may be self-scheduled by the project to capture additional profits. Margins on Undispatched Energy sales are shared between ACE

(40%) and the project (60%). Energy not committed to ACE under the Base PPA and not called upon by DuPont under the energy services agreement may also be sold into the market under a similar margin sharing arrangement with ACE (30% to ACE and 70% to Chambers). The agreement also provides for the sale by Chambers into the market of capacity not contracted under the Base PPA pursuant to the same margin sharing arrangement with ACE (30% to ACE and 70% to Chambers).

The power sales agreement expired in July 2010 and we entered into a one-month extension in order to negotiate the terms of a new power sales agreement.

Steam Sales Agreement

Some of the steam generated at the Chambers project is sold to DuPont under the energy services agreement, which expires in 2024, but will continue in effect thereafter unless terminated by either party on at least 36 months prior notice. The agreement requires steam to be provided to DuPont up to the peak steam requirement levels that vary throughout the year. DuPont may purchase steam in excess of the peak steam requirement from any third party, subject to Chambers' right of first refusal to provide steam at the same price. Subject to certain conditions, DuPont has the option to construct and operate its own steam generation facility after 2014. DuPont is required to purchase a minimum quantity of steam necessary for the project to maintain its status as a QF. The steam price is subject to quarterly adjustments based on the price of coal delivered to the project. DuPont has the option in certain circumstances to take over operation of the steam facility in the event of prolonged failure to deliver steam.

Fuel Supply Arrangements

Coal is supplied to the Chambers project pursuant to a coal purchase agreement with Consol Energy Inc. ("Consol"), which expires in 2014 and is subject to a five to ten-year renewal based on good faith negotiations. The agreement governs the sale of coal (including transportation) to the project and the disposal of related ash. Consol is obligated to supply the entire coal requirements for the project, which may include stockpiling. The price escalator under the Base PPA with ACE uses the same index as the coal supply agreement (average coal cost of 25 mid-Atlantic region coal power plants), effectively passing through changes in coal prices to ACE.

Operations & Maintenance

Operations and maintenance of the Chambers project is performed pursuant to an agreement with Cogentrix, which expires in April 2014. Thereafter, the agreement will be automatically renewed for periods of five years until terminated by either party on six months notice. Cogentrix is paid a base annual fee in addition to cost reimbursement. Cogentrix is also eligible for performance fees based on facility net availability, efficiency and excess energy optimization, and is eligible for an additional management performance bonus. The majority owner of the project is currently in the process of transferring management services from Cogentrix to Power Plant Management Services. We expect this transition to be complete in late August 2010.

Regional Greenhouse Gas Initiative

With New Jersey's implementation of the RGGI on January 1, 2009, the Chambers project was required to obtain carbon dioxide ("CO_2") allowances in an amount corresponding to the CO_2 emissions of the facility. Previously in 2008, the State of New Jersey passed legislation that provided for the sale of CO_2 allowances at the price of $2.00 per allowance to certain generating facilities which were certified by the New Jersey Department of Environmental Protection ("NJDEP"). Chambers received this certification from the NJDEP in late 2009. Earlier in 2009, the project purchased approximately 480,000 allowances through the quarterly RGGI auctions and broker purchases. In

December 2009, Chambers purchased 2.1 million allowances from the NJDEP at the price of $2 per allowance. A portion of the NJDEP purchase, in combination with the previously purchased allowances, satisfies the project's RGGI compliance requirements for 2009. The remainder of the 2009 NJDEP allowance purchase will be used to meet the 2010 requirements along with 2010 NJDEP allowance purchases.

Factors Influencing Project Results

The Chambers project derives a significant portion of its operating margin through capacity revenues received under the Base PPA. In the event the facility does not maintain a minimum level of availability under the Base PPA, the project's capacity payments from ACE would be reduced or eliminated, although it has never experienced such a reduction. Energy sales under the Base PPA are expected to generate positive margins due to the effective hedging of energy prices and coal costs through the use of identical indexing in the energy payment under the Base PPA and the coal prices under the coal supply contract. While the indexing is identical, adjustments to the energy price under the Base PPA occur annually, whereas coal price adjustments occur quarterly.

During periods of low spot market electricity prices, energy sales margins may be negatively impacted due to the pricing structure under the Base PPA and power sales agreement. ACE will reduce purchases under the Base PPA to the minimum requirement when the spot electricity price is below the price under the Base PPA. When spot market prices drop below the Base PPA price, but exceed the project's variable production cost, ACE pays for energy based on the power sales agreement, under which a portion of the margin above the project's production cost is shared with ACE. In the unusual situation when the spot electricity price is in excess of the Base PPA but less than the project's variable production cost (which may occur during off-peak periods), Chambers is required to sell energy to ACE at below its production cost. In some cases, the project is further negatively impacted by the facility's reduced fuel efficiency while operating at partial load to minimize operating at a negative margin.

The debt at our wholly-owned Epsilon holding company includes restrictions on the upstream distribution of our share of partner distributions from Chambers. Cash flow from Chambers may be held in a reserve account by Epsilon's lender to the extent certain debt service coverage ratios are not achieved. Upon meeting the coverage ratio requirements, funds are distributed to us.

Path 15 Segment

General Description

The Path 15 Segment consists of our ownership of 72% of the TSRs in the Path 15 project, an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in central California. The Path 15 project commenced commercial operations in 2004. The Path 15 project facilitates the movement of power from the Pacific Northwest to southern California in the summer months and from generators in southern California to northern California in the winter months. The TSRs entitle us to receive an annual revenue requirement that is regulated by the FERC The annual revenue requirement is collected from California utilities and remitted to owners of TSRs by the California Independent System Operator ("CAISO").

The Path 15 project and right of way is owned and operated by the Western Area Power Administration, a U.S. Federal power agency that operates and maintains approximately 17,000 miles of transmission lines. The operation of the Path 15 project consists entirely of the transmission of electric power, which is not subject to the same operating risks of a power plant or the volatility that may arise from changes in the price of electricity or fuel.

The CAISO is a not-for-profit corporation that acts as a clearinghouse to settle third-party transactions involving the purchase and sale of power in California. Owners of transmission assets must place their assets under the operational control of the CAISO by entering into a standard transmission control agreement with them. In general, the CAISO coordinates the dispatch of power generation and manages the reliability of, and provides open access to, the transmission grid.

Three of our wholly-owned subsidiaries have incurred non-recourse debt relating to our interest in the Path 15 project. Total debt outstanding at the Path 15 project as of June 30, 2010 is $157.6 million, which is required to fully amortize over their remaining term ending 2028. See "Project-Level Debt" on page 61 of this prospectus for additional details. We have provided letters of credit totaling $8.4 million to support these debt service obligations.

Annual Revenue Requirement FERC Rate Case

The revenue collected by Path 15 is regulated by the FERC on a cost-of-service rate base methodology. Path 15 files a rate case with the FERC every three years to establish its revenue requirement for the next three year period. The revenue requirement includes all prudently incurred operating costs, depreciation and amortization, taxes, and a return on capital.

In December 2007, we filed a rate application with the FERC to establish Path 15's revenue requirement through 2010. In January 2008, several parties filed protests and interventions to become parties to the proceeding. In February 2008, the FERC issued an order summarily approving the requested return on equity and, allowing the requested rates to go into effect as of February 20, 2008, subject to refund. California Public Utilities Commission and Southern California Edison filed requests for rehearing of that order. In February 2009, we filed an unopposed motion requesting suspension of the trial schedule to allow the parties to the rate case to finalize a settlement. In March 2009, we filed a settlement offer with the FERC. The settlement was supported by all parties to the proceeding. In August 2009, the FERC issued an order approving the settlement offer. We believe that the settlement was reasonable and has not significantly impacted the expected cash flow from the project. On October 30, 2009, the Path 15 project issued refunds reflecting the difference between the rates collected as of February 2008 pursuant to the December 2007 filing and the rates provided for under the settlement.

Factors Influencing Project Results

The primary factor influencing the Path 15 project results is its FERC-regulated revenue requirement. Under the FERC's cost of service methodology, all prudently incurred expenses are permitted to be recovered in the revenue requirement including costs of the rate case itself every three years. Cash distributions to us could be adversely impacted by factors such as which year is used to establish the revenue requirement for the next three years and whether the FERC approves a return on equity less than 13.5% in future rate cases.

Other Project Assets

Orlando Project

General Description

The Orlando project, a 129 MW natural gas-fired combined-cycle cogeneration facility located in an industrial park near Orlando in Orange County, Florida, commenced commercial operation in 1993 as a QF. We own a 50% interest in the project and Northern Star Generation, LLC ("Northern Star") owns the remaining 50% interest. The project is situated on a four acre site located adjacent to an air separation facility owned by Air Products and Chemicals, Inc. ("Air Products and Chemicals"), which serves as the project's steam customer. Orlando sells all of its electricity to PEF and Reedy Creek

Improvement District ("Reedy Creek") under long-term PPAs, and also sells chilled water produced using steam from the project to Air Products and Chemicals. The Orlando project typically operates as a baseload plant. Both we and Northern Star have provided letters of credit in the amount of $1.6 million each in support of the project's obligations under the PEF PPA.

Power Purchase Agreements

Progress Energy Florida

Orlando sells electrical capacity and energy to PEF under a PPA that expires on December 31, 2023. The project is obligated to sell and deliver a committed capacity of 79.2 MW and has committed to a 93% on-peak capacity factor. Orlando receives a monthly capacity payment based on achieving the on-peak capacity factor and a monthly energy payment based on the total amount of electric energy actually delivered to PEF. The capacity payment escalates at 5.1% annually and is reduced if the facility's on-peak capacity factor is below 93%, on a 12-month rolling average basis. Energy payments are comprised of a fuel component based on the cost of coal purchased at two PEF-owned coal-fired generating stations, an operations and maintenance component, a voltage adjustment and an hourly performance adjustment. Off-peak energy prices are based on the on-peak spot market energy price discounted by 10%.

On August 4, 2009, PEF provided notice to Orlando that the committed capacity under its PPA would be increased to 115 MW upon expiration of the Reedy Creek PPA in 2013, upon meeting certain conditions.

Reedy Creek Improvement District

Orlando sells electrical capacity and energy to the Reedy Creek, a municipal district serving the Walt Disney World complex, under a PPA that expires in 2013. Orlando is obligated to sell and deliver 35 MW of electricity and has committed to a 93% average capacity factor. Orlando receives a monthly capacity payment based on the actual average capacity factor and a monthly energy payment based on the total amount of electric energy actually delivered to Reedy Creek. The PPA may be extended for an additional ten-year term upon the consent of both parties. The capacity payment is fixed at a rate that escalates at 4.5% annually and is based upon achieving a 93% average capacity factor, calculated on a three-year rolling average basis. The agreement provides both incentive and penalty provisions for performance above and below a 93% average capacity factor, respectively. Reedy Creek also reimburses Orlando for a portion of the reservation charges associated with the project's firm gas transportation agreement with Florida Gas. In 2005, Orlando executed an agreement with Reedy Creek for periodic sales of up to 15 MW of non-firm available energy at firm rates.

Excess Energy Sales

In 2006, Orlando executed a master purchase and sale agreement with Rainbow Energy Marketing Corporation ("Rainbow"). Under the agreement, Rainbow markets up to 15 MW of non-firm energy at spot market rates subject to the profitability of such sales. The arrangements with Rainbow can be terminated by either party upon 30 days notice.

Steam Sales Agreement

Orlando entered into an agreement with a subsidiary of Air Products and Chemicals to supply chilled water produced using steam from the project to its cryogenic air separation facility. Orlando does not have any minimum steam delivery requirements beyond the thermal and efficiency requirements required to maintain its QF status. Orlando is required to purchase its nitrogen requirements from Air Products and Chemicals, but does not have a minimum purchase requirement.

Both the purchase price of nitrogen and the sales price of chilled water are at fixed prices that adjust based on the percentage increase/decrease in the producer price index.

Because of reduced demand for chilled water at Air Products and Chemicals during certain periods, and to ensure continued compliance with QF requirements, Orlando procured and installed water distiller units in 2009, and entered into contracts to provide the distilled water to unaffiliated third parties in the local area.

Fuel Supply Arrangements

Orlando buys natural gas from Orlando Power Holdings, LLC, which is indirectly owned by Northern Star, under an agreement expiring on December 31, 2013. Orlando Power has a back-to-back agreement for the purchase and supply of natural gas from Vastar Gas Marketing, Inc. ("Vastar"), which is a wholly-owned subsidiary of BP Energy Company. Under the agreement, which expires on December 31, 2013, Vastar is obligated to provide Orlando Power with its entire daily natural gas requirement. Orlando's purchase price is tied to the same coal-based and fixed escalators used for calculating the energy payments under the PPAs. Orlando also has a gas supply agreement with TGS, but is not currently purchasing any natural gas under this agreement.

Peoples Gas has entered into co-terminus back-to-back agreements with Florida Gas for the delivery of natural gas to the project. Orlando has a contractual right to extend these agreements. Transportation costs under the agreements are determined by Florida Gas' rate schedule as filed with the FERC. These agreements provide for the transportation of up to 23,600 Mmbtu per day to the project.

Operations & Maintenance

The Orlando project is operated and maintained by an affiliate of Northern Star under an operations and administrative services agreement expiring on December 31, 2023. The operator is compensated on a cost-reimbursement basis plus a fixed general and administrative charge. In addition, the operator is entitled to receive an incentive fee equal to a percentage of the excess of Orlando's operating cash flow after deducting originally anticipated maintenance capital and anticipated debt service. In 1997, Orlando also entered into a maintenance agreement with Alstom Power Inc. for the long-term supply of hot gas path gas turbine parts, under which Alstom receives a monthly fee from the partnership and additional fees in certain circumstances.

Factors Influencing Project Results

The Orlando project receives a significant portion of its revenues through capacity payments received under the PPA with PEF. In the event the facility's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward or eliminated. The energy payment under the PEF PPA largely consists of an energy component, which is adjusted based on the same coal index as used in the gas supply pricing.

The energy payment under the PPA with PEF includes a performance adjustment. During on-peak periods in which the market price for energy exceeds the PPA energy rate, for energy deliveries in excess of PEF scheduled capacity, the project receives the then as-available energy rate, determined according to regulatory methodology. Conversely, during on-peak periods when the project delivers less than the scheduled capacity, the project incurs negative performance adjustment charges corresponding to the difference between the then as-available energy rate and the PPA energy rate.

The Reedy Creek PPA also contains incentive and penalty provisions for performance above and below a specified capacity factor.

Selkirk Project

General Description

The Selkirk project is a 345 MW dual-fuel, combined-cycle cogeneration plant located in the Town of Bethlehem in Albany County, New York, and commenced commercial operation in 1994 as a QF. The project includes two units: Unit I (80 MW) sells electricity into the New York merchant market and Unit II (265 MW) sells electricity to Consolidated Edison, Inc. (or "Con Ed"). The Selkirk project is typically operated as a mid-merit plant. The other partners include affiliates of Cogentrix, Energy Investors Funds, The McNair Group, and Fort Point Power LLC (an affiliate of Osaka Gas Energy America Corporation). Each of the partners has an interest in cash distributions by the project which changes when certain partners achieve a specified return on their equity contributions as set forth in the partnership agreement. We own: (i) 13.62% interest in the priority distributions up to a fixed semi-annual amount as described below; (ii) 19.94% interest on any distributions in excess of the priority distributions; and (iii) 17.7% of all distributions made after the last priority distribution is made, estimated to occur in 2012. If priority distributions are not made at the maximum amount, the unpaid amounts accumulate and are paid when funds are available in subsequent periods. As of December 31, 2009, our 13.62% share of unpaid priority distributions was $0.5 million. In addition to this accumulated amount, our share of the maximum semi-annual priority distributions in 2010, 2011 and 2012 is approximately $1.2 million, $0.8 million and $0.7 million, respectively. The 15.7 acre project site is situated adjacent to a Saudi Arabia Basic Industries Corporation (or "SABIC") plastics manufacturing plant, which also purchases steam from the project. Selkirk leases the project site under a long-term lease from SABIC.

The Selkirk project has 8.98% first mortgage bonds outstanding. Our share of the outstanding amount of these bonds was $15.2 million as of June 30, 2010, which fully amortizes over the remaining term ending in 2012. See "Project-Level Debt" on page 61 of this prospectus for additional details.

Power Purchase Agreements

Since the expiration of Selkirk's agreement to sell 80 MW of capacity and energy from Unit I to National Grid in July 2008, Selkirk has been selling energy from Unit 1 into the New York merchant market. 265 MW of capacity and energy from Unit II is sold to Con Ed under a PPA that expires on September 1, 2014, subject to a ten-year extension at the option of Con Ed under certain conditions. It is not known whether Con Ed intends to exercise this option. The Unit II PPA provides for a capacity payment, a fuel payment, an operations and maintenance payment and a payment for transmission from the project to Con Ed. The capacity payment, a portion of the fuel payment, a portion of the operations and maintenance payment and the transmission payment are fixed charges to be paid on the basis of plant availability.

Steam Sales Agreement

Selkirk sells steam generated at the project to the SABIC plastics manufacturing plant under an agreement that expires on September 1, 2014. Under the agreement, SABIC is not charged for steam in an amount up to the annual equivalent of 160,000 lbs/hr during each hour in which the SABIC plant is in production. SABIC pays the project a variable price for steam in excess of this amount. SABIC is required to purchase the minimum thermal output necessary for Selkirk to maintain its QF status.

Fuel Supply Arrangements

Selkirk buys natural gas for Unit I at spot market prices under a contract with Coral Energy Canada Inc. expiring on October 31, 2012. Selkirk has gas supply agreements for Unit II with Imperial Oil Resources Limited, EnCana Corporation and Canadian Forest Oil Ltd., which expire on October 31, 2014.

The project also has long-term contracts for the transportation of Units I and II natural gas volume on a firm 365-day per year basis in place with TransCanada Pipelines Limited, Iroquois Gas Transmission System LP and Tennessee Gas Pipeline Company. The Unit I and Unit II gas transportation contracts expire on November 1, 2012 and November 1, 2014, respectively.

Natural gas that is not used by Selkirk to generate power under its gas supply arrangements may be remarketed. Under certain market conditions, additional income is generated from such re-sales of natural gas. Units I and II have the capability to operate on fuel oil subject to certain limitations under the project's air permit and are able to switch fuel sources from natural gas to fuel oil and back without interrupting the generation of electricity.

Operations & Maintenance

GE operates the Selkirk project under an agreement expiring on December 31, 2012. The agreement provides for a fixed fee, capital parts discounts, a pass-through of management costs and a performance bonus. Management services for Selkirk are provided by Cogentrix under an administrative services agreement that expires in September 2014. Cogentrix is entitled to compensation under the agreement which is subject to renegotiation every four years and provides for the full recovery of its actual costs and properly allocated overhead plus a reasonable fee which must be approved by all of the Selkirk partners. The majority owner of the project is currently in the process of transferring management services from Cogentrix to Power Plant Management Services. We expect this transition to be completed in late August 2010.

Regional Greenhouse Gas Initiative

In 2009, in order to comply with RGGI, the project commenced purchasing CO_2 allowances in the quarterly RGGI auctions. At year-end, the project had purchased adequate allowances to cover the amount needed for RGGI compliance in 2009, except for approximately 184,000 allowances. Under the RGGI rules, a compliance period consists of three years, during which time the emitter is required to obtain allowances corresponding to its CO_2 emissions during the same period. New York State allocates a limited number of free allowances to generators that have long-term contracts. A portion of the project's 2009 requirement will be met with these free allowances. The project expects to purchase additional allowances in 2010 in order to satisfy its 2009 requirement. In resolution of a lawsuit brought by an unaffiliated owner of another New York power plant in 2009 challenging New York's RGGI rules, a consent decree is being finalized under which ConEd will reimburse the Selkirk project for the cost of additional allowances needed in excess of the free allowances allocated by New York.

Factors Influencing Project Results

Energy produced by Unit I (80 MW) is sold at market prices based on the project's bid into the spot market. The project is therefore exposed to fluctuations in market energy prices which may impact Unit I energy sales margins. Under the PPA with Con Ed, the Project receives significant capacity revenues based on meeting availability requirements and also receives an energy payment whenever Con Ed calls on Unit II (265 MW) to generate electricity. The energy payment is primarily dependent on the fuel price component, indexed predominantly to natural gas prices, but also has a small component based on oil prices.

In periods when Unit I or Unit II is not generating electricity, substantial volumes of natural gas are available to be re-sold. Depending on market prices when reselling compared to contract prices when the gas was nominated at the beginning of each month, the excess gas has been resold at significant positive margins and occasionally at a loss.

Gregory Project

General Description

The Gregory project is a 400 MW natural gas-fired combined cycle cogeneration QF located near Corpus Christi, Texas that commenced commercial operation in 2000. The Gregory project is owned by Gregory Power Partners, LP, a Texas limited partnership, and our ownership interest in Gregory Power is approximately 17%. The other owners are affiliates of JPMorgan Chase & Co. and John Hancock Life Insurance Company. Gregory currently sells approximately 345 MW of its capacity to Fortis Energy Marketing and Trading GP and sells up to 33 MW of electric energy and capacity to Sherwin Alumina Company, which is owned by Glencore International AG, with the remainder sold in the spot market. While not strictly a baseload facility, Gregory typically is operated at a high capacity factor. The project is located on a site adjacent to Sherwin Alumina's production facility, which also serves as the project's steam customer. Gregory leases the land on which the project is located from Sherwin under an operating lease which expires in August 2035.

The Gregory project was financed by ING Capital Corporation ("ING") and a consortium of other lenders. The loan matures in 2017 and is required to be amortized over its remaining term. Our share of the total debt outstanding at the Gregory project as of June 30, 2010 was $15.2 million. See "Project-Level Debt" on page 61 of this prospectus for additional details.

In November 2008, Gregory's managing partner, discovered that the state authorization of the project's Prevention of Significant Deterioration Air Permit had lapsed due to a discrepancy in the representation of the renewal date of the state authorization by a consultant in 2002. The issue was self-reported to the Texas Commission of Environmental Quality (or "TCEQ"). During the first quarter of 2009, Gregory submitted its initial draft permit application to the TCEQ, which deemed it administratively complete, and completed the technical aspects of the permitting process. In December 2009, the TCEQ provided Gregory Power a draft of a new permit, and on March 15, 2010, the TCEQ issued the new permit. We believe the new permit limits are achievable by the project and will not require the installation of additional emissions control equipment.

Power Purchase Agreements

Gregory sells 345 MW of its output to Fortis under a PPA that began on January 1, 2009 and expires December 31, 2013. Under the terms of the Fortis agreement, Fortis pays a fixed capacity payment and an energy payment that is based on the price of natural gas at Houston Ship Channel and a contract heat rate. (Heat rate refers to the amount of energy that is required to generate one kilowatt hour of electricity.) Energy sales to Fortis consist of two tranches; a 234 MW "must-run" block and a 111 MW "dispatchable" block. The must-run block corresponds to the project's minimum energy output while satisfying Sherwin's electricity and steam requirements without the use of Gregory's auxiliary boilers. The dispatchable block is the portion of Gregory's output that can be scheduled at the option of Fortis as either energy, ancillary services or balancing energy. Credit support for the PPA consists of a $10 million letter of credit issued by ING which is backed by letters of credit from the project's partners, including a $1.7 million letter of credit provided by Atlantic Power.

Steam Sales Agreement

Gregory sells steam to Sherwin under an agreement that expires in 2020. Under the terms of the agreement, Gregory is the exclusive source of steam to Sherwin's alumina plant, up to a maximum of 1,500,000 lbs/hr.

Fuel Supply Arrangements

Gregory purchases natural gas under various short-term and long-term agreements. Gregory has the option of procuring 100% of its natural gas requirements from Kinder Morgan Tejas Pipeline, L.P., under a market-based gas supply agreement that expires in August 2010. Gregory Power has finalized a replacement supply agreement with Kinder Morgan and is seeking lender approval, as required under the project's financing agreements.

In March and June 2008, the project entered into pay fixed, receive floating, natural gas swap agreements with Sempra Energy Trading Corp. for the period January 2009 through December 2010. While Gregory has structured its power and steam sales agreements to mitigate the price risk between its fuel supply and electricity sales agreements, the project has some residual exposure to natural gas price risk due to the difference between the project's actual heat rate and the contractually guaranteed heat rate under the Fortis PPA. The swap agreements partially mitigate this natural gas price risk.

Operations & Maintenance

An affiliate of Babcock and Wilcox Power Generation Group, Inc. ("Babcock and Wilcox") is responsible for the operation and maintenance of the Gregory project under an agreement that terminates in July 14, 2015. The operator receives a fee for management of the facility (subject to escalation) on a quarterly basis and reimbursement of certain costs.

Energy Management Services

Tenaska Power Services, Co. ("Tenaska") provides Gregory with energy management services such as marketing excess power from the Project through the end of 2011. Tenaska optimizes Gregory's assets in the ancillary services market of the Electric Reliability Council of Texas, purchases natural gas for operations, provides scheduling services, provides back-office support and serves as Gregory's retail energy provider and qualified scheduling entity.

Factors Influencing Project Results

The Gregory project derives a significant portion of its operating margin through energy revenues under its PPA with Fortis. Energy revenues are dependent on the price of natural gas at Houston Ship Channel and a contract heat rate. The project achieves a margin on its energy revenue due to the facility's actual heat rate being lower than the contractually guaranteed heat rate.

Gregory also receives a capacity payment under the Fortis PPA which is dependent on maintaining certain minimum performance requirements. The project's capacity payments are subject to reduction or elimination if it fails to meet these requirements. Due to a forced outage in 2009, the project only received 98% of the full capacity revenue. However, historically the project has met all of the performance standards under the Fortis PPA.

Topsham Project

General Description

The Topsham project is a 14 MW hydroelectric facility located on the Androscoggin River at the Pejepscot dam near Topsham, Maine and began commercial operation in 1987 as a QF. A 100% undivided interest in the Topsham project and a 100% undivided interest in the Topsham project site are owned by a financial institution, in its capacity as owner trustee for the benefit of Atlantic Power (50%) and DaimlerChrysler Services North America LLC (50%) as owner participants. Electricity is sold to the Central Maine Power Company (or "CMP") under a PPA that expires in 2011.

The Topsham project is leased and operated by Topsham Hydro Partners Limited Partnership ("THP"), a Minnesota limited partnership. Pursuant to a sale and lease back transaction, THP leases both our interests in the project and in the project site until November 17, 2011. At the end of the lease term, THP has the option to renew the lease or acquire our share of the project and the project site. Lease payments made by THP are based on project's operating cash flows.

Power Purchase Agreement

Electrical output from the Topsham project is sold to CMP under a PPA that contains a fixed price schedule and terminates on December 31, 2011.

Operations & Maintenance

THP operates the project and provides all general and administrative services for the project under an agreement in effect until the earlier of December 31, 2027 or upon THP becoming the owner of 100% of the project and the project site.

Badger Creek Project

General Description

The Badger Creek project is a 46 MW simple-cycle, cogeneration facility located near Bakersfield, California which began commercial operation in 1991 as a QF. The Badger Creek project is owned by Badger Creek Limited, L.P. ("Badger"), a Texas limited partnership in which we own a 50% partnership interest. Juniper Generation, LLC, which is indirectly owned by affiliates of ArcLight Capital Partners, LLC, owns the other 50% partnership interest. Electricity is sold to Pacific Gas & Electric Corporation ("PG&E") under a PPA expiring in 2011. The project typically operates in a baseload configuration. Steam is sold to OXY USA Inc. ("OXY"), an affiliate of Occidental Petroleum Corporation, under an agreement that expires in 2011. Badger leases the approximately 3.5 acre site for the Badger Creek project under a ground lease. The term of the lease expires in July 2021 and the parties may extend for up to 10 additional one-year periods.

Power Purchase Agreement

Electricity generated by the Badger Creek project is purchased by PG&E under a PPA that expires in 2011. The PPA provides for monthly capacity and energy payments, and Badger is entitled to receive a performance bonus if the average on-peak capacity factor exceeds 85%. The energy price received under the PPA is linked to PG&E's interim "short-run avoided cost," as discussed below.

Steam Sales Agreement

Steam from the Badger Creek project is sold to OXY under an agreement which expires in 2011. The agreement provides for successive renewal terms of one year unless either party gives advance notice of termination. OXY utilizes the steam in its enhanced oil recovery operations to allow for more effective and efficient extraction of heavy crude oil. Subject to certain conditions, OXY has an obligation to buy steam under this agreement in an amount not less than the minimum requirements necessary to maintain the project's status as a QF. Although OXY is not currently purchasing any power from the project, the steam agreement allows for up to 1 MW of electricity to be sold to OXY.

Fuel Supply Arrangements

Natural gas is delivered to Badger Creek via a private pipeline that connects with the Kern River-Mojave Pipeline. The pipeline was constructed by a joint venture in which the project owns approximately 21%. An affiliate of Juniper operates the pipeline. In October 2006, Badger entered into a gas supply agreement, including transportation, with Sempra Energy Trading Corporation. In March 2008, the gas agreement was extended to cover fuel procurements through April 30, 2011.

Operations & Maintenance

Operations and maintenance for the Badger Creek project is performed by an affiliate of Juniper Generation, LLC under a fixed price operations and maintenance agreement. The agreement expires in

2011, but is terminable by either party upon six months' notice. The operator receives a base monthly fee, which is adjusted annually. In addition, the agreement provides for incentive fees and penalties based on the project's availability.

An affiliate of Juniper also provides all day-to-day management services required by the project and is paid a semi-annual fee for such management services based on a percentage of gross cash receipts of the project.

Factors Influencing Project Results

The Badger Creek Project derives a portion of its operating margin through energy revenues under the PG&E PPA. Energy revenues are dependent on PG&E's short-run avoided costs ("SRAC"), which is generally defined as the cost of electricity that a utility avoids incurring by purchasing the power from an independent power producer versus constructing and operating additional generating resources on its own. PG&E's SRAC is determined by the CPUC in conjunction with input from independent power producers, investor owned utilities and consumer groups through the state utility regulatory process. SRAC has been, and continues to be, a highly contested issue resulting in numerous CPUC proceedings and litigation. Until August 2009, SRAC was based on an administratively determined formula. In August 2009, the CPUC implemented a new SRAC methodology called the market index formula ("MIF"), which includes both a market-based component and an administratively determined component. Ultimately, the CPUC is moving toward a 100% market-based SRAC.

In April 2009, California's Market Reform and Technology Update energy market ("MRTU") commenced operation. The MRTU is expected to provide a robustly traded day-ahead market for energy that reflects the avoided marginal energy costs of California's utilities. Upon the determination by the CPUC that the MRTU is functioning properly, MIF will no longer include the administratively determined component, which is expected to lower MIF pricing and create larger differences between peak and off-peak prices. Such a determination has not been made by the CPUC.

Badger is a party to settlement negotiations among other QF facilities, California's major investor-owned utilities, and numerous consumer and independent power producer groups on a new energy pricing formula and possible extensions of firm capacity payments for project with existing contracts that will resolve many outstanding issues between the parties. Many of the SRAC and MIF related CPUC proceedings and litigation have been held in abeyance pending the outcome of the settlement negotiations.

It is expected that the CPUC regulations applicable to Badger will be in a state of transition for the foreseeable future, and there can be no assurance that decisions by the CPUC will not have an adverse impact on Badger.

Rumford Project

General Description

The Rumford Project is a 85 MW multi-fuel (coal, wood waste and tire-derived fuel) circulating fluidized bed boiler cogeneration facility located in the town of Rumford, Maine, which began commercial operation in 1990 as a QF. The Rumford project is owned by Rumford Cogeneration Company Limited Partnership, a Maine limited partnership ("Rumford LP"), in which we own an approximate 26% limited partnership interest. The project was constructed for the dual purpose of supplying steam and electricity to an adjacent paper mill, the Rumford Paper Company, owned by a subsidiary of NewPage Corporation ("NewPage") and electricity to the local utility. The project is situated on a site leased from the adjacent NewPage paper mill. The lease expires on December 31, 2020.

Power Purchase Agreement

In February 2007, Rumford LP executed an Interim Financial Obligation Consolidation Agreement with Rumford Paper Company. The agreement consolidated the payment obligations of the various prior agreements between Rumford LP and Rumford Paper Company into a single payment obligation effective January 1, 2007. The effect of the agreement is similar to a lease wherein Rumford Paper Company assumes the risk of fuel and power price volatility as well as most operating costs. Payments under the agreement have been made quarterly to Rumford LP over a three year term ended December 31, 2009. During 2009, as a result of a dispute between NewPage and the limited partners regarding the making of the 2009 distributions and the economic viability of the project following the expiration of the agreement with Rumford Paper Company at the end of 2009, a settlement agreement was entered into which provided for the payment of the 2009 distributions to the partners. The settlement agreement further provided for the purchase by NewPage of the partners' interests in Rumford LP under certain conditions. If NewPage does purchase the partners' interests in Rumford LP, our share of the proceeds is expected to be approximately $2.5 million.

Koma Kulshan Project

General Description

The Koma Kulshan project is a 13.3 MW run-of-the-river hydroelectric generation facility located on the slopes of Mount Baker, approximately 80 miles north of Seattle, Washington, and began commercial operation in 1990 as a QF. The Koma Kulshan project is owned by Koma Kulshan Associates, a California limited partnership in which we own a 49.75% economic interest, Mt. Baker Corporation owns a 0.25% economic interest and Covanta Energy Corporation ("Covanta") owns the remaining 50%. The Koma Kulshan project was issued a 50-year hydro license from the FERC which expires in 2037. The project and its electrical output is sold to Puget Sound Energy, Inc. under a PPA expiring in 2037.

Our and Mt. Baker Corporation's interests in the project are held through Concrete Hydro Partners, L.P. Under the Concrete partnership agreement, Mt. Baker Corporation is entitled to reimbursement of certain deferred costs associated with the original development of the project from a portion of the distributions from the project. The full repayment of these deferred costs is expected in 2010, following which distributions are projected to be made ratably to us and Mt. Baker Corporation.

Power Purchase Agreement

Energy generated by the Koma Kulshan project is sold to Puget Sound Energy pursuant to a long-term PPA expiring in 2037. Power is sold at a per kilowatt hour rate that is adjusted annually. The term of the PPA is coterminous with the FERC license. Puget Sound Energy has the right to renew the PPA for a term equivalent to the term of any subsequent license or annual license granted by the FERC for the project.

Operations & Maintenance

Covanta performs the operations and maintenance of the facility pursuant to an operations and maintenance agreement which expires December 31, 2010. In addition to being reimbursed for actual costs incurred, Covanta receives an annual fee adjusted for inflation.

Delta-Person Project

General Description

The Delta-Person Project is a 132 MW natural gas-fired peaking facility located near Albuquerque, New Mexico, is an EWG that commenced commercial operation in 2000. We own a 40% interest in

Delta-Person and affiliates of Olympus Power, LLC and John Hancock Mutual Life Insurance Company own the remaining interests. The Delta-Person Project is situated on PNM's (formerly Public Service of New Mexico) retired Delta Generating Station site under a lease agreement which is co-terminus with the project's PPA. The project operates as a peaking facility, which means that it is called upon to generate electricity only during unusually high periods of demand. The Delta-Person project sells all of its electrical output to PNM under a long-term PPA that expires in 2020.

Construction of the Delta-Person project was financed through a $59.7 million construction loan that was converted to permanent project financing once commercial operation was achieved. The permanent project financing was divided into two term loans: (i) Tranche A due March 31, 2017; and (ii) Tranche B due March 31, 2019, both of which amortize over their remaining terms. Our share of the total debt outstanding at the Delta-Person project as of June 30, 2010 was $11.1 million. See "Project-Level Debt" on page 61 of this prospectus for additional details.

Power Purchase Agreement

Electrical power generated by the Delta-Person project is purchased by PNM under a PPA that will expire in 2020. PNM has the unilateral right to extend the PPA for five years by giving written notice of such extension no later than two years prior to the end of the original term of the PPA. Subject to adjustments provided for in the PPA, PNM will purchase and accept the entire output of the project when PNM calls upon the capacity. Payments consist of: (i) the energy purchase price multiplied by the kilowatt hours delivered; (ii) the capacity purchase price multiplied by the dependable capacity; (iii) the project's cost of purchasing electric service from PNM for the operations and maintenance of the facility; and (iv) any other applicable charges. In order to earn full capacity payments, the project must maintain availability of at least 97%, which the project has historically achieved.

Fuel Supply Arrangements

The project purchases fuel from PNM Gas Services, a division of PNM, with fuel costs passed through to PNM under the PPA. The project has access to an interruptible gas supply and transportation like other standard industrial customers on PNM Gas Services' system.

Operations & Maintenance

As a simple cycle peaking facility, the project operations do not require extensive staffing and technical resources. Olympus Power provides asset management services, which include operational and contractual oversight of the facility, budget setting and environmental compliance.

Factors Influencing Project Results

The Delta-Person project derives a significant portion of its operating margin through capacity payments under the PPA with PNM. The capacity payment is based on two components which adjust annually with changes in inflation and interest rates. The capacity payment may be reduced on a monthly basis if the project's availability falls below 97%. The project has rarely experienced such adjustment. Energy payments are based on a variable operations and maintenance component, a fuel component and an availability incentive. The fuel component consists of the actual price the project pays for fuel and a contract heat rate. The contractually guaranteed heat rate is slightly higher than the project's average operating heat rate which generates additional energy revenue, because the contractually guaranteed heat rate represents the price that PNM pays for power that it purchases from Delta-Person. PNM will normally choose to purchase power from higher efficiency plants during periods of reduced demand. Reduced overall economic activity and related lower demand for electricity in the past two years has resulted in lower dispatch of Delta-Person by PNM.

Biomass Development Projects

Biomass-derived power is a well-established, conventional technology. In biomass power plants, the fuel is burned in a boiler to create steam that turns a turbine to generate electricity. In general, biomass power plants are designed to be operated as baseload units. While biomass encompasses a broad range of potential fuels, our activities are focused on "wood-residue" biomass. This feedstock includes virgin wood (from forests, wood processing facilities, etc.), agricultural residues, industrial and commercial waste, etc. Our facilities are eligible for renewable energy credits and may also qualify for certain federal tax benefits, depending on their construction schedule. We are pursuing six biomass projects with partners who bring specific skills to their development, as more fully described below.

Rollcast Energy, Inc.

Rollcast Energy, Inc. ("Rollcast") develops, owns and operates renewable power plants that use wood or biomass fuel. Rollcast, based in Charlotte, North Carolina, has five 50 MW biomass power plants in various stages of development in the southeastern U.S. In March 2009, we acquired a 40% equity interest in Rollcast for $3.0 million. In March 2010, we acquired an additional 15% interest for $1.2 million and in April 2010, we invested an additional $0.8 million to bring our total ownership interest to 60%. The terms of our investment in Rollcast provide us the option, but not the obligation, to invest directly in biomass power plants under development by Rollcast. Two of the development projects have obtained 20-year PPAs with terms that allow for the pass-through of fuel costs to the utility customer. In April 2010, Rollcast entered into a construction agreement for a 53.5 MW biomass project, known as Piedmont Green Power, to be located in Barnesville, Georgia. We are currently in advanced discussions that we expect will lead to our commitment to invest up to $75 million in the Piedmont Green Power project, representing substantially all of the equity interests in the project. We intend to use a sole arranger to syndicate project-level debt financiing for Piedmont.

Onondaga Renewables, LLC

Onondaga Renewables, LLC is a 50/50 joint venture between us and Catalyst Renewables LLC formed in December 2008 to repower our decommissioned 91 MW gas-fired cogeneration facility located in Geddes, New York. Utilizing locally acquired biomass fuel, the proposed facility is expected to have a capacity of approximately 45 MW. Onondaga is currently in the process of obtaining a PPA for the full output of the facility.

Asset Management

Our asset management strategy is to partner with recognized leaders in the independent power business. Most of our projects are managed by Caithness; Cogentrix, a subsidiary of Goldman Sachs; and, in the case of Path 15, Western, a U.S. Federal power agency. On a case-by-case basis, Caithness, Cogentrix, and Western may provide: (i) day-to-day project-level management, such as operations and maintenance and asset management activities; (ii) partnership level management tasks, such as insurance renewals; and (iii) passive partnership level management, such as acting as limited partner. In some cases these project managers or the project partnerships may subcontract with other firms experienced in project operations, such as GE, to provide for day-to-day plant operations. In addition, employees of Atlantic Power Corporation with significant experience managing similar assets are involved in most decisions with the objective to choose value-creating transactions such as contract restructurings, asset-level refinancing, acquisitions and divestitures.

Caithness is one of the largest privately-held independent power producers in the United States. For over 25 years in the independent power business, Caithness, has been actively engaged in the development, acquisition and management of independent power facilities for its own account as well as in venture arrangements with other entities. Caithness operates our Auburndale, Lake and Pasco projects and provides other asset management services for our Orlando, Selkirk and Badger Creek projects.

Cogentrix develops, owns, and operates independent power plants, located primarily in the U.S. Cogentrix manages the operation of the Chambers and Selkirk projects. New York-based investment firm Goldman Sachs Group acquired Cogentrix in December 2003. In November 2007, Goldman Sachs sold 80% of its interest in a number of the Cogentrix independent power plants, including Chambers and Selkirk to Energy Investors Funds, an established private equity fund manager that invests in the U.S. energy and electric power sector. Cogentrix continues to manage the Chambers and Selkirk projects.

Western markets and delivers hydroelectric power and related services within a 15-state region of the central and western United States. Western is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. Western's transmission system carries electricity from 57 power plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Together, these plants have an operating capacity of approximately 8,785 MW. Western owns and operates the Path 15 transmission line.

Industry Regulation

Overview

In the United States, the trend towards restructuring the electric power industry and the introduction of competition in electricity generation began with the passage and implementation of the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). Among other things, PURPA, as implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided cost. The FERC defines avoided cost as the incremental cost to a utility of energy or capacity which, but for the purchase from QFs, the utility would itself generate or purchase from another source. This requirement was modified in 2005, as discussed below.

Electric transmission assets, such as our Path 15 project, are regulated by the FERC on a traditional cost-of-service rate base methodology. This approach allows a transmission company to establish a revenue requirement which provides an opportunity to recover operating costs, depreciation and amortization, and a return on capital. The revenue requirement and calculation methodology is reviewed by the FERC in periodic rate cases. As determined by the FERC, all prudently incurred operating and maintenance costs, capital expenditures, debt costs and a return on equity may be collected in rates charged.

Carbon Emissions

In the United States, government policy addressing carbon emissions has continued to gain momentum over the last two years. Beginning in 2009, the RGGI was established in ten Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for CO_2 emissions. The states have varied implementation plans and schedules. Two of these states, New York and New Jersey, also provide cost mitigation for independent power projects with certain types of power contracts. Other states and regions in the United Sates are developing similar regulations and it is expected that federal climate legislation will be established in the future.

Federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have been introduced in both the U.S. House and Senate. Separately, the U.S. Environmental Protection Agency has taken several recent actions to regulate CO_2 emissions.

Additionally, more than half of the U.S. states and most Canadian provinces have set mandates requiring certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass. In order to meet CO_2 reduction goals, changes in the generation fuel mix are forecasted to include a reduction in existing coal resources, higher reliance on nuclear, natural gas, and renewable energy resources and an increase in demand-side resources. Investments in new or upgraded transmission lines will be required to move increasing renewable generation from more remote locations to load centers.

Regulation Generating Projects

Ten of our power generating projects are qualified facilities under PURPA and related FERC regulations. The Delta-Person and Pasco projects are not QFs but are both EWGs under the Public Utility Holding Company Act of 2005, as amended ("PUHCA"). The generating projects with QF status and which are currently party to a power purchase agreement with a utility or have been granted authority to charge market-based rates are exempt from FERC rate-making authority. The FERC has granted seven of the projects the authority to charge market-based rates based primarily on a finding that the project lacks market power. These projects are thus not subject to FERC rate-making. The generating projects are exempt from regulation under PUHCA and the projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities.

A QF falls into one or both of two primary classes, both of which would facilitate more efficient use of fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only. With the exception of QFs, generation, transmission and distribution of electricity remained largely owned by vertically integrated electric utilities until the enactment of the Energy Policy Act of 1992 (the "EP Act of 1992") and subsequent orders in 1996, along with electric industry restructuring initiated at the state level. Among other things, the EP Act of 1992 enhanced the FERC's power to order open access to power transmission systems, contributing to significant growth in the independent power generation industry.

In August 2005, the Energy Policy Act of 2005 (the "EP Act of 2005") was enacted, which removed certain regulatory constraints on investment in utility power producers. The EP Act of 2005 also limited the requirement from PURPA that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. Finally, the EP Act of 2005 amended and expanded the reach of the FERC's corporate merger approval authority under Section 203 of the Federal Power Act.

All of our projects are subject to reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC"). NERC is a self-regulatory organization that is a non-governmental entity which has statutory responsibility to regulate bulk power system users, generation and transmission owners and operators through the adoption and enforcement of standards for fair, ethical and efficient practices.

In March 2007, the FERC issued an order approving mandatory reliability standards proposed by NERC in response to the August 2003 northeastern U.S. blackouts. As a result, users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Senior Director for Asset Management as our FERC Compliance Officer responsible for meeting the FERC and NERC requirements and an outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

Regulation Transmission Project

The revenues received by the Path 15 project are regulated by the FERC through a rate review process every three years that sets an annual revenue requirement. Under terms of the initial rate case settlement, the project must go through the FERC review every three years.

The Path 15 project's initial three-year rate period's revenue requirement expired at the end of 2007. On December 21, 2007, the Project submitted to the FERC its revenue requirement for the 2008 through 2010 period. In an order issued February 2008, the FERC allowed the rates as filed in December 2007 to go into effect subject to refund pending the outcome of the regulatory proceedings. The FERC also accepted several of the project's key methodological approaches, including use of a 13.5% return on equity. A number of parties requested rehearing on such issues. On March 23, 2009, the Path 15 project filed an uncontested settlement offer with the FERC, for rehearing in the Path 15 project's rate case proceeding. We believe that the settlement was reasonable and will not significantly impact the expected cash flow from the project. On August 3, 2009, the FERC issued an order approving the settlement. Thereafter, on October 30, 2009 the Path 15 project issued refunds reflecting the difference between the rates collected as of February 2008 pursuant to the December 2007 filing and the rates provided for under the settlement. Since May 2009, the Path 15 project has been receiving revenues based on the revenue requirement established by the settlement. Pursuant to the terms of the settlement, Path 15 is required to submit its revenue requirement for the 2011 through 2013 rate period to the FERC in February 2011. The preparation of this new rate filing will commence in the third quarter of 2010.

Competition

The power generation industry is characterized by intense competition, and our projects compete against utilities, industrial companies and other independent power producers. In recent years, there has been increasing competition among generators in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the U.S. power industry.

The U.S. power industry is continuing to undergo consolidation and may offer attractive acquisition and investment opportunities, although we believe that we will continue to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms. We compete for acquisition opportunities with numerous private equity funds, Canadian and U.S. independent power firms, utility genco subsidiaries and other strategic and financial players. Our competitive advantages include our diversified projects, strong customer base, leading third-party managers and stability of project cash flow. We have similar strength in asset management and optimization.

Legal Proceedings

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of August 12, 2010 which we expect to have a material impact on our financial position or results of operations.

Employees

As of August 12, 2010, we had 13 full-time employees. None of our employees is represented by any collective bargaining unit or a party to any collective bargaining agreement.

Description of Property

We have included descriptions of the locations and general character of our principal physical operating properties, including an identification of the segments that use such properties, in "Business," which is incorporated herein by reference. A significant portion of our equity interests in the entities owning these properties are pledged as collateral under our senior credit facility or under non-recourse operating level debt arrangements. See Note 9 in the accompanying notes to our consolidated financial statements for additional information regarding our operating properties.

Our principal executive office is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts under a lease that expires in 2015.

MANAGEMENT

The following table sets forth the names, ages and positions of each of our directors and executive officers:

Name	Age	Position
Irving Gerstein	69	Director, Board Chairman, Nominating and Governance Committee Chairman
Ken Hartwick	47	Director, Audit Committee Chairman, Compensation Committee Chairman
John McNeil	68	Director
Richard Foster Duncan	56	Director
Holli Nichols	40	Director
Barry Welch	53	Director, President and Chief Executive Officer
Patrick Welch	42	Chief Financial Officer and Corporate Secretary
Paul Rapisarda	56	Managing Director, Acquisitions and Asset Management
William Daniels	51	Senior Director, Asset Management
John J. Hulburt	43	Corporate Controller

Irving R. Gerstein, C.M., O.Ont The Honourable Irving R. Gerstein has been a director of Atlantic Power since October 2004. Senator Gerstein is a Member of the Order of Canada and a Member of the Order of Ontario, and was appointed to the Senate of Canada in December 2008. He is a retired executive, and is currently a director of Medical Facilities Corporation, Student Transportation of America, Ltd., and Economic Investment Trust Limited, and previously served as a director of other public companies, including CTV Inc., Traders Group Limited, Guaranty Trust Company of Canada, Confederation Life Insurance Company and Scott's Hospitality Inc., and as an officer and director of Peoples Jewellers Limited. Senator Gerstein is an honorary director of Mount Sinai Hospital (Toronto), having previously served as Chairman of the Board, Chairman Emeritus and a director over a period of twenty-five years, and is currently a member of its Research Committee. Senator Gerstein earned his BSc in Economics from the University of Pennsylvania (Wharton School of Finance and Commerce).

Mr. Gerstein's substantial experience on the boards of numerous other public companies and his prior experience as an executive of a substantial public company make him a valued advisor and highly qualified to serve as chairman of our board of directors and as chairman of our Nominating and Corporate Governance Committee.

Ken Hartwick, C.A. has been a director of Atlantic Power since October 2004. Ken Hartwick has over 13 years of management experience in the energy sector, and 20 years experience in the financial sector. Mr. Hartwick's experience in the energy industry spans several markets having played an integral role as an executive officer for Just Energy since April 2004, helping launch their businesses in Alberta, British Columbia, Indiana, and Texas as well as growing the businesses already established in Manitoba, Ontario, Quebec, Illinois and New York. He currently serves as the President and CEO for, and is a director on the board of Just Energy, an integrated retailer of commodity products. Mr. Hartwick has served as President and CEO for Just Energy since June 2008, as President from 2006 until June 2008, and as Chief Financial Officer from April 2004 to 2006. Mr. Hartwick understands the issues facing the electricity industry through his previous role as Chief Financial Officer of one of the largest distribution companies in North America, Hydro One Inc., where he gained increasing executive-level responsibility throughout his career, and provided strategic direction as Ontario transitions towards a competitive energy marketplace. Mr. Hartwick earned his Honours of Business Administration from Trent University, Peterborough, Ontario.

Mr. Hartwick's substantial experience in the energy industry and financial sector make him a valued advisor and highly qualified to serve as a member of our board of directors and as chairman of our Audit and Compensation Committees.

John McNeil has been a director of Atlantic Power since October 2004. Mr. McNeil is President of BDR NorthAmerica Inc., an energy consulting company based in Toronto, Ontario. Prior to his appointment at BDR NorthAmerica Inc. in 2000, Mr. McNeil was Managing Director Investment Banking with Scotia Capital Inc. from 1996 to 1999. Previously, he was a Senior Vice-President and Director of ScotiaMcLeod Inc. from 1991 to 1995. Mr. McNeil has extensive expertise in the areas of asset management models, capitalization, mergers and acquisitions, business and enterprise valuations, capital markets and market ratings and has worked extensively throughout North America and Europe. Mr. McNeil specializes in the electric power sector and his major focus in recent years has been in the field of corporate and enterprise unbundling and reconstitution resulting from the restructuring of the electricity sector in North America. Mr. McNeil earned a B.A. (Honors) from Queens University, a Bachelor of Laws from the University of Toronto and a Master of Business Administration from the University of British Columbia.

Mr. McNeil's extensive experience in the financial and capital markets sectors, as well as his expertise in the electric power sector, make him a valued advisor and highly qualified to serve as a member of our board of directors.

Richard Foster Duncan was elected as a director of Atlantic Power at our annual general meeting of shareholders held on June 29, 2010. Mr. Duncan has more than 30 years of senior corporate, investment banking, and private equity experience. He joined Advantage Capital Partners in April 2009 as Managing Director with senior management responsibility for the firm's energy related portfolio and energy initiatives. From 2005 through April 2009, Mr. Duncan was managing member of KD Capital L.L.C., an affiliate of Kohlberg Kravis Roberts & Co. ("KKR"), which he and KKR formed in 2005. He worked with KKR and its portfolio companies in connection with creating value and identifying and investing in the energy, utility, natural resources, and infrastructure sectors. From 2001 through 2005 he was with Cinergy Corporation. Mr. Duncan joined Cinergy Corporation as Executive Vice President and CFO of Cinergy Corporation with overall corporate financial responsibility for all financial functions and also served as CEO and President of Cinergy's Commercial Business Unit in part of 2004 and 2005. While at Cinergy, he was responsible for Cinergy's energy merchant operations and regulated generation, including a portfolio of more than 19,000 megawatts. He was responsible for Cinergy's wholesale electric, natural gas and coal marketing, and international operations. Mr. Duncan is active with the Edison Electric Institute, serves as a member of the Wall Street Advisory Group, and is the past Chairman of the Finance Executive Advisory Committee. Earlier in his career, he has also held senior management positions at LG&E Energy Corp., a subsidiary of E.ON AG, and Freeport-McMoRan Copper & Gold and Howard, Weil, Labouisse, Friedrichs Inc. Mr. Duncan is on the board of directors of North American Energy Alliance, LLC in Iselin, NJ and SensorTran Inc. in Austin, TX and also serves on the Board of Advisors of GridPoint, Inc. in Arlington, VA. He is active in a number of civic organizations including the board of directors of the Eye, Ear, Nose and Throat Hospital Foundation in New Orleans, the Board of Trustees of Cincinnati Country Day School and in Charlottesville, Virginia the National Advisory Board of the University of Virginia Jefferson Scholars Program. Mr. Duncan graduated with Distinction from the University of Virginia and later received his MBA degree from the A. B. Freeman Graduate School of Business at Tulane University.

Mr. Duncan's extensive experience as a senior executive in the electric utility industry, as well as his experience in the private equity sector make him a valued advisor and highly qualified to serve on our board of directors.

Holli Nichols was elected as a director of Atlantic Power at our annual general meeting of shareholders held on June 29, 2010. Ms. Nichols has over 10 years of experience in financial roles at

Dynegy, Inc., a large independent power company listed on the NYSE, and is a Certified Public Accountant. She is currently Executive Vice President and Chief Financial Officer of Dynegy and has been in that role since December 2005. From May 2004 to December 2005, she was Senior Vice President and Treasurer. From June 2003 to May 2004, she was Senior Vice President and Controller and held other financial roles at the company from May 2000 through May 2004. Prior to joining Dynegy, Ms. Nichols was a Senior Audit Manager with PricewaterhouseCoopers. She also serves on the board of His Grace Foundation, which supports children who undergo bone marrow transplants. Ms. Nichols earned a bachelor's of science degree from Baylor University and a Masters of Business Administration from Rice University.

Ms. Nichols' extensive experience as a senior executive in the independent power industry, as well as her financial and accounting background make her a valued advisor and highly qualified to serve on our board of directors.

Barry Welch has been our President and Chief Executive Officer since October 2004 (until December 31, 2009, through the Manager) and a Director since June 2007. Prior to joining Atlantic Power Corporation, Mr. Welch was the Senior Vice President and co-head of the Bond & Corporate Finance Group of John Hancock Financial Services ("John Hancock"), Boston, Massachusetts, from 2000 to 2004. Mr. Welch served on several committees at John Hancock, including its Pension Investment Advisory Committee and Investment Operating Committee. Mr. Welch was Chairman of John Hancock's Bond Investment Committee and reported monthly on investment portfolio, strategy and activity to the Committee of Finance of John Hancock's board of directors. Mr. Welch also led the development and approval of John Hancock's involvement with ArcLight Capital Partners and served as a member of ArcLight Energy Partners Fund I's Investment Committee. During his time at John Hancock, Mr. Welch headed the Bond and Corporate Finance Group's Power and Energy investment team. From 1989 to 2004, he was involved directly or oversaw $25 billion of investments in more than 1,000 utility, project finance and oil and gas transactions. Prior to joining John Hancock, Mr. Welch spent more than three years as a developer of power projects at Thermo Electron Corporation's Energy Systems Division (later known as Thermo Ecotek). There, he was involved in greenfield development of natural gas, wood and waste-to-energy projects, as well as asset management roles for operating plants. Mr. Welch earned a Bachelors of Science in Mechanical and Aerospace Engineering from Princeton University, and a Masters of Business Administration from Boston College. Mr. Welch serves on the board of directors of the Walker Home and School in Needham, Massachusetts.

Mr. Welch's extensive experience in energy investment and related activities in the financial sector, as well as his in-depth knowledge of our company through his position as President and Chief Executive Officer, make him highly qualified to serve as a member of our board of directors.

Patrick Welch, who is not related to Barry Welch, has been our Chief Financial Officer since May 2006 (until December 31, 2009, through the Manager). He has an extensive background in the energy and independent power industries. Before joining Atlantic Power, from January 2004 to May 2006, Mr. Welch was Vice President and Controller of DCP Midstream, ("DCP") and DCP Midstream Partners, LP ("DCPLP") headquartered in Denver, Colorado. DCP is a private midstream natural gas company owned by Spectra Energy and ConocoPhillips and DCPLP is a public master limited partnership sponsored by DCP. In these roles, Mr. Welch was responsible for all accounting, budgeting, SEC and financial reporting and compliance with Section 404 of the Sarbanes-Oxley Act of 2002 for DCP and DCPLP. Prior to that he held various positions at Dynegy Inc. in Houston, Texas, including Vice President and Controller for Dynegy Generation, and Assistant Corporate Controller. Prior to Dynegy, Mr. Welch was a Senior Audit Manager in the Energy, Utilities and Mining Practice of PricewaterhouseCoopers LLP, predominantly in Houston, Texas, where he served several major energy clients. He earned his bachelors degree from the University of Central Oklahoma and is a Certified Public Accountant.

Paul Rapisarda has 25 years of experience in energy, utility and independent power investment banking. Mr. Rapisarda is currently Managing Director of Acquisitions and Asset Management at Atlantic Power. From 2001 to early 2008 he was a Principal with Compass Advisors, a boutique M&A advisory firm in New York, where he was involved in numerous strategic advisory, restructuring and principal transactions in the energy and power sectors. Prior to Compass Advisors, Mr. Rapisarda held senior positions with the energy and utilities investment banking teams at Schroders, Merrill Lynch and BT Securities. Prior to that he was a Managing Director and Co-Head, Utilities and Structured Finance, at Drexel Burnham Lambert. While at Drexel, he also worked with the firm's chief financial officer in making direct tax-oriented investments on the firm's behalf. Over the course of his career, Mr. Rapisarda has worked on a broad range of capital markets and advisory transactions including substantial experience in cross-border and emerging markets. He earned his Bachelors degree from Amherst College and his MBA from Harvard Business School.

William Daniels has been with Atlantic Power since March 2007. He is currently Senior Director of Asset Management. Mr. Daniels has 26 years of experience in oil and gas exploration, independent power development, project finance and asset management. Prior to joining Atlantic Power, from January 2006 to February 2007, Mr. Daniels was Director, Asset Management at American National Power. He has held various positions in asset management and project finance at Calpine Corp. (March 2001 to January 2006), Edison Mission Energy, Citizens Power and the Toronto-Dominion Bank. Prior to receiving his MBA, he worked with Mitchell Energy Corp. as an exploration geologist. Mr. Daniels earned a Bachelor of Science degree in Geology from the University of Rochester, a Master of Science in Geology from the Ohio State University, and an MBA from Columbia University Business School.

John J. Hulburt has been the Corporate Controller of Atlantic Power since June 2008. Mr. Hulburt has 14 years of experience in the accounting industry. Before joining Atlantic Power, from February 2007 to June 2008, Mr. Hulburt was Controller of GreatPoint Energy, Inc. headquartered in Cambridge, Massachusetts. GreatPoint Energy is a technology-driven natural resources company and the developer of a proprietary, highly-efficient catalytic process, known as hydromethanation. Mr. Hulburt was responsible for all accounting, budgeting and financial reporting for GreatPoint Energy. Prior to that he was the Chief Financial Officer at Datawatch Corporation (December 2004 to January 2007) in Chelmsford, Massachusetts, and the Chief Financial Officer at Bruker Daltonics in Billerica, Massachusetts (April 2000 to June 2004). Datawatch and Bruker Daltonics were publicly listed Companies on the NASDAQ Exchange. He was responsible for all accounting, budgeting, SEC and financial reporting for Datawatch and Bruker Daltonics. Prior to Bruker Daltonics, Mr. Hulburt was an Audit Manager in the Hi-Technology and Manufacturing Practice of Ernst & Young LLP, where he served several major Hi-Tech and Manufacturing clients. He earned his bachelors degree from the Merrimack College and is a Certified Public Accountant.

Composition of our board of directors

Our directors are elected by our shareholders at our annual meeting, which is generally held in June of each year. Directors hold office for one year or until their successors are chosen. At our annual general and special meeting of shareholders on June 29, 2010, shareholders approved increasing the size of the board from five to six directors and approved changes to our Articles of Continuance reducing the minimum Canadian residency requirement for directors from 50% to 25%.

Our board of directors has evaluated the independence of each director within the meaning of the requirements of the NYSE and has determined that each of Messrs. Gerstein, Hartwick, McNeil and Duncan and Ms. Nichols is an "independent director" under our independence standards and under the NYSE corporate governance rules. These five directors comprise a majority of our six-member board of directors.

Compensation of Directors

Director Fees

Each independent director is entitled to receive an annual retainer of $40,000 and $1,500 per meeting attended in person or $500 per meeting attended by phone. The chair of the board of directors' Audit Committee and Compensation Committee receive an additional $10,000 per year. Directors are reimbursed for out-of-pocket expenses for attending meetings. Our directors also participate in the insurance and indemnification arrangements described below.

Equity Ownership Guideline

On April 24, 2007, the board of directors adopted an equity ownership guideline for independent directors. The guideline provides that by April 24, 2010 (for existing independent directors) or within three years of their initial election (for new independent directors), each independent director should own equity securities of Atlantic Power (which will include notional shares issued under the deferred share unit plan described below), representing an investment by each independent director of three times their current annual retainer.

Deferred Share Unit Plan

On April 24, 2007, our board of directors established a deferred share unit plan ("DSU Plan") for directors. Under the DSU Plan, each non-management director is entitled to elect to have fees paid to them by Atlantic Power for their services as directors contributed to the DSU Plan. All fees contributed to the DSU Plan shall be credited to such director in the form of notional shares representing the estimated fair value, as determined by Atlantic Power, of the common share component of the IPSs at the time of contribution. For so long as the participant continues to serve on the board of directors, dividends will accrue on the notional shares consistent with amounts declared by the board of directors on our common shares and additional notional shares representing the dividends will be credited to the participant's notional share account. Notional shares credited to the participant's notional share account may be redeemed only when a participant no longer serves on the board of directors for any reason or upon a reorganization of Atlantic Power.

The following table describes director compensation for non-management directors for the year ended December 31, 2009. Directors who are also officers of Atlantic Power are not entitled to any compensation for their services as a director.

Name	Fees earned or Paid in Cash (US$)	Total Compensation (US$)
Irving R. Gerstein	107,000	107,000
Kenneth M. Hartwick(1)	100,500	100,500
John A. McNeil	90,500	90,500
William E. Whitman(2)	91,000	91,000

(1) Mr. Hartwick deferred all of his 2009 fees in the DSU Plan.

(2) Mr. Whitman deferred 25% of his 2009 fees in the DSU Plan. Mr. Whitman is no longer a director as of June 29, 2010.

Compensation Committee Interlocks and Insider Participation

None of the members of the compensation committee of our board of directors is an officer or employee of Atlantic Power. No named executive officer of Atlantic Power serves as a member of the board of directors or compensation committee of any entity that has one or more named executive officers serving on our compensation committee.

During 2009, Barry Welch, our President and Chief Executive Officer presented recommendations in connection with deliberations of our board of directors concerning executive officer compensation.

During the last year, none of our executive officers served as: (i) a member of the compensation committee (or other committee of the board of directors performing equivalent functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on our compensation committee; (ii) a director of another entity, one of whose executive officers served on our board of directors; or (iii) a member of the compensation committee (or other committee of the board of directors performing equivalent functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on our board of directors.

Compensation Discussion and Analysis

Introduction

Until December 31, 2009, we were managed through a management services agreement with Atlantic Power Management, LLC, which we refer to herein as the "Manager," which is owned by two private equity funds managed by ArcLight Capital Partners, LLC. As such, we did not have any executive officers or other employees and all of the persons listed in this prospectus as "named executive officers" were employed by the Manager. Effective December 31, 2009, the management agreement was terminated and all of the employees of the Manager became our employees. In addition, Barry Welch, Patrick Welch and Paul Rapisarda entered into executive employment agreements with us in connection with the termination of the management agreement.

Compensation Objectives

Compensation plays an important role in achieving short and long-term business objectives that ultimately drives business success in alignment with long-term shareholder goals. The objectives of our compensation program are to:

- attract and retain highly qualified executive officers with a history of proven success;
- align the interests of our executive officers with shareholders' interests and with the execution of our business strategy;
- establish performance goals that, if met by Atlantic Power, are expected to improve long-term shareholder value; and
- tie compensation to performance with respect to those goals and provide meaningful rewards for achieving them.

Our compensation program is designed to provide adequate reward for services and incentive for our senior management team to implement both short-term and long-term strategies aimed at increasing shareholder value, and aligning the interests of senior management with those of our shareholders.

Our compensation program has been established in order to compete with remuneration practices of companies similar to us and those which represent potential competition for our executive officers and other employees. In this respect, we identify remuneration practices and remuneration levels of public companies that are likely to compete for our employees. In designing the compensation program, our board of directors focuses on remaining competitive in the market with respect to total compensation for each of our executive officers. However, our board of directors does review each element of compensation for market competitiveness and it may weigh a particular element more heavily based on the executive officer's role.

The following table lists our principal executive officer, principal financial officer, our third senior officer and our two other most highly compensated non-officer employees, collectively referred to as named executive officers:

Barry E. Welch	President and CEO
Patrick J. Welch	CFO and Corporate Secretary
Paul H. Rapisarda	Managing Director, Asset Management and Acquisitions
William B. Daniels	Senior Director, Asset Management
John J. Hulburt	Corporate Controller

Elements of Compensation

The compensation of each named executive officer includes a base salary, cash bonus and eligibility for awards under the long-term incentive plan. All compensation decisions are made by the Compensation Committee of our board of directors.

Base Salary

The base salaries for our named executive officers for 2009 were established by the Manager, but reviewed by our board of directors as part of the annual approval of the Manager's budget. This review is based on the level of responsibility, the experience level attained by the relevant named executive officer and his or her personal contribution to our financial performance with a goal to ensure that the base salaries are appropriate and competitive.

Annual Cash Bonus (Non-equity Incentive Plan Compensation)

Possible annual cash bonus awards are generally based on whether or not duties have been performed well based on the relevant named executive officer's success in contributing to our operating and financial performance, including achieving annual goals and objectives approved by the Compensation Committee. The annual goals and objectives are established at the company level and are broadly based on (i) company growth strategy through acquisitions and organic growth; (ii) operating performance of existing assets; (iii) investor relations; and (iv) risk management and administrative functions.

In the case of Barry Welch, Patrick Welch and Paul Rapisarda, for each of the three years 2009 through 2011 per the terms of their respective employment contracts there are three components: (i) a portion of the annual cash bonus, identified as "Bonus" in the Summary Compensation Table on page 114, is fixed based on the average amount in 2007 and 2008 of the portion of their bonuses that were paid by the Manager and not reimbursed by Atlantic Power; (ii) a second component is based on our total shareholder return compared to a group of our peer companies. For this portion, which is included in the column identified as "Non-equity Incentive Plan Compensation" in the Summary Compensation Table on page 114, a scale establishes a minimum of zero and a maximum of 110% of a target amount equal to \$300,000, \$130,000 and \$130,000 for Barry Welch, Patrick Welch and Paul Rapisarda, respectively. Relative performance at greater than the 10th percentile of the peer group is required to earn the minimum award and at greater than the 85th percentile of the peer group in order to earn the maximum award; and (iii) a component from zero to a maximum of 20% of the target in (ii) above, which is also included in the column identified as "Non-equity Incentive Plan Compensation" in the Summary Compensation Table on page 114, is based on our board of directors' assessment of the senior officers' performance in contributing to achievement of the company's approved goals and objectives. Specifically in 2009, the directors based these assessments on (i) for

Barry Welch, his contributions to the achievement of goals related to our growth strategy, risk management and investor relations, (ii) for Patrick Welch, his contributions to the achievement of goals related to our growth strategy, risk management and investor relations, and (iii) for Paul Rapisarda, his contributions to the achievement of goals related to our growth strategy and operating performance of existing assets.

Total shareholder return refers to the rate of return that a shareholder would earn on an investment in our common shares (or, prior to the conversion of our IPSs to common shares, our IPSs) assuming the investment was held for the entire year and that monthly dividends were reinvested. Our Compensation Committee includes the following companies in the peer group for the purpose of determining our relative total shareholder return performance:

- Brookfield Renewable Power Fund;
- Capital Power Income LP;
- Northland Power Income Fund;
- Macquarie Power and Infrastructure Income Fund;
- Innergex Power Income Fund;
- Boralex, Inc.;
- Boralex Income Fund;
- Algonquin Power & Utilities Corp.; and
- Maxim Power Corp.

In 2009, our total shareholder performance return was at the 89% percentile of our peer group, as calculated by Hugessen Consulting Group ("Hugessen"). For non-officer executives, the non-equity incentive plan compensation is determined based on the process of (i) the CEO discussing their performance with their respective managers together as the officers group, and (ii) the review and discussion by the CEO with the Compensation Committee and their approval. The percentages of salaries for awards range from 0% to maximum levels that vary for each individual based on an overall assessment of their contributions to achieving the company's approved goals and objectives.

Long Term Incentive Plan ("LTIP")

In 2006, our board of directors retained Mercer Human Resource Consulting ("Mercer") to assist in its review of the compensation of the employees of the Manager. The two primary roles of Mercer were (i) to provide a compensation benchmarking review, and (ii) to provide a review of LTIP alternatives and assist our board of directors in the design of the LTIP that was ultimately approved by the board of directors and by our shareholders. The compensation benchmarking review provided the board of directors with an objective review of each component of compensation relative to the same components within a competitive peer group and identified the appropriateness and desirability of implementing the LTIP to further align the interests of employees of the Manager with those of Atlantic Power and holders of IPSs, and to adequately assist with attracting and retaining qualified employees in the relevant U.S. labor pool. The competitive peer group included the Canadian energy trusts, U.S. oil and gas master limited partnerships and U.S. real estate investment trusts listed in the following table, as compiled from their respective publicly-filed proxy information. Mercer also generally considered the overall compensation results shown in the 2005 Financial Services Survey Suite Private Equity Firms Compensation Survey. Mercer's review concluded that the overall compensation plan, including the LTIP plan and each other component, was reasonable and appropriate.

US REITs	Canadian Energy Trusts	US Oil & Gas MLPs
Developers Diversified Rlty	Just Energy Income Fund	Crosstex Energy Lp
Mack-Cali Realty Corp	Altagas Income Trust	Amerigas Partners Lp
Reckson Assocs Rlty Corp	ARC Energy Trust	Ferrellgas Partners Lp
Weingarten Realty Investment	Enerplus Res Fund	Inergy Lp
New Plan Excel Realty Tr	Fort Chicago Energy Ptnr	Genesis Energy Lp
SL Green Realty Corp	Bonavista Energy Trust	Magellan Midstream Prtnrs Lp
Carramerica Realty Corp	Acclaim Energy Trust	Northern Borders Partners Lp
Health Care Pptys Invest Inc.	PrimeWest Energy Trust	Pacific Energy Partners Lp
Arden Realty Inc.	Baytex Energy Trust	Markwest Energy Partners Lp
Federal Realty Invs Trust	Vermillion Energy Trust	Valero Lp
Regency Centers Corp	Pembina Pipeline Income Fund	K-Sea Transportation Lp
Equity Lifestyles Properties	Esprit Eng. Trust (fmr Cdn 88 Energy)	Atlas Pipeline Partner Lp
Glimcher Realty Trust	Paramount Energy Trust	
Heritage Ppty Investment Tr	Advantage Energy Income Fund	
Pan Pac Retail Pptys Inc.	Algonquin Power Income Fund	
Equity One Inc.	Trinidad Drilling Ltd.	
Affordable Residential Comm	Focus Energy Trust	
Boykin Lodging Corp.	Total Energy Svcs Ltd.	
Sun Communities Inc.		
Parkway Properties		
Tanger Factory Outlets Ctrs		
Associated Estates Realty Corp		

The named executive officers and other employees of the Company are eligible to participate in the LTIP as determined by our board of directors. The purpose of the LTIP is to align the interests of named executive officers with those of our shareholders and to assist in attracting, retaining and motivating key employees of the Manager by making a significant portion of their incentive compensation directly dependent upon the achievement of critical strategic, financial and operational objectives that are critical to ongoing growth and increasing the long-term value of Atlantic Power, as well as providing an opportunity to increase their share ownership over time. The LTIP is designed to help achieve short-term compensation objectives by setting yearly performance targets that trigger various levels of grants and also to achieve longer term objectives and assist in retention through the use of both a three-year vesting period and possible forfeiture of awards if certain levels of performance are not achieved during each grant's vesting period.

The following description applies to our initial LTIP, approved by shareholders in June 2006 and amended in June 2008. For each performance period (being, generally, a period of one calendar year commencing on January 1 of each year), for officers, the board of directors establishes LTIP award percentages that will determine the amount (based on a percentage of base salary) that each officer is entitled to receive under the LTIP if certain levels of target project cash flow for the performance period are achieved. For non-officers, a target range based on percentages of salaries is established by the officers and approved by the Compensation Committee, but the range is not directly tied to specific cash flow performance levels. Individual LTIP awards are proposed by the officers based on their evaluation of both the cash flow level achieved by the company and the individual's contribution to that performance, and approved by the Compensation Committee. Project cash flow is based on cash flows generated by our projects less management fees, administrative expenses, corporate interest, taxes and any other adjustments determined by our board of directors, which discretion is exercised narrowly and may reflect either increases or decreases to project cash flow performance. LTIP awards for each performance period are determined by the board of directors based on our actual cash flow. In making this determination, the board of directors has discretion to consider other factors, related to our performance. If certain levels of target project cash flow are achieved as determined by our board of directors, the named executive officer will be eligible to receive a number of notional units (including fractional units) to be calculated by dividing an incentive amount (based on the LTIP award percentages and the named executive officer's base salary) by the market price per IPS. The market price per IPS or common share is defined in the LTIP as the weighted average closing price of IPSs or common shares on the TSX for the five days immediately preceding the applicable day. Notional units are meant to track the investment performance of IPSs or common shares, under the amended LTIP, including share prices and dividends. Any notional units granted to a participant in respect of a performance period will be credited to a notional unit account for each participant on the determination date for such performance period. Each notional unit is entitled to receive distributions equal to the distributions on an IPS, to be credited in the form of additional notional units immediately following any distribution on the IPSs. Subsequent to our conversion to a common share structure, all references to "IPS" in the LTIP were changed to "Common Shares" and all references to distributions on IPSs were changed to dividends on common shares.

For grants under the LTIP, one-third of the notional units in a participant's notional unit account for a performance period vest on the 13-month anniversary following the determination date for such performance period, 50% of the notional units remaining in a participant's notional unit account for a performance period vest on the second anniversary date of the determination date for such performance period, and all remaining notional units in a participant's notional unit account for a performance period vest on the third anniversary of the determination date for such performance period.

On the applicable vesting date for notional units held in a participant's notional unit account, we redeem such vested notional units as follows: (i) one-third by lump sum cash payment (generally intended to be withheld toward payment of taxes that will be owed due to the vesting), and (ii) the remaining two-thirds by an exchange for common shares. Notwithstanding the foregoing, a named executive officer may elect to redeem such notional units for 100% common shares upon prior written notice of such election. All issuances of common shares on redemption of notional units under the

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LTIP are subject to compliance with applicable securities laws. In addition, the board of directors has the discretion to redeem notional units 100% with cash and has exercised this discretion for all notional units vested since the inception of the LTIP, except for those that have vested in the notional unit accounts of our senior officers.

If the net cash flows (as determined by our board of directors) achieved in a performance period are less than 80% of the target project cash flow previously approved by our board of directors for that performance period, all notional units having a vesting date in the next performance period will be cancelled, will no longer be redeemable for common shares and the executive officers will forfeit all rights, title and interest with respect to such notional units, unless otherwise expressly determined by our board of directors, as administrators of the LTIP.

Pursuant to each senior executive's employment agreement, each senior executive is eligible for an annual award under the LTIP up to a maximum of 150% of their annual base salary. The same percentages versus target cash flow levels are used for all of the officers. In 2009, achieving a minimum of $69.0 million of project cash flow was required to obtain the first tier of 50% of salaries for officers, and their maximum 150% award could be achieved only if the we achieved at least $90.9 million of project cash flow. Named executive officers other than senior executives are eligible for an annual award under the LTIP ranging from 0% to 80% of their annual base salary. For William Daniels and John Hulburt, the minimum award is 0% of their salary and the maximum award is 80% of their salary.

In 2009, Hugessen was retained to assist the Board in assessing our existing LTIP and proposing several design changes. The purpose of the LTIP changes is to further align the interests of our officers and employees with shareholders and to assist in attracting, retaining and motivating our key employees.

In early 2010, our board of directors approved amendments to the LTIP. The amendments do not impact grants for the 2009 performance year or unvested notional units related to grants made prior to the amendments. The amended LTIP will be effective for grants beginning with the 2010 performance year and was approved by the shareholders at our annual general meeting held on June 29, 2010.

Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as the notional units under the old LTIP. However, the number of notional units granted will be based, in part, on our total shareholder return compared to a group of peer companies in Canada. In addition, vesting of notional units for senior executives will occur on a three-year cliff basis as opposed to ratable vesting over three years under the old LTIP.

401(k) Matching Contributions

We also make annual matching contributions to each named executive officer's 401(k) plan account based upon a predetermined formula. The purpose of the matching contributions is to supplement the named executive officer's personal savings toward future retirement as we have no pension plan. The matching formula for all employees, including named executive officers, is equal to the employee's 401(k) contribution up to 7% of base salary and cash bonus, up to the maximum allowed by Internal Revenue Service ("IRS") regulations. The IRS maximum contribution in 2009 was $16,500 for participants under age 50 and $22,000 for participants 50 and over.

Summary Compensation Table

The following table sets forth a summary of salary and other annual compensation earned during the year ended December 31, 2009 by each named executive officer (in US$).

Name and Principal Position	Year	Salary	Bonus(1)	Stock Awards(2)	Non-equity Incentive Plan Compensation	All Other Compensation(3)	Total Compensation
Barry E. Welch Director, President and Chief Executive Officer	2009	535,000	400,000	472,500	390,000	22,000	1,819,500
Patrick J. Welch Chief Financial Officer and Corporate Secretary	2009	259,500	130,000	226,800	169,000	16,500	801,800
Paul H. Rapisarda Managing Director, Asset Management and Acquisitions	2009	257,500	130,000	225,000	169,000	22,000	800,500
William B. Daniels Senior Director Asset Management	2009	185,000		110,500	166,500	22,000	484,000
John J. Hulburt Corporate Controller	2009	180,000		87,500	80,000	12,601	360,101

(1) Represents the fixed portion of annual cash bonus for 2009 through 2011 payable under the terms of each executive officer's new employment contract executed in connection with the management internalization in December 2009. For 2009, these amounts were paid by the Manager and not reimbursed by Atlantic Power.

(2) The amounts shown above under "Stock Awards" reflect the grant date fair value of notional units granted during the year under the terms of the LTIP and are calculated in accordance with FASB ASC Topic 718.

(3) Amounts represent company matching contributions to the 401(k) plan accounts of each executive officer.

Following are grants of plan-based awards during the year ended December 31, 2009 for each named executive officer.

Name	Grant Date	Estimated Future Payouts Under Non-equity Incentive Plan Awards(a) Minimum ($)	Target ($)	Maximum ($)	All Other Stock Awards (#)(b)	Grant Date Fair Value of LTIP Awards ($)(I)
Barry E. Welch	N/A		300,000	390,000		
	3/31/09				82,008	472,500
Patrick J. Welch	N/A		130,000	169,000		
	3/31/09				39,364	226,800
Paul H. Rapisarda	N/A		130,000	169,000		
	3/31/09				39,052	225,000
William B. Daniels	N/A		138,750	185,000		
	3/31/09				19,179	110,500
John J. Hulburt	N/A		72,000	90,000		
	3/31/09				15,187	87,500

(a) Amounts shown represent the range of possible annual cash bonus. In addition Barry Welch, Patrick Welch and Paul Rapisarda receive an annual fixed bonus under the terms of their executive employment agreements. The amount of the annual fixed bonus is $400,000 for Barry Welch and $130,000 for Patrick Welch and for Paul Rapisarda.

(b) The amount shown represents the number of notional units granted for the 2008 performance year that was approved by our board of directors on March 31, 2009.

(c) Amounts are calculated in accordance with FASB ASC Topic 718.

Compensation of Barry Welch

Prior to December 31, 2009, Barry Welch was the President and Chief Executive Officer of the Manager. Beginning in 2010, Mr. Welch became our President and Chief Executive Officer. For the year ended December 31, 2009, Mr. Welch received a base salary of $535,000, an annual bonus of $790,000 ($400,000 of which was paid by the Manager and not reimbursed by us), and in March 2010 a grant of 41,565 notional units under the initial LTIP with an estimated total fair market value of $535,000 as at the date of grant.

Mr. Welch's base salary was historically established by the Manager, but reviewed by our independent directors as part of the annual approval of the Manager's budget, based on his responsibilities, his execution of our strategic business plan, whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary increased by $10,000 as of January 2009 and is unchanged for 2010.

Starting with the 2009 performance year, Mr. Welch's bonus was determined with one portion equal to the average level that the Manager's portion of his bonus had been paid for the prior two years, that being $400,000, which was paid by the Manager and not reimbursed by us. The other portion of Mr. Welch's bonus was determined based on the sum of a maximum $330,000 determined by our 2009 total shareholder return performance relative to our peer group and a maximum $60,000 based on the independent directors' assessment of his performance against annually approved goals and objectives.

The 2009 LTIP award to Mr. Welch was based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors, as well as progress in successfully executing our strategic plan and goals and objectives, which are also approved by our independent directors each year. The maximum annual award has been set at 150% of base salary with vesting occurring ratably over the three-year period immediately following the LTIP award. Based on our actual project cash flow of $78.8 million, and board of directors' discretion, the LTIP award for the 2009 performance year for all senior officers was set at 100% of their base salary, compared to the prior year's 90% and was granted by our board of directors on March 29, 2010.

Compensation of Patrick Welch

Prior to December 31, 2009, Patrick Welch was the Chief Financial Officer and Corporate Secretary of the Manager. Beginning in 2010, Mr. Welch became our Chief Financial Officer and Corporate Secretary. For the financial year ended December 31, 2009, Mr. Welch received a base salary of $259,000, and an annual bonus of $299,000 ($130,000 of which was paid by the Manager and not reimbursed by us), and in March 2010 a grant of 20,161 notional units under the LTIP with an estimated total fair market value of $259,500 as at the date of grant.

Mr. Welch's base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. Mr. Welch's salary was increased by $7,500 as of January 2009 and is unchanged for 2010.

Starting with the 2009 performance year, Mr. Welch's bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus had been paid for the prior two years, or $130,000, which was paid by the Manager and not reimbursed by us. The other portion of Mr. Welch's bonus was determined based on the sum of a maximum $143,000 determined by our 2009 total shareholder return performance relative to our peer group and a maximum $26,000 based on the independent directors' assessment of his performance against annually approved goals and objectives.

LTIP awards to Mr. Welch are based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors, as well as progress in successfully executing our strategic plan and goals and objectives, which are also approved by our independent directors each year. Currently, the maximum annual award has been set at 150% of base salary with vesting occurring ratably over the three-year period immediately following the LTIP award. Based on our actual cash flow of $78.8 million, and the board of directors' discretion, the LTIP award for the 2009 performance year for all senior officers was set at 100% of base salary compared to the prior year's 90% and was granted by our board of directors on March 29, 2010.

Compensation of Paul Rapisarda

Prior to December 31, 2009, Paul Rapisarda was the Managing Director, Asset Management and Acquisitions of the Manager. Beginning in 2010, Mr. Rapisarda became our Managing Director, Asset Management and Acquisitions. For the financial year ended December 31, 2009, Mr. Rapisarda received a base salary of $257,500, an annual bonus of $299,000 ($130,000 of which was paid by the Manager and not reimbursed by us), and a grant of 20,006 notional units under the LTIP with an estimated total fair market value of $257,500 as at the date of grant.

Mr. Rapisarda's base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was increased by $7,500 in 2009 and is unchanged in 2010.

Starting with the 2009 performance year, Mr. Rapisarda's bonus was determined with one portion fixed at approximately the average level that the Manager's portion of his bonus had been paid for the prior two years, or $130,000, which was paid by the Manager and not reimbursed by us. The other portion of Mr. Rapisarda's bonus was determined based on the sum of a maximum $143,000 determined by our 2009 total shareholder return performance relative to our peer group and a maximum $26,000 based on the independent directors' assessment of his performance against annually approved goals and objectives.

LTIP awards to Mr. Rapisarda are based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors, as well as progress in successfully executing our strategic plan and goals and objectives, which are also approved by our independent directors each year. Currently, the maximum annual award has been set at 150% of base salary with vesting occurring over the three-year period immediately following the LTIP award. Based on our actual cash flow of $78.8 million, and the board of directors' discretion, the LTIP award for the 2009 performance year for all senior officers was set at 100% of base salary versus the prior year's 90% and was granted by our board of directors on March 29, 2010.

Compensation of William Daniels

Prior to December 31, 2009, William Daniels was the Senior Director, Asset Management of the Manager. Beginning in 2010, Mr. Daniels became our Senior Director, Asset Management. For the financial year ended December 31, 2009, Mr. Daniels received a base salary of $185,000, an annual bonus of $166,500 ($136,000 of which was paid by the Manager and not reimbursed by us) and a grant of 10,061 notional units under the LTIP with an estimated total fair market value of $129,500 as at the date of grant.

Mr. Daniels' base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was increased by $15,000 in 2009 and is unchanged for 2010.

Mr. Daniels' 2009 annual bonus was determined using 90% of his salary, which was agreed upon among the Manager, the independent directors and our three senior executives based on an assessment of his contributions to achievement of our annual goals and objectives approved by our board of directors in January 2009.

LTIP awards to Mr. Daniels are based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors, as well as progress in successfully executing our strategic plan and goals and objectives, which are also approved by our independent directors each year. Vesting of this award occurs ratably over the three-year period immediately following the LTIP award. Based on our actual cash flow compared to the project cash flow levels, and the board of directors' discretion, Mr. Daniels' LTIP award in 2009 was set at 70% of base salary versus the prior year's 65% and was granted by our board of directors on March 29, 2010.

Compensation of John J. Hulburt

Prior to December 31, 2009, John Hulburt was the Corporate Controller of the Manager. Beginning in 2010, Mr. Hulburt became our Corporate Controller. For the financial year ended December 31, 2009, Mr. Hulburt received a base salary of $180,000, an annual bonus of $80,000 ($40,000 of which was paid by the Manager and not reimbursed by us) and a grant of 8,391 notional units under the LTIP with an estimated total fair market value of $108,000 as at the date of grant.

Mr. Hulburt's base salary was historically established by the Manager, but reviewed by our independent directors based on his responsibilities, his role in execution of our strategic business plan and whether it is appropriate and competitive relative to compensation of similar positions with competitive peer firms and changes to local cost of living. His salary was increased by $5,000 in 2009 and $3,000 beginning in January 2010.

Mr. Hulburt's 2009 annual bonus was determined using approximately 44% of his salary, which was agreed upon among the Manager, the independent directors and our three senior executives based on an assessment of his contributions to achievement of our annual goals and objectives approved by our board of directors in January 2009.

LTIP awards to Mr. Hulburt are based on his contribution to achieving target levels of a cash flow measure that are approved each year by our independent directors, as well as progress in successfully executing our strategic plan and goals and objectives, which are also approved by our independent directors each year. Vesting of this award occurs ratably over the three-year period immediately following the LTIP award. Based on our actual cash flow compared to the project cash flow levels, and the board of directors' discretion, the LTIP award for the 2009 performance year was set at 60% of base salary versus the prior year's 50% and was granted by our board of directors on March 29, 2010.

Outstanding Share-Based Awards

The following table sets forth, for each named executive officer, all share-based awards outstanding under the terms of the LTIP as of December 31, 2009:

	Share-Based Awards	
Name	**Number of shares or units of shares that have not vested(1)(2)**	**Market or pay-out value of share-based awards that have not vested (US$)(2)**
Barry E. Welch	178,317	1,945,442
Patrick J. Welch	85,592	933,812
Paul H. Rapisarda	50,943	555,793
William B. Daniels	30,543	333,222
John J. Hulburt	16,576	180,839

(1) Notional units granted under the LTIP vest over a three-year period in accordance with the terms of the LTIP, subject to performance-based forfeiture.

(2) This amount includes notional units credited under the LTIP to the Notional Unit Account of the Named Executive Officer at the time of the monthly distributions made on the IPSs during the fiscal year ended December 31, 2009.

Stock Vested

The following table sets forth, for each named executive officer, the value of all share-based incentive plan awards vested during the year ended December 31, 2009:

Name	**Number of Shares Acquired on Vesting (US$)**	**Value Realized on Vesting (US$)**
Barry E. Welch	38,055	416,196
Patrick J. Welch	18,266	199,775
Paul H. Rapisarda	2,529	27,665
William B. Daniels		31,936
John J. Hulburt		

Employment Contracts

Each of Barry Welch (President and Chief Executive Officer), Patrick Welch (Chief Financial Officer and Corporate Secretary) and Paul Rapisarda (Managing Director, Asset Management and Acquisitions) were employees of the Manager, which managed our business under the management agreement through its termination date of December 31, 2009. In connection with the termination of the management agreement on December 31, 2009, we hired all of the employees of the Manager. As a result, the employment agreements with our senior executives were terminated and were replaced with new employment agreements. To assist in the structuring and negotiation of the employment agreements, our independent directors employed Hugessen to review and advise on their terms to ensure that the agreements were consistent with best practices in the marketplace. The most significant change in the new employment agreements are the removal of the Manager as a party to the agreements and the assumption by our independent directors of all compensation decisions related to our senior executives. Each of the employment agreements provides the respective officer with the following: (i) an initial annual base salary, which is subject to annual review; (ii) eligibility for a performance-based annual cash bonus; (iii) eligibility to participate in the LTIP; and (iv) certain other customary employee benefits. Under the employment agreements, the annual base salary for 2010 for Barry Welch, Patrick Welch and Paul Rapisarda is $535,000, $259,500 and $257,500, respectively.

Termination and Change of Control Benefits

Each named senior executive officer's employment agreement provides that if the respective officer is terminated without cause, or within 90 days preceding or one year after a change in control or if he resigns within that time period because certain further triggering events have occurred including a constructive dismissal, reduction in salary or benefits, relocation, change in position of employment or reporting relationships, or breach of the employment agreement, then the following are paid or provided under the employment agreement: (i) his salary and bonus pro-rated through the termination date; (ii) a termination payment equal to three times the average (in the case of Barry Welch) or one times the average (in the case of Patrick Welch and Paul Rapisarda), during the last two years, of the sum of the respective officer's: (a) base salary, (b) annual cash bonus, and (c) the most recent matching contribution to his 401(k) plan; (iii) immediate vesting of all previous awards under the LTIP which had not yet vested; (iv) continuation of all employee benefits for a period of two years (in the case of Barry Welch) or one year (in the case of Patrick Welch and Paul Rapisarda) following termination; and (v) costs of outplacement services customary for senior executives at the respective officer's level for a period of 12 months following termination with the cost capped at $25,000. The employment agreements also contain non-competition and non-solicitation limitations on each of the officers following certain termination events. The non-competition restrictions apply for a period of one year or one month (in the case of Barry Welch) or a period of one month or six months (in the case of Patrick Welch and Paul Rapisarda) following termination depending on the circumstances of the termination and the non-solicitation restrictions apply for a period of two years (in the case of Barry Welch) or one year (in the case of Patrick Welch and Paul Rapisarda) following the date of termination.

In each senior executive officer's employment agreement, the term "Change in Control" means the occurrence of any of the following events: (i) the sale, lease or transfer to any person or group, in one or a series of related transactions, of our assets, directly or indirectly, which assets generated more than 50% of our cash flow in a 12-month period ended on the last day of the most recent fiscal quarter to any person or group; (ii) the adoption of a plan related to our liquidation or dissolution; (iii) the acquisition by any person or group of a direct or indirect interest in more than 50% of our common shares or voting power; (iv) our merger or consolidation with another person with the effect that immediately after such transaction our shareholders immediately prior to such transaction hold, directly or indirectly, less than 50% of the voting control over the person surviving such merger or consolidation; or (v) we enter into any agreement providing for any of the foregoing; or the date which is 90 days prior to a definitive announcement of any of the foregoing whichever is earlier, and the transaction contemplated thereby is ultimately consummated.

If Barry Welch, Patrick Welch or Paul Rapisarda is terminated for cause, then he will be entitled to all vested benefits under all incentive compensation or other plans in accordance with the terms and conditions of such plan, however he will not be entitled to the payments or benefits listed in items (i) through (v) in the second preceding paragraph above, except as may be required by applicable law. "Cause" is defined in each employment agreement as "a termination by reason of the Company's good faith determination that the Executive (i) engaged in willful misconduct in the performance of his duties, (ii) breached a fiduciary duty to the Company for personal profit to himself, (iii) after determination by a court of competent jurisdiction, willfully violated any law, rule or regulation of a governmental authority with jurisdiction over the Executive or the Company at the time and place of such violation (other than traffic violation or similar offenses) or any final cease and desist order of a court or other tribunal of competent jurisdiction, or (iv) materially and willfully breached this Agreement. No act, or failure to act, on the Executive's part shall be considered "willful" unless he has acted, or failed to act, with an absence of good faith and without a reasonable belief that this action or failure to act was in the best interest of the Company."

The following table provides, for each of the foregoing senior executive officers, an estimate of the payments payable by us, assuming a termination for any reason other than cause, including the occurrence of the triggering events described above, took place on December 31, 2009:

Name	Type of Payment	Termination Payment(1) (US$)	2009 Pro-Rata Bonus (US$)	Vesting of Stock Based Compensation (US$)	Employee Benefits (US$)	Total (US$)
Barry E. Welch	Termination without Cause or in connection with Change of Control	3,643,500	790,000	1,992,216	85,576	6,511,293
Patrick J. Welch	Termination without Cause or in connection with Change of Control	492,250	299,000	956,264	55,288	1,802,802
Paul H. Rapisarda	Termination without Cause or in connection with Change of Control	500,750	299,000	569,156	55,288	1,424,194

(1) Includes three times the average (in the case of Barry Welch) or one times the average (in the case of Patrick Welch and Paul Rapisarda), during the last two years, of the sum of the respective officer's: (a) base salary, (b) annual Bonus, and (c) the most recent matching contribution to his 401(k) plan.

Compensation Risk Assessment

We have reviewed our compensation policies and practices for all employees and concluded that any risks arising from our policies and programs are not reasonably likely to have a material adverse effect on our company. We believe that the mix and design of the elements of executive compensation do not encourage management to assume excessive risks. We reviewed the elements of executive compensation to determine whether any portion of executive compensation encouraged excessive risk taking and concluded:

- our allocation of compensation between cash compensation and long-term equity compensation, combined with the vesting schedule under our LTIP, discourages short-term risk taking;

- our approach of goal setting, setting of targets with payouts at multiple levels of performance, capping the amount of our incentive payouts, and evaluation of performance results assist in mitigating excessive risk-taking;

our compensation decisions include subjective considerations, which limit the influence of formulae or objective factors on excessive risk taking; and

our business does not face the same level of risks associated with compensation for employees at financial services firms (traders and instruments with a high degree of risk).

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

See the information regarding our executive officers' prior employment relationship with the Manager set forth in "Management Compensation Discussion and Analysis." We have also entered into indemnity agreements with our directors and executive officers, whereby we have agreed to indemnify the directors and officers to the extent permitted by our organizational documents and applicable law. Our articles of continuance permit us, subject to the limitations contained in applicable law, to purchase and maintain insurance on behalf of any person, as our board of directors may from time to time determine. Our directors and officers liability insurance coverage consists of three policies with aggregate limits of $30 million.

Our board of directors will review and approve all relationships and transactions in which we and any of our directors, director nominees and executive officers and their immediate family members, as well as holders of more than 5% of any class of its voting securities and their family members, have a direct or indirect material interest. In approving or rejecting such proposed relationships and transactions, our board of directors shall consider the relevant facts and circumstances available and deemed relevant to this determination. The Nominating and Governance Committee of our board of directors is responsible under its charter for monitoring compliance with the Code of Business Conduct and Ethics.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information regarding the beneficial ownership of our common shares as of August 12, 2010 with respect to:

each person (including any "group" of persons as that term is used in Section 13(d)(3) of the Exchange Act) who is known to us to be the beneficial owner of more than 5% of our outstanding common shares;

each of our directors;

each of our executive officers named in the Summary Compensation Table on page 114 of this prospectus; and

all of our directors and executive officers as a group.

Unless otherwise indicated below, the address of each beneficial owner listed in the following table is c/o Atlantic Power Corporation, 200 Clarendon Street, Floor 25, Boston, MA 02116.

Except as otherwise indicated in the footnotes to the following table, we believe, based on the information provided to us, that the persons named in the following table have sole voting and investment power with respect to the shares they beneficially own, subject to applicable community property laws.

Name of Beneficial Owner	Number of Common Shares Beneficially Owned	Percentage of Common Shares Beneficially Owned (%)(1)
Directors and Named Executive Officers		
Irving R. Gerstein	10,400	*
Kenneth M. Hartwick	46,033(3)	*
John A. McNeil	12,500	*
Richard Foster Duncan		*
Holli Nichols	31(3)	*
Barry E. Welch	380,399(2)	*
Patrick J. Welch	166,542(2)	*
Paul H. Rapisarda	114,177(2)	*
William B. Daniels	30,333(2)	*
John J. Hulburt	20,458(2)	*
All directors and named executive officers as a group (10 persons)	773,607	1.3

* Less than 1%

(1) The applicable percentage ownership is based on 60,510,070 common shares issued and outstanding as of August 12, 2010.

(2) Common shares beneficially owned include the following unvested notional units in our long-term incentive plan.

Barry E. Welch	222,203
Patrick J. Welch	108,609
Paul H. Rapisarda	99,128
William B. Daniels	30,333
John J. Hulburt	20,458

(3) Common shares beneficially owned include units held in our Directors' Deferred Share Unit Plan of 46,033 for Ken Hartwick and 31 for Holli Nichols.

See "Management Compensation Discussion and Analysis" for more information.

DESCRIPTION OF DEBENTURES

The Debentures will be governed by the terms of the trust indenture, dated as of December 17, 2009, between us and Computershare Trust Company of Canada, as trustee (the "Debenture Trustee"), as supplemented by a first supplemental indenture to be entered into at closing between us and the trustee. We refer to the trust indenture as the "Indenture" and to the first supplemental indenture as the "First Supplement." The following summary description sets forth some of the general terms and provisions of the Debentures and the Indenture. Because this is a summary description, it does not contain all of the information that may be important to you and is qualified in its entirety by reference to the Indenture, the First Supplement and the form of the Debentures, which are filed as exhibits to the registration statement of which this prospectus forms a part.

General

The Debentures will be issued under and pursuant to the provisions of the Indenture and the First Supplement. The Debentures will be limited to the aggregate principal amount of Cdn$. The Company may, however, from time to time, without the consent of the holders of the outstanding debentures of the Company, issue debentures in addition to the Debentures offered hereby. The Debentures will be issuable only in denominations of Cdn$1,000 and integral multiples thereof. At the closing of this offering, the Debentures will be available for delivery in book-entry form only through the facilities of CDS. Holders of beneficial interests in the Debentures will not have the right to receive physical certificates evidencing their ownership of Debentures except under certain circumstances described under "Description of Debentures Book Entry, Delivery and Form." No fractional Debentures will be issued.

The Debentures will bear interest from the date of issue at % per annum, which will be payable semi-annually on the day of and in each year, commencing on , computed on the basis of a 360-day year composed of twelve 30-day months. The first payment will represent accrued interest for the period from the closing of this offering up to, but excluding . The interest on the Debentures will be payable in lawful money of Canada as specified in the Indenture. Subject to any required regulatory approval and provided no event of default has occurred and is continuing, the Company shall have the option to pay such Interest by delivering a number of common shares to an agent for sale, in which event holders of the Debentures will be entitled to receive a cash payment equal to the Interest owed from the proceeds of the sale of the requisite number of common shares by the agent. The Indenture does not, and the First Supplement will not, contain a requirement for the Company to increase the amount of interest or other payments to holders of Debentures should the Company become required to withhold amounts in respect of income or similar taxes on payment of interest or other amounts. See "Risk Factors Risks Related to the Debentures The amount of interest or other payments will not increase upon an increase in amounts withheld for taxes on payments of interest or other amounts."

The principal on the Debentures will be payable in lawful money of Canada or, at the option of the Company and subject to applicable regulatory approval, by delivery of common shares to satisfy in whole or in part its obligation to repay principal under the Debentures as further described under "Description of Debentures Payment upon Redemption or Maturity" and "Description of Debentures Redemption and Purchase."

The Debentures will be direct obligations of the Company and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Company as described under "Description of Debentures Subordination."

The Indenture does not, and the First Supplement will not, restrict the Company from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness. The Debentures will be transferable, and may be presented for conversion, at the principal offices of the Debenture Trustee in Toronto, Ontario.

The Debentures will mature on .

Conversion Privilege

The Debentures will be convertible at the holder's option into fully paid, non-assessable and freely-tradeable common shares at any time prior to the close of business on the earlier of the Maturity Date and the last business day immediately preceding the date specified by the Company for redemption of the Debentures, at a conversion price of Cdn$ per common share, being a ratio of approximately common shares per Cdn$1,000 principal amount of Debentures. No adjustment will be made for dividends payable on common shares issuable upon conversion; however, holders converting their Debentures shall be entitled to receive, in addition to the applicable number of common shares, accrued and unpaid interest in respect thereof for the period up to but excluding the date of conversion from the latest Interest Payment Date.

Subject to the provisions thereof, the Indenture provides for the adjustment of the conversion rights in certain events including: (i) the subdivision or consolidation of the outstanding common shares; (ii) the issue of common shares or securities convertible into common shares by way of stock dividend or other distribution; (iii) the issuance of options, rights or warrants to all or substantially all the holders of common shares entitling them to acquire common shares or other securities convertible into common shares at less than 95% of the then current market price of the common shares; and (iv) the distribution to all or substantially all holders of common shares of any securities or assets (other than cash dividends and equivalent dividends in securities paid in lieu of cash dividends in the ordinary course).

Provided the common shares are then listed on the TSX, the term "current market price" is defined in the Indenture to mean the volume weighted average trading price of the common shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

There will be no adjustment of the conversion price in respect of any event described in (ii), (iii) or (iv) above if, subject to prior regulatory approval, if required, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. The Company will not be required to make adjustments in the conversion price unless the cumulative effect of such adjustments would change the conversion price by at least 1%. In the case of any reclassification or change (other than a change resulting only from consolidation or subdivision) of the common shares or in case of any amalgamation, consolidation or merger of the Company with or into any other entity, or in the case of any sale, transfer or other disposition of the properties and assets of the Company as, or substantially as, an entirety to any other entity, the terms of the conversion privilege shall be adjusted so that each Debenture shall, after such reclassification, change, amalgamation, consolidation, merger or sale, be exercisable for the kind and amount of securities or property of the Company, or such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, change, amalgamation, consolidation, merger or sale if on the effective date thereof it had been the holder of the number of common shares into which the Debenture was convertible prior to the effective date of such reclassification, change, amalgamation, consolidation, merger or sale.

No fractional common shares will be issued on any conversion of the Debentures, but in lieu thereof the Company shall satisfy such fractional interest by a cash payment equal to the current market price of such fractional interest. Upon conversion, the Company may offer, and the converting holder may agree to, the delivery of cash for all or a portion of the Debentures surrendered in lieu of common shares.

Redemption and Purchase

The Debentures may not be redeemed by the Company on or before (except in certain limited circumstances following a change of control). See "Description of Debentures Repurchase upon a Change of Control." After and prior to , the Debentures may be redeemed at the option of the Company, in whole at any time or in part from time to time, on not more than 60 days and not less than 30 days prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the volume weighted-average trading price of the common shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date on which notice of redemption is given is not less than 125% of the conversion price. On or after and prior to their maturity, the Debentures may be redeemed by the Company, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

The Company will have the right to purchase Debentures in the market, by tender or by private contract subject to regulatory requirements; provided, however, that if an event of default (as defined herein) has occurred and is continuing, the Company will not have the right to purchase the Debentures by private contract.

In the case of redemption of less than all of the Debentures, the Debentures to be redeemed will be selected by the Debenture Trustee on a *pro rata* basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

Payment upon Redemption or Maturity

On redemption (the "Redemption Date") or on the maturity date, the Company will repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding Debentures, together with accrued and unpaid interest thereon. The Company may, at its option, on not more than 60 days and not less than 40 days prior notice and subject to any required regulatory approvals, unless an event of default has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable common shares to the holders of the Debentures. The number of common shares to be issued will be determined by dividing the principal amount of the Debentures which are to be redeemed or have matured by 95% of the current market price of the common shares on the Redemption Date or maturity date, as the case may be.

No fractional common shares will be issued to holders of Debentures, but in lieu thereof, the Company shall satisfy such fractional interest by a cash payment equal to the current market price of such fractional interest.

Cancellation

All Debentures converted, redeemed or purchased will be cancelled and may not be reissued or resold.

Subordination

The payment of the principal of, and interest on, the Debentures will be subordinated in right of payment, in the circumstances referred to below and more particularly as set forth in the Indenture, to the prior payment in full of all existing and future Senior Indebtedness of the Company, including the convertible debentures of the Company issued on October 11, 2006. "Senior Indebtedness" of the Company is defined in the Indenture and includes: (a) indebtedness of the Company for borrowed money; (b) obligations of the Company evidenced by bonds, debentures, notes or other similar instruments; (c) obligations of the Company arising pursuant or in relation to bankers' acceptances, letters of credit and letters of guarantee (including payment and reimbursement obligations in respect thereof) or indemnities issued in connection therewith; (d) obligations of the Company under any swap, hedging or other similar contracts or arrangements; (e) obligations of the Company under guarantees, indemnities, assurances, legally binding comfort letters or other contingent obligations relating to the Senior Indebtedness or other obligations of any other person which would otherwise constitute Senior Indebtedness within the meaning of this definition, including the guarantee of the Company's credit facility; (f) all indebtedness of the Company representing the deferred purchase price of any property including, without limitation, purchase money mortgages; (g) accounts payable to trade creditors; (h) all renewals, extensions and refinancing of any of the foregoing; and (i) all costs and expenses incurred by or on behalf of the holder of any Senior Indebtedness in enforcing payment or collection of any such Senior Indebtedness, including enforcing any security interest securing the same. The Debentures will be effectively structurally subordinate to claims of creditors (including trade creditors) of the Company's subsidiaries, including Atlantic Power Holdings, Inc. ("Holdings"). As of August 12, 2010, we had an aggregate amount of $241.2 million of Senior Indebtedness outstanding.

The Debentures, the 2009 Debentures and each other series of debentures issued under the Indenture or under indentures supplemental to the Indenture will rank *pari passu* with each other (regardless of their actual date or terms of issue).

The Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation or reorganization or other similar proceedings relating to the Company, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of the Company, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Company, then holders of Senior Indebtedness will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon.

The Indenture also provides that the Company will not make any payment, and the holders of the Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures at any time when default or an event of default has occurred under the Senior Indebtedness and is continuing or upon the acceleration of certain Senior Indebtedness and the notice of such default or event of default or acceleration has been given by or on behalf of holders of Senior Indebtedness to the Company, unless such notice has been revoked, such default or event of default has been cured or the Senior Indebtedness has been repaid or satisfied in full as defined in the Indenture.

The Debenture Trustee and the Company will also be authorized (and obligated upon any request from certain holders of Senior Indebtedness) under the Indenture to enter into subordination agreements on behalf of the holders of Debentures with any holder of Senior Indebtedness.

Repurchase upon a Change of Control

Upon the occurrence of a change of control of the Company, the holders of the Debentures will have the right to require the Company to repurchase their Debentures, in whole or in part at a price equal to 100% of the principal amount thereof (the "Offer Price") plus accrued and unpaid interest thereon. A change of control will be deemed to occur upon: (i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of the *Securities Act* (Ontario)) of ownership of, or voting control or direction over, 50% or more of the common shares; or (ii) the sale or other transfer of all or substantially all of the consolidated assets of the Company.

A change of control will not include a sale, merger, reorganization, or other similar transaction if the previous holders of the common shares hold at least 50% of the voting control in such merged, reorganized or other continuing entity.

If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the change of control have been tendered for purchase following a change of control, the Company will have the right to redeem all the remaining Debentures on the purchase date, together with accrued and unpaid interest to such date. Notice of such redemption must be given to the Debenture Trustee by the Company within 10 days following expiry of the right to require repurchase after the change of control and, as soon as possible thereafter, by the Debenture Trustee to the holders of the Debentures not tendered for purchase.

The Indenture contains notification provisions to the effect that:

(a) the Company will promptly give written notice to the Debenture Trustee of the occurrence of a change of control and the Debenture Trustee will thereafter give to the Debenture holders a notice of the change of control, the right of the holders of Debentures to require repurchase and the right of the Company to redeem untendered Debentures under certain circumstances; and

(b) a Debenture holder, to exercise the right to require repurchase following the change of control, must deliver to the Debenture Trustee, not less than five business days prior to the date which is 30 days after the date the Debenture Trustee delivers notice of the change of control to the Debenture holder, written notice of the holder's exercise of the right to require repurchase, together with a duly endorsed form of transfer.

The Company will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of the Debentures in the event of a change of control.

Cash Change of Control

In addition to the requirement for the Company to repurchase Debentures following a change of control, if a change of control occurs in which 10% or more of the consideration for the common shares in the transaction or transactions constituting a change of control consists of:

- cash, other than cash payments for fractional common shares and cash payments made in respect of dissenter's appraisal rights;

- equity securities that are not traded or intended to be traded immediately following such transactions on a stock exchange; or

- other property that is not traded or intended to be traded immediately following such transactions on a stock exchange,

then subject to regulatory approvals, during the period beginning ten trading days before the anticipated date on which the change of control becomes effective and ending 30 days after the notice of change of control and offer to repurchase Debentures is delivered, holders of Debentures will be entitled to convert their Debentures, subject to certain limitations, and receive, in addition to the number of common shares they would otherwise be entitled to receive as set forth under "Description of Debentures Conversion Privilege" above, an additional number of common shares per Cdn$1,000 principal amount of Debentures as set forth below. Any such additional conversion entitlement shall be subject to the change of control transaction having been completed.

The number of additional common shares per Cdn$1,000 principal amount of Debentures constituting the make whole premium will be determined by reference to the table below and is based on the date on which the change of control becomes effective (the "Effective Date") and the price (the "Stock Price") paid per common share in the transaction constituting the change of control. If holders of common shares receive only cash in the transaction, the Stock Price shall be the cash amount paid per common share. Otherwise, the Stock Price shall be equal to the current market price of the common shares immediately preceding the Effective Date of such transaction.

The following table shows what the make whole premium would be for each hypothetical Stock Price and Effective Date set forth below, expressed as additional common shares per Cdn$1,000 principal amount of Debentures. For the avoidance of doubt, the Company shall not be obliged to pay the make whole premium otherwise than by issuance of common shares upon conversion, subject to the provisions relating to adjustment of the conversion price in certain circumstances and following the completion of certain types of transactions described under "Description of Debentures Conversion Privilege" above.

Make Whole Premium Upon a Change of Control
(Number of Additional Common Shares per Cdn$1,000 Debenture)

				Stock Price			
Effective Date	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**

				Stock Price			
Effective Date	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**	**Cdn$**

The actual Stock Price and Effective Date may not be set forth on the table, in which case:

- if the actual Stock Price on the Effective Date is between two Stock Prices on the table or the actual Effective Date is between two Effective Dates on the table, the make whole premium will be determined by a straight-line interpolation between the make whole premiums set forth for the two Stock Prices and the two Effective Dates on the table based on a 365-day year, as applicable;

- if the Stock Price on the Effective Date exceeds Cdn$ per common share, subject to adjustment as described below, the make whole premium will be zero; and

- if the Stock Price on the Effective Date is less than Cdn$ per common share, subject to adjustment as described below, the make whole premium will be zero.

The Stock Prices set forth in the first row of the table above will be adjusted as of any date on which the conversion rate of the Debentures is adjusted. The adjusted Stock Prices will equal the Stock Prices applicable immediately prior to such adjustment multiplied by a fraction, the numerator of which is the conversion rate immediately prior to the adjustment giving rise to the Stock Price adjustment and the denominator of which is the conversion rate as so adjusted. The number of additional common shares set forth in the table above will be adjusted in the same manner as the conversion rate as set forth above under "Description of Debentures Conversion Privilege," other than by operation of an adjustment to the conversion rate by adding the make whole premium as described above.

Modification

The rights of the Debenture holders as well as any other series of debentures that have been or may be issued under the Indenture or indentures supplemental to the Indenture may be modified in accordance with the terms of the Indenture. For that purpose, among others, the Indenture contains certain provisions which make binding on all Debenture holders resolutions passed at meetings of the Debenture holders by votes cast thereat by holders of not less than $66^2/_3\%$ of the principal amount of the then outstanding Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than $66^2/_3\%$ of the principal amount of the then outstanding Debentures. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of each particularly affected series of debentures, as the case may be. Under the Indenture, certain amendments may be made to the Indenture without the consent of the Debenture holders.

Events of Default

The Indenture provides that an event of default ("Event of Default") in respect of the Debentures will occur if certain events described in the Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to the Debentures: (i) failure for 15 days to pay interest on the Debentures when due; (ii) failure to pay principal or premium, if any, on the Debentures, whether at maturity, upon redemption, by declaration or otherwise; or (iii) certain events of bankruptcy, insolvency or reorganization of the Company under bankruptcy or insolvency laws. If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the then outstanding Debentures, declare the principal of (and premium, if any) and interest on all outstanding Debentures to be immediately due and payable.

Offers for Debentures

The Indenture contains provisions to the effect that if an offer is made for the Debentures which is a take-over bid for Debentures within the meaning of the *Securities Act* (Ontario) and not less than

90% of the Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by Debenture holders who did not accept the offer on the terms offered by the offeror.

Book Entry, Delivery and Form

Debentures will be issued in the form of fully registered global Debentures (the "Global Debentures") held by, or on behalf of, CDS or its successor (the "Depository"), as custodian for its participants.

All Debentures will be represented in the form of Global Debentures registered in the name of the Depository or its nominee. Purchasers of Debentures represented by Global Debentures will not receive Debentures in definitive form. Rather, the Debentures will be represented only in "book-entry only" form (unless the Company, in its sole discretion, elects to prepare and deliver definitive Debentures in fully registered form). Beneficial interests in the Global Debentures, constituting ownership of the Debentures, will be represented through book-entry accounts of institutions (including the underwriters) acting on behalf of beneficial owners, as direct and indirect participants of the Depository (the "participants"). Each purchaser of a Debenture represented by a Global Debenture will receive a customer confirmation of purchase from the underwriters or registered dealer from whom the Debenture is purchased in accordance with the practices and procedures of the selling underwriters or registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Debentures.

If the Depository notifies the Company that it is unwilling or unable to continue as depository in connection with the Global Debentures, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and the Company and the Debenture Trustee are unable to locate a qualified successor, or if the Company elects, in its sole discretion, to terminate the book-entry system, with the consent of the Debenture Trustee, or if under certain circumstances described in the Indenture, an Event of Default has occurred, beneficial owners of Debentures represented by Global Debentures at such time will receive Debentures in registered and definitive form (the "Definitive Debentures").

Transfer and Exchange of Debentures

Transfers of beneficial ownership in Debentures represented by Global Debentures will be effected through records maintained by the Depository for such Global Debentures or its nominees (with respect to interests of participants) and on the records of participants (with respect to interests of persons other than participants). Unless the Company elects, in its sole discretion, to prepare and deliver Definitive Debentures, beneficial owners who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interests in Global Debentures, may do so only through participants in the Depository's book-entry system.

The ability of a beneficial owner of an interest in a Debenture represented by a Global Debenture to pledge the Debenture or otherwise take action with respect to such owner's interest in a Debenture represented by a Global Debenture (other than through a participant) may be limited due to the lack of a physical certificate.

Registered holders of Definitive Debentures may transfer such Debentures upon payment of taxes or other charges incidental thereto, if any, by executing and delivering a form of transfer together with the Debentures to the registrar for the Debentures at its principal offices in Toronto, Ontario or such other city or cities as may from time to time be designated by the Company, whereupon new Debentures will be issued in authorized denominations in the same aggregate principal amount as the Debentures so transferred, registered in the names of the transferees. No transfer of a Debenture will be registered on any interest payment date or during the five business days preceding an interest payment date on the Debentures or on any Redemption Date or during the five business days preceding the Redemption Date.

Payments

Payments of interest and principal on each Global Debenture will be made to the Depository or its nominee, as the case may be, as the registered holder of the Global Debenture. As long as the Depository or its nominee is the registered owner of a Global Debenture, such Depository or its nominee, as the case may be, will be considered the sole legal owner of the Global Debenture for the purposes of receiving payments of interest and principal on the Debentures and for all other purposes under the Indenture and the Debentures. The record date for the payment of interest will be the fifth business day prior to the applicable interest payment date. Interest payments on Global Debentures will be made by electronic funds transfer or by cheque on the day interest is payable and delivered to the Depository or its nominee, as the case may be.

The Company understands that the Depository or its nominee, upon receipt of any payment of interest or principal in respect of a Global Debenture, will credit participants' accounts, on the date interest or principal is payable, with payments in amounts proportionate to their respective beneficial interest in the principal amount of such Global Debenture as shown on the records of the Depository or its nominee. The Company also understands that payments of interest and principal by participants to the owners of beneficial interests in such Global Debenture held through such participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name" and will be the responsibility of such participants. The responsibility and liability of the Company in respect of payments on Debentures represented by the Global Debenture is limited solely and exclusively, while the Debentures are registered in Global Debenture form, to making payment of any interest and principal due on such Debentures to the Depository or its nominee.

If Definitive Debentures are issued instead of or in place of Global Debentures, payments of interest on each Definitive Debenture will be made by electronic funds transfer, if agreed to by the holder of the Definitive Debenture, or by cheque dated the interest payment date and mailed to the address of the holder appearing in the register maintained by the registrar for the Debentures at least one business day prior to the applicable interest payment date. Payment of principal at maturity will be made at the principal office of the paying agent in the City of Toronto (or in such other city or cities as may from time to time be designated by the Company) against surrender of the Definitive Debentures, if any.

Reports to Holders

The Company shall file with the Debenture Trustee, within 15 days after the filing thereof with the securities commission or securities regulatory authority in the Canadian provinces in which the Company is a reporting issuer (the "Securities Commissions"), copies of the Company's annual report and the information, documents and other reports that the Company is required to file with the Securities Commissions and deliver to shareholders. Notwithstanding that the Company may not be required to remain subject to the reporting requirements of the Securities Commissions, the Company shall provide to the Debenture Trustee (a) within 90 days after the end of each fiscal year (or such later date as may be permitted by the Ontario Securities Commission (the "OSC")), an annual financial statement of the Company, and (b) within 45 days after the end of each of the first three fiscal quarters of each fiscal year (or such later date as may be permitted by the OSC), interim financial statements of the Company which shall, at a minimum, contain such information as is required to be provided in annual filings and quarterly reports under the laws of Canada or any province thereof to security holders of a company with securities listed on the TSX, whether or not the Company has any of its securities so listed. Each of such reports will be prepared in accordance with Canadian disclosure requirements for public companies. The Company will provide copies of such information, documents and reports to holders of Debentures upon request.

Governing Law

Each of the Indenture, the First Supplement and the Debentures will be governed by, and construed in accordance with, the laws of the Province of Ontario and the federal laws of Canada applicable therein applicable to contracts executed and to be performed entirely in such Province.

DESCRIPTION OF COMMON SHARES

The following summary description sets forth some of the general terms and provisions of our common shares. Because this is a summary description, it does not contain all of the information that may be important to you. For a more detailed description of our common shares, you should refer to the provisions of our Articles of Continuance, which we refer to as our "Articles."

The last reported sale price of our common shares on the TSX on August 12, 2010 was Cdn$13.25 per common share, and the last reported sale price of our common shares on the NYSE on August 12, 2010 was $12.69 per common share.

Common Shares

Our Articles authorize an unlimited number of common shares. At the close of business on August 12, 2010, 60,510,070 of our common shares were issued and outstanding.

Our common shares are listed on the TSX under the symbol "ATP" and began trading on the NYSE under the symbol "AT" on July 23, 2010. Holders of our common shares are entitled to receive dividends as and when declared by our board of directors and are entitled to one vote per common share on all matters to be voted on at meetings of shareholders. We are limited in our ability to pay dividends on our common shares by restrictions under the Business Corporations Act (British Columbia), which we refer to as the "BC Act," relating to our solvency before and after the payment of a dividend. Holders of our common shares have no preemptive, conversion or redemption rights and are not subject to further assessment by us.

Upon our voluntary or involuntary liquidation, dissolution or winding up, the holders of common shares are entitled to share ratably in the remaining assets available for distribution, after payment of liabilities.

Holders of our common shares will have one vote for each common share held at meetings of our common shareholders.

Pursuant to our Articles and the provisions of the BC Act, certain actions that may be proposed by us require the approval of our shareholders. We may, by special resolution and subject to our Articles, increase our authorized capital by such means as creating shares with or without par value or increasing the number of shares with or without par value. We may, by special resolution, alter our Articles to subdivide, consolidate, change from shares with par value to shares without par value or from shares without par value to shares with par value or change the designation of all or any of our shares. We may also, by special resolution, alter our Articles to create, define, attach, vary, or abrogate special rights or restrictions to any shares. Under the BC Act and our Articles, a special resolution is a resolution passed at a duly-convened meeting of shareholders by not less than two-thirds of the votes cast in person or by proxy at the meeting, or a written resolution consented to by all shareholders who would have been entitled to vote at the meeting of shareholders.

Certain Provisions of our Articles and the BC Act

We are governed by the BC Act. Our Articles contain provisions that could have the effect of delaying, deferring or discouraging another party from acquiring control of our company by means of a tender offer, a proxy contest or otherwise.

Advance Notice Procedures

Our Articles establish an advance notice procedure for "special business" and shareholder proposals to be brought before a meeting of shareholders. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location. Shareholders at an annual meeting may not consider proposals or nominations that are not specified in the notice of meeting or brought before the meeting by or at the direction of the board of directors or by a shareholder of record on the record date for the meeting, who is entitled to vote at the meeting.

Advance Notice Procedures

Under the BC Act, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities.

Shareholder Requisitioned Meeting

Under the BC Act, shareholders holding $^{1}/_{20}$ of our outstanding common shares may request the directors to call a general meeting of shareholders to deal with matters that may be dealt with at a general meeting, including election of directors. If the directors do not call the meeting within the timeframes specified in the Act, the shareholder can call the meeting and we must reimburse the costs.

Removal of Directors and Increasing Board Size

Under our Articles, directors may be removed by shareholders by passing an ordinary resolution of a simple majority of shareholders with the right to vote on such resolution. Further, under our Articles, the directors may appoint additional directors up to one-third of the directors elected by the shareholders.

Canadian Securities Laws

We are a reporting issuer in Canada and therefore subject to the securities laws in each province and territory in which we are reporting. Canadian securities laws require reporting of share purchases and sales by shareholders holding more than 10% of our common shares, including certain prescribed public disclosure of their intentions for their holdings. Canadian securities laws also govern how any offer to acquire more than 20% of our equity or voting shares must be conducted.

Transfer Agent and Registrar

Computershare Investor Services Inc. and Computershare Trust Company, N.A. serve as our transfer agents and registrars for our common shares.

DESCRIPTION OF CONCURRENT OFFERING OF COMMON SHARES

Concurrently with this offering, we are also conducting a separate public offering of common shares (plus up to an additional of our common shares that we may issue and sell upon the exercise of the underwriters' option to purchase additional shares). See "Description of Common Shares."

The common shares are being offered by means of a separate prospectus, and not this prospectus. The completion of this offering of Debentures is not conditioned on the completion of the concurrent offering of common shares and the completion of the concurrent offering of common shares is not conditioned on the completion of this offering.

CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following is a summary of certain U.S. federal income tax considerations relating to the ownership and disposition of the Debentures and the shares of common stock into which the Debentures may be converted by certain purchasers of the Debentures who are "U.S. Holders" (as defined below). Except where noted, this summary deals only with Debentures or common shares held as a capital asset (within the meaning of Section 1221 of the Internal Revenue Code of 1986, as amended (the "Code")), by a holder who purchases the Debentures on original issuance at the initial offering price (the first price at which a substantial portion of the Debentures is sold to persons other than bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). This summary assumes that the Debentures will be treated as debt and not equity for U.S. federal income tax purposes. This discussion does not address the tax consequences to subsequent purchasers of Debentures.

This summary does not purport to consider all of the U.S. federal income tax consequences of the purchase, ownership, conversion, and disposition of the Debentures, is not intended to reflect the particular tax position of any beneficial owner, is not a substitute for careful tax planning, and is not intended to constitute tax advice. In addition, this summary does not address the tax considerations that may be relevant to certain types of U.S. Holders subject to special treatment under U.S. federal income tax laws, such as:

- dealers in securities or currencies;
- financial institutions;
- regulated investment companies;
- real estate investment trusts;
- tax-exempt entities (including private foundations);
- qualified retirement plans, individual retirement accounts, and other tax-deferred accounts;
- insurance companies;
- persons holding the Debentures or common shares as a part of a hedging, integrated, conversion or constructive sale transaction or a straddle;
- persons that own, directly, indirectly or as a result of certain constructive ownership rules, stock representing 10% or more of the voting power in Atlantic Power, and persons related to such persons;
- traders in securities that elect to use a mark-to-market method of accounting;
- persons liable for alternative minimum tax;
- U.S. Holders whose "functional currency" is not the U.S. dollar; or
- U.S. tax expatriates and certain former citizens and long-term residents of the United States.

This summary does not address any estate, gift, state, local, non-U.S. or other tax consequences, except as specifically provided herein.

This summary is based upon the provisions of the Code, the United States Treasury Regulations promulgated thereunder, and administrative and judicial interpretations of the Code and the United States Treasury Regulations, all as currently in effect, and all subject to differing interpretations or change, possibly on a retroactive basis.

For purposes of this summary, a "U.S. Holder" means a person that holds Debentures or common shares that is, for U.S. federal income tax purposes:

- an individual who is a citizen or resident of the U.S. (as determined under U.S. federal income tax rules);
- a corporation (or other entity taxable as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States or of any political subdivision thereof;
- an estate, the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust if it (i) is subject to the primary supervision of a court within the United States and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) has in effect a valid election under applicable United States Treasury Regulations to be treated as a U.S. person.

If a partnership or an entity treated as a partnership for U.S. federal income tax purposes holds Debentures or common shares, the U.S. federal income tax treatment of a partner in the partnership will generally depend on the status of the partner and the activities of the partnership. Partnerships or a partner in a partnership holding Debentures or common shares should consult their own tax advisor regarding the consequences of the ownership and disposition of Debentures or common shares by the partnership.

The following summary is of a general nature only and is not a substitute for careful tax planning and advice. U.S. Holders of Debentures or common shares are urged to consult their own tax advisors concerning the U.S. federal income tax consequences of the issues discussed herein, in light of their particular circumstances, as well as any considerations arising under the laws of any foreign, state, local or other taxing jurisdiction.

Debentures

Payments of Interest

Although there can be no assurances in this regard, we expect that the Debentures should be treated as debt for U.S. federal income tax purposes, notwithstanding certain features that may be more characteristic of equity (including, for example, the fact that we may elect to repay the Debentures at maturity with our common shares).

It is expected that the Debentures will not be issued with original issue discount. If this is the case, payments of stated interest on a Debenture generally will be taxable to a U.S. Holder as ordinary income at the time it is received or accrued, in accordance with the holder's method of accounting for tax purposes. The amount of income recognized by a cash basis U.S. Holder will be the U.S. dollar value of the interest payment based on the exchange rate in effect on the date of receipt, regardless of whether the payment is in fact converted into U.S. dollars at that time. An accrual basis U.S. Holder may determine the amount of income recognized with respect to an interest payment denominated in, or determined by reference to, a foreign currency in accordance with either of two methods. Under the first method, the amount of income accrued will be based on the average exchange rate in effect during the interest accrual period (or, with respect to an accrual period that spans two taxable years of a U.S. Holder, the part of the period within the U.S. Holder's taxable year). Under the second method, the U.S. Holder may elect to determine the amount of income accrued on the basis of the exchange rate in effect on the last day of the accrual period or, in the case of an accrual period that spans two taxable years, the exchange rate in effect on the last day of the part of the period within the U.S. Holder's taxable year. Additionally, if a payment of interest is actually received within five business days of the last day of the accrual period or taxable year, an electing accrual basis U.S. Holder may instead translate the accrued interest into U.S. dollars at the exchange rate in effect on the day of actual receipt. Any such election will apply to all debt instruments held by the U.S. Holder at the beginning of the first taxable year to which the election applies or thereafter acquired by the U.S. Holder, and will be irrevocable without the consent of the IRS. Accordingly, accrual basis U.S. Holders should consult their own tax advisors regarding the desirability, mechanics and collateral consequences of making this election.

Upon receipt of the interest payment (including a payment attributable to accrued but unpaid interest upon the sale or other disposition of a Debenture), an accrual basis U.S. Holder will recognize U.S. source exchange gain or loss (taxable as ordinary income or loss) equal to the difference, if any, between the amount received (translated into U.S. dollars at the spot rate on the date of receipt) and the U.S. dollar value of the amount previously accrued, regardless of whether the payment is in fact converted into U.S. dollars at that time.

Interest paid by Atlantic Power on the Debentures and interest accrued with respect to the Debentures will generally constitute income from sources outside the United States.

Should any Canadian tax be withheld from payments on the Debentures, the amount withheld will be included in such holder's income at the time such amount is treated as received or accrued in accordance with such holder's method of tax accounting. Canadian withholding tax, if any, imposed on a U.S. Holder would, subject to limitations and conditions and at the election of such holder, be treated as foreign income tax eligible for credit against such holder's U.S. federal income tax liability or a deduction in computing taxable income, to the extent such tax is not otherwise refundable.

In certain circumstances (see "*Description of the Debentures*"), Atlantic Power may pay amounts in excess of stated interest or principal on the Debentures. According to U.S. Treasury regulations, the possibility that any such payments in excess of stated interest or principal will be made will not affect the amount of interest income a U.S. Holder recognizes if there is only a remote chance as of the date the Debentures were issued that such payments will be made. Atlantic Power believes that the likelihood that it will make any such payments is remote. Therefore, Atlantic Power does not intend to treat the potential payment of these amounts as part of the yield to maturity of the Debentures. Atlantic Power's determination that these contingencies are remote is binding on a U.S. Holder unless such holder discloses its contrary position in the manner required by applicable U.S. Treasury regulations. Atlantic Power's determination is not, however, binding on the IRS, and, if the IRS were to challenge this determination, a U.S. Holder might be required to accrue income on its Debentures in excess of the stated interest, and to treat as ordinary income rather than capital gain some or all of the income realized on the taxable disposition of a Debenture before the resolution of the contingencies. In the event a contingency occurs, it would affect the amount and timing of the income recognized by a U.S. Holder. If any such amounts are in fact paid, U.S. Holders will be required to recognize such amounts as income.

Sale, Exchange and Redemption of Debentures

Generally, upon the sale, exchange or redemption of a Debenture, a U.S. Holder will recognize taxable gain or loss equal to the difference between the amount realized on the sale, exchange, or redemption (less any amount attributable to accrued but unpaid interest not previously included in income, which will be taxable as such) and such U.S. Holder's adjusted tax basis in the Debenture. The amount realized on a sale or other disposition for an amount in foreign currency will be the U.S. dollar value of this amount on the date of sale or other disposition or, in the case of Debentures traded on an established securities market, as defined in the applicable U.S. Treasury regulations, that are sold by a cash basis U.S. Holder (or an accrual basis U.S. Holder that so elects), on the settlement date for the sale. Such an election by an accrual basis U.S. Holder must be applied consistently from year to year and cannot be revoked without the consent of the IRS. Accordingly, accrual basis U.S. Holders should consult their own tax advisors regarding the desirability, mechanics and collateral consequences of making this election. A U.S. Holder's adjusted tax basis in a Debenture will generally equal the cost of such Debenture to such U.S. Holder. A U.S. Holder's tax basis in a Debenture will be determined by reference to the U.S. dollar cost of the Debentures. The U.S. dollar cost of a Debenture purchased with a foreign currency will generally be the U.S. dollar value of the purchase price on the date of purchase or, in the case of Debentures traded on an established securities market, as defined in the applicable U.S. Treasury regulations, that are purchased by a cash basis U.S. Holder (or an accrual basis U.S. Holder that so elects), on the settlement date for the purchase. Unless we are a passive foreign investment company (as discussed below) during the U.S. Holder's holding period for the Debentures, and except to the extent that any gain is attributable to changes in exchange rates (as discussed below), such gain or loss generally will be capital gain or loss and will be long-term capital gain or loss if at the time of sale, exchange or redemption the Debenture has been held by such U.S. Holder for more than one year, and will generally be treated as from U.S. sources for the purposes of the U.S. foreign tax credit limitation. A non-corporate U.S. Holder may be eligible for reduced rates of taxation on any long-term capital gain recognized on the Debentures. The deductibility of capital losses is subject to limitations.

Gain or loss recognized by a U.S. Holder on the sale or other disposition of a Debenture that is attributable to changes in exchange rates generally will be treated as U.S. source ordinary income or loss. However, exchange gain or loss is taken into account only to the extent of total gain or loss realized on the transaction.

If the Company elects to repay in common shares the principal amount of any Debentures that are to be redeemed or that have matured, see " *Conversion of Debentures,"* below, for similar tax treatment.

Conversion of Debentures

A U.S. Holder generally will not recognize any income, gain or loss on the conversion of a Debenture into common shares, except with respect to (i) any foreign currency exchange gain or loss (to the extent of the total gain or loss "realized" on the conversion), (ii) any cash received in lieu of a fractional common share, and (iii) any cash received that is attributable to accrued and unpaid interest. The U.S. Holder's exchange gain or loss (which is generally treated as U.S. source ordinary income or loss) is limited to the total gain or loss "realized" on the conversion, even though such gain or loss generally would not actually be recognized, and is computed by translating the issue price at the spot rate on the conversion date and subtracting from such amount the issue price translated at the spot rate on the date the U.S. Holder acquired the Debenture. The U.S. Holder's aggregate tax basis in the common stock received (including the tax basis of any fractional share that is deemed to be issued and then redeemed as described below) generally will equal the U.S. Holder's tax basis in the Debenture plus or minus any foreign currency exchange gain or loss. The U.S. Holder's holding period in the common stock received generally will include the holding period in the Debenture.

With respect to cash received in lieu of a fractional common share, a U.S. Holder will be treated as if the fractional common share were issued and then immediately redeemed for cash. Accordingly, the U.S. Holder generally will recognize gain or loss equal to the difference between the cash received and that portion of the Holder's tax basis in the common stock (determined as discussed above) attributable to the fractional share. Any such gain recognized generally would be capital gain and would be long-term capital gain if, at the time of conversion, the Debenture has been held for more that one year.

Disposition of Foreign Currency

Foreign currency received as interest on a Debenture or on the sale or other disposition of a Debenture will have a tax basis equal to its U.S. dollar value at the time the interest is received or at the time of the sale or other disposition. Foreign currency that is purchased will generally have a tax basis equal to the U.S. dollar value of the foreign currency on the date of purchase. Any gain or loss recognized on a sale or other disposition of a foreign currency (including its use to purchase Debentures or an exchange for U.S. dollars) generally will be U.S. source ordinary income or loss.

Common Shares

Taxation of Distributions

The gross amount (i.e., before Canadian withholding tax) of distributions to a U.S. Holder on our common shares (other than distributions in liquidation or in redemption of stock that are treated as exchanges) will be treated as a dividend, to the extent paid out of our current or accumulated earnings and profits (as determined under U.S. federal income tax principles). Such dividend will be includible in a U.S. Holder's gross income on the day actually or constructively received. Distributions to a U.S. Holder in excess of earnings and profits will be treated first as a return of capital that reduces a U.S. Holder's tax basis in such common shares (thereby increasing the amount of gain or decreasing the amount of loss that a U.S. Holder would recognize on a subsequent disposition of our common shares), and then as gain from the sale or exchange of such common shares.

Non-corporate U.S. Holders will generally be eligible for the preferential U.S. federal rate on qualified dividend income for tax years beginning on or before December 31, 2010, provided that we are a "qualified foreign corporation," the stock on which the dividend is paid is held for a minimum holding period, and other requirements are satisfied.

A qualified foreign corporation includes a foreign corporation that is not a PFIC (as defined below) in the year of the distribution or in the prior tax year and that is eligible for the benefits of an income tax treaty with the United States, if such treaty contains an exchange of information provision and the United States Treasury Department has determined that the treaty is satisfactory for purposes of the legislation. Based on current law and applicable administrative guidance, our dividends paid before December 31, 2010 should be eligible for treatment as qualified dividend income, provided the holding period and other requirements are satisfied. In the absence of intervening legislation, dividends received by a U.S. Holder after tax years beginning on or after December 31, 2010 will be taxed to such Holder at ordinary income rates.

Distributions to U.S. Holders generally will not be eligible for the dividends received deduction generally allowed to U.S. corporations in respect of dividends received from other U.S. corporations.

A U.S. Holder will be taxed on the U.S. dollar value of any Canadian dollars received as dividends, generally determined at the spot rate as of the date the payment is actually or constructively received. No currency exchange gain or loss will be recognized by a U.S. Holder on such dividend payments if the Canadian dollars are converted into U.S. dollars on the date received at that spot rate. Any gain or loss on a subsequent conversion or other disposition of Canadian dollars generally will be treated as U.S.-source ordinary income or loss.

Taxation of Sale, Exchange or Other Taxable Disposition of Common Shares

Upon the sale, exchange or other taxable disposition of a common share, a U.S. Holder generally will recognize gain or loss equal to the difference between the amount realized upon the sale, exchange or other disposition and such U.S. Holder's tax basis in the common share. The amount realized on the sale, exchange or other taxable disposition of the common shares will be the U.S. dollar value of any Canadian dollars received in the transaction, which is determined for cash basis taxpayers on the settlement date for the transaction and for accrual basis taxpayers on the trade date (although accrual basis taxpayers can also elect the settlement date). Any such gain or loss will generally be capital gain or loss and will generally be long-term capital gain or loss if the U.S. Holder's holding period for the common shares transferred exceeds one year on the date of the sale or disposition. Long-term capital gains of non-corporate U.S. Holders derived with respect to the disposition of common shares are currently subject to tax at reduced rates. The deductibility of capital losses is subject to several limitations. Any gain or loss realized on a subsequent conversion or other disposition of Canadian dollars will be ordinary gain or loss.

Disclosure of Reportable Transactions

If a U.S. Holder sells or disposes of the Debentures or common shares at a loss or otherwise incurs certain losses that meet certain thresholds, such U.S. Holder may be required to file a disclosure statement with the IRS. For U.S. Holders that are individuals or trusts, there is a special reporting requirement threshold for foreign currency losses, which is US$50,000. Failure to comply with these and other reporting requirements could result in the imposition of significant penalties.

Foreign Tax Credit Limitations

U.S. Holders may be subject to Canadian withholding tax on payments made with respect to the Debentures or common shares. Subject to certain conditions and limitations, such withholding taxes may be treated as foreign taxes eligible for credit against a U.S. Holder's U.S. federal income tax liability. Such credit may not be available to U.S. holders owning the common shares in a non-taxable account. Additionally, foreign taxes may not be eligible to the extent they could have been reduced pursuant to an income tax treaty.

It is possible that we are, or at some future time will be, at least 50% owned by U.S. persons. Dividends paid by a foreign corporation that is at least 50% owned by U.S. persons may be treated as U.S.-source income (rather than foreign-source income) for foreign tax credit purposes to the extent the foreign corporation has more than an insignificant amount of U.S.-source income. The effect of this rule may be to treat a portion of any dividends we pay as U.S.-source income. Treatment of the dividends as U.S.-source income in whole or in part may limit a U.S. Holder's ability to claim a foreign tax credit for the Canadian withholding taxes payable in respect of the dividends. Subject to certain limitations, the Code permits a U.S. Holder entitled to benefits under the U.S.-Canadian income tax treaty to elect to treat any Company dividends as foreign-source income for foreign tax credit purposes. U.S. Holders should consult their own tax advisors about the desirability of making, and the method of making, such an election.

The rules governing foreign tax credits are complex. U.S. Holders are urged to consult their own tax advisors regarding the availability of foreign tax credits in their particular circumstances.

Passive Foreign Investment Company

A foreign corporation is a passive foreign investment company ("PFIC") within the meaning of Section 1297 of the Code if, during any taxable year, (i) 75% or more of its gross income consists of certain types of passive income, or (ii) the average value (or basis in certain cases) of its passive assets (generally assets that generate passive income) is 50% or more of the average value (or basis in certain cases) of all of its assets. If we were a PFIC while a taxable U.S. Holder held common shares, the PFIC rules could have the effect of subjecting such U.S. Holder to an interest charge on any deferred taxation and taxing gain upon the sale of our common shares as ordinary income. If we were a PFIC while a taxable U.S. Holder held Debentures, the interest charge and gain recharacterization rules described in the preceding sentence could potentially apply to such U.S. Holder with respect to its Debentures, or to any common shares received upon a conversion of the Debentures. In addition, under recently enacted legislation each U.S. Holder of a PFIC is required to file an annual report containing such information as the U.S. Department of the Treasury may require. If we were classified as a PFIC in any year with respect to which a U.S. Holder owns the Debentures or common shares, we would continue to be treated as a PFIC with respect to the U.S. Holder in all succeeding years during which the U.S. Holder owns the Debentures or common shares, regardless of whether we continue to meet the tests described above. However, if we ceased to be a PFIC, a U.S. Holder of our common shares could avoid some of the adverse effects of the PFIC regime by making a deemed sale election with respect to our common shares.

We do not believe we are a PFIC, and we do not expect to become a PFIC. If our income or asset composition were to become more passive (including through the acquisition of assets that generate passive income, or minority investments in stock of corporations), we could potentially become a PFIC. Our PFIC status for any taxable year may also depend upon the extent to which our revenue is subject to special PFIC rules with respect to "commodities," an analysis that raises uncertainties in application and interpretation. Additionally, if we were a PFIC and were to form or acquire non-U.S. subsidiaries that are treated as corporations for U.S. tax purposes, such subsidiaries could potentially be PFICs. If we owned a subsidiary that is a PFIC, then taxable U.S. Holders could be adversely affected as a result of their indirect ownership of stock in any subsidiary of ours that is a PFIC.

Information Reporting and Backup Withholding

In general, information reporting requirements will apply to payments with respect to the Debentures or common shares paid to a U.S. Holder other than certain exempt recipients (such as corporations). Backup withholding will apply to such payments if such U.S. Holder fails to provide a taxpayer identification number or certification of other exempt status or fails to comply with the applicable requirements of the backup withholding rules. Any amounts withheld under the backup withholding rules will be allowed as a refund or a credit against such U.S. Holder's U.S. federal income tax liability provided the required information is furnished by such U.S. Holder to the IRS in a timely manner. A U.S. Holder who does not provide a correct taxpayer identification number may be subject to penalties imposed by the IRS.

Recent Legislative Developments

Newly enacted legislation requires certain U.S. Holders that are individuals, estates or trusts to pay up to an additional 3.8% tax on, among other things, interest, dividends and capital gains for taxable years beginning after December 31, 2012. In addition, for taxable years beginning after March 18, 2010, new legislation requires certain U.S. Holders who are individuals that hold certain foreign financial assets (which may include the Debentures or common shares) to report information relating to such assets, subject to certain exceptions. U.S. Holders should consult their own tax advisors regarding the effect, if any, of this legislation on their ownership and disposition of the Debentures or common shares.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following is a summary of the principal Canadian federal income tax considerations generally applicable under the Income Tax Act (Canada) and the regulations thereunder (the "Tax Act") to a holder who acquires Debentures pursuant to the offering and who, for the purposes of the Tax Act and the Canada-United States Income Tax Convention (the "Canadian Treaty"), at all relevant times (a) is a resident of the United States and not resident, or deemed to be resident, in Canada, (b) holds the Debentures and will hold the common shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures as capital property, (c) deals at arm's length with the Company, (d) is not affiliated with the Company, and (e) does not use or hold and is not deemed to use or hold the Debentures or the common shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures in connection with a trade or business that the prospective purchaser carries on, or is deemed to carry on, in Canada at any time (a "U.S. Holder"). For the purpose of the Tax Act, related persons (as defined therein) are deemed not to deal at arm's length, and it is a question of fact whether persons not related to each other deal at arm's length. Special rules which are not discussed in this summary may apply to "financial institutions" (as defined in the Tax Act), to a U.S. Holder that is an insurer carrying on an insurance business in Canada and elsewhere and to an "authorized foreign bank" (as defined in the Tax Act), and, accordingly, such persons should consult their own tax advisors.

Limited liability companies ("LLCs") that are not taxed as corporations pursuant to the provisions of the Code do not qualify as resident in the U.S. for purposes of the Canadian Treaty. Under the Canadian Treaty, a resident of the U.S. who is a member of such an LLC and is otherwise eligible for benefits under the Canadian Treaty may generally be entitled to claim benefits under the Canadian Treaty in respect of income, profits or gains derived through the LLC.

The Canadian Treaty includes limitation on benefits rules that restrict the ability of certain persons who are resident in the U.S. for purposes of the Canadian Treaty to claim any or all benefits under the Canadian Treaty. U.S. Holders should consult their own tax advisors with respect to their eligibility for benefits under the Canadian Treaty, having regard to these rules.

This summary is of a general nature only and is based upon the facts set out herein, the provisions of the Tax Act, the Canadian Treaty and the current published administrative policies and assessing practices of the CRA, all in effect as of the date hereof. This summary is based on the assumption that the Debentures and the common shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures will at all relevant times be listed on the Toronto Stock Exchange. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof. There can be no assurance that any such proposals will be implemented in their current form or at all. This summary does not otherwise take into account or anticipate any changes in law or in the administrative policies and assessing practices of the CRA, whether by legislative, governmental or judicial decision or action, and does not take into account provincial, territorial or foreign tax legislation or considerations, which may differ significantly from those discussed herein.

This summary is not exhaustive of all possible Canadian federal tax considerations applicable to an investment in Debentures. Moreover, the Canadian tax consequences of acquiring, holding or disposing of Debentures or common shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures will vary depending on the U.S. Holder's particular circumstances. Accordingly, this summary is of a general nature only and is not intended to be, and should not be interpreted as, legal or tax advice to any prospective purchaser and no representation with respect to the tax consequence to any particular U.S. Holder is made. Prospective investors should consult their own tax advisor with respect to the Canadian tax consequences of an investment in Debentures based on their particular circumstances.

Prospective investors may also be subject to certain Canadian provincial or territorial tax consequences as a result of acquiring, holding or disposing of Debentures or common shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures. Accordingly, prospective investors are urged to consult with their tax advisors for advice with respect to Canadian provincial or territorial tax consequences of an investment in Debentures based on their particular circumstances.

For purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of Debentures or common shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures, including income, gain or profit, adjusted cost base and proceeds of disposition, must be converted into Canadian dollars based on the prevailing United States dollar exchange rate at the time such amounts arise in accordance with the detailed rules in the Tax Act.

Debentures

Taxation of Interest on Debentures

Based on the recently published administrative position of the CRA, a U.S. Holder will not be subject to Canadian withholding tax in respect of amounts paid or credited or deemed to have been paid or credited by the Company as, on account or in lieu of payment of, or in satisfaction of, interest or principal on the Debentures. However, a U.S. Holder who transfers or is deemed to transfer a Debenture to a holder resident or deemed to be resident in Canada for purposes of the Tax Act should consult its own tax advisor for advice with respect to the tax consequences of such transfer.

Exercise of Conversion Privilege

The conversion of a Debenture into common shares only on the exercise of a conversion privilege by a U.S. Holder will generally be deemed not to constitute a disposition of the Debenture and, accordingly, a U.S. Holder will not recognize a gain or a loss on such conversion.

Dividends on Common Shares

Dividends paid or credited on the common shares, or deemed under the Tax Act to be paid or credited on the common shares, to a U.S. Holder will generally be subject to Canadian withholding tax at the rate of 25%, unless the rate is reduced under the provisions of an applicable tax treaty. Under the Canadian Treaty, the withholding tax rate in respect of a dividend paid to a U.S. Holder who is the beneficial owner of the dividend and is entitled to full benefits under the Canadian Treaty is generally reduced to 15%.

Disposition of Debentures and Common Shares

A U.S. Holder will not be subject to tax under the Tax Act in respect of any capital gain realized by such U.S. Holder on a disposition of a Debenture or a common share, as the case may be, unless the Debenture or common shares constitutes "taxable Canadian property" (as defined in the Tax Act) of the U.S. Holder at the time of disposition and the U.S. Holder is not entitled to relief under an applicable tax treaty. Where the common shares are listed on a designated stock exchange (for purposes of the Tax Act) at a particular time the Debentures and the common shares will not constitute taxable Canadian property to a U.S. Holder at such time provided that at any time during the sixty-month period that ends at that time, either: (a) the U.S. Holder, persons with whom the U.S. Holder does not deal at arm's length, or the U.S. Holder together with all such persons, have not owned 25% or more of any class or series of shares of the capital stock of the Company; or (b) such common shares did not derive, directly or indirectly, more than 50% of their fair market value from one or any combination of (i) real or immovable property situated in Canada, (ii) "Canadian resource properties" (as defined in the Tax Act), (iii) "timber resource properties" (as defined in the Tax Act), and (iv) options or interests in respect of property described in (i), (ii) and (iii).

In the event that the Debentures or the common shares constitute or are deemed to constitute taxable Canadian property to any U.S. Holder, the Canadian Treaty (or other applicable tax treaty or convention) may exempt the U.S. Holder from tax under the Tax Act in respect of the disposition thereof, provided the value of such common shares is not derived principally from real property situated in Canada (as may be defined in the applicable tax treaty or convention). U.S. Holders whose common shares or Debentures may be taxable Canadian property should consult with their own tax advisors for advice having regard to their particular circumstances.

PLAN OF DISTRIBUTION

Subject to the terms and conditions contained in an underwriting agreement between us and the underwriters named below, we have agreed to issue and sell, and the underwriters have agreed to purchase, as principals, on the closing date, being , 2010 or such other date as may be agreed upon by us and the underwriters, but in any event not later than , 2010 an aggregate of Cdn$ principal amount of Debentures. The Debentures are being offered to the public in all of the provinces and territories of Canada (other than Quebec). No offers or sales of the Debentures will be made in the United States. Subject to certain conditions, the underwriters have agreed to purchase the aggregate principal amount of debentures indicated in the following table:

Underwriter	Principal Amount of Debentures
BMO Nesbitt Burns Inc.	

The underwriters are committed to take and pay for all of the Debentures being offered, if any are taken, other than Debentures covered by the option described below unless and until this option is exercised. The obligations of the underwriters under the underwriting agreement may be terminated at its discretion upon the occurrence of certain stated events. The underwriters propose to offer the Debentures to the public initially at the offering price and in the principal amount, respectively, specified on the cover page of this prospectus. After the underwriters have made a reasonable effort to sell all of the Debentures offered hereby at the offering price and in the principal amount, respectively, specified on the cover page, the price per Debenture for the Debentures may be decreased and may be further changed from time to time to amounts not greater than those set forth on the cover page. The compensation realized by the underwriters will be decreased by the amount that the aggregate price paid by the purchasers of the Debentures is less than the amount paid by the underwriters to us.

The Debentures will be issued in "book-entry only" form and must be purchased or transferred through a CDS Clearing and Depository Services Inc. ("CDS") participant (a "CDS Participant"). At closing, we will cause global certificates representing the Debentures being offered to be delivered to, and registered in the name of, CDS or its nominee. All rights of holders of the Debentures must be exercised through, and all payments or other property to which such holder is entitled will be made or delivered by, CDS or the CDS Participant through which the holder of Debentures holds such Debentures. Each person who acquires Debentures will receive only a customer confirmation of purchase from the underwriter or registered dealer from or through which the Debentures are acquired in accordance with the practices and procedures of that underwriter or registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book-entry accounts for its CDS Participants having interests in the Debentures.

Option to purchase additional Debentures

We have granted the underwriters an option to purchase up to an additional Cdn$ principal amount of Debentures at a price of Cdn$1,000 per Debenture on the same terms and conditions as this offering, exercisable in whole or in part, at the sole discretion of the underwriters at any one time on or prior to the 30th day after the closing of this offering, for the purposes of covering the underwriters' over-allotment position, if any.

Commissions and discounts

The following table shows the per share and total underwriting discounts to be paid to the underwriters by us. Such amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase an additional Cdn$ aggregate principal amount of Debentures:

	No exercise	Full Exercise
Per Debenture		
Total		

We estimate that the total expenses of this offering payable by us, not including the underwriting discounts but including our reimbursement of certain expenses of the underwriters, will be approximately $.

Lock-up

Subject to certain exceptions, we and our senior officers and directors have agreed with the underwriters, subject to certain exceptions, not to issue, offer, sell, contract to sell or otherwise dispose of any of the Debentures or common shares or any securities convertible into or exercisable or exchangeable for any Debentures or common shares or financial instruments convertible into or exercisable or exchangeable for Debentures or common shares, or announce any intention to effect any of the foregoing, for a period of 90 days from the date of closing without the prior written consent of the underwriters, which consent may not be unreasonably withheld.

Indemnification and contribution

We have agreed to indemnify the underwriters and their affiliates and controlling persons against certain liabilities. If we are unable to provide this indemnification, we have agreed to contribute to the payments the underwriters, their affiliates and controlling persons may be required to make in respect of those liabilities.

Listing

There is currently no trading market for the Debentures. Our outstanding common shares are listed on the TSX under the symbol "ATP" and on the NYSE under the symbol "AT."

Price stabilization, short positions and passive market making

Pursuant to policy statements of Canadian securities regulators, the underwriters may not, throughout the period of distribution, bid for or purchase the Debentures. This restriction is subject to exceptions, on the condition that the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in, or raising the price of, any of the Debentures. These exceptions include bids or purchases permitted under the Universal Market Integrity Rules for Canadian Marketplaces of Market Regulation Services Inc. relating to market stabilization and passive market making activities and bids or purchases made for and on behalf of a customer where the order was not solicited during the period of distribution. Under the first mentioned exception, in connection with this offering, the underwriters may effect transactions that stabilize or maintain the market price of the Debentures at levels other than those which might otherwise prevail in the open market. Those transactions, if commenced, may be interrupted or discontinued at any time.

Other Relationships

A bank affiliate of BMO Nesbitt Burns Inc. is a lender to Atlantic Power Holdings, Inc. ("Holdings"), an indirect wholly-owned subsidiary of the Company, under an existing credit facility.

Consequently, the Company may be considered a "connected issuer" of BMO Nesbitt Burns Inc. under applicable securities laws in certain Canadian provinces and territories. As of June 30, 2010, outstanding borrowings under the credit facility totaled $20.0 million, which we intend to repay with the proceeds of this offering. See "Use of Proceeds." Holdings is in compliance with the terms of the credit facility. Since the execution of the credit facility, the lenders have not waived a breach, on the part of Holdings, of the credit facility.

Agreement to Purchase Securities

FOR PURPOSES OF THE U.S. SECURITIES LAWS, NO BINDING COMMITMENT TO PURCHASE THE DEBENTURES OFFERED PURSUANT TO THIS PROSPECTUS IS MADE BY ANY INVESTOR, AND NO SALE OF THE DEBENTURES OFFERED PURSUANT TO THIS PROSPECTUS IS MADE TO ANY INVESTOR, UNTIL 5:00 P.M. (TORONTO TIME) ON THE SECOND BUSINESS DAY AFTER SUCH INVESTOR RECEIVES THIS PROSPECTUS. UNTIL SUCH TIME, ANY INVESTOR MAY CANCEL HIS OR HER INTENTION TO PURCHASE THE DEBENTURES WITHOUT PENALTY BY CONTACTING THE UNDERWRITERS NAMED IN THIS PROSPECTUS.

LEGAL MATTERS

Certain legal matters relating to the issue and sale in Canada of the Debentures offered hereby will be passed upon by Goodmans LLP on behalf of Atlantic Power and by Blake, Cassels & Graydon LLP on behalf of the underwriters. Goodwin Procter LLP, Boston, Massachusetts, is acting as U.S. counsel to Atlantic Power in this offering and Shearman & Sterling LLP, Toronto, Ontario, Canada, is acting as U.S. counsel for the underwriters.

EXPERTS

The consolidated financial statements of Atlantic Power Corporation and its subsidiaries as of December 31, 2009 and 2008, and for each of the years in the three-year period ended December 31, 2009, have been included herein in reliance upon the report of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

The consolidated financial statements of Selkirk Cogen Partners, L.P. and subsidiary as of December 31, 2007 and for the year then ended included in this Registration Statement on Form S-1 have been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of Chambers Cogeneration Limited Partnership and its subsidiaries as of December 31, 2008 and 2007, and for the years then ended included in this Registration Statement on Form S-1 have been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The combined financial statements of Gregory Partners, LLC and Gregory Power Partners, L.P. as of December 31, 2007 and for the year then ended included in this Registration Statement on Form S-1 have been so included in reliance on the report of PricewaterhouseCoopers LLP, independent accountants, given on the authority of said firm as experts in auditing and accounting.

The financial statements of Pasco Cogen, Ltd. as of December 31, 2007 and for the year then ended, have been included herein in reliance upon the report of KPMG LLP, independent accountants, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement under the Securities Act that registers the offer and sale of the securities offered by this prospectus. This prospectus is part of the registration statement, but the registration statement, including the accompanying exhibits included or incorporated by reference therein, contains additional relevant information about us. We have also filed a registration statement under the Securities Act that registers the offer and sale of common shares.

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file, including the registration statement containing this prospectus and the registration statement with respect to the registration of the common shares, at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. Our SEC filings are also available to the public from the SEC's website at *http://www.sec.gov* and on our website at *http://www.atlanticpower.com*. We have included the SEC's web address and our web address as inactive textual references only. Our website is not incorporated into, and does not constitute a part of, this prospectus or any other report or documents we file with or furnish to the SEC.

You may request a copy of these filings, and any exhibits we have specifically incorporated by reference as an exhibit in this prospectus, at no cost by writing or telephoning us at the following: Atlantic Power Corporation, 200 Clarendon Street, Floor 25, Boston, Massachusetts 02116, Attention: Patrick Welch. Our telephone number is (617) 977-2400.

Atlantic Power Corporation
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Report of Independent Registered Public Accounting Firm

The Board of Directors
Atlantic Power Corporation:

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation as of December 31, 2009 and 2008, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule "Schedule II. Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in note 2 to the consolidated financial statements, on January 1, 2009, Atlantic Power Corporation adopted FASB's ASC 805 Business Combinations, on January 1, 2008, Atlantic Power Corporation changed its method of accounting for fair value measurements in accordance with FASB ASC 820 Fair Value Measurements; and on January 1, 2007, Atlantic Power Corporation changed its method of accounting for income tax uncertainties in accordance with guidance provided in FASB ASC 740 Income Taxes.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
April 12, 2010 except as to notes 4, 9, and 19 which are as of May 26, 2010 and as to Notes 2(a), 18 and 21 which are as of June 16, 2010.

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. dollars)

	December 31,	
	2009	**2008**
Assets		
Current assets:		
Cash and cash equivalents	$ 49,850	$ 37,327
Restricted cash	14,859	15,434
Accounts receivable	17,480	28,000
Current portion of derivative instruments asset (Notes 12 and 13)	5,619	
Prepayments, supplies and other	3,019	3,349
Deferred income taxes (Note 14)	17,887	11,121
Refundable income taxes (Note 14)	10,552	997
Total current assets	119,266	96,228
Property, plant and equipment (Note 5)	193,822	204,171
Transmission system rights (Note 6)	195,984	203,833
Equity investments in affiliates (Note 4)	259,230	287,775
Other intangible assets (Note 6)	71,770	93,644
Goodwill (Note 2)	8,918	8,918
Derivative instruments asset (Notes 12 and 13)	14,289	224
Other assets	6,297	13,202
Total assets	$ 869,576	$ 907,995
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 21,661	$ 19,342
Current portion of long-term debt (Note 9)	18,280	12,008
Revolving credit facility (Note 8)		55,000
Current portion of derivative instruments liability (Notes 12 and 13)	6,512	6,206
Interest payable on subordinated notes and debentures	800	3,455
Dividends payable	5,242	1,918
Other current liabilities	752	3,941
Total current liabilities	53,247	101,870
Long-term debt (Note 9)	224,081	243,097
Subordinated notes (Note 10)		319,984
Convertible debentures (Note 11)	139,153	49,261
Derivative instruments liability (Notes 12 and 13)	5,513	14,211
Deferred income taxes (Note 14)	28,619	26,779
Other non-current liabilities	4,846	1,167
Shareholders' equity:		
Common shares, No par value, unlimited authorized shares; 60,404,093 and 60,940,731 issued and outstanding at December 31, 2009 and 2008, respectively	541,917	215,163
Accumulated other comprehensive loss	(859)	(3,136)
Retained deficit	(126,941)	(60,401)
Total shareholders' equity	414,117	151,626
Commitments and contingencies (Note 20)		
Subsequent events (Note 21)		
Total liabilities and shareholders' equity	$ 869,576	$ 907,995

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands of U.S. dollars, except per share amounts)

	Years ended December 31, 2009	2008	2007
Project revenue:			
Energy sales	$ 58,953	$ 64,237	$ 42,799
Energy capacity revenue	88,449	77,691	35,625
Transmission services	31,000	31,528	34,524
Other	1,115	356	309
	179,517	173,812	113,257
Project expenses:			
Fuel	59,522	55,366	18,537
Operations and maintenance	24,038	17,711	10,718
Project operator fees and expenses	4,115	3,727	1,854
Depreciation and amortization	41,374	29,528	19,725
	129,049	106,332	50,834
Project other income (expense):			
Change in fair value of derivative instruments (Note 12 and 13)	(6,813)	(16,026)	(22,264)
Equity in earnings of unconsolidated affiliates (Note 4)	8,514	1,895	44,368
Gain (loss) on sales of equity investments, net (Note 3)	13,780		(5,115)
Interest, net	(18,800)	(17,709)	(13,216)
Other project expense	1,266	5,366	3,922
	(2,053)	(26,474)	7,695
Project income	48,415	41,006	70,118
Administrative and other expenses (income):			
Management fees and administration	26,028	10,012	8,185
Interest, net	55,698	43,275	44,307
Foreign exchange loss (gain) (Note 13)	20,506	(47,247)	30,142
Other expense, net	362	425	975
	102,594	6,465	83,609
Income (loss) from operations before income taxes	(54,179)	34,541	(13,491)
Income tax expense (benefit) (Note 14)	(15,693)	(13,560)	17,105
Net income (loss)	$ (38,486)	$ 48,101	$ (30,596)
Net income (loss) per share basic (Note 17)	$ (0.63)	$ 0.78	$ (0.50)
Net income (loss) per share diluted (Note 17)	$ (0.63)	$ 0.73	$ (0.50)

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(In thousands of U.S. dollars)

	Common Stock (Shares)	Common Stock (Amount)	Retained Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
December 31, 2006	61,470	$ 216,636	$ (53,571)	$	$ 163,065
Dividends declared			(24,665)		(24,665)
Comprehensive Income:					
Net loss			(30,596)		(30,596)
Net comprehensive income					(30,596)
December 31, 2007	61,470	216,636	(108,832)		107,804
Common shares issued for LTIP	30	127			127
Common stock repurchases	(559)	(1,600)			(1,600)
Adoption of accounting standard for Fair Value Measurement			25,179		25,179
Dividends declared			(24,849)		(24,849)
Comprehensive loss:					
Net income			48,101		48,101
Unrealized losses on hedging activities, net of tax of $2,091				(3,136)	(3,136)
Net comprehensive income					44,965
December 31, 2008	60,941	215,163	(60,401)	(3,136)	151,626
Subordinated notes conversion	(114)	327,691			327,691
Common shares issued for LTIP	59	151			151
Common stock repurchases	(482)	(1,088)			(1,088)
Dividends declared			(28,054)		(28,054)
Comprehensive Income:					
Net loss			(38,486)		(38,486)
Unrealized gains on hedging activities, net of tax of ($1,518)				2,277	2,277
Net comprehensive loss					(36,209)
December 31, 2009	60,404	$ 541,917	$ (126,941)	$ (859)	$ 414,117

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

	Years ended December 31,		
	2009	**2008**	**2007**
Cash flows from operating activities:			
Net (loss) income	$ (38,486)	$ 48,101	$ (30,596)
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation and amortization	41,374	29,528	19,725
Impairment of equity investment (Note 3)	5,500		
Common share conversion costs recorded in interest expense	4,508		
Subordinated note redemption premium recorded in interest expense (Note 10)	1,935		
Loss (gain) on sale of property, plant and equipment	933	(5,163)	8,627
Earnings from unconsolidated affiliates	(14,213)	(1,895)	(44,368)
(Gain) loss on sales of equity investments, net (Note 3)	(13,780)		5,115
Distributions from unconsolidated affiliates	27,884	41,031	46,653
Change in gas transportation contract liability (Note 7)			(13,019)
Gain on extinguishment of gas transportation contract (Note 7)			(10,554)
Unrealized foreign exchange (gain) loss (Note 13)	24,370	(39,203)	37,716
Change in fair value of subordinated note prepayment option	106	27	
Change in fair value of derivative instruments (Note 13)	6,813	16,026	22,264
Change in deferred income taxes (Note 14)	(6,436)	(14,009)	12,289
Change in other operating balances, net of acquisitions and disposition effects:			
Accounts receivable	10,520	216	2,523
Prepayments, refundable income taxes and other assets	(3,454)	12,229	6,222
Accounts payable and accrued liabilities	2,959	(20)	1,166
Other liabilities	(84)	(9,080)	(5,675)
Cash provided by operating activities	50,449	77,788	58,088
Cash flows provided by (used in) investing activities:			
Acquisitions, net of cash acquired (Note 3)	(3,068)	(141,688)	(23,213)
Change in restricted cash (Note 2a)	575	6,335	11,386
Proceeds from sale of property, plant and equipment	167	7,889	3,073
Purchases of property, plant and equipment	(2,016)	(1,102)	(15,695)
Proceeds from sale of equity investments (Note 3)	29,300		6,195
Purchases of auction rate securities (Note 12)		(75,518)	(120,153)
Sales of auction rate securities (Note 12)		75,518	120,153
Cash provided by (used in) investing activities	24,958	(128,566)	(18,254)
Cash flows provided by (used in) financing activities:			
Redemption of IPSs	(3,369)	(1,612)	
Redemption of subordinated notes (Note 10)	(40,638)	(3,064)	
Costs associated with common share conversion	(4,508)		
Dividends paid	(24,955)	(24,612)	(24,342)
Proceeds from convertible debentures, net of offering costs	78,330		
Proceeds from issuance of project level debt		35,000	48,056
Repayment of project-level debt	(12,744)	(22,275)	(71,117)
Repayment of revolving credit facility borrowings (Note 8)	(55,000)		(31,000)
Proceeds from revolving credit facility borrowings		55,000	31,000
Proceeds from escrow used for redemption of non-controlling interest (Note 19)			74,433
Repayment of obligation to non-controlling interest (Note 19)			(76,888)
Cash (used in) provided by financing activities	(62,884)	38,437	(49,858)
Increase (decrease) in cash and cash equivalents	12,523	(12,341)	(10,024)

Cash and cash equivalents, beginning of year	37,327	49,668	59,692
Cash and cash equivalents, end of year	$ 49,850	$ 37,327	$ 49,668
Supplemental cash flow information:			
Interest paid	$ 69,186	$ 72,129	$ 62,366
Income taxes (paid) refunded	$ (216)	$ 2,418	$ (10,483)

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS

1. Nature of business

Atlantic Power Corporation ("Atlantic Power") is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. We issued income participating securities ("IPSs") for cash pursuant to an initial public offering on November 18, 2004. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016 . On November 27, 2009 the shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. See Notes 10 and 15 for additional information.

We currently own, through our wholly-owned subsidiaries Atlantic Power Transmission, Inc. and Atlantic Power Generation, Inc. indirect interests in 12 power generation projects and one transmission line located in the United States. Four of our Projects are wholly-owned subsidiaries: Lake Cogen Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P. and Atlantic Path 15, LLC.

Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 and our headquarters is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. The telephone number is (617) 977-2400. The address of our website is *atlanticpower.com*. Our recent Canadian securities filings are available through our website.

2. Summary of significant accounting policies

(a) Basis of consolidation and accounting:

The accompanying consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America and include the consolidated accounts and operations of our subsidiaries in which we have a controlling interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

As such, we apply the standard that requires consolidation of variable interest entities, or VIEs, for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party will absorb a majority of the expected losses of the VIE, receive the majority of the expected residual returns of the VIE, or both. We have determined that our investments are not VIEs by evaluating their design and capital structure. Accordingly, we record all of our investments in less than 100% owned entities under the equity method of accounting. See Note 4, for further information.

We eliminate all intercompany accounts and transactions in consolidation.

Beginning in the first quarter of 2010, changes in restricted cash in the consolidated statement of cash flows has been reported as an investing activity to reflect the use of the restricted cash in the current period. In previous periods, changes in restricted cash were reported as cash flow from operating activities. The prior period amounts have been reclassified to conform with the current year presentation. This reclassification does not impact the consolidated balance sheet or the consolidated statements of operations. We have changed the classification of restricted cash because the revised presentation is more widely used by companies in our industry.

These financial statements and notes reflect our evaluation of events occurring subsequent to the balance sheet date through June 16, 2010, the date the financial statements were issued.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(b) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(c) Regulatory accounting:

Path 15 accounts for certain income and expense items in accordance with a standard where certain costs are deferred, which would otherwise be charged to expense, as regulatory assets based on Path 15's ability to recover these costs in future rates.

(d) Revenue:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. Revenue associated with capacity payments under the PPAs are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

Transmission services revenue is recognized as transmission services are provided. The annual revenue requirement for transmission services is regulated by the Federal Energy Regulatory Commission ("FERC") and is established through a rate-making process that occurs every three years. When actual cash receipts from transmission services revenue are different than the regulated revenue requirement because of timing differences, the over or under collections are deferred until the timing differences reverse in future periods.

(e) Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less when purchased.

(f) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the Projects to support payments for major maintenance costs and meet project-level contractual debt obligations.

(g) Use of fair value:

We utilize a fair value hierarchy that gives the highest priority to quoted prices in active markets and is applicable to fair value measurements of derivative contracts and other instruments that are subject to mark-to-market accounting. Refer to Note 12, for more information.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(h) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps, indexed swap hedges and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. On occasion, we have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas which is a major production cost. We do not enter into derivative financial instruments for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of operations.

The following table summarizes derivative financial instruments that are not designated as hedges and the accounting treatment in the consolidated statements of operations of the changes in fair value of such derivative financial instrument:

Derivative financial instrument	Location of changes in fair value
Foreign currency forward contracts	Foreign exchange loss (gain)
Lake natural gas swaps	Change in fair value of derivative instruments
Auburndale natural gas swaps	Change in fair value of derivative instruments
Interest rate swap	Change in fair value of derivative instruments
Onondaga Indexed swap and indexed swap hedges	Change in fair value of derivative instruments

Certain derivative instruments qualify for a scope exception to fair value accounting, as they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Unrealized gains or losses on the interest rate swap designated within a designated hedging relationship are deferred and recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

(i) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. As major maintenance occurs, and as parts are replaced on the plant's combustion and steam turbines, these maintenance costs are either expensed or transferred to property, plant and equipment if the maintenance extends the useful lives of the major parts. These costs are depreciated over the parts' estimated useful lives, which is generally three to six years, depending on the nature of maintenance activity performed.

(j) Transmission system rights:

Transmission system rights are an intangible asset that represents the long-term right to approximately 72% of the capacity of the Path 15 transmission line in California. Transmission system rights are amortized on a straight-line basis over 30 years, the regulatory life of Path 15.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(k) Asset retirement obligations:

The fair value for an asset retirement obligation is recorded in the period in which it is incurred. Retirement obligations associated with long-lived assets are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss.

(l) Impairment of long-lived assets, non-amortizing intangible assets and equity method investments:

Long-lived assets, such as property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level, non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, an appropriate write-down is recorded based on the excess of the carrying value over the best estimate of fair value of the investment.

(m) Distributions from equity method investments:

We make investments in entities that own independent power producing assets with the objective of generating accretive cash flow that is available to be distributed to our shareholders. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows.

We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

(n) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is allocated, as of the date of the business combination, to our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired and the second step of the impairment test is unnecessary.

The second step is carried out when the carrying amount of a reporting unit exceeds its fair value, in which case, the implied fair value of the reporting unit's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of goodwill is determined in a business combination described in the preceding paragraph, using the fair value of the reporting unit as if it were the purchase price. When the carrying amount of reporting unit goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess and is recorded in the consolidated statements of operations.

Goodwill at December 31, 2009 and 2008 relates to the Path 15 segment.

(o) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects.

Power purchase agreements are valued at the time of acquisition based on the prices received under the PPAs compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the PPA. The weighted average period of remaining amortization is 4 years.

Fuel supply agreements are valued at the time of acquisition based on the prices projected to be paid under the fuel supply agreement relative to projected market prices. The weighted average period of remaining amortization is 3 years.

(p) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 14, for more information.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(q) Foreign currency translation:

Our functional currency and reporting currency is the United States dollar. The functional currency of our subsidiaries and other investments is the United States dollar. Monetary assets and liabilities denominated in Canadian dollars are translated into United States dollars using the rate of exchange in effect at the end of the year. All transactions denominated in Canadian dollars are translated into United States dollars at average exchange rates.

(r) Long-term incentive plan:

The officers and other employees of Atlantic Power are eligible to participate in the Long-Term Incentive Plan ("LTIP") that was implemented in 2007 and continued in effect until the end of 2009. On an annual basis, the Board of Directors of Atlantic Power establishes awards that are based on the cash flow performance of Atlantic Power in the most recently completed year, each participant's base salary and the market price of the shares at the award date. Awards are granted in the form of notional units that have similar economic characteristics to our common shares. Notional units vest ratably over a three-year period and are redeemed in a combination of cash and shares upon vesting.

Unvested notional awards are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested awards are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award at each balance sheet date. Fair value of the awards is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. Forfeitures are recorded as they occur and are not included in the estimated fair value of the awards. The aggregate number of shares which may be issued from treasury under the LTIP is limited to one million. All awards are accounted for as liability awards.

In early 2010, the Board of Directors approved an amendment to the LTIP. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units granted will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a 3-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

(s) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt which range from five to 28 years. The net carrying amount of deferred financing costs recorded in other assets on the consolidated balance sheets was $5.5 million and $11.7 million at December 31, 2009 and 2008, respectively. Amortization expense for the years ended December 31, 2009, 2008 and 2007 was $14.6 million, $1.1, and $0.6 million, respectively.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(t) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash, restricted cash, derivatives and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative contracts. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to payment history. See Note 18, *Segment and related information*, for a further discussion of customer concentrations.

(u) Segments:

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets. Each of our projects is an operating segment. Based on similar economic and other characteristics, we aggregated several of the projects into the Other Project Assets reportable segment.

(v) Recently issued accounting standards:

In June 2009, the FASB approved the "FASB Accounting Standards Codification" ("Codification") as the single source of authoritative, nongovernmental, U.S. Generally Accepted Accounting Principles ("GAAP") as of July 1, 2009. The Codification does not change current U.S. GAAP or how we account for our transactions or nature of related disclosures made; instead it is intended to simplify user access to all authoritative literature related to a particular topic in one place. All existing accounting standard documents will be superseded, and all other accounting literature not included in the Codification will be considered non-authoritative. The Codification is effective for interim and annual periods ending after September 15, 2009. The Codification became effective for Atlantic Power beginning the quarter ending September 30, 2009 and did not have an impact in our balance sheet or results of operations for the year ended December 31, 2009.

In 2009, the FASB amended the consolidation guidance applied to VIEs. This standard replaces the quantitative approach previously required to determine which entity has a controlling financial interest in a VIE with a qualitative approach. Under the new approach, the primary beneficiary of a VIE is the entity that has both (a) the power to direct the activities of the VIE that most significantly impact the entity's economic performance, and (b) the obligation to absorb losses of the entity, or the right to receive benefits from the entity, that could be significant to the VIE. This standard also requires ongoing reassessments of whether an entity is the primary beneficiary of a VIE and enhanced disclosures about an entity's involvement in VIEs. The standard is effective for fiscal years beginning after November 15, 2009. We do not expect this standard to have a material effect upon our financial statements.

In 2010, the FASB amended the Fair Value Measurements and Disclosures Topic of the FASB Accounting Standards Codification to require additional disclosures about 1) transfers of Level 1 and Level 2 fair value measurements, including the reason for transfers, 2) purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, 3) additional disaggregation to include fair value measurement disclosures for each class of assets and liabilities and 4) disclosure of inputs and valuation techniques used to measure fair value for both recurring and nonrecurring fair value measurements. The amendment is effective for fiscal years beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements, which is effective for fiscal years beginning

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

after December 15, 2010. We do not expect this standard to have a material effect upon our financial statements.

We adopted the FASB's revised standard for business combinations on January 1, 2009. The provisions of the standard are applied prospectively to business combinations for which the acquisition date occurs after January 1, 2009. The statement requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are required to be expensed as incurred. This standard was further amended and clarified with regards to application issues on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. Our adoption of the standard did not have an impact on the results of operations, financial position, or cash flows.

In May 2009, the FASB issued a standard that incorporates the accounting and disclosure requirements related to subsequent events found in auditing standards into U.S. GAAP, effectively making management directly responsible for subsequent events accounting and disclosures. The standard also requires disclosure of the date through which subsequent events have been evaluated. The standard is effective for interim and annual reporting periods ending after June 15, 2009, and shall be applied prospectively. Our adoption of the standard did not have an impact on the results of operations, financial position, or cash flows.

In 2008, the FASB amended the disclosure requirements to improve financial reporting about derivatives and hedging activities. This standard became effective on January 1, 2009. We have adopted this standard as of January 1, 2009 and have adjusted our current disclosures accordingly.

In September 2006, the FASB issued a standard which provides enhanced guidance for using fair value measurements in financial reporting. While the standard does not expand the use of fair value in any new circumstance, it has applicability to several current accounting standards that require or permit entities to measure assets and liabilities at fair value. The standard defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. The impact of our adoption of this standard on January 1, 2008 resulted in a $25.2 million decrease to retained deficit.

In July 2006, the FASB issued an interpretation that requires a new evaluation process for all tax positions taken, recognizing tax benefits when it is more-likely-than-not that a tax position will be sustained upon examination by the authorities. The benefit from a position that has surpassed the more-likely-than-not threshold is the largest amount of benefit that is more than 50% likely to be realized upon settlement. Differences between the amounts recognized in the statement of financial position prior to the adoption of the interpretation and the amounts reported after adoption are to be accounted for as an adjustment to the beginning balance of retained earnings. Our adoption of the standard on January 1, 2007 did not have an impact on the results of operations, financial position, or cash flows.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments

(a) Stockton sale

On November 30, 2009, we sold our 50% interest in the assets of Stockton Cogen Company LP for a nominal cash payment. Stockton is a 55 MW coal/biomass cogeneration facility located in Stockton, California. During the year ended December 31, 2009, we recorded a loss on the sale of $2.0 million. The loss on sale was recorded in gain (loss) on sales of equity investments in the in the accompanying consolidated statements operations.

(b) Mid-Georgia sale

On November 24, 2009, we sold our 50% interest in the assets of Mid-Georgia Cogen LP for $29.1 million. Mid-Georgia is a 308 MW dual-fueled, combined-cycle, cogeneration plant located in Kathleen, Georgia. We recorded a gain on sale of asset of $15.8 million. The gain on sale was recorded in gain (loss) on sales of equity investments in the in the accompanying consolidated statements of operations.

(c) Pasco Acquisition

In December 2007, we acquired substantially all of the remaining 50.1% interest in the Pasco Project from our existing partners. During 2008, we finalized the allocation of purchase price to the net assets acquired with no significant changes from the preliminary allocation in the following table:

Working capital	$	4,466
Other long-term assets		20,518
Total purchase price		24,984
Less cash acquired		(1,771)
Cash paid, net of cash acquired	$	23,213

(d) Rollcast

On March 31, 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina Corporation. Rollcast is a developer of biomass power plants in the southeastern U.S. with five, 50 MW projects in various stages of development. The investment in Rollcast gives us the option but not the obligation to invest equity in Rollcast's biomass power plants. Two of the development projects have secured 20-year power purchase agreements with terms that allow for fuel cost pass-through to the utility customer. Total cash paid for the investment was $3.0 million and is accounted for under the equity method of accounting.

In March 2010, we agreed to invest an additional $2.0 million to increase our ownership interest in Rollcast to 60%. Under the terms of the agreement, $1.2 million of the investment was made in March 2010 and the remaining $0.8 million will be payable if Rollcast achieves certain milestones on its first biomass development project. As a result of this additional investment, we will begin to consolidate our investment in Rollcast beginning in the first quarter of 2010. See Note 21 for additional information.

(e) Onondaga Renewables

In the first quarter of 2009, we transferred our remaining net assets of Onondaga Cogeneration Limited Partnership at net book value, into a 50% owned joint venture, Onondaga Renewables, LLC,

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

which is redeveloping the Project into a 35-40 MW biomass power plant. Our investment in Onondaga Renewables is accounted for under the equity method of accounting.

(f) Rumford impairment

During the three months ended September 30, 2009, we reviewed the recoverability of our 23.5% equity investment in the Rumford project. The review was undertaken as a result of not receiving distributions from the Project through the first nine months of 2009 and our view about the long-term economic viability of the plant upon expiration of the Project's PPA on December 31, 2009.

Based on this review, we determined that the carrying value of the Rumford project was impaired and recorded a pre-tax long-lived asset impairment of $5.5 million during 2009. The Rumford project is accounted for under the equity method of accounting and the impairment charge is included in equity in earnings of unconsolidated affiliates in the consolidated statements of operations.

In the fourth quarter of 2009, Atlantic Power and the other limited partners in the Rumford Project settled a dispute with the general partner related to the general partner's failure to pay distributions to the limited partners in 2009. Under the terms of the settlement, we received $2.9 million in distributions from Rumford in the fourth quarter of 2009. In addition, the general partner has agreed to purchase the interests of all the limited partners in 2010. However, the general partner is relieved of this obligation if certain conditions are met before June 30, 2010. If the general partner does purchase the limited partners interests, our share of the proceeds will be approximately $2.5 million. The carrying value of our investment in Rumford as of December 31, 2009 is $0.8 million.

(g) Auburndale acquisition

On November 21, 2008, we acquired 100% of Auburndale Power Partners, L.P., which owns and operates a 155 MW natural gas-fired combined cycle cogeneration facility located in Polk County, Florida. The purchase price was funded by cash on hand, a borrowing under our credit facility and $35 million of acquisition debt. The cash payment for the acquisition, including acquisition costs, has been allocated to the net assets acquired based on our preliminary estimate of the fair value.

Total cash paid for the acquisition, less cash acquired, during 2008 was $141.7 million. In 2009, we received a working capital adjustment from the sellers in the amount of $1.8 million, resulting in final purchase price of $139.9 million.

The allocation of the purchase price to the net assets acquired is as follows:

Working capital	$	11,589
Property, plant and equipment		56,301
Power purchase agreements		45,980
Fuel supply agreements		33,846
Other long-term assets		663
Total purchase price		148,379
Less cash acquired		(8,471)
Cash paid, net of cash acquired	$	139,908

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestments (Continued)

(h) Jamaica Private Power Company Ltd. Divestment

In 2007, we sold our equity investment in the Jamaica Project for $6.2 million. The carrying value of the equity investment exceeded the sales price and, accordingly, a loss of $5.1 million was recorded in gain (loss) on sales of equity investments in the consolidated statement of operations for the year ended December 31, 2007.

4. Equity method investments

The following table summarizes our equity method investments:

Entity name	Percentage of Ownership as of December 31, 2009	Carrying value as December 31, 2009	2008
Badger Creek Limited	50.0%	$ 9,949	$ 11,677
Chambers Cogen, LP	40.0%	129,501	124,032
Delta-Person, LP	40.0%		644
Gregory Power Partners, LP	17.1%	2,931	3,381
Koma Kulshan Associates	49.8%	7,003	6,736
Mid-Georgia Cogen, LP	0.0%		15,340
Onondaga Renewables, LLC	50.0%	1,757	
Orlando Cogen, LP	50.0%	36,387	45,910
Rollcast Energy, Inc	40.0%	2,801	
Rumford Cogeneration, LP	26.2%	845	5,649
Selkirk Cogen Partners, LP	18.5%	57,030	60,307
Topsham Hydro Assets	50.0%	10,825	11,151
Other		201	2,948
Total		$ 259,230	$ 287,775

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

4. Equity method investments (Continued)

Equity in earnings of unconsolidated affiliates was as follows:

	Year Ended December 31,		
Entity name	**2009**	**2008**	**2007**
Badger Creek Limited	$ 1,948	$ 2,477	$ 2,619
Chambers Cogen, LP	6,599	16,250	16,601
Delta-Person LP	(644)	(1,076)	(1,111)
Gregory Power Partners, LP	1,791	4,621	3,886
Koma Kulshan Associates	458	580	827
Mid-Georgia Cogen, LP	(2,686)	(2,068)	(1,051)
Onondaga Renewables, LLC	(600)		
Orlando Cogen Limited LP	3,152	2,920	2,410
Rollcast Energy, Inc	(267)		
Rumford Cogeneration LP	(1,904)	2,922	3,081
Selkirk Cogen Partners, LP	(280)	(6,958)	8,696
Topsham Hydro Assets	1,506	2,064	1,321
Other	(559)	(19,837)	7,089
Total	8,514	1,895	44,368
Distributions from equity method investments	(27,884)	(41,031)	(46,653)
Equity in earnings (loss) of unconsolidated affiliates, net of distributions	$ (19,370)	$ (39,136)	$ (2,285)

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

4. Equity method investments (Continued)

The following summarizes the balance sheets at December 31, 2009, 2008 and 2007, and operating results for each of the years in the three-year period ended December 31, 2009, for our equity method investments:

	2009	2008	2007
Assets			
Current assets			
Chambers	$ 10,356	$ 14,418	$ 12,696
Mid-Georgia		13,967	13,950
Orlando	6,725	9,366	8,370
Other	25,198	29,152	34,217
Non-current assets			
Chambers	259,989	266,686	272,815
Mid-Georgia		53,706	56,414
Orlando	34,975	40,026	45,382
Other	134,908	158,143	203,611
	$ 472,151	$ 585,464	$ 647,455
Liabilities			
Current liabilities			
Chambers	$ 16,898	$ 16,692	$ 12,354
Mid-Georgia		3,938	11,487
Orlando	5,313	3,482	7,362
Other	21,112	22,675	24,637
Non-current liabilities			
Chambers	123,946	140,381	153,574
Mid-Georgia		48,394	41,469
Orlando			
Other	45,852	62,127	94,881
	$ 213,121	$ 297,689	$ 345,764
Operating results			
Revenue			
Chambers	$ 50,745	$ 68,893	$ 66,629
Mid-Georgia	6,521	14,992	19,000
Orlando	41,911	34,372	37,392
Other	112,242	177,143	187,936
Project expenses			
Chambers	40,540	44,264	41,652
Mid-Georgia	6,519	13,509	16,147
Orlando	38,694	31,819	34,662
Other	99,483	158,587	155,810
Project other income (expense)			
Chambers	(3,606)	(8,379)	(8,376)
Mid-Georgia	13,137	(3,551)	(3,904)
Orlando	(65)	367	(319)
Other	(13,355)	(33,763)	(10,834)
Project income (loss)			
Chambers	$ 6,599	$ 16,250	$ 16,601
Mid-Georgia	13,139	(2,068)	(1,051)
Orlando	3,152	2,920	2,411
Other	(596)	(15,207)	21,292

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

5. Property, plant and equipment

	2009	2008	Depreciable Lives
Land	$ 2,081	$ 1,577	
Office equipment, machinery and other	6,331	5,383	3 - 10 Years
Leasehold improvements	2,411	2,411	7 - 15 Years
Plant in service	257,566	258,291	1 - 30 Years
	268,389	267,662	
Less accumulated depreciation	(74,567)	(63,491)	
	$ 193,822	$ 204,171	

Depreciation expense of $11,126, $6,907 and $6,588 was recorded for the years ended December 31, 2009, 2008, and 2007 respectively.

6. Other intangible assets and transmission system rights

Other intangible assets include power purchase agreements that are not separately recorded as financial instruments and fuel supply agreements. Transmission system rights represent the long-term right to approximately 72% of the regulated revenues of the Path 15 transmission line.

The following tables summarize the components of our intangible assets subject to amortization for the years ended December 31, 2009 and 2008:

	Transmission System rights	Power Purchase Agreements	Fuel supply Agreements	Total
Gross balances, December 31, 2009	$ 231,669	$ 73,880	$ 43,258	$ 348,807
Less: accumulated amortization	(35,685)	(26,608)	(18,760)	(81,053)
Net carrying amount, December 31, 2009	$ 195,984	$ 47,272	$ 24,498	$ 267,754

	Transmission System rights	Power Purchase Agreements	Fuel supply Agreements	Total
Gross balances, January 1, 2008	$ 231,669	$ 27,900	$ 9,411	$ 268,980
Acquisition of businesses during 2008		45,980	33,847	79,827
Adjusted gross amount at December 31, 2008	231,669	73,880	43,258	348,807
Less: accumulated amortization	(27,836)	(14,202)	(9,292)	(51,330)
Net carrying amount, December 31, 2008	$ 203,833	$ 59,678	$ 33,966	$ 297,477

The following table presents amortization of intangible assets for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
Transmission system rights	$ 7,849	$ 7,506	$ 7,506
Power purchase agreements	12,406	4,206	3,207
Fuel supply agreements	9,468	2,940	2,039
Total amortization	$ 29,723	$ 14,652	$ 12,752

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

6. Other intangible assets and transmission system rights (Continued)

The following table presents estimated future amortization related to our transmission system rights, purchase power agreements and fuel supply agreements:

Year Ended December 31,	Transmission System rights	Power Purchase Agreements	Fuel supply Agreements	Total
2010	$ 7,849	$ 12,405	$ 8,449	$ 28,703
2011	7,849	12,405	8,449	28,703
2012	7,849	12,405	7,600	27,854
2013	7,849	10,056		17,905
2014	7,849			7,849

7. Gas transportation contract liability

Prior to June 2007, Onondaga had certain long-term commitments for the provision of natural gas transportation service to the Onondaga Project through the year 2013. The contracts provided for fixed monthly demand charges, in addition to variable commodity charges based on the quantity of gas transported. Obligations related to the long-term gas transportation agreements were recognized as liabilities in purchase accounting upon the acquisition of Onondaga in 2004. These obligations were previously being amortized over the remaining lives of the contracts. In 2007, Onondaga paid $9.8 million to an unrelated third party in exchange for the assumption by the third party of the obligations under the long-term gas transportation agreements. The carrying value of the transportation contract liability at the date of the transaction exceeded the amount paid by Onondaga to extinguish the liability, resulting in a gain of approximately $10 million in 2007. The gain was recorded in other project income in the consolidated statement of operations.

8. Credit facility

We maintain a credit facility with a capacity of $100 million, $50 million of which may be utilized for letters of credit. The credit facility matures in August 2012.

In November 2008, we borrowed $55 million under the credit facility and used the proceeds to partially fund the acquisition of Auburndale. We executed an interest rate swap to fix the interest rate at 2.4% through November 2011 for $40 million of the balance outstanding under this borrowing. During 2009, the outstanding borrowings under the credit facility were repaid with cash on hand and the interest rate swap was terminated. The remaining amount in accumulated other comprehensive income for this swap was recorded as interest expense in the consolidated statement of operations.

Outstanding amounts under the credit facility bear interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.50% and 3.25% that varies based on certain credit statistics of a subsidiary of Atlantic Power. As of December 31, 2009, the applicable margin was 1.50% (0.875% in 2008). In connection with the common share conversion, we made amendments to the credit facility. The purpose of these amendments was to facilitate the common share conversion. Under the terms of the amendment, we paid a fee of $0.3 million and amended the pricing table that determines the applicable margin.

As of December 31, 2009, $43.9 million of the credit facility capacity was allocated, but not drawn, to support letters of credit for contractual credit support at seven of our projects.

We must meet certain financial covenants under the terms of the credit facility, which are generally based on our cash flow coverage ratio and indebtedness ratios. The most restrictive of these covenants could restrict the payment of dividends and interest on our common shares and convertible debentures.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

8. Credit facility (Continued)

The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

9. Long-term debt

Long-term debt represents our consolidated share of project long-term debt and the unamortized balance of purchase accounting adjustments that were recorded in connection with the Path 15 acquisition in order to adjust the debt to its fair value on the acquisition date. Project debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

	2009	2008
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 230,331	$ 242,349
Plus: purchase accounting fair value adjustments	12,030	12,756
Less: current portion of long-term debt	(18,280)	(12,008)
Long-term debt	$ 224,081	$ 243,097

Principal payments due in the next five years and thereafter are as follows:

2010	$ 18,280
2011	19,287
2012	17,167
2013	17,302
2014	13,065
Thereafter	145,230
	$ 230,331

All of the debt in the table above is represented by non-recourse debt of the projects. Project-level debt is secured by the respective project and its contracts with no other recourse to us. The loans have certain financial covenants that must be met. At December 31, 2009, all of our Projects were in compliance with the covenants contained in project-level debt, but our Chambers, Selkirk and Delta-Person projects had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to making distributions and were therefore restricted from making distributions to us.

The required coverage ratio at Chambers is based on a four-quarter rolling average coverage calculation. In addition, the coverage ratio requirement at Epsilon Power Partners is based, in part, on the coverage ratio calculation at Chambers. The primary reason for the Chambers project not meeting the minimum coverage test is a planned outage in the second quarter of 2009 which resulted in very low cash flows for the project in that quarter.

The required coverage ratio at Selkirk is calculated based on both historical cash project cash flows for the previous six months, as well as projected project cash flows for the next six months. Increased natural gas costs attributable to a contractual price increase at Selkirk are the primary contributor to the project not currently meeting its minimum coverage ratio.

The required coverage ratio at Delta-Person is based on the most recent four-quarter period. In 2009, Delta person incurred higher than anticipated operations and maintenance costs due to an

9. Long-term debt (Continued)

unanticipated repair. The higher operations and maintenance costs caused Delta Person to fail its debt service coverage ratio and restrict cash distributions for four quarters.

As at December 31, 2009, the amount of restricted net assets of our unconsolidated subsidiaries that may not be distributed to us in the form of a dividend is approximately $187 million and the amount of undistributed earnings of unconsolidated subsidiaries was approximately $91 million.

10. Subordinated notes

On November 27, 2009 our shareholders approved a conversion from the IPS Structure to a traditional common share structure. Each IPS has been exchanged for one new common share of Atlantic Power and each old common share that did not form part of an IPS was exchanged for approximately 0.44 of a new common share. This transaction resulted in the extinguishment of Cdn$347.8 principal value of subordinated notes.

A loss on the common share conversion in the amount of $13.1 million was recorded in interest expense within administrative and other expenses and was comprised of the write off of unamortized deferred financing costs of $7.5 million, the costs associated with the common share conversion of $4.7 million and the write off of the unamortized subordinated note premium of $0.9 million.

On December 17, 2009, the Company exercised its subordinated note call option to redeem the remaining Cdn$40,677 principal value of Subordinated Notes at 105% of the principal amount. A loss on the redemption of the subordinated notes in the amount of $3.1 million was recorded in interest expense within administrative and other expenses and was comprised of the write off of unamortized deferred financing costs of $1.2 million and the 5% premium paid in the amount of $1.9 million.

The subordinated notes were due to mature in November 2016 subject to redemption under specified conditions at the option of Atlantic Power, commencing on or after November 18, 2009 (Note 13). Interest was payable monthly in arrears at an annual rate of 11% and the principal repayment was to occur at maturity.

The subordinated notes were denominated in Canadian dollars and were secured by a subordinated pledge of our interest in certain subsidiaries, and contained certain restrictive covenants. Cdn$39.5 million principal value of the subordinated notes were separately held by two investors and the remaining amount of the outstanding subordinated notes formed a part of our publicly traded IPSs.

Interest expense related to the subordinated notes was $36.4 million and $40.2 million for the years ended December 31, 2009 and 2008, respectively.

11. Convertible debentures

In 2006 we issued, in a public offering, Cdn$60 million ($57.1 million at December 31, 2009) aggregate principal amount of 6.25% convertible secured debentures (the "2006 Debentures") for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The 2006 Debentures had an initial maturity date of October 31, 2011 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share.

In connection with the common share conversion on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

11. Convertible debentures (Continued)

On December 17, 2009, we issued, in a public offering, Cdn$75 million ($68.1 million at December 31, 2009, net of deferred financing costs) aggregate principal amount of 6.25% convertible unsecured debentures (the "2009 Debentures") for gross proceeds of $71.4 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning on September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share.

On December 24, 2009, the underwriters exercised their over-allotment option in full to purchase an additional Cdn$11.3 million ($10.3 million at December 31, 2009, net of deferred financing costs) aggregate principal amount of the 2009 Debentures for gross proceeds of $10.7 million.

Aggregate interest expense related to the 2006 Debentures and 2009 Debentures was $3.5 million, $3.5 million and $3.5 million for the years ended December 31, 2009, 2008 and 2007, respectively.

12. Fair value of financial instruments

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 49,850	$ 49,850	$ 37,327	$ 37,327
Restricted cash	14,859	14,859	15,434	15,434
Derivative assets current	5,619	5,619		
Derivative assets non-current	14,289	14,289	224	224
Derivative liabilities current	6,512	6,512	6,206	6,206
Derivative liabilities non-current	5,513	5,513	14,211	14,211
Long-term debt, including current portion	242,361	259,633	255,105	333,738
Convertible debentures	139,153	141,251	49,261	46,675
Subordinated Notes			319,984	264,739

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

The three levels of the fair value hierarchy are defined below:

Level 1 Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2 Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3 Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

The following represents the fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2009 and December 31, 2008. Financial assets and

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

12. Fair value of financial instruments (Continued)

liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 49,850	$	$	$ 49,850
Restricted cash	14,859			14,859
Derivative asset		19,908		19,908
Total	$ 64,709	$ 19,908	$	$ 84,617
Liabilities:				
Derivative liabilities	$	$ 12,025	$	$ 12,025
Total	$	$ 12,025	$	$ 12,025

	December 31, 2008			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 37,327	$	$	$ 37,327
Restricted cash	15,434			15,434
Derivative assets		224		224
Total	$ 52,761	$ 224	$	$ 52,985
Liabilities:				
Derivative liabilities	$	$ 20,417	$	$ 20,417
Total	$	$ 20,417	$	$ 20,417

The fair value of our derivative instruments are based on price quotes from brokers in active markets who regularly facilitate those transactions and we believe such price quotes are executable. We apply a credit reserve to reflect credit risk which is calculated based on our credit rating or the credit rating of our counterparties. To the extent that our net exposure under a specific master agreement is an asset, we use the counterparty's commercial credit rating. If the exposure under a specific master agreement is a liability, we use our estimate of our own corporate credit rating. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume our liabilities or that a market participant would be willing to pay for our assets. As of December 31, 2009, the credit reserve resulted in a $0.1 million increase in fair value which is comprised of a $0.1 million gain in OCI and a $0.3 million gain in change in fair value of derivative instruments and a $0.3 million loss in foreign exchange loss (gain).

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. The fair-value of long-term debt, subordinated notes and convertible debentures were determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

12. Fair value of financial instruments (Continued)

As of December 31, 2007, approximately $26 million of our cash and cash equivalents were invested in auction-rate securities ("ARSs"). ARSs typically have an underlying maturity of up to 40 years but have historically traded in seven or 28 day intervals in a highly liquid market. The ARSs that were held at December 31, 2007 were redeemed at auctions held in January 2008 and the proceeds were re-invested in ARSs.

In early 2008, the overall market for ARSs suffered a significant decline in liquidity and most of the auctions of ARSs were unsuccessful, resulting in our continuing to hold these securities and the issuers paying interest at the maximum contractual rate. In September and November 2008, all of our investments in ARS were sold at par plus accrued interest for $36.5 million.

Purchases and sales of ARSs are presented gross in the consolidated statements of cash flows because they are classified as available-for-sale securities.

13. Accounting for derivative instruments and hedging activities

Fair value of derivative instruments

We have elected to disclose derivative assets and liabilities on a trade by trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value within the derivative assets and liabilities on our consolidated balance sheets:

	Derivative Assets	Derivative Liabilities
Derivatives designated as cash flow hedges:		
Interest rate swap contract current	$	$ 726
Interest rate swap contract long-term		167
Total derivatives designated as cash flow hedges		893
Derivatives not designated as cash flow hedges:		
Interest rate swap contract current		1,705
Interest rate swap contract long-term		1,707
Foreign currency forward contracts current	5,619	
Foreign currency forward contracts long-term	14,289	
Natural gas swap contracts current	95	4,174
Natural gas swap contracts long-term	14	3,655
Total derivatives not designated as cash flow hedges	20,017	11,241
Total derivatives	$ 20,017	$ 12,134

Impact of derivative instruments on the consolidated income statements

Realized and unrealized gains and losses on derivative contracts designated as cash flow hedges have been recognized in the consolidated statements of operations as follows: interest rate swaps have been recognized as a component of other comprehensive income (unrealized) and interest expense (realized); and forward physical purchases on natural gas swap contracts have been recognized as a component of fuel expense.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

13. Accounting for derivative instruments and hedging activities (Continued)

Unrealized losses for interest rate swaps recognized as a component of other comprehensive income totaled $0.6 million and settlement losses of $1.3 million were recognized in interest expense, net for the year ended December 31, 2009.

Other comprehensive loss recorded for natural gas swap contracts accounted for as cash flow hedges totaled $5.1 million, net of tax prior to de-designation on July 1, 2009. Amortization of the loss of $7.2 million is recorded as a component of change in fair value of derivative instruments as of December 31, 2009.

The following table summarizes the amount of gain (loss) recognized in income for derivatives not designated as cash flow hedges:

	Location of gain (loss) recognized in income	Year ended December 31, 2009	
Natural gas swaps	Fuel	$	10,089
Foreign currency forwards	Foreign exchange loss (gain)		(3,864)
Interest rate swaps	Interest, net		1,446

Unrealized gains and losses associated with changes in the fair value of derivative instruments not designated as cash flow hedges and ineffectiveness of derivatives designated as cash flow hedges are reflected in current period earnings. The following table summarizes the pre-tax changes in the fair value of derivative financial instruments that are not designated as cash flow hedges.

		2009		2008		2007
Change in fair value of derivative instruments:						
Interest rate swaps	$	369	$	(1,804)	$	
Indexed swap and hedge				(10,844)		(20,290)
Natural gas swaps		(7,182)		(3,378)		(1,974)
	$	(6,813)	$	(16,026)	$	(22,264)

Notional volumes of derivative transactions

The following table summarizes the net notional volume buy/(sell) of our derivative transactions by commodity, excluding those derivatives that qualified for the normal purchases and normal sales exception as of December 31, 2009:

	Units	Total balance as of December 31, 2009	
Interest rate swaps	US$	$	7,134
Currency forwards	Cdn$	$	7,900
Natural gas swaps	Mmbtu		16,220

Foreign currency forward contracts

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates, as we earn our income in the United States but pay dividends to shareholders and interest on convertibles debentures predominantly in Canadian dollars. Since inception, we have established a hedging strategy for the purpose of reinforcing the long-term sustainability of cash distributions to

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

13. Accounting for derivative instruments and hedging activities (Continued)

holders of IPSs and common shares. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate of Cdn$1.134 per U.S. dollar in amounts sufficient to make monthly distributions through December 2013 at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on the 2009 Debentures. It is our intention to periodically consider extending the length of these forward contracts.

In addition, we have executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on the 2006 Debentures. The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a rate of Cdn$1.1075 per U.S. dollar.

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and our estimation of the counterparty's credit risk. The fair value of our forward foreign currency contracts at December 31, 2009 is an asset of $19.9 million. Changes in the fair value of the foreign currency forward contracts are reflected in foreign exchange (gain) loss in the consolidated statements of operations.

The following table contains the components of recorded foreign exchange (gain) loss for the periods indicated:

	2009	2008	2007
Unrealized foreign exchange (gains) losses:			
Subordinated notes and convertible debentures	$ 55,508	$ (85,212)	$ 68,419
Forward contracts and other	(31,138)	46,009	(30,703)
	24,370	(39,203)	37,716
Realized foreign exchange gains on forward contract settlements	(3,864)	(8,044)	(7,574)
	$ 20,506	$ (47,247)	$ 30,142

The following table illustrates the impact on our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2009:

Convertible debentures	$ 13,915
Foreign currency forward contracts	30,204
	$ 44,119

Natural gas swaps

The Pasco project's operating margin was exposed to changes in natural gas prices for the second half of 2008 as a result of the expiry of its favorably-priced natural gas supply contract on June 30, 2008 before the expiry of its PPA at the end of 2008. In the second quarter of 2008, we entered into a series of financial swaps that effectively fixed the price of natural gas at the Pasco project during the second half of 2008 at a weighted average price of $12.24/Mmbtu.

These natural gas swaps are derivative financial instruments and were recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps were recorded in change in fair value of derivative instruments in the consolidated statements of operations. The natural gas swaps at Pasco expired in December 2008.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

13. Accounting for derivative instruments and hedging activities (Continued)

Beginning January 1, 2009, a new ten-year PPA at the Pasco project requires the utility customers to provide natural gas needed to operate the plant and, as a result, the Pasco project is no longer exposed to changes in market prices of natural gas.

The Lake project's operating margin is exposed to changes in natural gas spot market prices from the expiration of its natural gas supply contract on June 30, 2009 through the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the Project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the Project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiry of the fuel contract in mid-2012 until the termination of its PPA.

We continue to execute our strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale by periodically entering into financial swaps that effectively fix the price of natural gas required at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, we have de-designated these natural gas swap hedges and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of operations. Amounts in accumulated other comprehensive income remaining prior to de-designation are amortized into the consolidated statements of operations over the remaining lives of the natural gas swaps.

Interest Rate Swaps

We have executed interest rate swaps on the revolving credit facility and at our consolidated Auburndale project to economically fix a portion of their respective exposure to changes in interest rates related to variable-rate debt. The interest rate swap agreements were designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt and the credit facility when they were executed in November 2008. The original interest rate swap expiration date for the Auburndale project-level debt was November 30, 2009. In November 2009, we executed a new interest rate swap designated as a cash flow hedge at Auburndale that expires on November 30, 2013. On November 30, 2009, we terminated the interest rate swap on the revolving credit facility when the remaining outstanding balance on the credit facility was repaid. The remaining amount in accumulated other comprehensive income for this swap was recorded as interest expense in the statements of operations.

The interest rate swaps are derivative financial instruments designated as cash flow hedges. The instruments are recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swaps are recorded in other comprehensive income (loss).

We did not record accumulated other comprehensive income for the year ended December 31, 2007 because we did not utilize hedge accounting for any of our derivatives. The following table

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

13. Accounting for derivative instruments and hedging activities (Continued)

summarizes the effects of applying hedge accounting on accumulated other comprehensive income balance attributable to hedged derivatives, net of tax:

Year ended December 31, 2009	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2008	$ (501)	$ (2,635)	$ (3,136)
Realized from OCI during the period:			
Due to realization of previously deferred amounts	528		528
Due to de-designation of cash flow hedge accounting		4,299	4,299
Change in fair value of cash flow hedges	(565)	(1,985)	(2,550)
Accumulated OCI balance at December 31, 2009	(538)	(321)	(859)
Gains (losses) expected to be realized from OCI during the next 12 months, net of $674 tax	$	$ 1,012	$ 1,012

Year ended December 31, 2008	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2007	$	$	$
Change in fair value of cash flow hedges	(501)	(2,635)	(3,136)
Accumulated OCI balance at December 31, 2008	(501)	(2,635)	(3,136)

14. Income taxes

	2009	2008	2007
Current income tax expense (benefit)	$ (9,257)	$ 449	$ 4,816
Deferred tax expense (benefit)	(6,436)	(14,009)	12,289
Total income tax expense (benefit)	$ (15,693)	$ (13,560)	$ 17,105

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 30%, 33.5% and 36.12% at December 31, 2009, 2008 and 2007, respectively, to the provision for income taxes in the consolidated statements of operations:

	2009	2008	2007
Computed income taxes at Canadian statutory rate	$ (16,254)	$ 11,571	$ (4,873)
Decrease resulting from:			
Operating countries with different income tax rates	(5,418)	2,245	(523)
	(21,672)	13,816	(5,396)
Valuation allowance	22,005	(37,111)	46,266
	333	(23,295)	40,870
Non-taxable foreign-source income			(475)
Permanent differences	(1,131)	10,787	(10,754)
Canadian loss carryforwards	(13,204)	(2,787)	(12,051)
Branch profits tax		2,368	993
Prior year true-up	(1,970)	(841)	(1,544)
Other	279	208	66
	(16,026)	9,735	(23,765)

Income tax expense (benefit)	$	(15,693)	$	(13,560)	$	17,105

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

14. Income taxes (Continued)

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2009 and 2008 are presented below:

	2009	2008
Deferred tax assets:		
Intangible assets	$ 45,237	$ 45,078
Loss carryforwards	62,926	41,514
Other accrued liabilities	16,212	15,885
Unrealized foreign exchange loss on subordinated notes		4,474
IPS issuance costs	1,374	540
Natural gas and interest rate hedges	573	2,092
Total deferred tax assets	126,322	109,583
Valuation allowance	(67,131)	(45,126)
	59,191	64,457
Deferred tax liabilities		
Property, plant and equipment	(69,639)	(72,024)
Unrealized foreign exchange gain	(284)	(6,713)
Other		(1,378)
Total deferred tax liabilities	(69,923)	(80,115)
Net deferred tax asset (liability)	$ (10,732)	$ (15,658)

The following table summarizes the net deferred tax position as of December 31, 2009 and 2008:

	2009	2008
Current deferred tax assets	$ 17,887	$ 11,121
Long-term deferred tax liabilities	(28,619)	(26,779)
Net deferred tax asset (liability)	$ (10,732)	$ (15,658)

As of December 31, 2009, we have recorded a valuation allowance of $67.1 million. This amount is comprised primarily of provisions against available Canadian and U.S net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

As of December 31, 2009, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

2014	$ 6,093
2015	33,321
2026	35,848
2027	43,494
2028	41,806
2029	42,895
	$ 203,457

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

15. Common stock and normal course issuer bid

On November 27, 2009 the shareholders approved the conversion from the IPS Structure to a traditional common share structure. Each IPS has been exchanged for one new common share of and each old common share not forming part of an IPS was exchanged for approximately 0.44 of a new common share.

In 2008, we approved a normal course issuer bid to purchase up to four million IPSs, representing approximately 8% of Atlantic Power's public float at the same time. As of December 31, 2009 and 2008, we acquired 481,600 and 558,620 IPSs at an average price of Cdn$8.42 and Cdn$8.78, respectively, under the terms of our existing normal course issuer bid. As of December 31, 2009, we have acquired a cumulative total of 1,040,220 IPSs at an average price of Cdn$8.61 since the inception of the issuer bid in July 2008. We paid the market price at the time of acquisition for any IPSs purchased through the facilities of the Toronto Stock Exchange, and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009.

16. Long-Term Incentive Plan

On March 30, 2009, March 26, 2008 and March 28, 2007, the Board of Directors approved grants of notional units to acquire a maximum of 267,408, 142,717 and 172,071 IPSs, respectively, under the terms of the LTIP. Subsequent to the Conversion, notional units for IPSs became notional units for common shares.

The weighted average fair value per notional unit granted was Cdn$7.27, Cdn$10.18 and Cdn$10.93 for the years ended December 31 2009, 2008 and 2007, respectively. Compensation expense related to the LTIP was recorded in the amounts of $2.2 million, $0.8 million and $1.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. Fair value of the awards is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. See Note 2(r) for information about the amended LTIP that will be effective beginning in 2010.

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

16. Long-Term Incentive Plan (Continued)

The following table presents information related to the notional units:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at January 1, 2007		$
Granted	172,021	9.43
Additional shares from dividends	12,889	9.43
Forfeited	(5,882)	9.43
Vested		
Outstanding at December 31, 2007	179,028	9.43
Granted	142,717	9.99
Additional shares from dividends	28,138	9.71
Forfeited	(37,944)	9.43
Vested	(48,346)	9.43
Outstanding at December 31, 2008	263,593	9.76
Granted	267,408	5.76
Additional shares from dividends	49,540	7.80
Forfeited		
Vested	(109,260)	9.71
Outstanding at December 31, 2009	471,281	$ 7.30

17. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2009. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss during the years ended December 31, 2009 and 2007, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive.

The following table sets forth the weighted average number of shares outstanding and potentially dilutive shares utilized in per share calculations:

	2009	2008	2007
Basic shares outstanding	60,632	61,290	61,471
Dilutive potential shares:			
Convertible debentures	5,095	4,839	4,839
LTIP notional units	476	221	156
Fully diluted shares	66,203	66,350	66,466

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

18. Segment and related information

We have six reportable segments: Path 15, Auburndale, Lake, Pasco Chambers and Other Project Assets.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income less interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use unaudited Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is set out below under "Project Adjusted EBITDA".

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Year ended December 31, 2009:								
Operating revenues	$ 31,000	$ 74,875	$ 62,285	$ 11,357	$	$	$	$ 179,517
Segment assets	219,586	130,053	118,925	42,479			358,533	869,576
Expenditures for additions to long-lived assets		321	1,278	355			62	2,016
Project Adjusted EBITDA	$ 27,691	$ 35,221	$ 25,378	$ 3,299	$ 13,595	$ 38,995	$	$ 144,179
Change in fair value of derivative instruments		2,118	5,064		(2,236)	101		5,047
Depreciation and amortization	8,511	19,780	10,098	2,987	3,392	22,875		67,643
Interest, net	12,911	2,833	(4)		4,613	11,158		31,511
Other project (income) expense	(1,230)			(26)	1,227	(8,408)		(8,437)
Project income	7,499	10,490	10,220	338	6,599	13,269		48,415
Interest, net							55,698	55,698
Management fees and administration							26,028	26,028
Foreign exchange loss							20,506	20,506
Other expense, net							362	362
Loss from operations before income taxes	7,499	10,490	10,220	338	6,599	13,269	(102,594)	(54,179)
Income tax expense (benefit)							(15,693)	(15,693)
Net loss	7,499	10,490	10,220	338	6,599	13,269	(86,901)	$ (38,486)

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

18. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Year ended December 31, 2008:								
Operating revenues	$ 31,528	$ 10,003	$ 61,610	$ 58,897	$	$ 11,774	$	$ 173,812
Segment assets	235,198	151,524	130,083	52,925			338,265	907,995
Expenditures for additions to long-lived assets			814	175			113	1,102
Project Adjusted EBITDA	$ 28,872	$ 4,461	$ 32,892	$ 21,953	$ 27,603	$ 58,908	$	$ 174,689
Change in fair value of derivative instruments				3,378	2,491	24,045		29,914
Depreciation and amortization	7,917	2,127	11,232	11,154	2,973	24,722		60,125
Interest, net	13,232	225	(32)	978	5,309	10,604		30,316
Other project expense					580	12,748		13,328
Project income	7,723	2,109	21,692	6,443	16,250	(13,211)		41,006
Interest, net							43,275	43,275
Management fees and administration							10,012	10,012
Foreign exchange gain							(47,247)	(47,247)
Other expense, net							425	425
Income (loss) from operations before income taxes	7,723	2,109	21,692	6,443	16,250	(13,211)	(6,465)	34,541
Income tax expense (benefit)							(13,560)	(13,560)
Net income (loss)	7,723	2,109	21,692	6,443	16,250	(13,211)	7,095	$ 48,101

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

18. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Year ended December 31, 2007:								
Operating revenues	$ 34,524	$	$ 53,210	$	$	$ 25,523	$	$ 113,257
Segment assets	240,459		137,641	79,442			423,209	880,751
Expenditures for additions to long-lived assets			2,886			13,294	670	16,850
Project Adjusted EBITDA	$ 31,564	$	$ 28,042	$ 14,225	$ 28,028	$ 83,359	$	$ 185,218
Change in fair value of derivative instruments						21,693		21,693
Depreciation and amortization	7,874		11,261	7,468	3,462	29,076		59,141
Interest, net	12,016		9	747	8,375	11,278		32,425
Other project (income) expense			8,554	(149)	(410)	(6,154)		1,841
Project income	11,674		8,218	6,159	16,601	27,466		70,118
Interest, net							44,307	44,307
Management fees and administration							8,815	8,185
Foreign exchange loss							30,142	30,142
Other							975	975
Loss from operations before income taxes	11,674		8,218	6,159	16,601	27,466	(83,609)	(13,491)
Income tax expense							17,105	17,105
Net income (loss)	11,674		8,218	6,159	16,601	27,466	(100,714)	$ (30,596)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 71.1%, 17.3%, respectively, of total revenues for the year ended December 31, 2009, 75.1% and 18.1% for the year ended December 31, 2008 and 57.8% and 24.2% for the year ended December 31, 2007. Progress Energy Florida purchases electricity from Auburndale and Lake and the CAISO makes payments to Path 15. In addition, during 2008 and 2007 Progress Energy Florida purchased electricity from Pasco.

19. Related party transactions

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by Arclight Capital Partners, LLC. On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15 million, to be satisfied by a payment of $6 million at the termination date, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. We have recorded the remaining liability associated with the termination fee at its estimated fair value of $8.1 million and recorded $14.1 million of expense, which includes the $6 million payment made on the termination date, in management fees and administration expense within administrative and other expenses in the accompanying consolidated financial statements.

During the year ended December 31, 2009, in accordance with the management agreement between Atlantic Power and the Manager, we incurred management and incentive fees of $0.6 million and $1.3 million, respectively. During the year ended December 31, 2008, we incurred management and

NOTES TO CONSOLIDATED AUDITED FINANCIAL STATEMENTS (Continued)

19. Related party transactions (Continued)

incentive fees of $0.4 million and $0.9 million, respectively. During the year ended December 31, 2007, we incurred management and incentive fees of $0.6 million and $0.9 million, respectively.

On November 21, 2008, we acquired Auburndale from an entity owned by the ArcLight funds and Caisse de dépôt et placement du Québec, which, at that time, owned approximately 19% of our IPSs and Cdn$36.5 million of our outstanding Subordinated Notes.

In connection with the our initial public offering, the ArcLight funds and the other original investor in Atlantic Holdings (the "Former Investors") acquired the right to request, at any time, that Atlantic Holdings purchase for cancellation all or any portion of the Former Investors' interests in Atlantic Holdings, subject to a minimum remaining 10% interest for a two-year period from November 18, 2004. The Former Investors exercised the liquidity right in a series of transactions between the initial public offering and February 2007.

At December 31, 2006, $74.4 million was held in escrow pending regulatory approval of a transaction whereby all of the remaining interests of the Former Investors were acquired by Atlantic Holdings. In February 2007, the required regulatory approval was obtained and the transaction was completed.

20. Commitments and contingencies

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and records estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2009 which are expected to have a material impact on our financial position or results of operations.

21. Subsequent events

These financial statements and notes reflect our evaluation of events occurring subsequent to the balance sheet date through June 16, 2010, the date the financial statements were issued.

In early 2010, the Board of Directors approved amendments to the LTIP. See Note 2(r) for additional information.

In March 2010, we agreed to invest an additional $2.0 million to increase our ownership interest in Rollcast to 60%. See Note 2(c) for additional information.

VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008 and 2007
(in thousands)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Income tax valuation allowance, deducted from deferred tax assets:					
Year ended December 31, 2009	45,126	22,005			67,131
Year ended December 31, 2008	82,237	(37,111)			45,126
Year ended December 31, 2007	35,971	46,266			82,237

PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. dollars)

	June 30, 2010 (unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 63,314	$ 49,850
Restricted cash	14,579	14,859
Accounts receivable	18,433	17,480
Current portion of derivative instruments asset (Notes 7 and 8)	4,251	5,619
Prepayments, supplies, and other	4,019	3,019
Deferred income taxes	15,106	17,887
Refundable income taxes	10,588	10,552
Total current assets	130,290	119,266
Property, plant, and equipment, net (Note 5)	189,916	193,822
Transmission system rights (Note 5)	192,059	195,984
Equity investments in unconsolidated affiliates	259,443	259,230
Other intangible assets, net (Note 5)	64,810	71,770
Goodwill (Note 4)	12,453	8,918
Derivative instruments asset (Notes 7 and 8)	7,952	14,289
Other assets	5,602	6,297
Total assets	$ 862,525	$ 869,576
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 18,513	$ 21,661
Revolving credit facility	20,000	
Current portion of long-term debt (Note 6)	18,330	18,280
Current portion of derivative instruments liability (Notes 7 and 8)	5,108	6,512
Interest payable on convertible debentures	3,332	800
Dividends payable	5,184	5,242
Other current liabilities	10	752
Total current liabilities	70,477	53,247
Long-term debt (Note 6)	214,527	224,081
Convertible debentures	137,376	139,153
Derivative instruments liability (Notes 7 and 8)	17,011	5,513
Deferred income taxes	33,697	28,619
Other non-current liabilities	4,802	4,846
Shareholders' equity		
Common shares	544,647	541,917
Accumulated other comprehensive loss (Note 8)	(194)	(859)

Retained deficit	(163,299)	(126,941)
Noncontrolling interest (Note 4)	3,481	
Total shareholders' equity	384,635	414,117
Commitments and contingencies (Note 15)		
Subsequent events (Note 16)		
Total liabilities and shareholders' equity	$ 862,525	$ 869,576

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands of U.S. dollars, except per share amounts)

(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
Project revenue:				
Energy sales	$ 16,659	$ 14,090	$ 32,572	$ 30,015
Energy capacity revenue	23,195	22,112	46,389	44,224
Transmission services	7,729	7,708	15,373	15,416
Other	321	360	791	649
	47,904	44,270	95,125	90,304
Project expenses:				
Fuel	15,771	12,627	31,928	27,588
Operations and maintenance	5,459	4,712	10,500	9,650
Project operator fees and expenses	983	758	1,902	2,031
Depreciation and amortization	10,071	10,588	20,142	21,254
	32,284	28,685	64,472	60,523
Project other income (expense):				
Change in fair value of derivative instruments (Notes 7 and 8)	992	469	(11,202)	360
Equity in earnings of unconsolidated affiliates	3,026	(982)	8,462	3,969
Interest expense, net	(4,308)	(4,816)	(8,719)	(9,320)
Other income, net	211	1,205	211	1,205
	(79)	(4,124)	(11,248)	(3,786)
Project income	15,541	11,461	19,405	25,995
Administrative and other expenses (income):				
Management fees and administration	3,843	3,105	7,943	5,484
Interest, net	2,518	10,553	5,312	20,170
Foreign exchange loss (Note 8)	4,224	12,929	2,432	9,506
Other income, net	(26)	(14)	(26)	(30)
	10,559	26,573	15,661	35,130
Income (loss) from operations before income taxes	4,982	(15,112)	3,744	(9,135)
Income tax expense (benefit) (Note 9)	3,618	(4,383)	8,491	(2,649)
Net income (loss)	1,364	(10,729)	(4,747)	(6,486)
Net loss attributable to noncontrolling interest	(81)		(129)	
Net income (loss) attributable to Atlantic Power Corporation	$ 1,445	$ (10,729)	$ (4,618)	$ (6,486)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 11)				
Basic	$ 0.02	$ (0.18)	$ (0.08)	$ (0.11)
Diluted	$ 0.04	$ (0.18)	$ (0.08)	$ (0.11)

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

(Unaudited)

	Six months ended June 30, 2010	Six months ended June 30, 2009
Cash flows from operating activities:		
Net loss	$ (4,747)	$ (6,486)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	20,142	21,254
Loss on sale of property, plant and equipment		333
Gain on step-up valuation of Rollcast acquisition	(211)	
Earnings from unconsolidated affiliates	(8,462)	(3,969)
Distributions from unconsolidated affiliates	5,718	13,021
Unrealized foreign exchange loss	5,199	9,630
Change in fair value of derivative instruments	11,202	(360)
Change in deferred income taxes	7,416	564
Change in other operating balances		
Accounts receivable	(953)	7,880
Prepayments, refundable income taxes and other assets	(481)	(5,859)
Accounts payable and accrued liabilities	(956)	(5,767)
Other liabilities	2,111	283
Cash provided by operating activites	35,978	30,524
Cash flows used in investing activities:		
Acquisitions and investments, net of cash acquired	324	(3,000)
Change in restricted cash (Note 1)	280	347
Biomass development costs	(948)	
Proceeds from sale of property, plant and equipment		167
Purchase of property, plant and equipment	(1,520)	(933)
Cash used in investing activities	(1,864)	(3,419)
Cash flows used in financing activities:		
Shares acquired in normal course issuer bid (Note 14)		(3,369)
Proceeds from revolving credit facility borrowings	20,000	
Equity investment from noncontrolling interest	200	
Dividends paid	(31,709)	(11,672)
Repayment of project-level debt	(9,141)	(6,414)
Cash used in financing activities	(20,650)	(21,455)
Increase in cash and cash equivalents	13,464	5,650
Cash and cash equivalents at beginning of period	49,850	37,327
Cash and cash equivalents at end of period	$ 63,314	$ 42,977
Supplemental cash flow information		
Interest paid	$ 11,437	$ 29,162
Income taxes paid (refunded), net	$ 1,045	$ 651

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of presentation

Overview

Atlantic Power Corporation ("Atlantic Power") is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. We issued income participating securities ("IPSs") for cash pursuant to an initial public offering on the Toronto Stock Exchange, or the TSX, on November 18, 2004. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. On November 27, 2009 our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. Our shares trade on the TSX under the symbol "ATP" and began trading on the New York Stock Exchange, or the NYSE, under the symbol "AT" on July 23, 2010.

Our current portfolio consists of interests in 12 operational power generation projects across eight states, one wind project under construction in Idaho, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW"), in which our ownership interest is approximately 808 MW.Four of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P. and Atlantic Path 15, LLC. The interim consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles ("GAAP") with a reconciliation to Canadian GAAP in Note 17. The Canadian securities legislation allow issuers that are required to file reports with the Securities and Exchange Commission ("SEC") in the United States to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. Prior to 2010, we prepared our consolidated financial statements in accordance with Canadian GAAP.

The interim consolidated financial statements do not contain all the disclosures required by United States and Canadian GAAP. The interim consolidated financial statements have been prepared in accordance with the SEC's regulations for interim financial information and with the instructions to Form 10-Q. The accounting policies we follow are set forth below in Note 2, *Summary of significant accounting policies.* The interim consolidated financial statements follow the same accounting principles and methods of application as the most recent annual consolidated financial statements as there are no material differences in our accounting policies between United States and Canadian GAAP at June 30, 2010 other than as denoted in Note 17. Interim results are not necessarily indicative of results for a full year.

In our opinion, the accompanying unaudited interim consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly our consolidated financial position as of June 30, 2010, the results of operations for the three and six month periods ended June 30, 2010 and 2009, and our cash flows for the six month periods ended June 30, 2010 and 2009.

Beginning in the first quarter of 2010, changes in restricted cash in the consolidated statement of cash flows have been reported as an investing activity to reflect the use of the restricted cash in the current period. In previous periods, changes in restricted cash were reported as cash flows from operating activities. The prior period amounts have been reclassified to conform with the current year presentation. This reclassification does not impact the consolidated balance sheet or the consolidated

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of presentation (Continued)

statements of operations. We have changed the classification of restricted cash because the revised presentation is more widely used by companies in our industry.

2. Summary of significant accounting policies

(a) Basis of consolidation and accounting:

The accompanying interim consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America and include the consolidated accounts and operations of our subsidiaries in which we have a controlling financial interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

As such, we apply the standard that requires consolidation of variable interest entities ("VIEs"), for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party will absorb a majority of the expected losses of the VIE, receive the majority of the expected residual returns of the VIE, or both. We have determined that our investments are not VIEs by evaluating their design and capital structure. Accordingly, we record all of our investments that we do not financially control under the equity method of accounting.

We eliminate all intercompany accounts and transactions in consolidation.

(b) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(c) Revenue:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. Revenue associated with capacity payments under the power purchase agreements ("PPAs") are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

Transmission services revenue is recognized as transmission services are provided. The annual revenue requirement for transmission services is regulated by the Federal Energy Regulatory

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

Commission ("FERC") and is established through a rate-making process that occurs every three years. When actual cash receipts from transmission services revenue are different than the regulated revenue requirement because of timing differences, the over or under collections are deferred until the timing differences reverse in future periods.

(d) Use of fair value:

We utilize a fair value hierarchy that gives the highest priority to quoted prices in active markets and is applicable to fair value measurements of derivative contracts and other instruments that are subject to mark-to-market accounting. Refer to Note 7 for more information.

(e) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a major production cost. We do not enter into derivative financial instruments for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of operations.

The following table summarizes derivative financial instruments that are not designated as hedges and the accounting treatment in the consolidated statements of operations of the changes in fair value of such derivative financial instrument:

Derivative financial instrument	Classification of changes in fair value
Foreign currency forward contracts	Foreign exchange loss (gain)
Lake natural gas swaps	Change in fair value of derivative instruments
Auburndale natural gas swaps	Change in fair value of derivative instruments
Interest rate swap	Change in fair value of derivative instruments

Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Unrealized gains or losses on the interest rate swap designated as a hedge are deferred and recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(f) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. As major maintenance occurs and parts are replaced on the plant's combustion and steam turbines, maintenance costs are either expensed or transferred to property, plant and equipment if the maintenance extends the useful lives of the major parts. These costs are depreciated over the parts' estimated useful lives, which is generally three to six years, depending on the nature of maintenance activity performed.

(g) Transmission system rights:

Transmission system rights are an intangible asset that represents the long-term right to approximately 72% of the capacity of the Path 15 transmission line in California. Transmission system rights are amortized on a straight-line basis over 30 years, the regulatory life of Path 15.

(h) Impairment of long-lived assets, non-amortizing intangible assets and equity method investments:

Long-lived assets, such as property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(i) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects.

Power purchase agreements are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

(j) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 9 for more information.

(k) Foreign currency translation:

Our functional currency and reporting currency is the United States dollar. The functional currency of our subsidiaries and other investments is the United States dollar. Monetary assets and liabilities denominated in Canadian dollars are translated into United States dollars using the rate of exchange in effect at the end of the period. All transactions denominated in Canadian dollars are translated into United States dollars at average exchange rates.

(l) Long-term incentive plan:

The officers and other employees of Atlantic Power are eligible to participate in the Long-Term Incentive Plan ("LTIP") that was implemented in 2007. In the second quarter of 2010, the Board of Directors approved an amendment to the LTIP and the amended plan was approved by our shareholders on June 29, 2010. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted for the 2010 performance period with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The aggregate number of shares which may be issued from treasury under the LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(m) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivatives and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative contracts. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to payment history. See Note 12, *Segment and related information*, for a further discussion of customer concentrations.

(n) Segments:

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets. Each of our projects is an operating segment. Based on similar economic and other characteristics, we aggregate several of the projects into the Other Project Assets reportable segment.

3. Comprehensive income (loss)

The following table summarizes the components of comprehensive income (loss), net of tax of $120 and $1,081, respectively, for the three months ended June 30, 2010 and 2009, and net of tax of $109 and $(1,393), respectively, for the six months ended June 30, 2010 and 2009:

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 1,364	$ (10,729)	$ (4,747)	$ (6,486)
Unrealized gain (loss) on hedging activity	180	1,622	164	(2,089)
Comprehensive income (loss)	$ 1,544	$ (9,107)	$ (4,583)	$ (8,575)

4. Acquisitions

Rollcast

On March 31, 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina Corporation for $3.0 million in cash. On March 1, 2010, we paid $1.2 million in cash for an additional 15% of the shares of Rollcast, increasing our interest from 40% to 55% and providing us control of Rollcast. We consolidated Rollcast as of this date. We previously accounted for our 40% interest in Rollcast as an equity method investment. On April 28, 2010, we paid an additional $0.8 million to increase our ownership interest in Rollcast to 60%.

Rollcast is a developer of biomass power plants in the southeastern U.S. with five, 50 MW projects in various stages of development. The investment in Rollcast gives us the option but not the obligation to invest equity in Rollcast's biomass power plants.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Acquisitions (Continued)

The following table summarizes the consideration transferred to acquire Rollcast and the preliminary estimated amounts of identifiable assets acquired and liabilities assumed at the acquisition date, as well as the fair value of the non-controlling interest in Rollcast at the acquisition date:

Fair value of consideration transferred:		
Cash	$	1,200
Other items to be allocated to identifiable assets acquired and liabilities assumed:		
Fair value of our investment in Rollcast at the acquisition date		2,758
Fair value of noncontrolling interest in Rollcast		3,410
Gain recognized on the step acquisition		211
Total	$	7,579
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Cash	$	1,524
Property, plant and equipment		130
Prepaid expenses and other assets		133
Capitalized development costs		2,705
Trade and other payables		(448)
Total identifiable net assets		4,044
Goodwill		3,535
	$	7,579

As a result of obtaining control over Rollcast, our previously held 40% interest was remeasured to fair value, resulting in a gain of $0.2 million. This has been recognized in other income (expense) in the consolidated statements of operations.

The fair value of the noncontrolling interest of $3.4 million in Rollcast was estimated by applying an income approach using the discounted cash flow method. This fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 fair value measurement. The fair value estimate utilized an assumed discount rate of 9.4% which is composed of a risk-free rate and an equity risk premium determined by the capital asset pricing of companies deemed to be similar to Rollcast. The estimate assumed that no fair value adjustments are required because of the lack of control or lack of marketability that market participants would consider when estimating the fair value of the noncontrolling interest in Rollcast.

The goodwill is attributable to the value of future biomass power plant development opportunities. It is not expected to be deductible for tax purposes. All of the $3.5 million of goodwill was assigned to the Other Project Assets segment.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Accumulated depreciation and amortization

The following table presents accumulated depreciation of property, plant and equipment and the accumulated amortization of transmission system rights and other intangible assets as of June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
Property, plant and equipment	$ 80,154	$ 74,567
Transmission system rights	39,611	35,685
Other intangible assets	55,800	45,368

6. Long-term debt

Long-term debt represents our consolidated share of project long-term debt and the unamortized balance of purchase accounting adjustments that were recorded in connection with the Path 15 acquisition in order to adjust the debt to its fair value on the acquisition date. Project debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

	June 30, 2010	December 31, 2009
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 221,190	$ 230,331
Purchase accounting fair value adjustments	11,667	12,030
Less: current portion of long-term debt	(18,330)	(18,280)
Long-term debt	$ 214,527	$ 224,081

Project-level debt is secured by the respective projects and their contracts with no other recourse to us. At June 30, 2010, all of our projects were in compliance with the covenants contained in project-level debt.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Fair value of financial instruments

The following represents the fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of June 30, 2010 and December 31, 2009. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 63,314	$	$	$ 63,314
Restricted cash	14,579			14,579
Derivative instruments asset		12,203		12,203
Total	$ 77,893	$ 12,203	$	$ 90,096
Liabilities:				
Derivative instruments liability	$	$ 22,119	$	$ 22,119
Total	$	$ 22,119	$	$ 22,119

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 49,850	$	$	$ 49,850
Restricted cash	14,859			14,859
Derivative instruments asset		19,908		19,908
Total	$ 64,709	$ 19,908	$	$ 84,617
Liabilities:				
Derivative instruments liability		12,025		12,025
Total	$	$ 12,025	$	$ 12,025

We adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating or the credit rating of our counterparties. As of June 30, 2010, the credit reserve resulted in a $1.3 million net increase in fair value, which is comprised of a $0.3 million gain in other comprehensive income and a $1.1 million gain in change in fair value of derivative instruments offset by a $0.1 million loss in foreign exchange.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accounting for derivative instruments and hedging activities

Fair value of derivative instruments

We have elected to disclose derivative instruments assets and liabilities on a trade-by-trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

	June 30, 2010	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swap contract current	$	$ 479
Interest rate swap contract long-term		141
Total derivative instruments designated as cash flow hedges		620
Derivative instruments not designated as cash flow hedges:		
Interest rate swap contract current		1,190
Interest rate swap contract long-term		2,387
Foreign currency forward contracts current	4,251	
Foreign currency forward contracts long-term	7,952	
Natural gas swap contracts current		3,439
Natural gas swap contracts long-term		14,483
Total derivative instruments not designated as cash flow hedges	12,203	21,499
Total derivative instruments	$ 12,203	$ 22,119

	December 31, 2009	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swap contract current	$	$ 726
Interest rate swap contract long-term		167
Total derivative instruments designated as cash flow hedges		893
Derivative instruments not designated as cash flow hedges:		
Interest rate swap contract current		1,705
Interest rate swap contract long-term		1,707
Foreign currency forward contracts current	5,619	
Foreign currency forward contracts long-term	14,289	
Natural gas swap contracts current	95	4,174
Natural gas swap contracts long-term	14	3,655
Total derivative instruments not designated as cash flow hedges	20,017	11,241

Total derivative instruments	$ 20,017	$ 12,134

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accounting for derivative instruments and hedging activities (Continued)

Natural gas swaps

The Lake project's operating margin is exposed to changes in natural gas spot market prices from the expiration of its natural gas supply contract on June 30, 2009 through the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiry of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

Our strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale consists of periodically entering into financial swaps that effectively fix the price of natural gas required at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, we de-designated these natural gas swap hedges and the changes in their fair value subsequent to July 1, 2009 are now recorded in change in fair value of derivative instruments in the consolidated statements of operations. Amounts in accumulated other comprehensive income (loss) remaining prior to de-designation are amortized into the consolidated statements of operations over the remaining lives of the natural gas swaps.

Interest Rate Swaps

We have executed an interest rate swap at our consolidated Auburndale project to economically fix a portion of its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

The interest rate swap is a derivative financial instrument designated as a cash flow hedge. The instrument is recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swap are recorded in accumulated other comprehensive income (loss).

Impact of derivative instruments on the consolidated income statements

Unrealized gains on interest rate swaps designated as cash flow hedges have been recorded in the consolidated statements of operations as a gain in other comprehensive income of $0.3 million for each of the three and six month periods ended June 30, 2010. Realized losses on these interest rate swaps of $0.2 million and $0.4 million were recorded in interest expense, net for the three and six month periods ended June 30, 2010.

Unrealized gains and losses on natural gas swaps designated as cash flow hedges are recorded in other comprehensive income in the consolidated statements of operations. In the period in which the unrealized gains and losses are settled, the cash settlement payments are recorded as fuel expense. Other comprehensive loss recorded for natural gas swap contracts accounted for as cash flow hedges totaled $5.1 million, net of tax, prior to July 1, 2009 when hedge accounting for these natural gas swaps

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accounting for derivative instruments and hedging activities (Continued)

was discontinued prospectively. Amortization of the loss of $0.4 million and $0.8 million was recorded in change in fair value of derivative instruments for the three and six month periods ended June 30, 2010.

Unrealized gains and losses on derivative instruments not designated as cash flow hedges are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

The following table summarizes realized gains and losses for derivatives not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Three months ended June 30, 2010	Six months ended June 30, 2010
Natural gas swaps	Fuel	$ 2,621	$ 4,439
Foreign currency forwards	Foreign exchange gain	(1,599)	(2,767)
Interest rate swaps	Interest, net	474	949

Unrealized gains and losses associated with changes in the fair value of derivative instruments not designated as cash flow hedges and ineffectiveness of derivatives designated as cash flow hedges are reflected in current period earnings. The following table summarizes the pre-tax changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Change in fair value of derivative instruments:				
Interest rate swaps	$ (120)	$ 469	$ (166)	$ 360
Natural gas swaps	1,112		(11,036)	
	$ 992	$ 469	$ (11,202)	$ 360

Notional volumes of derivative transactions

The following table summarizes the net notional volume of our derivative transactions by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of June 30, 2010:

	Units	Notional amount as of June 30, 2010
Interest rate swaps	US$	$ 10,219
Currency forwards	Cdn$	$ 257,700
Natural gas swaps	Mmbtu	15,900

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accounting for derivative instruments and hedging activities (Continued)

Foreign currency forward contracts

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of reinforcing the long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate of Cdn$1.134 per U.S. dollar in amounts sufficient to make monthly dividend payments at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on our 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), through December 2013.

In addition, we have executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on our 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"). The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a rate of Cdn$1.1075 per U.S. dollar. It is our intention to periodically consider extending the length of these forward contracts.

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and our estimation of the counterparty's credit risk. The fair value of our forward foreign currency contracts at June 30, 2010 is an asset of $12.2 million. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

The following table contains the components of recorded foreign exchange (gain) loss for the three and six month periods ended June 30, 2010 and 2009:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Unrealized foreign exchange (gain) loss:				
Subordinated notes and convertible debentures	$ (6,486)	$ 30,401	$ (2,505)	$ 17,635
Forward contracts and other	12,309	(16,792)	7,704	(8,005)
	5,823	13,609	5,199	9,630
Realized foreign exchange gains on forward contract settlements	(1,599)	(680)	(2,767)	(124)
	$ 4,224	$ 12,929	$ 2,432	$ 9,506

The following table illustrates the impact on our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of June 30, 2010:

Convertible debentures	$ 13,738
Foreign currency forward contracts	26,133

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accounting for derivative instruments and hedging activities (Continued)

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of a 40% effective tax rate:

For the three month period ended June 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2010	$ (554)	$ (73)	$ (627)
Change in fair value of cash flow hedges	391		391
Realized from OCI during the period	(211)	253	42
Accumulated OCI balance at June 30, 2010	$ (374)	$ 180	$ (194)

For the six month period ended June 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2009	$ (538)	$ (321)	$ (859)
Change in fair value of cash flow hedges	595		595
Realized from OCI during the period	(431)	501	70
Accumulated OCI balance at June 30, 2010	$ (374)	$ 180	$ (194)

9. Income taxes

The difference between the actual tax expense of $3.6 million and $8.5 million for the three and six months ended June 30, 2010, respectively, and the expected income tax expense, based on a combined Federal and State tax rate of 40%, of $2.0 million and $1.5 million, respectively, is primarily due to an increase in the valuation allowance and various other permanent differences.

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Current income tax expense (benefit)	$ 1,038	$ (1,743)	$ 1,075	$ (3,213)
Deferred tax expense (benefit)	2,580	(2,640)	7,416	564
Total income tax expense (benefit)	$ 3,618	$ (4,383)	$ 8,491	$ (2,649)

Valuation Allowance

As of June 30, 2010, we have recorded a valuation allowance of $69.1 million. This amount is comprised primarily of provisions against available Canadian and U.S net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Long-Term Incentive Plan

The following table summarizes the changes in outstanding LTIP notional units during the six months ended June 30, 2010:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2009	471,281	$ 7.30
Granted	305,112	$ 12.16
Additional shares from dividends	27,489	$ 8.94
Vested	(222,266)	$ 3.13
Outstanding at June 30, 2010	581,616	$ 9.68

In the second quarter of 2010, the Board of Directors approved an amendment to the LTIP. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return ("TSR") of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Vested notional units will be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Notional units granted prior to the 2010 performance period are subject to the vesting conditions of the LTIP before the amendments made in 2010. We reclassified the portion of outstanding awards expected to vest in common shares totaling $1.4 million from accounts payable and accrued liabilities and other non-current liabilities to common shares as of the date the LTIP was modified. The amended LTIP was approved by our shareholders on June 29, 2010.

On March 29, 2010, our board of directors approved the grant of 138,892 notional LTIP units for the 2009 performance period under the terms of the LTIP before the 2010 amendments. In May 2010, our board of directors approved the initial grant of 83,110 notional LTIP units for executive officers under the amended LTIP for the 2010-2012 performance period, subject to final shareholder approval of the amended LTIP, which occurred on June 29, 2010. Also in May 2010 and subject to the final shareholder approval of the amended LTIP, our board of directors granted transition awards to our executive officers consisting of an additional 83,110 notional LTIP units. The transition awards are designed to mitigate the impact of the changes in vesting provisions of the LTIP from a ratable vesting over three years to cliff vesting at the end of three years. The transition awards are subject to the performance measurement and other provisions of the amended LTIP, except that $^{1}/_{3}$ of the transition awards vest in March 2011 and the other $^{2}/_{3}$ vest in March 2012.

The notional units, other than the transition awards, granted under the amended LTIP cliff-vest three years after the grant date. The final number of notional units that will vest, if any, at the end of the three year vesting period will be based on the Company's achievement of target levels of relative TSR, which is the change in the value of an investment in the Company's common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Long-Term Incentive Plan (Continued)

period. The total number of notional units vesting could equal up to a maximum 150% of the number of notional units in the executives' accounts on the vesting date for that award, depending on the level of achievement of target levels of TSR during the measurement period.

For new awards granted under the amended LTIP, we record compensation expense ratably from the grant date through the end of the performance period based on the grant date fair value. Compensation expense is recognized regardless of whether the TSR market condition is satisfied, provided that the LTIP participant remains employed by the Company. The fair value of the outstanding notional units at June 30, 2010, $2.0 million, is based upon a Monte Carlo simulation model, which encompasses estimated TSR during the performance period compared to the estimated TSR of the peer companies.

In calculating the fair value of the award, the Monte Carlo simulation model utilizes multiple input variables over the performance period in order to determine the probability of satisfying the TSR market condition stipulated in the award. The Monte Carlo simulation model computed simulated TSR for the Company and for its peer companies during the remaining time in the performance period with the following inputs: (i) stock price on the measurement date (ii) expected volatility; (iii) risk-free interest rate; (iv) dividend yield and (v) correlations of historical common stock returns between the Company and the peer companies and among the peer companies. Expected volatilities utilized in the Monte Carlo model are based on historical volatility of the Company's and the peer companies' stock prices over a period equal in length to that of the remaining vesting period. The risk-free interest rate is derived from the U.S. Treasury yield curve in effect at the time of grant with a term equal to the performance period assumption at the time of grant.

The calculation of simulated TSR under the Monte Carlo model for the remaining time in the performance period included the following assumptions:

	Six months ended June 30, 2010
Weighted average risk free rate of return	0.9%
Dividend yield	9.4%
Expected volatility Company	45%
Expected volatility peer companies	30 - 60%
Weighted average remaining measurement period	1.8 years

11. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2009. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the six month period ended June 30, 2010 and the three and six month periods ended June 30, 2009, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Basic and diluted earnings (loss) per share (Continued)

The following table sets forth the weighted average number of shares outstanding and potentially dilutive shares utilized in per share calculations for the three and six month periods ended June 30, 2010 and 2009:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Basic shares outstanding	60,481	60,600	60,443	60,769
Dilutive potential shares:				
Convertible debentures	11,473	4,839	11,473	4,839
LTIP notional units	409	539	402	425
Potentially dilutive shares	72,363	65,978	72,318	66,033

12. Segment and related information

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income less interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use unaudited Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Segment and related information (Continued)

contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is included in the table below.

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2010:								
Operating revenues	$ 7,729	$ 19,570	$ 17,842	$ 2,763	$	$	$	$ 47,904
Segment assets	213,275	120,929	115,822	40,620		8,322	363,557	862,525
Goodwill	8,918					3,535		12,453
Project Adjusted EBITDA	$ 7,062	$ 10,431	$ 7,299	$ 1,002	$ 4,141	$ 8,591	$	$ 38,526
Change in fair value of derivative instruments		597	(1,709)		(207)	1,529		210
Depreciation and amortization	2,095	4,950	2,267	746	839	5,699		16,596
Interest, net	3,096	415	(4)		1,651	939		6,097
Other project (income) expense					204	(122)		82
Project income	1,871	4,469	6,745	256	1,654	546		15,541
Interest, net							2,518	2,518
Administration							3,843	3,843
Foreign exchange gain							4,224	4,224
Other income, net							(26)	(26)
Loss from operations before income taxes	1,871	4,469	6,745	256	1,654	546	(10,559)	4,982
Income tax expense (benefit)	990						2,628	3,618
Net loss	$ 881	$ 4,469	$ 6,745	$ 256	$ 1,654	$ 546	$ (13,187)	$ 1,364

	Path 15	Auburndale	Lake	Pasco	Chambers	Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2009:								
Operating revenues	$ 7,708	$ 18,263	$ 15,239	$ 3,060	$	$	$	$ 44,270
Segment assets	225,167	144,228	125,381	44,671		3,215	331,261	873,923
Goodwill	8,918							8,918
Project Adjusted EBITDA	$ 6,931	$ 10,386	$ 7,723	$ 901	$ (1,128)	$ 9,172	$	$ 33,985
Change in fair value of derivative instruments					(1,010)	(1,311)		(2,321)
Depreciation and amortization	2,115	4,949	2,777	747	844	5,990		17,422
Interest, net	3,221	693		3	2,015	2,555		8,487
Other project (income) expense	(1,229)		61	(25)	207	(78)		(1,064)
Project income	2,824	4,744	4,885	176	(3,184)	2,016		11,461
Interest, net							10,553	10,553
Administration							3,105	3,105
Foreign exchange gain							12,929	12,929
Other income, net							(14)	(14)
Loss from operations before income taxes	2,824	4,744	4,885	176	(3,184)	2,016	(26,573)	(15,112)
Income tax expense (benefit)							(4,383)	(4,383)
Net loss	$ 2,824	$ 4,744	$ 4,885	$ 176	$ (3,184)	$ 2,016	$ (22,190)	$ (10,729)

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2010:								
Operating revenues	$ 15,373	$ 40,037	$ 34,083	$ 5,632	$	$	$	$ 95,125
Segment assets	213,275	120,929	115,822	40,620		8,322	363,557	862,525
Goodwill	8,918					3,535		12,453
Project Adjusted EBITDA	$ 14,115	$ 19,802	$ 14,612	$ 2,417	$ 10,129	$ 16,200	$	$ 77,275
Change in fair value of derivative instruments		4,809	6,226		(380)	2,074		12,729
Depreciation and amortization	4,194	9,898	4,536	1,492	1,676	11,186		32,982
Interest, net	6,242	886	(6)		3,327	1,429		11,878
Other project (income) expense					403	(122)		281
Project income	3,679	4,209	3,856	925	5,103	1,633		19,405
Interest, net							5,312	5,312
Administration							7,943	7,943
Foreign exchange gain							2,432	2,432
Other income, net							(26)	(26)
Loss from operations before income taxes	3,679	4,209	3,856	925	5,103	1,633	(15,661)	3,744
Income tax expense (benefit)	1,739						6,752	8,491
Net loss	$ 1,940	$ 4,209	$ 3,856	$ 925	$ 5,103	$ 1,633	$ (22,413)	$ (4,747)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2009:								
Operating revenues	$ 15,416	$ 37,989	$ 31,104	$ 5,795	$	$	$	$ 90,304
Segment assets	225,167	144,228	125,381	44,671		3,215	331,261	873,923
Goodwill	8,918							8,918
Project Adjusted EBITDA	$ 13,833	$ 18,547	$ 15,621	$ 2,869	$ 5,024	$ 19,161	$	$ 75,055
Change in fair value of derivative instruments					(1,524)	935		(589)
Depreciation and amortization	4,311	9,882	5,566	1,494	1,687	12,065		35,005
Interest, net	6,444	1,314	(6)	(43)	4,029	3,875		15,613
Other project (income) expense	(1,229)		62	(25)	410	(187)		(969)
Project income	4,307	7,351	9,999	1,443	422	2,473		25,995
Interest, net							20,170	20,170
Administration							5,484	5,484
Foreign exchange gain							9,506	9,506
Other income, net							(30)	(30)
Loss from operations before income taxes	4,307	7,351	9,999	1,443	422	2,473	(35,130)	(9,135)
Income tax expense (benefit)							(2,649)	(2,649)
Net loss	$ 4,307	$ 7,351	$ 9,999	$ 1,443	$ 422	$ 2,473	$ (32,481)	$ (6,486)

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Segment and related information (Continued)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 77% and 16%, respectively, of total consolidated revenues for the three months ended June 30, 2010 and 75% and 17% for the three months ended June 30, 2009 and 77% and 16%, respectively, of total consolidated revenues for the six months ended June 30, 2010 and 76% and 17% for the six months ended June 30, 2009. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

13. Related party transactions

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by Arclight Capital Partners, LLC ("ArcLight"). On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15 million, to be satisfied by a payment of $6 million that was made at the termination date, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. We recorded the remaining liability associated with the termination fee at its estimated fair value of $8.1 million at December 31, 2009. The contract termination liability is being accreted to the final amounts due over the term of these payments.

14. Normal course issuer bid

In 2008, we initiated a normal course issuer bid to purchase up to four million IPSs, representing approximately 8% of Atlantic Power's public float at that time. For the six months ended June 30, 2009, we acquired 481,600 IPSs at an average price of Cdn$8.42 under the terms of our existing normal course issuer bid. As of June 30, 2009, we had acquired a cumulative total of 1,040,220 IPSs at an average price of Cdn$8.61 since the inception of the issuer bid in July 2008. We paid the market price at the time of acquisition for any IPSs purchased through the facilities of the Toronto Stock Exchange, and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009.

15. Commitments and contingencies

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of June 30, 2010 which are expected to have a material impact on our financial position or results of operations.

16. Subsequent events

These financial statements and notes reflect our evaluation of events occurring subsequent to the balance sheet date through August 9, 2010, the date the interim consolidated financial statements were issued.

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("IWP") for approximately $40 million. IWP recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is expected to be completed in late 2010 or early 2011. IWP has 20-year PPAs with Idaho Power Company. Our investment in IWP was funded with cash on hand and a

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Subsequent events (Continued)

$20 million borrowing under our senior credit facility. Idaho Wind will be accounted for under the equity method of accounting.

17. United States and Canadian accounting policy differences

In accordance with Canadian securities legislation, issuers that file reports with the Securities and Exchange Commission in the United States are allowed to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. We have included a reconciliation highlighting the material differences between our consolidated financial statements prepared in accordance with United States GAAP compared to its consolidated financial statements prepared in accordance with Canadian GAAP below.

Consolidated reconciliation of net income and shareholders' equity

Net income (loss) and shareholders' equity reconciled to Canadian GAAP are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss), based on United States GAAP	$ 1,364	$ (10,729)	$ (4,747)	$ (6,486)
Changes in fair value of power purchase agreement, net of tax(1)	(4,593)	27,600	(16,892)	(10,126)
Projects accounted for under the cost method of accounting, net of tax(2)	1,744	2,733	1,822	4,012
Net income (loss), based on Canadian GAAP	$ (1,485)	$ 19,604	$ (19,817)	$ (12,600)

	June 30,	
	2010	**2009**
Shareholders' equity, based on United States GAAP	$ 384,635	$ 130,510
Adjusted for cumulative effect of US/Canadian differences	70,312	51,844
	454,947	182,354
Net earnings for the period, Canadian GAAP	(19,817)	(12,600)
Shareholders' equity, based on Canadian GAAP	$ 435,130	$ 169,754

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(1) The accounting standard for derivative instruments provides an exemption for PPAs that contain both a capacity payment and an energy component which, if certain criteria are met, qualifies the PPA for the normal purchases and normal sales treatment. A similar exemption does not exist under Canadian GAAP and accordingly, a PPA with a capacity payment, a minimum or specified quantity of energy and delivery into a liquid market is subject to fair value accounting. Our PPA at the Chambers project meets the normal purchases and normal sales exemption under United States GAAP and is not subject to fair value accounting.

(2) We follow a standard under United States GAAP that establishes a presumption of significant influence with a low threshold of ownership in investments in limited partnerships and requires accounting under the equity method. Our investments in the Selkirk and Gregory projects are

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. United States and Canadian accounting policy differences (Continued)

accounted for under the cost method for Canadian GAAP because there is not a different threshold for ownership interest in limited partnerships and we do not exercise significant influence over the operating and financial policies of these investments.

Earnings per share

	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Earnings per share under Canadian GAAP				
Basic	$ (0.02)	$ 0.32	$ (0.33)	$ (0.21)
Diluted	$ (0.02)	$ 0.30	$ (0.33)	$ (0.21)

Condensed consolidated balance sheet

	June 30, 2010 (Canadian GAAP)	December 31, 2009 (Canadian GAAP)
Assets		
Current assets	$ 151,215	$ 149,340
Equity investments in unconsolidated affiliates(1)	57,877	61,037
Other long-term assets	782,865	827,175
Total assets	$ 991,957	$ 1,037,552
Liabilities and Shareholders' Equity		
Current liabilities	$ 93,055	$ 77,471
Other non-current liabilities	463,772	480,398
Shareholders' equity:		
Common shares	544,034	541,304
Accumulated other comprehensive loss	(194)	(859)
Retained deficit	(112,191)	(60,762)
Noncontrolling interest	3,481	
Total shareholders' equity	435,130	479,683
Total liabilities and shareholders' equity	$ 991,957	$ 1,037,552

(1) We follow a standard under United States GAAP that requires the equity method of accounting for our investments with 50% or less ownership interest in which we do not have a controlling interest. Under Canadian GAAP, our share of each of the assets, liabilities, revenues and expenses of our investments that are subject to joint control is proportionately consolidated.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. United States and Canadian accounting policy differences (Continued)

Condensed consolidated statement of operations

	Three months ended June 30, 2010 (Canadian GAAP)	Three months ended June 30, 2009 (Canadian GAAP)	Six months ended June 30, 2010 (Canadian GAAP)	Six months ended June 30, 2009 (Canadian GAAP)
Project Income				
Project revenue	$ 75,912	$ 73,242	$ 153,539	$ 156,792
Project expenses	56,245	60,214	113,477	123,492
Project other expenses	(12,321)	46,311	(55,456)	(20,289)
	7,346	59,339	(15,394)	13,011
Administration and other expenses, net	10,560	26,117	15,662	34,671
Loss from operations before income taxes	(3,214)	33,222	(31,056)	(21,660)
Income tax expense (benefit)	(1,729)	13,618	(11,239)	(9,060)
Net income (loss)	(1,485)	19,604	(19,817)	(12,600)
Less: Net loss attributable to noncontrolling interest	(81)		(129)	
Net income (loss) attributable to Atlantic Power Corporation	$ (1,404)	$ 19,604	$ (19,688)	$ (12,600)

Condensed consolidated statement of cash flows

	Three months ended June 30, 2010 (Canadian GAAP)	Three months ended June 30, 2009 (Canadian GAAP)	Six months ended June 30, 2010 (Canadian GAAP)	Six months ended June 30, 2009 (Canadian GAAP)
Cash provided by operating activities	$ 17,398	$ 10,100	$ 40,976	$ 31,722
Cash used in investing activities	6,811	11,113	(2,380)	656
Cash used in financing activities	(5,116)	(17,243)	(26,374)	(26,756)
Increase in cash and cash equivalents	19,093	3,970	12,222	5,622
Cash and cash equivalents, beginning of period	47,632	44,218	54,503	42,566
Cash and cash equivalents, end of period	$ 66,725	$ 48,188	$ 66,725	$ 48,188

Selkirk Cogen Partners, L.P. and Subsidiary
Consolidated Financial Statements
December 31, 2009 and 2008

The consolidated financial statements of Selkirk Cogen Partners, L.P. and its subsidiary for the years ended December 31, 2009 and 2008, are presented herein without the related report of independent accountants.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Balance Sheets

December 31, 2009 and 2008

(in thousands of dollars)	2009	2008
Assets		
Current assets		
Cash and cash equivalents	$ 4,038	$ 4,457
Restricted cash	5,299	6,760
Accounts receivable	22,990	22,819
Inventory	722	3,793
Derivative contracts	12,852	19,434
Other assets	1,747	1,700
Total current assets	47,648	58,963
Restricted cash	30,723	34,584
Derivative contracts	40,564	39,952
Property and equipment, net of accumulated depreciation of $201,614 and $188,617, respectively	179,466	192,396
Deferred financing costs, net of accumulated amortization of $15,633 and $15,134, respectively	658	1,157
Other assets	4,424	4,764
Total assets	$ 303,483	$ 331,816
Liabilities and Partners' Capital		
Current liabilities		
Current portion of long-term debt	$ 44,579	$ 43,905
Accounts payable	12,941	16,079
Due to affiliates	216	120
Accrued property taxes	4,203	2,050
Other accrued liabilities	3,860	4,742
Derivative contracts	1,597	2,154
Total current liabilities	67,396	69,050
Long-term debt	84,474	129,053
Derivative contracts	4,208	4,413
Other liabilities	129	1,333
Total liabilities	156,207	203,849
Commitments and contingencies		
Partners' capital		
General partners	1,418	1,228
Limited partners	145,858	126,739
Total partners' capital	147,276	127,967
Total liabilities and partners' capital	$ 303,483	$ 331,816

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Statements of Operations

Years Ended December 31, 2009 and 2008

(in thousands of dollars)	2009	2008
Operating revenues		
Energy	$ 97,316	$ 182,175
Capacity	86,341	106,933
Commodity sales	44,585	60,219
Transmission	11,080	11,038
Total operating revenues	239,322	360,365
Operating expenses		
Fuel	89,567	180,822
Operations and maintenance	25,739	19,264
Commodity cost of sales	34,339	46,651
Transmission	8,636	12,191
General and administrative	5,291	5,344
Depreciation	12,997	13,112
Unrealized loss on derivative contracts	5,208	55,882
Total operating expenses	181,777	333,266
Operating income	57,545	27,099
Other income (expense)		
Interest income	1,009	1,835
Interest expense	(15,321)	(19,379)
Net income	$ 43,233	$ 9,555

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Statements of Changes in Partners' Capital

Years Ended December 31, 2009 and 2008

(in thousands of dollars)	General Partners	Limited Partners	Total
Partners' capital at December 31, 2007	$ 270	$ 32,030	$ 32,300
Implementation of fair value guidance (Note 7)	1,269	125,385	126,654
Net income	96	9,459	9,555
Capital distributions	(407)	(40,135)	(40,542)
Partners' capital at December 31, 2008	1,228	126,739	127,967
Net income	433	42,800	43,233
Capital distributions	(243)	(23,681)	(23,924)
Partners' capital at December 31, 2009	$ 1,418	$ 145,858	$ 147,276

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Statements of Cash Flows

Years Ended December 31, 2009 and 2008

(in thousands of dollars)	**2009**	**2008**
Cash flows from operating activities		
Net income	$ 43,233	$ 9,555
Noncash items included in net income:		
Depreciation	12,997	13,112
Amortization of deferred financing costs	499	626
Amortization of deferred revenue		(354)
Accretion of asset retirement obligation	8	6
Unrealized loss on derivative contracts	5,208	55,882
Changes in operating assets and liabilities:		
Accounts receivable	(964)	3,926
Inventory	4,045	2,233
Other assets	112	80
Accounts payable	(3,138)	905
Due to affiliates	96	(162)
Accrued property taxes	941	(1,950)
Other accrued liabilities	(870)	668
Other liabilities		(1,179)
Net cash provided by operating activities	62,167	83,348
Cash flows from investing activities		
Decrease in restricted cash	5,322	1,591
Capital expenditures	(79)	(695)
Net cash provided by investing activities	5,243	896
Cash flows from financing activities		
Repayment of long-term debt	(43,905)	(42,998)
Capital distributions	(23,924)	(40,542)
Cash used in financing activities	(67,829)	(83,540)
Net (decrease) increase in cash and cash equivalents	(419)	704
Cash and cash equivalents		
Beginning of year	4,457	3,753
End of year	$ 4,038	$ 4,457
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 14,899	$ 18,449
Noncash investing activities		
Capital expenditures which were accrued but not paid	$	$ 12
Capital expenditures previously accrued which were paid	$ 12	$ 550

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

1. Organization and Business

Selkirk Cogen Partners, L.P. was organized on December 15, 1989 as a Delaware limited partnership. Selkirk Cogen Funding Corporation (the "Funding Corporation"), a wholly-owned subsidiary of Selkirk Cogen Partners, L.P. (collectively, the "Partnership"), was organized for the sole purpose of facilitating financing activities of the Partnership and has no other operating activities (Note 4).

The managing general partner of the Partnership is JMC Selkirk, LLC ("JMC Selkirk" or the "Managing General Partner"). The other general partner of the Partnership (together with JMC Selkirk, the "General Partners") is RCM Selkirk GP, Inc. ("RCM Selkirk GP"). The limited partners of the Partnership (the "Limited Partners", and together with the General Partners, the "Partners") are JMC Selkirk, PentaGen Investors, L.P. ("PentaGen"), Teton Selkirk, LLC ("Teton Selkirk") and RCM Selkirk, L.P. ("RCM Selkirk LP").

The general and limited partners and their respective equity interests are as follows:

			Interest(1)	
Partners	**Affiliated With**	**Preferred (i)**	**Original (ii)**	**Residual (iii)**
General Partners				
JMC Selkirk	Cogentrix Energy, LLC and EIF Calypso, LLC(2)	0.09%	1.00%	0.81%
RCM Selkirk GP	Robert C. McNair and Family	1.00%	0.00%	0.22%
Limited Partners				
JMC Selkirk	Cogentrix Energy, LLC and EIF Calypso, LLC(2)	1.95%	21.40%	17.33%
PentaGen	Cogentrix Energy, LLC, EIF Calypso, LLC(2), and Osaka Gas Energy America Corporation	5.25%	57.60%	46.66%
Teton Selkirk	Atlantic Power Holdings, LLC	13.55%	20.00%	17.70%
RCM Selkirk LP	Robert C. McNair and Family	78.16%	0.00%	17.28%

(1) Percentages indicate the interest of (i) each of the Partners in certain priority distributions of available cash of the Partnership, up to fixed semi-annual amounts (the "Level I Distributions"), (ii) JMC Selkirk, PentaGen and Teton Selkirk in 99% of distributions of the remaining available cash of the Partnership; and (iii) each of the Partners in the residual tier of interests in cash distributions after the initial 18-year period following the commercial operation of Unit 2 (August 2012 or, if later, the date when all Level I Distributions have been paid).

(2) Prior to November 2007, Cogentrix Energy, LLC ("CELLC"), indirectly owned 100% of the general and limited partner interests of JMC Selkirk and 50% of the limited partner interest of PentaGen. In November 2007, CELLC transferred 100% of its ownership interest in JMC Selkirk and 99.5712% of its ownership interest in PentaGen to Calypso Energy Holdings LLC ("Calypso"). Subsequent to the transfer, CELLC sold an 80% interest in Calypso to EIF Calypso, LLC, a Delaware limited liability company managed by Energy Investor Funds ("EIF"), a private equity fund manager, resulting in CELLC holding a 20% membership interest.

The Managing General Partner is responsible for managing and controlling the business and affairs of the Partnership, subject to certain powers which are vested in the management committee of the Partnership (the "Management Committee") under the Partnership Agreement. Each General Partner

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

1. Organization and Business (Continued)

has a voting representative on the Management Committee, which, subject to certain limited exceptions, acts by unanimity. Thus, the General Partners, and principally the Managing General Partner, exercise control over the Partnership. JMCS I Management, LLC ("JMCS I Management"), an affiliate of the Managing General Partner and wholly-owned subsidiary of CELLC, is acting as the project management firm (the "Project Management Firm") for the Partnership, and as such is responsible for the implementation and administration of the Partnership's business under the direction of the Managing General Partner. Upon the occurrence of certain events specified in the Partnership Agreement, RCM Selkirk GP may assume the powers and responsibilities of the Managing General Partner and of the Project Management Firm. Under the Partnership Agreement, each General Partner other than the Managing General Partner may convert its general partnership interest to that of a Limited Partner. Under terms of the limited liability agreement of Calypso, (the "Calypso LLC Agreement"), EIF indirectly has the power to control the Managing General Partner, subject to certain restrictions contained in the Calypso LLC Agreement.

The Partnership was formed for the purpose of constructing, owning and operating a natural gas- fired, combined-cycle cogeneration facility located on a 15.7 acre site leased from Saudi Basic Industries Corporation ("SABIC") in Bethlehem, New York (the "Facility"). The Facility has a total electric generating capacity of 345-megawatts ("MW") with a maximum average steam output of 400,000 pounds per hour ("lbs/hr"). The Facility consists of one unit ("Unit 1") with an electric generating capacity of approximately 79.9 MW and a second unit ("Unit 2") with an electric generating capacity of approximately 265.0 MW (collectively, the "Units"). The Units have been designed to operate independently for electrical generation, while thermally integrated for steam generation. Unit 1 commenced commercial operations on April 17, 1992 and Unit 2 commenced commercial operations on September 1, 1994.

The Partnership had a long-term contract with Niagara Mohawk Power Corporation ("Niagara Mohawk") for the sale of electric capacity and energy produced by Unit 1, which expired June 30, 2008 ("Amended and Restated Niagara Mohawk Power Purchase Agreement"). The Partnership has a long-term contract with Consolidated Edison Company of New York, Inc. ("Con Edison") for the sale of electric capacity and energy produced by Unit 2. The Partnership has a long-term contract with SABIC for the sale of steam produced by the Facility and delivered to SABIC Innovative Plastics, ("SABIC IP"), a subsidiary of Saudi Basic Industries Corporation. The Facility uses natural gas purchased principally from Canadian suppliers under long-term gas supply contracts as its primary fuel input.

The Facility is certified by the Federal Energy Regulatory Commission as a qualifying facility ("Qualifying Facility") under the Public Utility Regulatory Policy Act of 1978, as amended ("PURPA"). As a Qualifying Facility, the prices charged for the sale of energy and steam are not regulated. Certain fuel supply and transportation agreements entered into by the Partnership are also subject to regulation on the federal and provincial levels in Canada. The Partnership has obtained all material Canadian governmental permits and authorizations required for its operation.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Significant Accounting Policies

Basis of Presentation

The Partnership is required to consolidate an entity for which it absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interest in the entity.

The Partnership determines whether it is the primary beneficiary of a variable interest entity ("VIE") by first performing a qualitative analysis of the VIE that includes a review of, among other factors, its capital structure, contractual terms, which interests create or absorb variability, related party relationships and the design of the VIE. For purposes of allocating a VIE's expected losses and expected residual returns to its variable interest holders, the Partnership utilizes the "top down" method. Under that method, the Partnership calculates its share of the VIE's expected losses and expected residual returns using the specific cash flows that would be allocated to it, based on contractual arrangements and/or the Partnership's position in the capital structure of the VIE, under various probability-weighted scenarios.

The Funding Corporation was determined to be a VIE. Based on an analysis performed, Selkirk Cogen Partners, L.P. was deemed to be the primary beneficiary. As a result, Funding Corporation is included in the Partnership's consolidated financial statements. All material intercompany transactions have been eliminated.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for debt service, major maintenance and other specifically designated accounts under a deposit and disbursement agreement ("Depositary Agreement"). Restricted cash associated with transactions expected to occur beyond one-year are classified as long-term. All other restricted accounts are classified as current assets.

Inventory

Spare parts are valued at the lower of average cost or market and consist of Facility equipment components and maintenance supplies required to be maintained in order to facilitate maintenance activities. Spare parts which are expected to be utilized during the next year are classified as current in

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Significant Accounting Policies (Continued)

the accompanying consolidated balance sheets. Spare parts of approximately $3,523,000 and $4,497,000 which are not expected to be utilized within the next year are classified as long-term and included in other assets in the accompanying consolidated balance sheets at December 31, 2009 and 2008, respectively.

The Partnership performs periodic assessments to determine the existence of obsolete, slow- moving and non-usable spare parts and records necessary provisions to reduce such inventories to net realizable value.

Emission Allowances

Emission allowances are valued under the weighted average costing method subject to the lower of cost or market principle. In applying the lower of cost or market principle, a reduction in the carrying value is not recognized so long as the Partnership will recover/pass-through the cost in its operating margin.

The historical cost of emission allowances is calculated as follows:

Granted from regulatory body emission allowances obtained via grants are not assigned any value by the Partnership as their cost is zero.

Acquired as part of an acquisition emission allowances are recorded at fair value as of the acquisition date, subject to pro rata reduction if overall purchase price is less than the entity's fair value.

Purchased from third parties emission allowances that are transferable and can be purchased or sold in the normal course of business are recorded at cost.

At December 31, 2009, the Partnership has accrued approximately $461,000 in emission allowances which are classified as current and included in other liabilities in the accompanying consolidated balance sheets.

Derivative Contracts

In accordance with guidance on accounting for derivative instruments and hedging activities all derivatives should be recognized at fair value. Derivatives or any portion thereof, that are not designated as, and effective as, hedges must be adjusted to fair value through earnings. Derivative contracts are classified as either assets or liabilities on the consolidated balance sheets. Certain contracts that require physical delivery may qualify for and be designated as normal purchases/normal sales. Such contracts are accounted for on an accrual basis.

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board ("FASB") issued guidance that defines fair value, provides guidance for measuring fair value and requires certain disclosures. This guidance does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Significant Accounting Policies (Continued)

A fair value hierarchy was established that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy are described below:

Level 1:	Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.
Level 2:	Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
Level 3:	Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (Note 7). Upon implementation of this guidance, the Partnership recognized an approximate $126.7 million gain on January 1, 2008, on its gas supply contracts, as an adjustment to retained earnings.

In February 2008, the FASB issued a one-year deferral for non-financial assets and liabilities to comply with issued fair value guidance. As of December 31, 2009, the Partnership does not have any non-financial assets or liabilities remeasured at fair value on a recurring basis.

Property and Equipment

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the consolidated results of operations for the respective period. Depreciation is provided over the estimated useful lives ("EUL") of the related assets using the straight-line method. Capitalized modifications to leased properties are depreciated using the straight-line method over the shorter of the lease term or the asset's estimated useful life (Note 3).

The Partnership's depreciation is based on the Facility being considered as a single property unit. Certain components of the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where replacement of a Facility component is significant and the Partnership can reasonably estimate the original cost of the component being replaced, the Partnership will write-off the replaced component and capitalize the cost of the replacement. The component will be depreciated over the lesser of the EUL of the component or the remaining useful life of the Facility.

The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of property and equipment may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Significant Accounting Policies (Continued)

property and equipment. The factors considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property and equipment is used, and the effects of obsolescence, demand, competition, and other economic factors.

Deferred Financing Costs

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the relaed financing (Note 4).

Asset Retirement Obligations

Asset retirement obligations, including those conditioned on future events, are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset in the same period. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the EUL of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership recognized an asset retirement obligation at December 31, 2009 and 2008 of approximately $128,000 and $120,000, respectively. This obligation is included in other liabilities and represents the costs the Partnership would incur to perform environmental clean-up or remove certain portions of the Facility.

Revenue Recognition

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in fuel and transmission expenses.

The Partnership's long-term gas supply contracts are not designated as, nor do they qualify as, held for trading purposes. Thus, the related realized gains and losses on these derivative contracts are reported in the accompanying statement of operations.

Revenues from the sale of gas are recorded in the month sold and take place in the form of (i) short-term transactions whereby the Partnership resells its firm natural gas supply volumes when Unit 1 or Unit 2 is dispatched off-line or at less than full capacity ("Gas Resales"), and (ii) short-term transactions whereby the Partnership attempts to lower the cost of natural gas delivered to the Facility by reselling certain of its firm natural gas supply volumes and purchasing replacement gas supply volumes at lower prices in the spot market, to meet the Facility's scheduled operation ("Gas Supply Cost Mitigation"). Gas Resales are recorded on a gross basis on the accompanying consolidated statements of operations in commodity sales, with the associated costs recorded in commodity cost of sales. Gas Resales are recorded on a gross basis because the Partnership's decision to sell its firm natural gas supply is primarily driven by the dispatch of the Facility. Gas Supply Cost Mitigation is included on a net basis in fuel expense on the accompanying consolidated statements of operations

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Significant Accounting Policies (Continued)

based on the premise that the Partnership's decision to sell its firm natural gas supply is primarily driven by the intent to lower the cost of natural gas delivered to the Facility for scheduled operation.

Income Taxes

As a partnership, the income tax effects accrue directly to the partners, and each partner is individually responsible for its share of the combined income or loss. Accordingly, no income tax provision is recorded in the accompanying consolidated statements of operations.

Reclassifications

Certain reclassifications have been made to the prior year's consolidated financial statements to conform to the current year presentation. These reclassifications had no effect on the previously reported results of operations or partners capital.

Subsequent Events

The Partnership evaluated subsequent events through March 12, 2010.

Recent Accounting Pronouncements

Effective July 1, 2009 the Partnership adopted the Accounting Standards Codification ("ASC") issued by the FASB. The ASC does not change GAAP, but instead takes the numerous individual accounting pronouncements that previously constituted GAAP and reorganizes them into approximately 90 accounting topics, which are then broken down into subtopics, sections and paragraphs. The intent is to simplify user access to authoritative GAAP by providing all of the guidance related to a particular topic in one place. ASC supersedes all previously existing non-Security and Exchange Commission or non-grandfathered accounting and reporting standards. The adoption of ASC did not have any impact on the Partnership's consolidated financial statements.

In June 2009, the FASB issued guidance to revise the approach to determine when a VIE should be consolidated. The new consolidation model for VIEs considers whether the Partnership has the power to direct the activities that most significantly impact the VIE's economic performance and shares in the significant risks and rewards of the entity. The guidance on VIEs requires companies to continually reassess VIEs to determine if consolidation is appropriate and provide additional disclosures. The guidance is effective for the Partnership's fiscal year beginning January 1, 2010. The Partnership expects the adoption of this guidance will have no material impact on its financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

3. Property and Equipment

Property and equipment consisted of the following components as of December 31:

(in thousands of dollars)	2009	2008
Facility	$ 376,635	$ 377,065
Facility improvements	493	71
Leasehold improvements	353	353
Machinery and equipment	929	876
Computer systems	2,358	2,336
Office equipment	312	312
	381,080	381,013
Less: Accumulated depreciation	(201,614)	(188,617)
	$ 179,466	$ 192,396

The EULs for significant property and equipment categories are as follows:

Facility	30 years
Facility improvements	10 - 30 years
Leasehold improvements	Lesser of lease term or asset's EUL
Machinery and equipment	5 - 15 years
Computer systems	3 - 5 years
Office equipment	5 years

4. Long-term Debt

Long-term debt consisted of the following components as of December 31:

(in thousands of dollars)

	As of December 31, 2009			For the Year Ended December 31, 2009		
Description	Commitment Amount	Due Date	Balance Outstanding	Interest Expense	Commitment Fees	Letter of Credit Fees
2012 Bonds(1)	$ 129,053	6/26/12	$ 129,053	$ 14,446	N/A	N/A
Credit Agreement(2)						
Working Capital Loan	27,075	6/30/12			$ 108	N/A
Letter of Credit Facility						
Fuel Supply	10,000	6/30/12		N/A	N/A	$ 100
Fuel Management	5,000	6/30/12		N/A	N/A	51
Gas Transportation	2,925	6/30/12		N/A	N/A	30
			129,053			
Less: Current portion			44,579			
			$ 84,474			

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

4. Long-term Debt (Continued)

(in thousands of dollars)

	As of December 31, 2008			For the Year Ended December 31, 2008		
Description	**Commitment Amount**	**Due Date**	**Balance Outstanding**	**Interest Expense**	**Commitment Fees**	**Letter of Credit Fees**
2012 Bonds(1)	$ 172,958	6/26/12	$ 172,958	$ 18,449	N/A	N/A
Credit Agreement(2)						
Working Capital Loan	22,075	6/30/12			$ 108	N/A
Letter of Credit Facility						
Fuel Supply	10,000	6/30/12		N/A	N/A	$ 108
Fuel Management	5,000	6/30/12		N/A	N/A	50
Gas Transportation	2,925	8/3/09		N/A	N/A	29
CO^2 Allowance Auction	5,000	1/2/09		N/A	N/A	4
			172,958			
Less: Current portion			43,905			
			$ 129,053			

(1) The 2012 bonds were issued by the Funding Corporation on May 9, 1994 ("2012 Bonds") and are pledged by substantially all of the assets of the Partnership and are non-recourse to the individual Partners. The obligations of the Funding Corporation with respect to the 2012 Bonds are unconditionally guaranteed by the Partnership. The trust indenture restricts the ability of the Partnership to make distributions to the Partners under certain circumstances. Interest is fixed at 8.98% with interest payments due semi-annually on June 26 and December 26. Principal payments commenced on December 26, 2007, and are payable semi-annually thereafter.

(2) The Partnership has a credit agreement for $45,000,000, which is available to the Partnership for working capital purposes, including the provision of letters of credit (the "Credit Agreement"). Outstanding balances of loans under the Credit Agreement bear interest at a rate equal to, at the Partnership's option, either (i) a base rate equal to the greater of (x) the sum of the federal funds rate plus 0.50% and (y) the prime rate publicly announced by Citizens Bank of Massachusetts, payable quarterly in arrears, or (ii) LIBOR plus 1.00% (increased to 1.25% if the Partnership's credit rating from Standard & Poor's ("S&P") falls below BBB-), payable at the end of the applicable interest period (or quarterly for interest periods of more than three months). As of December 31, 2009 and 2008, the Partnership has issued letters of credit totaling approximately $17,925,000 and $22,925,000 to support obligations under certain of the Partnership's fuel related agreements (Note 9), respectively.

Included in other accrued liabilities at December 31, 2009 and 2008 was approximately $188,000 and $265,000 of accrued interest expense, respectively.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

4. Long-term Debt (Continued)

Future minimum principal repayments as of December 31, 2009 are as follows:

(in thousands of dollars)	
2010	$ 44,579
2011	55,070
2012	29,404
	$ 129,053

The Partnership is subject to various operational and financial covenants. As of December 31, 2009 the Partnership had not complied with certain covenants related to the 2012 Bonds and the credit agreement. The Partnership subsequently cured these covenant violations in January 2010.

5. Operating Leases

The Partnership leases certain equipment, land and buildings under non-cancelable operating leases expiring at various dates through 2014. For the years ended December 31, 2009 and 2008, the Partnership incurred lease expense of approximately $1,002 and $1,003, respectively, which is included in operations and maintenance expense and general and administrative expense in the accompanying consolidated statements of operations.

Future minimum lease payments under the terms of the non-cancelable operating leases, as of December 31, 2009, are as follows:

(in thousands of dollars)	
2010	$ 1,001
2011	1,000
2012	1,000
2013	1,000
2014	667
	$ 4,668

6. Payment in Lieu of Taxes

In October 1992, the Partnership entered into a Payment in Lieu of Taxes ("PILOT") agreement with the Town of Bethlehem Industrial Development Agency ("IDA"), a corporate governmental agency which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1993, and will terminate on December 31, 2012. The Partnership amended the PILOT agreement effective January 1, 2010; as a result payments are due monthly in 2010 and semi-annually thereafter. The Partnership which recognizes PILOT payments on a straight-line basis over the term of the agreement expensed $2,920,000 for each of the years ended December 31, 2009 and 2008 which is included in general and administrative expense in the accompanying consolidated statements of operations.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

6. Payment in Lieu of Taxes (Continued)

As of December 31, 2009, the future payments remaining under the PILOT are as follows:

(in thousands of dollars)	
2010	$ 4,203
2011	4,300
2012	4,400
	$ 12,903

7. Fair Value of Financial Instruments

The Partnership's natural gas supply contracts are accounted for as derivative contracts (Note 2). The Partnership uses a valuation model to derive the fair value of its derivative contracts based upon the present value of known or estimated cash flows taking into consideration multiple inputs including commodity prices, volatility factors and discount rates, as well as counterparty credit ratings and credit enhancements. The model used reflects the contractual terms of, and specific risks inherent in, the contracts as well as the availability of pricing information in the market. Where possible, the Partnership verifies the values produced by its pricing model to market transactions. Due to the fact that the Partnership's contracts trade in less liquid markets, model selection requires significant judgment because such contracts tend to be more complex and pricing information is less available in these markets. Price transparency is inherently more limited for more complex structures because of the nature, location and tenor of the arrangement, which requires additional inputs such as correlations and volatilities. In addition to model selection, management makes significant judgments based upon the Partnership's proprietary views of market factors and conditions regarding price and correlation inputs in unobservable periods and adjustments to reflect various factors such as liquidity, bid/offer spreads and credit considerations. If available, these adjustments are based on market evidence.

The Partnership adjusts the inputs to its valuation models only to the extent that changes in these inputs can be verified by similar market transactions, third-party pricing services and/or broker quotes, or can be derived from other substantive evidence such as empirical market data. In circumstances where the Partnership cannot verify the model to market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

7. Fair Value of Financial Instruments (Continued)

The following table sets forth the Partnership's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level at December 31, 2009:

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets				
Derivative contract	$	$	$ 53,416	$ 53,416
Liabilities				
Derivative contract			(5,805)	(5,805)
	$	$	$ 47,611	$ 47,611

The following table sets forth a reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs for the year ended December 31, 2009.

(in thousands of dollars)	
Fair value of derivatives based on significant unobservable inputs at January 1, 2009	$ 52,819
Unrealized losses(1)	(5,208)
Fair value of derivatives based on significant unobservable inputs at December 31, 2009	$ 47,611

The following table sets forth the Partnership's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level at December 31, 2008:

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)	Total
Assets				
Derivative contract	$	$	$ 59,386	$ 59,386
Liabilities				
Derivative contract			(6,567)	(6,567)
	$	$	$ 52,819	$ 52,819

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

7. Fair Value of Financial Instruments (Continued)

The following table sets forth a reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs for the year ended December 31, 2008.

(in thousands of dollars)

Fair value of derivatives based on significant unobservable inputs at January 1, 2008(2)	$ 108,701
Unrealized losses(1)	(55,882)
Fair value of derivatives based on significant unobservable inputs at December 31, 2008	$ 52,819

(1) Unrealized losses on derivative contracts are reflected in operating expenses in consolidated statements of operations for the years ended December 31, 2009 and 2008. Each of the contracts contributing to the unrealized loss was still held by the Partnership at December 31, 2009.

(2) Includes Day One gain of $126.7 million, recorded as an adjustment to retained earnings upon the adoption of fair value guidance (Note 2).

The fair value of the 2012 Bonds as of December 31, 2009 and 2008 was $142,777,000 and $173,527,000, respectively. The estimated fair values were based on a valuation model which discounts future cash flows produced by the 2012 Bonds at a rate determined by applying a spread based on the credit rating to the U.S. Treasury rates. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the fair value estimates as of December 31, 2009 and 2008, are not necessarily indicative of amounts the Partnership could have realized in current markets.

The Partnership's additional financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, due to affiliates, and accrued liabilities. These instruments approximate their fair values as of December 31, 2009 and 2008 due to their short-term nature.

8. Concentration of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations (including accounts receivable). The Partnership primarily conducts business with counterparties in the energy industry, such as investor-owned utilities, energy trading companies, financial institutions, gas production companies and gas transportation companies located in the United States and Canada. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated at investment grade or better by a major credit rating agency or have a history of reliable performance within the energy industry.

As of December 31, 2009, the Partnership's credit risk is primarily concentrated with the following customers: Con Edison, New York Independent System Operator ("NYISO"), Shell Energy North America (Canada) Inc. and ("Shell Energy North America"). These counterparties provided 96% of the Partnership's revenues for the year ended December 31, 2009 and accounted for approximately

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

8. Concentration of Credit Risk (Continued)

89% of the Partnership's accounts receivable balance at December 31, 2009. The Partnership also has credit risk concentrated with counterparties who are contractually obligated to provide fuel supply and transportation (Note 9).

9. Commitments and Contingencies

Power Purchase Agreements

The Partnership has a power purchase agreement with Con Edison for a term of 20-years that began on September 1, 1994, the date Unit 2's commercial operations commenced (the "Con Edison Power Purchase Agreement"). The Con Edison Power Purchase Agreement provides Con Edison the right to schedule Unit 2 for dispatch on a daily basis at full capability, partial capability or off-line. Con Edison's scheduling decisions are required to be based in part on economic criteria which, pursuant to the governing rules of the NYISO, take into account the variable cost of the electricity to be delivered. The Con Edison Power Purchase Agreement provides for Con Edison to make a monthly contract payment to the Partnership consisting of four components: (i) capacity, (ii) fuel, (iii) O&M, and (iv) wheeling. The capacity payment, a portion of the fuel payment, a portion of the O&M payment, and the wheeling payment are fixed and paid on the basis of the availability of Unit 2 to operate, whether or not Unit 2 is dispatched on-line. The fixed charges are subject to reduction if Unit 2's average availability is less than 90% for the four-month summer period (June through September) or is less than 80% during the rest of the year. The variable portions of the fuel payment and O&M payment are payable based on the amount of electricity produced by Unit 2 and delivered to Con Edison. The total fixed and variable fuel payment is capped at a ceiling price established in accordance with the Con Edison Power Purchase Agreement. Payments from Con Edison may also include a "savings component", which is equal to one-half of the amount by which Unit 2's actual fixed and variable fuel commodity and transportation costs are less than the ceiling price.

Steam Sale Agreements

The Partnership has a steam sales agreement, as amended, with SABIC for a term of 20-years from the commercial operations date of Unit 2 which may be extended under certain circumstances (the "Steam Sales Agreement"). The Steam Sales Agreement may be terminated by the Partnership with a one-year advanced written notice upon the termination of the power purchase agreement with Con Edison. The Steam Sales Agreement may also be terminated by SABIC with a 2-year advanced written notice if the SABIC IP plant no longer has a requirement for steam. Pursuant to the Steam Sales Agreement the Partnership is obligated to sell up to 400,000 lbs/hr of the thermal output of Unit 1 and Unit 2 for use as process steam by the SABIC IP plant adjacent to the Facility. The Partnership charges SABIC a nominal price for delivered steam in an amount up to the annual equivalent of 160,000 lbs/hr during each hour in which the SABIC IP plant is in production (the "Discounted Quantity"). Steam sales in excess of the Discounted Quantity are priced at SABIC's avoided variable direct cost, subject to an "annual true-up" to ensure that SABIC receives the annual equivalent of the Discounted Quantity at nominal pricing.

Under the Steam Sales Agreement, SABIC is obligated to purchase the minimum quantities of steam necessary for the Facility to maintain its Qualifying Facility status (Note 1). In the event SABIC

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

9. Commitments and Contingencies (Continued)

fails to meet the minimum purchase quantity, the Partnership may acquire title to the Facility site and terminate the operating lease agreement with SABIC at no cost to the Partnership.

Supply and Transportation Agreements

The Unit 1 gas supply contract with Shell Energy North America has a 7-year term beginning November 1, 2005, and gives the Partnership the right to purchase a maximum daily quantity of natural gas of 15,000 MMBtu at a commodity price that adjusts, on a monthly basis, with changes in a specified market index for natural gas, and does not impose a minimum contract volume purchase obligation on the Partnership. The Partnership also has a fuel management agreement with Shell Energy North America for a 7-year period beginning November 1, 2005. The Partnership has posted two letters of credit in the aggregate amount of $15,000,000 to support obligations under its agreements with Shell Energy North America (Note 4).

The Partnership entered into long-term contracts (collectively, the "Unit 1 Gas Transportation Contracts") for the transportation of natural gas volumes generally used to operate Unit 1 on a firm basis with TransCanada Pipelines Limited ("TransCanada"), Iroquois Gas Transmissions System, L.P. ("Iroquois") and Tennessee Gas Pipeline Company ("Tennessee"). Each of the Unit 1 Gas Transportation Contracts has a term of 20-years beginning November 1, 1992. In conjunction with the restructuring of the long-term gas supply agreement generally used to supply natural gas to operate Unit 1, effective November 1, 2005, the Partnership permanently assigned the capacity under the Unit 1 Gas Transportation Contract with TransCanada to Shell Energy North America.

To supply natural gas needed to operate Unit 2, the Partnership entered into 15-year gas supply agreements beginning November 1, 1994 ("Original Unit 2 Gas Supply Contracts") with Imperial Oil Resources ("Imperial"), EnCana Corporation ("EnCana") and Canadian Forest Oil Ltd. ("CFOL"), (collectively, the "Unit 2 Gas Suppliers"), each on a firm basis. During the fourth quarter of 2004, the Partnership restructured its agreements with the Unit 2 Gas Suppliers to modify the Original Unit 2 Gas Supply Contracts and/or enter into new agreements for an extended term ("Restructured Unit 2 Gas Supply Contracts"). As a result of the restructuring, the Unit 2 Gas Suppliers will continue supplying gas to the Partnership for an additional five-year period beginning November 1, 2009. The commodity price of natural gas under the Restructured Unit 2 Gas Supply Contracts adjusts, on a monthly basis, with changes in specified market indices for natural gas or a combination of natural gas and oil. The Restructured Unit 2 Gas Supply Contracts allow for the Partnership to purchase a maximum daily quantity of natural gas of 58,660 MMBtu with an average minimum contract volume purchase obligation of approximately 55% of the maximum daily quantity.

The Partnership entered into certain long-term contracts (collectively, the "Unit 2 Gas Transportation Contracts") for the transportation of natural gas volumes generally used to operate Unit 2 on a firm basis with TransCanada, Iroquois and Tennessee. Each of the Unit 2 Gas Transportation Contracts has a term of 20-years beginning November 1, 1994. Under one of these agreements, the fuel transporter has exercised its right to require the Partnership to post letters of credit on an annual basis. The Partnership has posted a letter of credit for approximately $2,925,000 U.S. dollars and two fuel suppliers, on behalf of the Partnership, have posted letters of credit totaling approximately $8,769,000 Canadian dollars (Note 4). The Partnership is obligated to reimburse the fuel

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

9. Commitments and Contingencies (Continued)

suppliers for all amounts related to obtaining and maintaining the letters of credit and, under certain circumstances, for any amounts drawn upon the letters of credit.

Electric Transmission Agreements

The Partnership has an interconnection agreement with Niagara Mohawk to interconnect the power output from Unit 1 to Niagara Mohawk's electric transmission system through April 16, 2012. Payments under the interconnection agreement are fixed at $39,000 per year, prorated for 2012.

The Partnership also has a 20-year firm transmission agreement with Niagara Mohawk to transmit the power output from Unit 2 to Con Edison through August 31, 2014, with payment fixed at $5,702,000 per year. Co-terminus with this agreement, the Partnership has an interconnection agreement with Niagara Mohawk to interconnect the power output from Unit 2 to Niagara Mohawk's electric transmission system. Payments under this interconnection agreement are fixed at $450,000 per year.

Operations and Maintenance Agreement

The Partnership has an operations and maintenance services agreement ("O&M Agreement") with General Electric Company ("GE") whereby GE provides certain operation and maintenance services to the Facility through December 31, 2012. Payments under the O&M Agreement include, in addition to other payments, a fixed payment of $235,000 annually through the term of the O&M Agreement.

The Partnership also has a multi-year maintenance program agreement ("MMP Agreement") with GE. Under the MMP Agreement the Partnership is obligated to purchase approximately $9,750,000 in parts and services by December 31, 2012. As of December 31, 2009, the Partnership purchased approximately $13,216,000 in parts and services from GE under the MMP Agreement.

Other

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

10. Related Parties

JMCS I Management manages the day-to-day operation of the Partnership and is compensated at agreed-upon billing rates that are adjusted every four-years in accordance with an administrative services agreement. The cost of services provided by JMCS I Management were approximately $2,043,000 and $1,984,000 for the years ended December 31, 2009 and 2008, respectively, and are included in operation and maintenance expense in the accompanying consolidated statements of operations. The total amount due to JMCS I Management at December 31, 2009 and 2008 was approximately $216,000 and $120,000, respectively.

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Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Financial Statements

December 31, 2008 and 2007

The consolidated financial statements of Selkirk Cogen Partners, L.P. and its subsidiary for the years ended December 31, 2008 and 2007, are presented herein without the related report of independent accountants for the year ended December 31, 2008. The report of independent accountants is presented for the year ended December 31, 2007 pursuant to the requirements of Rule 3-09 of Regulation S-X.

PricewaterhouseCoopers LLP
Two Commerce Square, Suite 1700
2001 Market Street
Philadelphia PA 19103-7042
Telephone (267) 330 3000
Facsimile (267) 330 3300

Report of Independent Auditors

To the Partners of
Selkirk Cogen Partners, LP.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, of changes in partners' (deficit) capital, and of cash flows present fairly, in all material respects, the financial position of Selkirk Cogen Partners, L.P. and its subsidiary (collectively, the "Partnership") at December 31, 2007, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

March 10, 2008

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Balance Sheets

December 31, 2008 and 2007

(in thousands of dollars)	2008	2007
Assets		
Current assets		
Cash and cash equivalents	$ 4,457	$ 3,753
Restricted cash	6,760	10,710
Accounts receivable	22,819	26,745
Inventory	3,793	4,566
Derivative contracts	19,434	24,168
Other assets	1,700	2,059
Total current assets	58,963	72,001
Restricted cash	34,584	32,225
Inventory	4,497	5,957
Derivative contracts	39,952	61,175
Property and equipment, net of accumulated depreciation of $188,617 and $175,505, respectively	192,396	205,339
Deferred financing costs, net of accumulated amortization of $15,134 and $14,508, respectively	1,157	1,783
Other assets	267	
Total assets	$ 331,816	$ 378,480
Liabilities and Partners' Capital		
Current liabilities		
Current portion of long-term debt	$ 43,905	$ 42,998
Accounts payable	16,079	15,218
Due to affiliates	120	774
Accrued property taxes	2,050	4,000
Other accrued liabilities	4,742	4,076
Derivative contracts	2,154	2,647
Deferred revenue		354
Total current liabilities	69,050	70,067
Long-term debt	129,053	172,958
Derivative contracts	4,413	100,650
Other liabilities	1,333	2,505
Total liabilities	203,849	346,180
Commitments and contingencies		
Partners' capital		
General partners	1,228	270
Limited partners	126,739	32,030
Total partners' capital	127,967	32,300
Total liabilities and partners' capital	$ 331,816	$ 378,480

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Statements of Operations

Years Ended December 31, 2008 and 2007

(in thousands of dollars)	2008	2007
Operating revenues		
Energy	$ 182,175	$ 140,329
Capacity	106,933	122,685
Commodity sales	60,219	58,847
Transmission	11,038	10,606
Steam		360
Total operating revenues	360,365	332,827
Operating expenses		
Fuel	180,822	136,068
Operations and maintenance	19,264	12,744
Commodity cost of sales	46,651	45,595
Transmission	12,191	11,216
General and administrative	5,344	5,483
Depreciation	13,112	12,953
Unrealized loss on derivative contracts	55,882	876
Total operating expenses	333,266	224,935
Total operating income	27,099	107,892
Other income (expense)		
Interest income	1,835	3,338
Interest expense	(19,379)	(23,011)
Net income	$ 9,555	$ 88,219

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Statements of Operations (Continued)

Years Ended December 31, 2008 and 2007

(in thousands of dollars)	General Partners	Limited Partners	Total
Partners' (deficit) capital at December 31, 2006	$ (39)	$ 376	$ 337
Net income	884	87,335	88,219
Capital distributions	(575)	(55,681)	(56,256)
Partners' capital at December 31, 2007	270	32,030	32,300
Implementation of SFAS 157	1,269	125,385	126,654
Net income	96	9,459	9,555
Capital distributions	(407)	(40,135)	(40,542)
Partners' capital at December 31, 2008	$ 1,228	$ 126,739	$ 127,967

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Consolidated Statements of Cash Flows

Years Ended December 31, 2008 and 2007

(in thousands of dollars)	**2008**	**2007**
Cash flows from operating activities		
Net income	$ 9,555	$ 88,219
Noncash items included in net income:		
Depreciation	13,112	12,953
Amortization of deferred financing costs	626	745
Amortization of deferred revenue	(354)	(708)
Accretion of asset retirement obligation	6	7
Loss on disposal of equipment		8
Unrealized loss on derivative contracts	55,882	876
Changes in operating assets and liabilities:		
Accounts receivable	3,926	(3,225)
Inventory	2,233	(106)
Other assets	80	(502)
Accounts payable	905	2,316
Accrued property taxes	(1,950)	100
Other accrued liabilities	668	(855)
Due to affiliates	(162)	29
Other liabilities	(1,179)	(1,079)
Net cash provided by operating activities	83,348	98,778
Cash flows from investing activities		
Decrease (increase) in restricted cash	1,591	(1,744)
Capital expenditures	(695)	(649)
Net cash provided by (used in) investing activities	896	(2,393)
Cash flows from financing activities		
Distributions to partners	(40,542)	(56,256)
Repayment of long-term debt	(42,998)	(39,441)
Cash used in financing activities	(83,540)	(95,697)
Net increase in cash and cash equivalents	704	688
Cash and cash equivalents		
Beginning of year	3,753	3,065
End of year	$ 4,457	$ 3,753
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 18,449	$ 22,006
Noncash investing activities		
Capital expenditures which were accrued but not paid	$ 12	$ 550
Capital expenditures previously accrued which were paid	$ 550	$ 53

The accompanying notes are an integral part of these consolidated financial statements.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

1. Organization and Nature of Business

Selkirk Cogen Partners, L.P. was organized on December 15, 1989 as a Delaware limited partnership. Selkirk Cogen Funding Corporation (the "Funding Corporation"), a wholly-owned subsidiary of Selkirk Cogen Partners, L.P. (collectively, the "Partnership"), was organized for the sole purpose of facilitating financing activities of the Partnership and has no other operating activities (Note 4).

The managing general partner of the Partnership is JMC Selkirk, LLC, (f/k/a JMC Selkirk, Inc.), ("JMC Selkirk" or the "Managing General Partner"). The other general partner of the Partnership (together with JMC Selkirk, the "General Partners") is RCM Selkirk GP, Inc. ("RCM Selkirk GP"). The limited partners of the Partnership (the "Limited Partners", and together with the General Partners, the "Partners") are JMC Selkirk, PentaGen Investors, L.P. ("PentaGen"), Teton Selkirk, LLC ("Teton Selkirk") and RCM Selkirk, L.P. ("RCM Selkirk LP").

The general and limited partners and their respective equity interests are as follows:

Partners	Affiliated With	Preferred (i)	Interest(1) Original (ii)	Residual (iii)
General Partners				
JMC Selkirk	Cogentrix Energy, LLC and EIF Calypso, LLC(2)	0.09%	1.00%	0.81%
RCM Selkirk GP	Robert C. McNair and Family	1.00%	0.00%	0.22%
Limited Partners				
JMC Selkirk	Cogentrix Energy, LLC and EIF Calypso, LLC(2)	1.95%	21.40%	17.33%
PentaGen	Cogentrix Energy, LLC, EIF Calypso, LLC(2), and Osaka Gas Energy America Corporation	5.25%	57.60%	46.66%
Teton Selkirk	Atlantic Power Holdings, LLC	13.55%	20.00%	17.70%
RCM Selkirk	Robert C. McNair and Family	78.16%	0.00%	17.28%

(1) Percentages indicate the interest of (i) each of the Partners in certain priority distributions of available cash of the Partnership, up to fixed semi-annual amounts (the "Level I Distributions"), (ii) JMC Selkirk, PentaGen and Teton Selkirk in 99% of distributions of the remaining available cash of the Partnership; and (iii) each of the Partners in the residual tier of interests in cash distributions after the initial 18-year period following the commercial operation of Unit 2 (August 2012 or, if later, the date when all Level I Distributions have been paid).

(2) Prior to November 2007, Cogentrix Energy, LLC (f/k/a Cogentrix Energy, Inc.), ("CELLC"), indirectly owned 100% of the general and limited partner interests of JMC Selkirk and 50% of the limited partner interest of PentaGen. In November 2007, CELLC transferred 100% of its ownership interest in JMC Selkirk and 99.5712% of its ownership interest in PentaGen to Calypso Energy Holdings LLC ("Calypso"). Subsequent to the transfer, CELLC sold an 80% interest in Calypso to EIF Calypso, LLC, a Delaware limited liability company managed by Energy investor Funds ("EIF"), a private equity fund manager, resulting in CELLC holding a 20% membership interest in Calypso at December 31, 2007.

The Managing General Partner is responsible for managing and controlling the business and affairs of the Partnership, subject to certain powers, which are vested in the management committee of the

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

1. Organization and Nature of Business (Continued)

Partnership (the "Management Committee") under the Partnership Agreement. Each General Partner has a voting representative on the Management Committee, which, subject to certain limited exceptions, acts by unanimity. Thus, the General Partners, and principally the Managing General Partner, exercise control over the Partnership. JMCS I Management, LLC ("JMCS I Management"), an affiliate of the Managing General Partner and wholly-owned subsidiary of CELLC, is acting as the project management firm (the "Project Management Firm") for the Partnership, and as such is responsible for the implementation and administration of the Partnership's business under the direction of the Managing General Partner. Upon the occurrence of certain events specified in the Partnership Agreement, RCM Selkirk GP may assume the powers and responsibilities of the Managing General Partner and of the Project Management Firm. Under the Partnership Agreement, each General Partner other than the Managing General Partner may convert its general partnership interest to that of a Limited Partner. Under terms of the limited liability agreement of Calypso, (the "Calypso LLC Agreement"), EIF indirectly has the power to control the Managing General Partner, subject to certain restrictions contained in the Calypso LLC Agreement.

The Partnership was formed for the purpose of constructing, owning and operating a natural gas-fired, combined-cycle cogeneration facility located on a 15.7 acre site leased from Saudi Basic Industries Corporation ("SABIC") in Bethlehem, New York (the "Facility"), which SABIC acquired from the General Electric Company ("GE") in 2007. The Facility has a total electric generating capacity of 345 megawatts ("MW") with a maximum average steam output of 400,000 pounds per hour ("lbs/hr"). The Facility consists of one unit ("Unit 1") with an electric generating capacity of approximately 79.9 MW and a second unit ("Unit 2") with an electric generating capacity of approximately 265.0 MW (collectively, the "Units"). The Units have been designed to operate independently for electrical generation, while thermally integrated for steam generation. Unit 1 commenced commercial operations on April 17, 1992, and Unit 2 commenced commercial operations on September 1, 1994.

The Partnership had a long-term contract with Niagara Mohawk Power Corporation ("Niagara Mohawk") for the sale of electric capacity and energy produced by Unit 1, which expired June 30, 2008 ("Amended and Restated Niagara Mohawk Power Purchase Agreement"). The Partnership has a long-term contract with Consolidated Edison Company of New York, Inc. ("Con Edison") for the sale of electric capacity and energy produced by Unit 2. The Partnership has a long-term contract with SABIC for the sale of steam produced by the Facility and delivered to SABIC Innovative Plastics, ("SABIC IP"), a subsidiary of Saudi Basic Industries Corporation. The Facility uses natural gas purchased principally from Canadian suppliers under long-term gas supply contracts as its primary fuel input.

The Facility is certified by the Federal Energy Regulatory Commission as a qualifying facility ("Qualifying Facility") under the Public Utility Regulatory Policy Act of 1978, as amended ("PURPA"). As a Qualifying Facility, the prices charged for the sale of energy and steam are not regulated. Certain fuel supply and transportation agreements entered into by the Partnership are also subject to regulation on the federal and provincial levels in Canada. The Partnership has obtained all material Canadian governmental permits and authorizations required for its operation.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Significant Accounting Policies

Basis of Presentation

The Partnership applies the provisions of Financial Accounting Standards Board ("FASB") Interpretation No. ("FIN") 46-R, *Consolidation of Variable Interest Entities an Interpretation of ARB 51* and associated FASB Staff Positions. FIN 46-R requires the consolidation of an entity by an enterprise that absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interest in the entity.

The Funding Corporation was determined to be a variable interest entity ("VIE") in accordance with FIN 46-R. Based on an analysis performed in conjunction with the adoption of FIN 46-R, Selkirk Cogen Partners, L.P. was deemed to be the primary beneficiary. As a result, Funding Corporation is included in the Partnership's consolidated financial statements. All significant intercompany transactions and balances have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for debt service, major maintenance and other specifically designated accounts under a deposit and disbursement agreement ("Depositary Agreement").

Included in long-term assets at December 31, 2008 was approximately $30,723,000 and $3,861,000 in restricted cash for debt service reserve and major maintenance reserve, respectively. At December 31, 2007, approximately $30,723,000 and $1,502,000 in restricted cash was included in long-term assets for debt service and major maintenance, respectively.

Inventory

Spare parts are valued at the lower of average cost or market and consist of Facility equipment components and maintenance supplies required to be maintained in order to facilitate maintenance activities. Spare parts which are expected to be utilized during the next year are classified as current in the accompanying consolidated balance sheets. Spare parts which are not expected to be utilized within the next year are classified as long-term in the accompanying consolidated balance sheets.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Significant Accounting Policies (Continued)

The Partnership performs periodic assessments to determine the existence of obsolete, slow-moving and non-usable spare parts and records necessary provisions to reduce such inventories to net realizable value.

Derivative Contracts

The Partnership follows Statement of Financial Accounting Standards No. ("SFAS") 133, *Accounting for Derivative Instruments and Hedging Activities as Amended and Interpreted.* SFAS 133 requires the Partnership to recognize all derivatives, as defined in the statement, on the consolidated balance sheets at fair value. Derivatives or any portion thereof, that are not designated as, and effective as, hedges must be adjusted to fair value through earnings. Derivative contracts are classified as either assets or liabilities on the consolidated balance sheets (Note 6).

Fair Value Measurements

The Partnership adopted SFAS 157, *Fair Value Measurements,* for financial assets and liabilities effective January 1, 2008. This standard defines fair value, provides guidance for measuring fair value and requires certain disclosures. This standard does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements. As a result of the adoption of SFAS 157 the Partnership recognized an approximate $126.7 million gain as an adjustment to retained earnings previously prohibited by Emerging Issues Task Force No. ("EITF") 02-3, *Issues Involved in Energy Trading and Risk Management Activities.*

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under SFAS 157 are described below:

Level 1: Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2: Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3: Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (Note 6).

Property and Equipment

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Significant Accounting Policies (Continued)

is included in the results of operations for the respective period. Depreciation is provided over the estimated useful lives of the related assets using the straight-line method. Capitalized modifications to leased properties are depreciated using the straight-line method over the shorter of the lease term or the asset's estimated useful life (Note 3).

The Partnership's depreciation is based on the Facility being considered as a single property unit. Certain components of the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where replacement of a Facility component is significant and the Partnership can reasonably estimate the original cost of the component being replaced, the Partnership will write off the replaced component and capitalize the cost of the replacement. The component will be depreciated over the lesser of the estimated useful life of the component or the remaining useful life of the Facility.

The Partnership accounts for the impairment or disposal of their property and equipment in accordance with SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property is used, and the effects of obsolescence, demand, competition, and other economic factors.

Asset Retirement Obligation

The Partnership accounts for asset retirement obligations in accordance with SFAS 143, *Accounting for Asset Retirement Obligations* and FIN 47, *Accounting for Conditional Asset Retirement Obligations.* These statements require that an asset retirement obligation, including those conditioned on future events, be recorded at fair value in the period in which it is incurred, if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership recognized an asset retirement obligation at December 31, 2008 and 2007 of approximately $120,000 and $114,000, respectively. This obligation is included in other liabilities and represents the costs the Partnership would incur to perform environmental clean-up or remove certain portions of the Facility.

Deferred Financing Costs

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the related financing.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Significant Accounting Policies (Continued)

Accounting for Income Taxes

As a partnership, the income tax effects accrue directly to the partners, and each partner is individually responsible for its share of the combined income or loss. Accordingly, no income tax provision is recorded in the accompanying consolidated statements of operations.

Revenue Recognition

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in fuel and transmission expenses.

The Partnership's long-term gas supply contracts are not designated as, nor do they qualify as, held for trading purposes. Thus, the related realized gains and losses on these derivative contracts are reported in the statement of operations in accordance with EITF 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement 133 and Not Held for Trading Purposes* as *Defined in EITF 02-3.*

Revenues from the sale of gas are recorded in the month sold and take place in the form of (i) short-term transactions whereby the Partnership resells its firm natural gas supply volumes when Unit 1 or Unit 2 is dispatched off-line or at less than full capacity ("Gas Resales"), and (ii) short-term transactions whereby the Partnership attempts to lower the cost of natural gas delivered to the Facility by reselling certain of its firm natural gas supply volumes and purchasing replacement gas supply volumes at lower prices in the spot market, to meet the Facility's scheduled operation ("Gas Supply Cost Mitigation"). Gas Resales are recorded on a gross basis on the accompanying consolidated statements of operations in commodity sales, with the associated costs recorded in commodity cost of sales. Gas Resales are recorded on a gross basis because the Partnership's decision to sell its firm natural gas supply is primarily driven by the dispatch of the Facility. Gas Supply Cost Mitigation is included on a net basis in fuel on the accompanying consolidated statements of operations based on the premise that the Partnership's decision to sell its firm natural gas supply is primarily driven by the intent to lower the cost of natural gas delivered to the Facility for scheduled operation.

Reclassifications

Certain reclassifications have been made to the prior year's consolidated financial statements to conform to the current year presentation. These reclassifications had no effect on the previously reported results of operations or retained earnings.

Recent Accounting Pronouncements

In March 2008, the Financial Accounting Standards Board ("FASB") issued SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities.* This standard is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements; how derivative instruments and related hedged items are accounted for under SFAS No 133; and how derivative instruments and related hedged items affect its financial

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Significant Accounting Policies (Continued)

position, financial performance and cash flows. SFAS No. 161 will be effective for the Company's fiscal year beginning January 1, 2009.

In February 2008, the FASB issued a one-year deferral for non-financial assets and liabilities to comply with SFAS 157. The Partnership expects the adoption of SFAS 157 as it applies to non-financial assets and liabilities will have no material effect on the consolidated financial statements.

3. Property and Equipment

As of December 31, property and equipment consisted of the following components:

(in thousands of dollars)	2008	2007
Facility	$ 377,065	$ 377,056
Facility improvements	71	
Leasehold improvements	353	353
Machinery and equipment	876	824
Computer systems	2,336	2,299
Office equipment	312	312
	381,013	380,844
Less: Accumulated depreciation	(188,617)	(175,505)
	$ 192,396	$ 205,339

The estimated useful lives ("EUL") for significant property and equipment categories are as follows:

Facility	30 years
Facility improvements	10 - 30 years
Leasehold improvements	Lesser of lease term or asset's EUL
Machinery and equipment	5 - 15 years
Computer systems	3 - 5 years
Office equipment	5 years

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

4. Long-term Debt

As of December 31, the Partnership had the following bonds and loans payable:

(in thousands of dollars)

	As of December 31, 2008			For the Year Ended December 31, 2008		
Description	**Commitment Amount**	**Due Date**	**Balance Outstanding**	**Interest Expense**	**Commitment Fees**	**Letter of Credit Fees**
2012 Bonds(1)	$ 172,958	6/26/12	$ 172,958	$18,449	N/A	N/A
Credit Agreement(2)						
Working Capital Loan	22,075	6/30/12			$ 108	N/A
Letter of Credit Facility						
Fuel Supply	10,000	6/30/12		N/A	N/A	$ 100
Fuel Management	5,000	6/30/12		N/A	N/A	50
Gas Transportation	2,925	8/3/09		N/A	N/A	29
CO^2 Allowance Auction	5.000	1/2/09		N/A	N/A	4
			172,958			
Less: Current portion			43,905			
			$ 129,053			

(in thousands of dollars)

	As of December 31, 2007			For the Year Ended December 31, 2007		
Description	**Commitment Amount**	**Due Date**	**Balance Outstanding**	**Interest Expense**	**Commitment Fees**	**Letter of Credit Fees**
2007 Bonds	$	12/26/07	$	$ 1,594	N/A	N/A
2012 Bonds(1)	215,956	6/26/12	215,956	20,374	N/A	N/A
Credit Agreement(2)						
Working Capital Loan	27,075	10/31/10			$ 108	N/A
Letter of Credit Facility						
Fuel Supply	10,000	10/31/10		N/A	N/A	$ 100
Fuel Management	5,000	10/23/10		N/A	N/A	50
Gas Transportation	2,925	8/3/09		N/A	N/A	29
			215,956			
Less: Current portion			42,998			
			$ 172,958			

(1)
The 2012 bonds were issued by the Funding Corporation on May 9, 1994 ("2012 Bonds") and are pledged by substantially all of the assets of the Partnership and are non-recourse to the individual Partners. The obligations of the Funding Corporation with respect to the 2012 Bonds are unconditionally guaranteed by the Partnership. The trust indenture restricts the ability of the Partnership to make distributions to the Partners under certain circumstances. Interest is fixed at

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

4. Long-term Debt (Continued)

8.98% with interest payments due semi-annually on June 26 and December 26. Principal payments commenced on December 26, 2007, and are payable semi-annually thereafter.

(2)

The Partnership has a credit agreement for $45,000,000, which is available to the Partnership for working capital purposes, including the provision of letters of credit (the "Credit Agreement"). Outstanding balances of loans under the Credit Agreement bear interest at a rate equal to, at the Partnership's option, either (i) a base rate equal to the greater of (x) the sum of the federal funds rate plus 0.50% and (y) the prime rate publicly announced by Citizens Bank of Massachusetts, payable quarterly in arrears, or (ii) LIBOR plus 1.00% (increased to 1.25% if the Partnership's credit rating from Standard & Poor's ("S&P") falls below BBB-), payable at the end of the applicable interest period (or quarterly for interest periods of more than three months). As of December 31, 2008 and 2007, the Partnership has issued letters of credit totaling approximately $22,925,000 and $17,925,000 to support obligations under certain of the Partnership's fuel related agreements (Note 8), respectively.

As of December 31, 2008, the scheduled principal payments on the 2012 Bonds are as follows:

(in thousands of dollars)		
2009	$	43,905
2010		44,579
2011		55,070
2012		29,404
	$	172,958

Included in other accrued liabilities at December 31, 2008 and 2007 was approximately $216,000 and $215,000 of accrued interest expense, respectively. The Partnership is subject to various operational and financial covenants all of which the Partnership was in compliance with at December 31, 2008.

5. Property Taxes

In October 1992, the Partnership entered into a Payment in Lieu of Taxes ("PILOT") agreement with the Town of Bethlehem Industrial Development Agency ("IDA"), a corporate governmental agency which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1993, and will terminate on December 31, 2012. PILOT payments are due semiannually and are recognized on a straight-line basis over the term of the agreement. The Partnership expensed approximately $2,920,000 related to the PILOT, which is included in general and administrative expense in the accompanying consolidated statements of operations for the years ended December 31, 2008 and 2007, respectively.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

5. Property Taxes (Continued)

As of December 31, 2008, the payments remaining under the PILOT are as follows:

(in thousands of dollars)	
2009	$ 2,050
2010	4,200
2011	4,300
2012	4,400
	$ 14,950

6. Fair Value of Financial Instruments

The Partnership's natural gas supply contracts are accounted for as derivative contracts under the provisions of SFAS 133. The Partnership uses a valuation model to derive the fair value of its derivative contracts based upon the present value of known or estimated cash flows taking into consideration multiple inputs including commodity prices, volatility factors and discount rates, as well as counterparty credit ratings and credit enhancements. The model used reflects the contractual terms of, and specific risks inherent in, the contracts as well as the availability of pricing information in the market. Where possible, the Partnership verifies the values produced by its pricing model to market transactions. Due to the fact that the Partnership's contracts trade in less liquid markets, model selection requires significant judgment because such contracts tend to be more complex and pricing information is less available in these markets. Price transparency is inherently more limited for more complex structures because of the nature, location and tenor of the arrangement, which requires additional inputs such as correlations and volatilities. In addition to model selection, management makes significant judgments based upon the Partnership's proprietary views of market factors and conditions regarding price and correlation inputs in unobservable periods and adjustments to reflect various factors such as liquidity, bid/offer spreads and credit considerations. If available, these adjustments are based on market evidence.

The Partnership adjusts the inputs to its valuation models only to the extent that changes in these inputs can be verified by similar market transactions, third-party pricing services and/or broker quotes, or can be derived from other substantive evidence such as empirical market data. In circumstances where the Partnership cannot verify the model to market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

6. Fair Value of Financial Instruments (Continued)

The following table sets forth the Partnership's financial assets and liabilities and other fair value measurements made on a recurring basis by fair value hierarchy level at December 31, 2008.

(in thousands of dollars)	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Siginificant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets				
Derivative contract	$	$	$ 59,386	$ 59,386
Liabilities				
Derivative contract			(6,567)	(6,567)
	$	$	$ 52,819	$ 52,819

The following table sets forth a reconciliation of changes in the fair value of derivatives that are based on significant unobservable inputs for the year ended December 31, 2008.

(in thousands of dollars)	
Fair value of derivatives based on significant unobservable inputs at January 1, 2008(1)	$ 108,701
Unrealized losses(2)	(55,882)
Fair value of derivatives based on significant unobservable inputs at December 31, 2008	$ 52,819

(1) Includes Day One gain of $126.7 million, recorded as an adjustment to retained earnings upon the adoption of SFAS 157 (Note 2).

(2) Unrealized losses on derivative contracts are reflected in operating expenses in consolidated statement of operations for the year ended December 31, 2008. Each of the contracts contributing to the unrealized loss was still held by the Partnership at December 31, 2008.

The fair value of the 2012 Bonds as of December 31, 2008 and 2007 was $173,527 and $236,237 respectively. The estimated fair values were based on a valuation model which discounts future cash flows produced by the 2012 Bonds at a rate determined by applying a spread to the U.S. Treasury rates. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the fair value estimates as of December 31, 2008 and 2007, are not necessarily indicative of amounts the Partnership could have realized in current markets.

The carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, due to affiliates and other accrued liabilities approximate their fair value due primarily to their short-term nature.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

7. Concentration of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations (including accounts receivable). The Partnership primarily conducts business with counterparties in the energy industry, such as investor-owned utilities, energy trading companies, financial institutions, gas production companies and gas transportation companies located in the United States and Canada. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated at investment grade or better by a major credit rating agency or have a history of reliable performance within the energy industry.

As of December 31, 2008, the Partnership's credit risk is primarily concentrated with the following customers: Con Edison, NYISO, Shell Energy North America (Canada) Inc. (f/k/a Coral Energy Canada, Inc.), ("Shell Energy North America") and Sempra Energy Trading LLC ("Sempra"), which provide for approximately 93% of the Partnership's revenues for the year ended December 31, 2008 and account for approximately 100% of the Partnership's accounts receivable balance at December 31, 2008. The Partnership also has credit risk concentrated with counterparties who are contractually obligated to provide fuel supply and transportation (Note 8).

8. Commitments and Contingencies

Power Purchase Agreements

The Partnership has a power purchase agreement with Con Edison for a term of 20 years that began on September 1, 1994, the date Unit 2's commercial operations commenced (the "Con Edison Power Purchase Agreement"). The Con Edison Power Purchase Agreement provides Con Edison the right to schedule Unit 2 for dispatch on a daily basis at full capability, partial capability or off-line. Con Edison's scheduling decisions are required to be based in part on economic criteria which, pursuant to the governing rules of the NYISO, take into account the variable cost of the electricity to be delivered. The Con Edison Power Purchase Agreement provides for Con Edison to make a monthly contract payment to the Partnership consisting of four components: (i) capacity, (ii) fuel, (iii) O&M, and (iv) wheeling. The capacity payment, a portion of the fuel payment, a portion of the O&M payment, and the wheeling payment are fixed and paid on the basis of the availability of Unit 2 to operate, whether or not Unit 2 is dispatched on-line. The fixed charges are subject to reduction if Unit 2's average availability is less than 90% for the four-month summer period (June through September) or is less than 80% during the rest of the year. The variable portions of the fuel payment and O&M payment are payable based on the amount of electricity produced by Unit 2 and delivered to Con Edison. The total fixed and variable fuel payment is capped at a ceiling price established in accordance with the Con Edison Power Purchase Agreement. Payments from Con Edison may also include a "savings component", which is equal to one-half of the amount by which Unit 2's actual fixed and variable fuel commodity and transportation costs are less than the ceiling price.

Steam Sale Agreements

The Partnership has a steam sales agreement, as amended, with SABIC for a term of 20 years from the commercial operations date of Unit 2 which may be extended under certain circumstances (the "Steam Sales Agreement"). The Steam Sales Agreement may be terminated by the Partnership

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

8. Commitments and Contingencies (Continued)

with a one-year advanced written notice upon the termination of the power purchase agreement with Con Edison. The Steam Sales Agreement may also be terminated by SABIC with a 2-year advanced written notice if the SABIC IP plant no longer has a requirement for steam. Pursuant to the Steam Sales Agreement the Partnership is obligated to sell up to 400,000 lbs/hr of the thermal output of Unit 1 and Unit 2 for use as process steam by the SABIC IP plant adjacent to the Facility. The Partnership charges SABIC a nominal price for delivered steam in an amount up to the annual equivalent of 160,000 lbs/hr during each hour in which the SABIC IP plant is in production (the "Discounted Quantity"). Steam sales in excess of the Discounted Quantity are priced at SABIC's avoided variable direct cost, subject to an "annual true-up" to ensure that SABIC receives the annual equivalent of the Discounted Quantity at nominal pricing.

Under the Steam Sales Agreement, SABIC is obligated to purchase the minimum quantities of steam necessary for the Facility to maintain its Qualifying Facility status (Note 1). In the event SABIC fails to meet the minimum purchase quantity, the Partnership may acquire title to the Facility site and terminate the operating lease agreement with SABIC at no cost to the Partnership.

Gas Supply and Transportation Agreements

The Unit 1 Gas Supply Contract with Shell Energy North America has a 7-year term beginning November 1, 2005, and gives the Partnership the right to purchase a maximum daily quantity of natural gas of 15,000 MMBtu at a commodity price that adjusts, on a monthly basis, with changes in a specified market index for natural gas, and does not impose a minimum contract volume purchase obligation on the Partnership. The Partnership also has a fuel management agreement with Shell Energy North America for a 7-year period beginning November 1, 2005. The Partnership has posted two letters of credit in the aggregate amount of $15,000,000 to support obligations under its agreements with Shell Energy North America (Note 4).

The Partnership entered into long-term contracts (collectively, the "Unit 1 Gas Transportation Contracts") for the transportation of natural gas volumes generally used to operate Unit 1 on a firm basis with TransCanada Pipelines Limited ("TransCanada"), Iroquois Gas Transmissions System, L.P. ("Iroquois") and Tennessee Gas Pipeline Company ("Tennessee"). Each of the Unit 1 Gas Transportation Contracts has a term of 20 years beginning November 1, 1992. In conjunction with the restructuring of the long-term gas supply agreement generally used to supply natural gas to operate Unit 1, effective November 1, 2005, the Partnership permanently assigned the capacity under the Unit 1 Gas Transportation Contract with TransCanada to Shell Energy North America.

To supply natural gas needed to operate Unit 2, the Partnership entered into 15-year term gas supply agreements beginning November 1, 1994 ("Original Unit 2 Gas Supply Contracts") with Imperial Oil Resources ("Imperial"), EnCana Corporation ("EnCana", formerly known as PanCanadian Petroleum Limited) and Canadian Forest Oil Ltd. ("CFOL", formerly known as Producers Marketing Ltd.), (collectively, the "Unit 2 Gas Suppliers"), each on a firm basis. During the fourth quarter of 2004, the Partnership restructured its agreements with the Unit 2 Gas Suppliers to modify the Original Unit 2 Gas Supply Contracts and/or enter into new agreements for an extended term ("Restructured Unit 2 Gas Supply Contracts"). As a result of the restructuring, the Unit 2 Gas Suppliers will continue supplying gas to the Partnership for an additional five-year period beginning November 1, 2009. The commodity price of natural gas under the Restructured Unit 2 Gas Supply

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

8. Commitments and Contingencies (Continued)

Contracts adjusts, on a monthly basis, with changes in specified market indices for natural gas or a combination of natural gas and oil. The Restructured Unit 2 Gas Supply Contracts allow for the Partnership to purchase a maximum daily quantity of natural gas of 58,660 MMBtu with an average minimum contract volume purchase obligation of approximately 55% of the maximum daily quantity.

The Partnership entered into certain long-term contracts (collectively, the "Unit 2 Gas Transportation Contracts") for the transportation of natural gas volumes generally used to operate Unit 2 on a firm basis with TransCanada, Iroquois and Tennessee. Each of the Unit 2 Gas Transportation Contracts has a term of 20 years beginning November 1, 1994. Under one of these agreements, the fuel transporter has exercised its right to require the Partnership to post letters of credit on an annual basis. The Partnership has posted a letter of credit for approximately $2,925,000 U.S. dollars and two fuel suppliers, on behalf of the Partnership, have posted letters of credit totaling approximately $8,769,000 Canadian dollars (Note 4). The Partnership is obligated to reimburse the fuel suppliers for all amounts related to obtaining and maintaining the letters of credit and, under certain circumstances, for any amounts drawn upon the letters of credit.

Gas Sale Agreement

The Partnership entered into natural gas sale agreement with Sempra for the firm sale of 15,000 MMBTtu of natural gas per day from December 1, 2008 through March 31, 2009, at a commodity price that adjusts, on a monthly basis, with changes in a specified market index for natural gas plus $1.54 per MMBtu.

Electric Transmission Agreements

The Partnership has an interconnection agreement with Niagara Mohawk to interconnect the power output from Unit 1 to Niagara Mohawk's electric transmission system through April 16, 2012. Payments under the interconnection agreement are fixed at $150,000 per year, prorated for 2012.

The Partnership also has a 20-year firm transmission agreement with Niagara Mohawk to transmit the power output from Unit 2 to Con Edison through August 31, 2014, with payment fixed at $5,702,000 per year. Co-terminus with this agreement, the Partnership has an interconnection agreement with Niagara Mohawk to interconnect the power output from Unit 2 to Niagara Mohawk's electric transmission system. Payments under this interconnection agreement are fixed at $450,000 per year.

Operations and Maintenance Agreement

The Partnership has an operations and maintenance services agreement ("O&M Agreement") with GE whereby GE provides certain operation and maintenance services to the Facility through December 31, 2012. Payments under the O&M Agreement include, in addition to other payments, a fixed payment of $235,000 annually through the term of the O&M Agreement.

The Partnership also has a multi-year maintenance program agreement ("MMP Agreement") with GE. Under the MMP Agreement the Partnership is obligated to purchase approximately $9,750,000 in parts and services by December 31, 2012. As of December 31, 2008, the Partnership purchased approximately $8,240,000 in parts and services from GE under the MMP Agreement.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

8. Commitments and Contingencies (Continued)

Site Lease

The Partnership has a site lease agreement with SABIC which SABIC acquired from GE in 2007. The amended lease term expires on August 31, 2014, and is renewable for the greater of 5 years or until termination of either the power purchase agreement with Con Edison, up to a maximum of 20 years. The lease may be terminated by the Partnership under certain circumstances with the appropriate written notice. The lease provides certain tracts of land for a fixed fee as well as provides for certain utilities and other services based on a fixed fee with annual escalation. The annual lease payment is fixed at $1,000,000 per year, prorated for 2014.

Environmental

The Partnership is subject to the compliance provisions of Regional Greenhouse Gas Initiative ("RGGI"), a mandatory, market-based CO_2 emissions reduction program in ten Northeast and Mid- Atlantic states. Under RGGI, the Partnership will be able to use CO_2 allowances issued by any of the ten participating states to demonstrate compliance with the state of New York's program. RGGI which is effective January 1, 2009, limits the Facilty's CO_2 emissions and requires a 10 percent reduction in CO_2 emissions by 2018. RGGI also requires that the Partnership hold allowances covering the Facility's CO_2 emissions which as of December 31, 2008, the Partnership anticipates the compliance cost to be approximately $2,900,000, for 2009, based on the market clearing price.

Steam Generator Damage

On December 27, 2006, the Unit 2 Steam Turbine Generator was inadvertently energized by utility workers performing maintenance in the interconnection switchyard, which resulted in an unplanned maintenance outage. As a result of this incident, the Partnership, in accordance with SFAS 5, *Accounting for Contingencies,* accrued approximately $900,000 for the inspection and repair of the Unit 2 Steam Turbine Generator which was included in operations and maintenance in the accompanying consolidated statements of operations for the year ended December 31, 2006. On January 24, 2007, the Unit 2 Steam Turbine Generator returned to service. In June 2007, the Partnership received approximately $920,000 as reimbursement for costs incurred in repair of the Unit 2 Steam Generator which is reflected as a reduction in operations and maintenance in the accompanying consolidated statements of operations for the year ended December 31, 2007.

Other

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

Selkirk Cogen Partners, L.P. and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

9. Related Parties

JMCS I Management manages the day-to-day operation of the Partnership and is compensated at agreed-upon billing rates that are adjusted every four years in accordance with an administrative services agreement. The cost of services provided by JMCS I Management were approximately $1,986,000 and $1,935,000 for the years ended December 31, 2008 and 2007, respectively, and are included in general and administrative expense in the accompanying consolidated statements of operations. The total amount due to JMCS I Management at December 31, 2008 and 2007 was approximately $120,000 and $774,000, respectively.

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Chambers Cogeneration Limited Partnership and Subsidiary

Consolidated Financial Statements

December 31, 2009 and 2008

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The consolidated financial statements of Chambers Cogeneration Limited Partnership and Subsidiary for the years ended December 31, 2009 and 2008, are presented herein without the related report of independent accountants.

Chambers Cogeneration Limited Partnership and Subsidiary

Consolidated Balance Sheets

December 31, 2009 and 2008

(in thousands of dollars)	2009	2008
Assets		
Current assets		
Cash and cash equivalents	$ 99	$ 134
Restricted cash	6,305	13,652
Accounts receivable	11,965	14,674
Inventory	4,469	4,990
Emission allowances	2,540	
Other assets	1,162	2,867
Total current assets	26,540	36,317
Property and equipment, net of accumulated depreciation of $181,368 and $173,608, respectively	358,875	366,697
Deferred financing costs, net of accumulated amortization of $4,958 and $4,714, respectively	1,873	2,117
Other assets	2,846	3,600
Total assets	$ 390,134	$ 408,731
Liabilities and Partners' Capital		
Current liabilities		
Current portion of long-term debt	$ 27,628	$ 23,920
Accounts payable	5,406	6,689
Due to affiliates	1,784	2,228
Accrued liabilities	1,655	2,461
Interest rate swap	5,851	6,432
Total current liabilities	42,324	41,730
Long-term debt	187,611	215,239
Interest rate swap	4,842	9,860
Asset retirement obligation	1,998	1,895
Total liabilities	236,775	268,724
Commitments and contingencies		
Partners' capital		
General partners	93,687	86,747
Limited partner	62,456	57,830
Accumulated other comprehensive loss	(2,784)	(4,570)
Total partners' capital	153,359	140,007
Total liabilities and partners' capital	$ 390,134	$ 408,731

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership and Subsidiary

Consolidated Statements of Operations

Years Ended December 31, 2009 and 2008

(in thousands of dollars)	2009	2008
Operating revenues		
Energy	$ 52,727	$ 100,936
Capacity	59,665	59,627
Steam	14,266	11,784
Total operating revenues	126,658	172,347
Operating expenses		
Fuel	53,625	74,146
Operations and maintenance	34,322	24,489
General and administrative	4,975	4,736
Depreciation	8,278	8,190
Loss on disposal of assets	1,030	
Total operating expenses	102,230	111,561
Operating income	24,428	60,786
Other income (expense)		
Interest income	3	173
Unrealized gain (loss) on interest rate swaps	5,599	(6,025)
Interest expense	(15,614)	(17,963)
Net income	$ 14,416	$ 36,971

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership and Subsidiary

Consolidated Statements of Changes in Partners' Capital and Comprehensive Income

Years Ended December 31, 2009 and 2008

(in thousands of dollars)	General Partners	Limited Partner	Comprehensive Income	Accumulated Other Comprehensive Loss	Total
Partners' capital at December 31, 2007	$ 80,464	$ 53,642		$ (6,894)	$ 127,212
Net income	22,183	14,788	$ 36,971		36,971
Amortization of previously deferred loss on interest rate swap agreement			2,324	2,324	2,324
Total comprehensive income	22,183	14,788	$ 39,295		
Capital distributions	(15,900)	(10,600)			(26,500)
Partners' capital at December 31, 2008	86,747	57,830		(4,570)	140,007
Net income	8,650	5,766	$ 14,416		14,416
Amortization of previously deferred loss on interest rate swap agreement			1,786	1,786	1,786
Total comprehensive income	8,650	5,766	$ 16,202		
Capital distributions	(1,710)	(1,140)			(2,850)
Partners' capital at December 31, 2009	$ 93,687	$ 62,456		$ (2,784)	$ 153,359

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership and Subsidiary

Consolidated Statements of Cash Flows

Years Ended December 31, 2009 and 2008

(in thousands of dollars)	**2009**	**2008**
Cash flows from operating activities		
Net income	$ 14,416	$ 36,971
Noncash items included in net income:		
Amortization of deferred interest rate swap losses	1,786	2,324
Unrealized (gain) loss on interest rate swaps	(5,599)	6,025
Depreciation	8,278	8,190
Amortization of deferred financing costs	244	259
Accretion of asset retirement obligation	103	83
Loss on disposal of assets	1,030	
Changes in operating assets and liabilities:		
Accounts receivable	2,709	800
Inventory	1,116	(914)
Emission allowances	(2,540)	
Other assets	1,864	(1,765)
Accounts payable	(1,265)	1,280
Due to affiliates	(444)	37
Accrued liabilities	(740)	405
Net cash provided by operating activities	20,958	53,695
Cash flows from investing activities		
Decrease (increase) in restricted cash	7,347	(2,983)
Proceeds from the sale of assets	32	
Capital expenditures	(1,602)	(363)
Net cash provided by (used in) investing activities	5,777	(3,346)
Cash flows from financing activities		
Repayments of long-term debt	(23,920)	(20,786)
Capital distributions	(2,850)	(29,500)
Cash used in financing activities	(26,770)	(50,286)
Net (decrease) increase in cash and cash equivalents	(35)	63
Cash and cash equivalents		
Beginning of year	134	71
End of year	$ 99	$ 134
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 13,586	$ 15,716
Noncash investing and financing activities:		
Capital expenditures which were accrued but not paid	$ 2	$ 86

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

1. Organization and Business

Chambers Cogeneration Limited Partnership (the "Partnership") is a Delaware limited partnership formed on August 17, 1988. The general partners are Peregrine Power, LLC ("Peregrine"), a California limited liability company, and Cogentrix/Carneys Point, LLC ("Cogentrix/Carneys"), a Delaware limited liability company. Epsilon Power is a limited partner. Cogentrix/Carneys and Peregrine were each wholly-owned indirect subsidiaries of Cogentrix Energy, LLC ("CELLC"). In November 2007, CELLC transferred 100% of its indirect equity interest in Peregrine and Cogentrix/Carneys to Calypso Energy Holdings LLC ("Calypso"), then, a wholly-owned subsidiary of CELLC. Following such transfer, on November 14, 2007, CELLC sold an 80% equity interest in Calypso to EIF Calypso, LLC, a limited liability company owned by one or more private equity funds managed by EIF Management, LLC (collectively, the "Calypso Transaction"). As a result, CELLC holds a 20% equity interest in Calypso and a 12% indirect interest in the Partnership.

The Partnership was formed to construct, own and operate a 262-megawatt ("MW") coal-fired cogeneration station (the "Facility") at DuPont's Chambers Works chemical complex in Carneys Point, New Jersey. The Facility produces energy for sale to Atlantic City Electric Company ("AE"), and energy and process steam to E.I. DuPont de Nemours & Company ("DuPont") for use in its industrial operations. The Facility achieved final completion and commercial operations in 1994.

In December 2008, the Partnership submitted an application to PJM Interconnection ("PJM") to increase the Facility's capacity rating from 225 MW to 240 MW. On April 28, 2009, the Partnership received notice from PJM that the capacity interconnection rights assigned to the Facility have been increased to 240 MW. The Facility currently sells excess energy under a separate power sales agreement (Note 10).

The net income and losses of the Partnership are allocated to Peregrine, Cogentrix/Carneys and Epsilon (collectively, the "Partners") based on the following ownership percentages:

Peregrine	50%
Cogentrix/Carneys	10%
Epsilon	40%

All distributions other than liquidating distributions are made based on the Partners' percentage interests, as shown above, in accordance with the Partnership documents and at such times and in such amounts as the Board of Control of the Partnership determines.

Carneys Point Generating Company, L.P.

The Partnership has a lease agreement with Carneys Point Generating Company, L.P. ("CPGC"), which is equally owned by Topaz Power, LLC ("Topaz") and by Garnet Power, LLC (Garnet"), both of which were wholly-owned direct subsidiaries of Power Services Company ("PSC"), an indirect wholly-owned subsidiary of CELLC. In November 2007, CELLC transferred 100% of its ownership interest in Topaz and Garnet to Calypso in connection with the Calypso Transaction. CPGC leases the facility and subleases the site from the Partnership. In addition, certain contracts and agreements related to the Partnership have been assigned to CPGC by the Partnership. The lease commenced on September 20, 1994 and has a 24-year term. CPGC's operations have been established to effectively break-even under the lease agreement.

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

1. Organization and Business (Continued)

The Partnership is managed by PSC pursuant to a management services agreement (Note 11). The Facility is operated by U.S. Operating Services Company ("OSC"), pursuant to an operation and maintenance agreement (Note 11). OSC is a wholly-owned indirect subsidiary of CELLC.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Partnership is required to consolidate an entity for which it absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interest in the entity.

The Partnership determines whether it is the primary beneficiary of a variable interest entity ("VIE") by first performing a qualitative analysis of the VIE that includes a review of, among other factors, its capital structure, contractual terms, which interests create or absorb variability, related party relationships and the design of the VIE. For purposes of allocating a VIE's expected losses and expected residual returns to its variable interest holders, the Partnership utilizes the "top down" method. Under that method, the Partnership calculates its share of the VIE's expected losses and expected residual returns using the specific cash flows that would be allocated to it, based on contractual arrangements and/or the Partnership's position in the capital structure of the VIE, under various probability-weighted scenarios.

CPGC is a variable interest entity of which the Partnership is the primary beneficiary. Accordingly, the Partnership consolidates CPGC. All material intercompany transactions have been eliminated.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for operations, debt service, major maintenance and other specifically designated accounts under a disbursement agreement. Restricted cash associated with transactions expected to occur beyond one-year are classified as long-term. All other restricted accounts are classified as current assets.

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Summary of Significant Accounting Policies (Continued)

Inventory

Fuel is valued using the average cost method and includes the fuel contract purchase price as well as the transportation and related costs incurred to deliver the fuel to the Facility (Note 3).

Spare parts are recorded at the lower of average cost or market and consist of Facility equipment components and supplies required to facilitate maintenance activities. Spare parts which are expected to be utilized during the next year are classified as current in the accompanying consolidated balance sheets. Spare parts which are not expected to be utilized within the next year are classified as long-term and included in other assets in the accompanying consolidated balance sheets (Note 3).

The Partnership performs periodic assessments to determine the existence of obsolete, slow- moving and unusable inventory and records necessary provisions to reduce such inventories to net realizable value.

Emission Allowances

Emission allowances are valued under the weighted average costing method subject to the lower of cost or market principle. In applying the lower of cost or market principle, a reduction in the carrying value is not recognized so long as the Partnership will recover/pass-through the cost in its operating margin.

The historical cost of emission allowances is calculated as follows:

Granted from regulatory body emission allowances obtained via grants are not assigned any value by the Partnership as their cost is zero.

Acquired as part of an acquisition emission allowances are recorded at fair value as of the acquisition date, subject to pro rata reduction if overall purchase price is less than the entity's fair value.

Purchased from third parties emission allowances that are transferable and can be purchased or sold in the normal course of business are recorded at cost.

Derivative Contracts

In accordance with guidance on accounting for derivative instruments and hedging activities all derivatives should be recognized at fair value. Derivatives or any portion thereof, that are not designated as, and effective as, hedges must be adjusted to fair value through earnings. Derivative contracts are classified as either assets or liabilities on the consolidated balance sheets. Certain contracts that require physical delivery may qualify for and be designated as normal purchases/normal sales. Such contracts are accounted for on an accrual basis. The Partnership's interest rate swap agreement (Notes 5 and 8) and power purchase agreement ("PPA") (Note 10) meet the definition of a derivative. The Partnership's PPA qualifies for, and the Partnership has elected, the normal purchases and normal sales exception and accordingly accounts for the PPA on an accrual basis.

The Partnership engages in activities to manage risks associated with changes in interest rates. The Partnership has entered into swap agreements to reduce exposure to interest rate fluctuations on certain debt commitments (Note 5). These agreements were designated and qualified as cash flow

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Summary of Significant Accounting Policies (Continued)

hedging instruments through December 31, 2004. The Partnership discontinued applying cash flow hedge accounting on January 1, 2005. The balance of accumulated other comprehensive loss, as of December 31, 2004, is amortized as interest expense in the accompanying consolidated statements of operations in accordance with the originally forecasted interest payments schedule through the expiration of the interest rate swaps on March 31, 2014.

Fair Value Measurements

The Financial Accounting Standards Board ("FASB") issued guidance that defines fair value, provides guidance for measuring fair value and requires certain disclosures. This guidance does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements.

A fair value hierarchy was established that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy are described below:

Level 1: Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2: Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3: Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (Note 8).

In February 2008, the FASB issued a one-year deferral for non-financial assets and liabilities to comply with issued fair value guidance. As of December 31, 2009, the Partnership does not have any non-financial assets or liabilities remeasured at fair value on a recurring basis

Property and Equipment

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. Depreciation is provided over the estimated useful life ("EUL") of the related assets using the straight-line method (Note 4).

The Partnership's depreciation is based on the Facility being considered a single property unit. Certain components within the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where a replacement of a Facility component is significant and the Partnership

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Summary of Significant Accounting Policies (Continued)

can reasonably estimate the original cost of the component being replaced, the Partnership will write-off the replaced component and capitalize the cost of the replacement. The component will be depreciated over the lesser of the EUL of the component or the remaining useful life of the Facility.

The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property is used, and the effects of obsolescence, demand, competition, and other economic factors.

Deferred Financing Costs

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the related financing (Note 5).

Asset Retirement Obligations

Asset retirement obligations, including those conditioned on future events, are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset in the same period. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the EUL of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership records at fair value all reclamation costs the Partnership would incur to perform environmental clean-up of land under lease to the Partnership.

Income Taxes

As a partnership, the income tax effects accrue directly to the partners, and each partner is individually responsible for its share of the combined income or loss. Accordingly, no provision has been made for income taxes.

Revenue Recognition

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in operating expenses.

Subsequent Events

The Partnership evaluated subsequent events through March 12, 2010.

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

2. Summary of Significant Accounting Policies (Continued)

Recent Accounting Pronouncements

Effective July 1, 2009 the Partnership adopted the Accounting Standards Codification ("ASC") issued by the FASB. The ASC does not change GAAP, but instead takes the numerous individual accounting pronouncements that previously constituted GAAP and reorganizes them into approximately 90 accounting topics, which are then broken down into subtopics, sections and paragraphs. The intent is to simplify user access to authoritative GAAP by providing all of the guidance related to a particular topic in one place. ASC supersedes all previously existing non-Security and Exchange Commission or non-grandfathered accounting and reporting standards. The adoption of ASC did not have any impact on the Partnership's consolidated financial statements.

In June 2009, the FASB issued guidance to revise the approach to determine when a VIE should be consolidated. The new consolidation model for VIEs considers whether a company has the power to direct the activities that most significantly impact the VIE's economic performance and shares in the significant risks and rewards of the entity. The guidance on VIEs requires companies to continually reassess VIEs to determine if consolidation is appropriate and provide additional disclosures. The guidance is effective for the Partnership's fiscal year beginning January 1, 2010. The Partnership expects the adoption of this guidance will have no material impact on its financial statements.

3. Inventory

Inventory consisted of the following as of December 31:

(in thousands of dollars)	2009	2008
Coal	$ 3,142	$ 3,715
Fuel oil	376	652
Lime	95	110
Spare parts	3,621	3,873
	7,234	8,350
Less: Current portion	(4,469)	(4,990)
	$ 2,765	$ 3,360

4. Property and Equipment

Property and equipment consisted of the following components as of December 31:

(in thousands of dollars)	2009	2008
Facility	$ 537,175	$ 537,331
Other equipment	3,068	2,974
	540,243	540,305
Less: Accumulated depreciation	(181,368)	(173,608)
	$ 358,875	$ 366,697

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

4. Property and Equipment (Continued)

The EUL for significant property and equipment categories are as follows:

Facility	60 years
Other equipment	5 to 60 years

5. Long-Term Debt

Long-term debt consisted of the following as of December 31:

(in thousands of dollars)

	As of December 31, 2009			For the Year Ended December 31, 2009	
Description	Commitment Amount	Due Date	Balance Outstanding	Interest Expense	Letter of Credit Fees
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	$ 1,795	N/A
Loan payable(2)		6/10/09		3	N/A
Credit agreement					
Term loans(3)(6)	115,239	3/31/14	115,239	2,856	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	1,495
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	389
			215,239		
Less: Current portion			27,628		
			$ 187,611		

(in thousands of dollars)

	As of December 31, 2008			For the Year Ended December 31, 2008	
Description	Commitment Amount	Due Date	Balance Outstanding	Interest Expense	Letter of Credit Fees
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	$ 2,307	N/A
Loan payable(2)	93	6/10/09	93	8	N/A
Credit agreement					
Term loans(3)(6)	139,066	3/31/14	139,066	7,207	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	1,352
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	387
			239,159		
Less: Current portion			23,920		
			$ 215,239		

(1) The bonds are collateralized by an irrevocable letter of credit and provide for interest at variable rates. The weighted-average interest rates on the bonds were 1.79% and 2.30% for the years ended

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

5. Long-Term Debt (Continued)

December 31, 2009 and 2008, respectively. Remarketing fees paid to the remarketing agent were approximately $100,000 in both 2009 and 2008. These fees are included in interest expense in the accompanying consolidated statements of operations.

(2) Loan payable is collateralized by equipment. The term is 60-months commencing July 2004 with interest fixed at 6.25%.

(3) The term loans accrue interest at the applicable London Interbank Offered Rate ("LIBOR"), plus an applicable margin (1.125% at December 31, 2009). The weighted average interest rates on the term loan were 2.16% and 4.74% for 2009 and 2008, respectively.

(4) The letter of credit fee was 1.25% and 1.125 for 2009 and 2008, respectively. In addition, the facility provides for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(5) The letter of credit fee for 2009 and 2008 was 1.5%. In addition, the facility provided for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(6) All bonds, loans and credit facilities are collateralized by the assets of the Facility and the real estate covered by the ground lease (Note 1) and are nonrecourse to the Partners.

(7) As of December 31, 2009 and 2008, there were no amounts available under the letter of credit commitments.

Accrued interest payable of $81,000 and $81,000 is included in accrued liabilities in the consolidated balance sheets as of December 31, 2009 and 2008, respectively.

Future minimum principal payments as of December 31, 2009 are as follows:

(in thousands of dollars)	
2010	$ 27,628
2011	28,235
2012	30,439
2013	26,957
2014	1,980
Thereafter	100,000
	$ 215,239

In connection with the various agreements discussed above, certain financial covenants must be met and reported on an annual basis. The Partnership was in compliance with all debt covenants at December 31, 2009.

Interest Rate Swap Agreements

The Partnership is a party to two amortizing interest rate swap agreements with notional amounts outstanding aggregating $115,239,000 at December 31, 2009 and expiring on various dates through March 31, 2014. Swap payments related to the agreements covering the variable rate bank debt are

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

5. Long-Term Debt (Continued)

made based on the spread between 5.21% (weighted average of all agreements as of December 31, 2009) and LIBOR multiplied by the notional amounts outstanding. Net amounts paid to the counterparties were approximately $6,891,000 and $3,935,000 in 2009 and 2008, respectively. These amounts were recorded as interest expense in the accompanying consolidated statements of operations.

6. Operating Leases

The Partnership leases certain equipment under non-cancelable operating leases expiring at various dates through 2022. For the years ended December 31, 2009 and 2008, the Partnership incurred lease expense of approximately $219,000 and $224,000, respectively, which is included in operations and maintenance expense and general and administrative expense in the accompanying consolidated statements of operations.

Future minimum lease payments, as of December 31, 2009, are as follows:

(in thousands of dollars)	
2010	$ 201
2011	196
2012	194
2013	192
2014	192
Thereafter	1,357
	$ 2,332

7. Payment in Lieu of Taxes

In January 1991, the Partnership entered into a Payment in Lieu of Taxes ("PILOT") agreement with the Township of Carneys Point, a municipal corporation of the state of New Jersey, which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1994, and will terminate on December 31, 2033. PILOT payments are paid annually and are expensed as incurred over the term of the agreement. Property taxes are due and paid quarterly and are deducted from the annual PILOT payments made. The Partnership expensed approximately $2,600,000 and $2,400,000 related to the PILOT which is included in general and administrative in the accompanying consolidated statements of operations for the years ended December 31, 2009 and 2008, respectively.

As of December 31, 2009, future payments remaining under the PILOT are as follows:

(in thousands of dollars)	
2010	$ 2,700
2011	2,800
2012	3,000
2013	3,400
2014	3,700
Thereafter	118,600
	$ 134,200

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

8. Fair Value of Financial Instruments

The fair value of the Partnership's swap agreements, based upon Level 2 significant other observable inputs, is estimated to be a liability of approximately $10,693,042 and $16,292,000 as of December 31, 2009 and 2008, respectively (Notes 2 and 5). The valuation of the Partnership's swap agreements is based on widely accepted valuation techniques including discounted cash flow analyses which take into consideration among other things the contractual terms of the swap agreements, observable market based inputs when available, interest rate curves and counterparty credit risk. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the fair value estimates as of December 31, 2009 and 2008, are not necessarily indicative of amounts the Partnership could have realized in current markets.

The Partnership's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, other assets, accounts payable, due to affiliates, and accrued liabilities. These instruments approximate their fair values as of December 31, 2009 and 2008 due to their short-term nature.

The fair value of the Partnership's bonds and term loans payable approximates their carrying value due to the variable nature of the interest obligations thereon.

9. Concentrations of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations. The Partnership primarily conducts business with counterparties in the energy industry. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated investment grade by a major credit rating agency or have a history of reliable performance within the energy industry.

The Partnership's credit risk is primarily concentrated with AE, DuPont and the Partnership's coal supplier. AE and DuPont provided 78.7% and 21.3%, respectively, of the Partnership's revenues for the year ended December 31, 2009 and accounted for approximately 74.3% and 25.7%, respectively, of the Partnership's accounts receivable balance at December 31, 2009. The Partnership has a coal supply contract with Consolidated Coal Company, Consolidated Pennsylvania Coal Company, Consolidated Coal Sales Company and Nineveh Coal Company (together "Consol") who are responsible for providing 100% of the Partnership's coal requirements through 2014. The Partnership's credit risk is also impacted by the credit risk associated with its issuing bank of the bond letter of credit, Dexia Credit Locale.

The Partnership is exposed to credit-related losses in the event of nonperformance by counterparties to the Partnership's interest rate swap agreements (Notes 2 and 5). The Partnership does not obtain collateral or other security to support such agreements, but continually monitors its positions with, and the credit quality of, the counterparties to such agreements.

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

10. Commitments and Contingencies

Power Purchase Agreement

The Partnership has a power purchase agreement ("PPA") with AE for sales of the Facility's power output during a 30-year period commencing in 1994. The PPA provides AE with dispatch rights over the Facility, with a contractual minimum of the equivalent of 3,500 hours of full load operation. The pricing structure provides for both capacity and energy payments. Capacity payments are fixed over the life of the contract. Energy payments are based on a contractual formula which is adjusted annually, as defined in the PPA, based on a utility coal index.

Power Sales Agreement

The Partnership has entered into a supplemental power sales agreement ("PSA") with AE which provides the Partnership self-dispatch rights for both undispatched PPA and excess energy as well as the right to market excess capacity. The pricing structure provides for both capacity and energy payments. The Partnership shares margins on the self-dispatched energy with AE based on hourly wholesale prices. Excess capacity is sold in PJM's periodic auctions and the resulting revenue is shared between the Partnership and AE. The PSA expires on July 31, 2010.

Steam and Electricity Sales Agreement

The Partnership has a steam and electricity sales agreement with DuPont (the "DuPont Agreement") for a 30-year period commencing in 1994. Thereafter, the agreement will remain in effect unless terminated by either party upon at least 36-months' notice. DuPont is required to purchase a minimum of 525,600,000 pounds of process steam per year and no minimum amount of electricity. The steam price is adjusted quarterly based on coal price index formulas defined in the agreement. The electricity price is also adjusted quarterly based on coal price index formulas and the AE average retail rate, as defined in the agreement. The Partnership has an ongoing dispute with DuPont over electric energy payment calculation. Amounts under dispute have not been reflected in revenues in the accompanying consolidated statements of operations.

Fly Ash Disposal Agreement

The Partnership has an agreement with Consolidation Coal Company, Consol Pennsylvania Coal Company, Consolidation Coal Sales Company and Nineveh Coal Company, jointly, for a 20-year period commencing in 1990 for the disposal of fly ash with a minimum requirement of 130,000 tons per contract year. The Partnership does not anticipate meeting this requirement by the end of the contract year ending on March 14, 2010. Accordingly, the Partnership has accrued approximately $246,000 related to this shortage at December 31, 2009 which is included in fuel expense on the accompanying consolidated statement of operations.

Other

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

Chambers Cogeneration Limited Partnership and Subsidiary

Notes to Consolidated Financial Statements (Continued)

December 31, 2009 and 2008

11. Related Parties

Management Services Agreement

The Partnership has a management services agreement with PSC to provide day-to-day management and administration of the Partnership's business relating to the Facility through September 20, 2018. Compensation to PSC under the agreement includes a monthly fee of $50,000, wages and benefits for employees working on behalf of the Partnership and other costs directly related to the Partnership. The Partnership recorded related expense of $1,860,000 and $1,971,000 in operations and maintenance in the consolidated statements of operations in 2009 and 2008, respectively. As of December 31, 2009 and 2008, the Partnership owed PSC approximately $135,000 and $116,000, respectively, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, $50,000 of the amounts owed for each of 2009 and 2008 is subordinate to debt service for the Partnership's bonds payable and term loans.

Operations and Maintenance Agreement

The Partnership's O&M Agreement with OSC provides for the operations and maintenance of the Facility through April 1, 2014. Thereafter, the agreement will be automatically renewed for periods of five-years until terminated by either party with 12-months prior notice. Compensation to OSC under the agreement includes (i) an annual base fee, of which a portion is subordinate to debt service and certain other costs, (ii) certain earned fees and bonuses based on the Facility's performance and (iii) reimbursement for certain costs, including payroll, supplies, spare parts, equipment, certain taxes, licensing fees, insurance and indirect costs expressed as a percentage of payroll and personnel costs. The fees are adjusted annually by a measure of inflation as defined in the agreement. If targeted Facility performance is not reached on a monthly basis, OSC may be required to pay liquidated damages to the Partnership. The Partnership incurred related expense of approximately $9,857,000 and $9,556,000 which is recorded in operations and maintenance in the consolidated statements of operations during the years ended December 31, 2009 and 2008, respectively. As of December 31, 2009 and 2008, the Partnership owed OSC $1,649,000 and $2,112,000, respectively, under the O&M Agreement, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, approximately $287,000 and $591,000 of the amounts owed at December 31, 2009 and 2008, respectively, is subordinate to the debt service for the Partnership's bonds payable and term loans. In addition, approximately $599,000 and $549,000 in other costs had been advanced to OSC at December 31, 2009 and 2008, respectively, and are included in other current assets in the accompanying consolidated balance sheets.

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Chambers Cogeneration Limited Partnership
Consolidated Financial Statements
December 31, 2008 and 2007

PricewaterhouseCoopers LLP
Two Commerce Square, Suite 1700
2001 Market Street
Philadelphia PA 19103-7042
Telephone (267) 330 3000
Facsimile (267) 330 3300

Report of Independent Auditors

To the Board of Control of
Chambers Cogeneration Limited Partnership:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in partners' capital and comprehensive income, and of cash flows present fairly, in all material respects, the financial position of Chambers Cogeneration Limited Partnership and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, the Company changed its accounting for spare parts inventory in 2008,

/s/ PricewaterhouseCoopers LLP

March 13, 2009

Chambers Cogeneration Limited Partnership

Consolidated Balance Sheets

December 31, 2008 and 2007

(in thousands of dollars)	**2008**	**2007**
Assets		
Current assets		
Cash and cash equivalents	$ 134	$ 71
Restricted cash	13,652	9,703
Accounts receivable	14,674	15,474
Inventory	4,990	4,688
Other assets	2,867	1,342
Total current assets	36,317	31,278
Restricted cash		966
Property and equipment, net of accumulated depreciation of $173,608 and $165,418, respectively	366,697	375,137
Deferred financing costs, net of accumulated amortization of $4,714 and $4,455, respectively	2,117	2,376
Other assets	3,600	2,722
Total assets	$ 408,731	$ 412,479
Liabilities and Partners' Capital		
Current liabilities		
Current portion of long-term debt	$ 23,920	$ 20,776
Accounts payable	6,689	5,409
Dividend payable		3,000
Due to affiliates	2,228	2,683
Accrued liabilities	2,461	1,970
Interest rate swap	6,432	3,025
Total current liabilities	41,730	36,863
Long-term debt	215,239	239,169
Interest rate swap	9,860	7,242
Asset retirement obligation	1,895	1,993
Total liabilities	268,724	285,267
Commitments and contingencies		
Partners' capital		
General partners	86,747	80,464
Limited partner	57,830	53,642
Accumulated other comprehensive loss	(4,570)	(6,894)
Total partners' capital	140,007	127,212
Total liabilities and partners' capital	$ 408,731	$ 412,479

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership

Consolidated Statements of Operations

Years Ended December 31, 2008 and 2007

(in thousands of dollars)	2008	2007
Operating revenues		
Energy	$ 100,936	$ 97,096
Capacity	59,627	58,869
Steam	11,784	10,785
Total operating revenues	172,347	166,750
Operating expenses		
Fuel	74,146	67,163
Operations and maintenance	24,489	22,990
General and administrative	4,736	4,879
Depreciation	8,190	8,205
Loss on disposal of assets		177
Total operating expenses	111,561	103,414
Operating income	60,786	63,336
Other income (expense)		
Interest income	173	530
Interest expense	(23,988)	(24,415)
Net income	$ 36,971	$ 39,451

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership

Consolidated Statements of Changes in Partners' Capital and Comprehensive Income

Years Ended December 31, 2008 and 2007

	General Partners		Limited Partner			
(in thousands of dollars)	**Peregrine Power, LLC**	**Cogentrix/ Carneys Point, LLC**	**Epsilon Power**	**Comprehensive Income**	**Accumulated Other Comprehensive Loss**	**Total**
Partners' capital, December 31, 2006, as originally stated	$ 62,252	$ 12,451	$ 49,802		$ (9,990)	$ 114,515
Cumulative effect of change in accounting principle	375	75	300			750
Partners' capital at December 31, 2006, as adjusted for change in accounting principle	62,627	12,526	50,102		(9,990)	115,265
Net income	19,726	3,945	15,780	$ 39,451		39,451
Amortization of previously deferred loss on interest rate swap agreement				3,096	3,096	3,096
Total comprehensive income	19,726	3,945	15,780	$ 42,547		
Dividend declared	(1,500)	(300)	(1,200)			(3,000)
Capital distributions	(13,800)	(2,760)	(11,040)			(27,600)
Partners' capital, December 31, 2007	67,053	13,411	53,642		(6,894)	127,212
Net income	18,486	3,697	14,788	$ 36,971		36,971
Amortization of previously deferred loss on interest rate swap agreement				2,324	2,324	2,324
Total comprehensive income	18,486	3,697	14,788	$ 39,295		
Capital distributions	(13,250)	(2,650)	(10,600)			(26,500)
Partners' capital, December 31, 2008	$ 72,289	$ 14,458	$ 57,830		$ (4,570)	$ 140,007

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership

Consolidated Statements of Cash Flows

Years Ended December 31, 2008 and 2007

(in thousands of dollars)	**2008**	**2007**
Cash flows from operating activities		
Net income	$ 36,971	$ 39,451
Noncash items included in net income:		
Amortization of deferred interest rate swap losses	2,324	3,096
Unrealized loss on interest rate swaps	6,025	2,886
Depreciation	8,190	8,205
Amortization of deferred financing costs	259	273
Accretion of asset retirement obligation	83	107
Loss on disposal of assets		177
Changes in operating assets and liabilities:		
Accounts receivable	800	(3,001)
Inventory	(914)	1,036
Other assets	(1,765)	(309)
Accounts payable	1,280	(1,845)
Due to affiliates	37	(360)
Accrued liabilities	405	1,518
Net cash provided by operating activities	53,695	51,234
Cash flows from investing activities		
Increase in restricted cash	(2,983)	(3,111)
Capital expenditures	(363)	(492)
Cash used in investing activities	(3,346)	(3,603)
Cash flows from financing activities		
Repayments of long-term debt	(20,786)	(20,016)
Capital distributions	(29,500)	(27,600)
Cash used in financing activities	(50,286)	(47,616)
Net (decrease) increase in cash and cash equivalents	63	15
Cash and cash equivalents		
Beginning of year	71	56
End of year	$ 134	$ 71
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 15,716	$ 16,415
Non-cash investing and financing activities:		
Dividend declared but not paid	$	$ 3,000
Capital expenditures which were accrued but not paid	$ 86	$ 492

The accompanying notes are an integral part of these consolidated financial statements.

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

1. Organization and Business

Chambers Cogeneration Limited Partnership (the "Partnership") is a Delaware limited partnership formed on August 17, 1988. The general partners are Peregrine Power, LLC ("Peregrine"), a California limited liability company, and Cogentrix/Carneys Point, LLC, (f/k/a Cogentrix/Carneys Point, Inc.), ("Cogentrix/Carneys"), a Delaware limited liability company. Epsilon Power is a limited partner. Cogentrix/Carneys and Peregrine were each wholly-owned indirect subsidiaries of Cogentrix Energy, LLC, (f/k/a Cogentrix Energy, Inc.), ("CELLC"). In November 2007, CELLC transferred 100% of its indirect equity interest in Peregrine and Cogentrix/Carneys to Calypso Energy Holdings LLC ("Calypso"), then, a wholly-owned subsidiary of CELLC. Following such transfer, on November 14, 2007, CELLC sold an 80% equity interest in Calypso to EIF Calypso, LLC, a limited liability company owned by one or more private equity funds managed by EIF Management, LLC (collectively, the "Calypso Transaction"). As a result, CELLC holds a 20% equity interest in Calypso and, ultimately the Partnership.

The Partnership was formed to construct, own and operate a 262-megawatt coal-fired cogeneration station (the "Facility") at DuPont's Chambers Works chemical complex in Carneys Point, New Jersey. The Facility produces energy for sale to Atlantic City Electric Company, (f/k/a Atlantic City Electric Company/Conectiv), ("AE"), and process steam to E.I. DuPont de Nemours & Company ("DuPont") for use in its industrial operations. The Facility achieved final completion and commercial operations in 1994.

In December 2008, the Partnership submitted an application to PJM to increase the Facility's capacity rating from 225MW to 240MW. At December 31, 2008, PJM was drafting an interconnection agreement that when complete would allow the Partnership to sell the 15MW in additional capacity. The Facility currently sells excess energy under a separate power sales agreement (Note 9).

The net income and losses of the Partnership are allocated to Peregrine, Cogentrix/Carneys and Epsilon (collectively, the "Partners") based on the following ownership percentages:

Peregrine	50%
Cogentrix/Carneys	10%
Epsilon	40%

All distributions other than liquidating distributions are made based on the Partners' percentage interests, as shown above, in accordance with the Partnership documents and at such times and in such amounts as the Board of Control of the Partnership determines.

Carneys Point Generating Company, L.P.

The Partnership has a lease agreement with Carneys Point Generating Company, L.P. ("CPGC"), which is equally owned by Topaz Power. LLC ("Topaz") and by Garnet Power, LLC (Garnet"), both of which were wholly-owned direct subsidiaries of Power Services Company ("PSC"), an indirect wholly-owned subsidiary of CELLC. In November 2007, CELLC transferred 100% of its ownership interest in Topaz and Garnet to Calypso in connection with the Calypso Transaction. CPGC leases the facility and subleases the site from the Partnership. In addition, certain contracts and agreements related to the Partnership have been assigned to CPGC by the Partnership. The lease commenced on

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

1. Organization and Business (Continued)

September 20, 1994 and has a 24-year term. CPGC's operations have been established to effectively break-even under the lease agreement.

The Partnership is managed by PSC pursuant to a management services agreement. The Facility is operated by U.S. Operating Services Company ("OSC"), pursuant to an operation and maintenance agreement. OSC is a wholly-owned indirect subsidiary of CELLC.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Partnership applies the provisions of Financial Accounting Standards Board ("FASB") Interpretation No. ("FIN") 46-R, *Consolidation of Variable Interest Entities, an Interpretation of ARB 51* and associated FASB Staff Positions. FIN 46-R requires the consolidation of an entity by an enterprise that absorbs a majority of the entity's expected losses, receives a majority of the entity's expected residual returns, or both, as a result of ownership, contractual or other financial interest in the entity. CPGC is a variable interest entity of which the Partnership is the primary beneficiary. Accordingly, the Partnership consolidates CPGC. All significant intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for operations, debt service, major maintenance and other specifically designated accounts under a disbursement agreement. Restricted cash associated with transactions occurring beyond one year are classified as long term. All other restricted accounts are classified as current assets.

Inventory

Fuel is valued using the average cost method and includes the fuel contract purchase price as well as the transportation and related costs incurred to deliver the fuel to the Facility (Note 3).

Spare parts are recorded at the lower of average cost or market and consist of Facility equipment components and supplies required to facilitate maintenance activities. Spare parts which are expected to be utilized during the next year are classified as current in the accompanying consolidated balance

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (Continued)

sheets. Spare parts which are not expected to be utilized within the next year are classified as long-term and included in other assets in the accompanying consolidated balance sheets (Note 3).

The Partnership performs periodic assessments to determine the existence of obsolete, slow-moving and unusable inventory and records necessary provisions to reduce such inventories to net realizable value.

Property and Equipment

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. Depreciation is provided over the estimated useful life ("EUL") of the related assets using the straight-line method (Note 4).

The Partnership's depreciation is based on the Facility being considered a single property unit. Certain components within the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where a replacement of a Facility component is significant and the Partnership can reasonably estimate the original cost of the component being replaced, the Partnership will write-off the replaced component and capitalize the cost of the replacement. The component will be depreciated over the lesser of the estimated useful life of the component or the remaining useful life of the Facility.

The Partnership accounts for the impairment or disposal of property and equipment in accordance with of Financial Accounting Standards No. ("SFAS") 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property is used, and the effects of obsolescence, demand, competition, and other economic factors.

Deferred Financing Costs

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the related financing (Note 5).

Derivative Contracts

The Partnership follows SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended and interpreted. SFAS 133 requires the Partnership to recognize all derivatives, as defined in the statement, on the consolidated balance sheets at fair value. Derivatives or any portion thereof, that

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (Continued)

are not designated as, or effective as, hedges must be adjusted to fair value through earnings. Derivatives are classified as either assets or liabilities on the consolidated balance sheets. The Partnership's interest rate swap agreement (Notes 5 and 7) and power purchase agreement (Note 9) meet the definition of a derivative under SFAS 133. The Partnership's power purchase agreement qualifies for, and the Partnership has elected, the normal purchases and normal sales exception included in SFAS 133.

The Partnership engages in activities to manage risks associated with changes in interest rates. The Partnership has entered into swap agreements to reduce exposure to interest rate fluctuations on certain debt commitments (Note 5). These agreements were designated and qualified as cash flow hedging instruments through December 31, 2004. The Partnership discontinued applying cash flow hedge accounting on January 1, 2005. Accordingly, the changes in fair value of the interest rate swaps from that point forward are included in interest expense in the consolidated statements of operations. The balance of accumulated other comprehensive loss, as of December 31, 2004, is amortized as interest expense in the accompanying consolidated statements of operations in accordance with the originally forecasted interest payments schedule through the expiration of the interest rate swaps on March 31, 2014.

Fair Value Measurements

The Partnership adopted SFAS 157, *Fair Value Measurements,* for financial assets and liabilities effective January 1, 2008. There was no material effect upon adoption of this new accounting pronouncement on the Partnership's consolidated financial statements. This standard defines fair value, provides guidance for measuring fair value and requires certain disclosures. This standard does not require any new fair value measurements, but rather applies to all other accounting pronouncements that require or permit fair value measurements.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under SFAS 157 are described below:

- Level 1: Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
- Level 3: Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (Note 7).

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligation

The Partnership accounts for its asset retirement obligation in accordance with SFAS 143, *Accounting for Asset Retirement Obligations* and FIN 47, *Accounting for Conditional Asset Retirement Obligations.* These statements require that an asset retirement obligation, including those conditioned on future events, be recorded at fair value in the period in which it is incurred, if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership records at fair value all reclamation costs the Partnership would incur to perform environmental clean-up of land under lease to the Partnership.

Accounting for Income Taxes

As a partnership, the income tax effects accrue directly to the partners, and each partner is individually responsible for its share of the combined income or loss. Accordingly, no provision has been made for income taxes.

Revenue Recognition

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in operating expenses.

Reclassification

Certain reclassifications have been made to the prior year consolidated financial statements to conform to the current year presentation. These reclassifications had no effect on the previously reported results of operation or member's equity.

Recent Accounting Developments

In March 2008, the FASB issued SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities.* This standard is intended to improve financial reporting by requiring transparency about the location and amounts of derivative instruments in an entity's financial statements; how derivative instruments and related hedged items are accounted for under SFAS No 133; and how derivative instruments and related hedged items affect its financial position, financial performance and cash flows. SFAS No. 161 will be effective for the Partnership's fiscal year beginning January 1, 2009.

In February 2008, the FASB issued a one-year deferral for non-financial assets and liabilities to comply with SFAS 157. The Partnership expects the adoption of SFAS 157 will have no material effect on consolidated the financial statements as it applies to non-financial assets and liabilities (Note 7).

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

3. Inventory

Inventory is comprised of the following as of December 31:

(in thousands of dollars)	2008	2007
Coal	$ 3,715	$ 3,672
Fuel oil	652	465
Lime	110	47
Spare parts	3,873	3,226
	8,350	7,410
Less: Current portion	(4,990)	(4,688)
	$ 3,360	$ 2,722

On January 1, 2008, the Partnership elected to change its method of accounting for spare parts inventory. Under the new accounting method, spare parts inventory is capitalized when purchased and expensed when put into service. In prior years spare parts inventory was expensed as purchased or capitalized and included in property and equipment during construction. The Partnership believes that the change in accounting principle is preferable as the new method provides better matching of revenue and expenses as well as enhances comparability in the consolidated statements of operations.

In accordance with SFAS 154, *Accounting Changes and Error Corrections,* the change in accounting principle was applied retrospectively by restating the prior year consolidated financial statements. The increase to net income for the year ended December 31, 2007, was $473,000.

If the Partnership had not changed its policy for accounting for spare parts inventory, net income would have been lower by $459,000 for the year ended December 31, 2008.

The effect of the change on previously reported consolidated operating results for the year ended December 31, 2007 was as follows:

(in thousands of dollars)	As Previously Reported	Effect of Change	As Restated
Assets			
Inventory	$ 4,184	$ 504	$ 4,688
Property and equipment	377,140	(2,003)	375,137
Other assets(1)		2,722	2,722
Partners' capital			
General partners	$ 79,730	$ 734	$ 80,464
Limited partners	53,153	489	53,642

(1) Represents the long-term portion of spare parts on the accompanying balance sheets.

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

4. Property and Equipment

Property and equipment consisted of the following components as of December 31:

(in thousands of dollars)	2008	2007
Facility	$ 537,331	$ 537,582
Other equipment	2,974	2,973
	540,305	540,555
Less: Accumulated depreciation	(173,608)	(165,418)
	$ 366,697	$ 375,137

The EUL for significant property and equipment categories are as follows:

Facility	60 years
Other equipment	5 to 60 years

5. Long-Term Debt

Long-term debt consisted of the following as of December 31:

(in thousands of dollars)

	As of December 31, 2008			For the Year Ended December 31, 2008	
Description	Commitment Amount	Due Date	Balance Outstanding	Interest Expense	Letter of Credit Fees
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	$ 2,307	N/A
Loan payable(2)	93	6/10/09	93	8	N/A
Credit agreement					
Term loans(3)(6)	139,066	3/31/14	139,066	7,207	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	$1,352
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	387
			239,159		
Less: Current portion			23,920		
			$ 215,239		

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

5. Long-Term Debt (Continued)

(in thousands of dollars)

Description	As of December 31, 2007 Commitment Amount	Due Date	Balance Outstanding	For the Year Ended December 31, 2007 Interest Expense	Letter of Credit Fees
Bonds payable(1)(6)	$ 100,000	7/1/21	$ 100,000	$ 3,768	N/A
Loan payable(2)	150	6/10/09	150	11	N/A
Credit agreement					
Term loans(3)(6)	159,795	3/31/14	159,795	11,250	N/A
Bond letter of credit(4)(6)(7)	102,466	12/31/12		N/A	$1,352
Debt service reserve letter of credit(5)(6)(7)	22,750	12/31/12		N/A	318
			259,945		
Less: Current portion			20,776		
			$ 239,169		

(1) The bonds are collateralized by an irrevocable letter of credit and provide for interest at variable rates. The weighted-average interest rates on the bonds were 2.30% and 3.77% for the years ended December 31, 2008 and 2007, respectively. Remarketing fees paid to the remarketing agent were approximately $100,000 in both 2008 and 2007. These fees are included in interest expense in the accompanying consolidated statements of operations.

(2) Loan payable is collateralized by equipment. The term is 60-months commencing July 2004 with interest fixed at 6.25%.

(3) The term loans accrue interest at the applicable London Interbank Offered Rate ("LIBOR"), plus an applicable margin (1.125% at December 31, 2008). The weighted average interest rates on the term loan were 4.74% and 6.63%, for 2008 and 2007, respectively.

(4) The letter of credit fee for 2008 and 2007 was 1.125%. In addition, the facility provides for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(5) The letter of credit fee for 2008 and 2007 was 1.50%. In addition, the facility provided for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(6) All bonds, loans and credit facilities are collateralized by the assets of the Project and the real estate covered by the ground lease (Note 1) and are nonrecourse to the Partners. These agreements require compliance with certain negative and affirmative covenants. The Partnership was in compliance with all debt covenants at December 31, 2008.

(7) As of December 31, 2008 and 2007, there were no amounts available under the letter of credit commitments.

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

5. Long-Term Debt (Continued)

Future minimum payments as of December 31, 2008 are as follows:

(in thousands of dollars)	
2009	$ 23,920
2010	27,628
2011	28,235
2012	30,439
2013	26,957
Thereafter	101,980
	$ 239,159

Interest Rate Swap Agreements

The Partnership is a party to three amortizing interest rate swap agreements with notional amounts outstanding aggregating $139,066,000 at December 31, 2008 and expiring on various dates through March 31, 2014. Swap payments related to the agreements covering the variable rate bank debt are made based on the spread between 6.081% (weighted average of all agreements as of December 31, 2008) and LIBOR multiplied by the notional amounts outstanding. Net amounts paid to the counterparties were approximately $3,935,000 and $1,287,000 in 2008 and 2007, respectively. These amounts were recorded as interest expense in the accompanying consolidated statements of operations.

6. Payment in Lieu of Taxes

In January 1991, the Partnership entered into a Payment in Lieu of Taxes ("PILOT"), agreement with the Township of Carneys Point, a municipal corporation of the state of New Jersey, which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1994, and will terminate on December 31, 2033. PILOT payments are due quarterly and are expensed as incurred over the term of the agreement. The Partnership expensed approximately $2,400,000 and $2,300,000 related to the PILOT which is included in general and administrative in the accompanying consolidated statements of operations for the years ended December 31, 2008 and 2007, respectively.

As of December 31, 2008, future payments remaining under the PILOT are as follows:

(in thousands of dollars)	
2009	$ 2,600
2010	2,700
2011	2,800
2012	3,000
2013	3,400
Thereafter	122,300
	$ 136,800

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

7. Fair Value of Financial Instruments

The fair value of the Partnership's swap agreements, based upon Level 2 significant other observable inputs, is estimated to be a liability of approximately $16,292,000 and $10,267,000 as of December 31, 2008 and 2007, respectively (Notes 2 and 5). The valuation of the Partnership's swap agreements is based on widely accepted valuation techniques including discounted cash flow analyses which take into consideration among other things the contractual terms of the swap agreements, observable market based inputs when available, interest rate curves and counterparty credit risk. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the fair value estimates as of December 31, 2008 and 2007, are not necessarily indicative of amounts the Partnership could have realized in current markets.

The carrying amounts of the Partnership's cash and cash equivalents, restricted cash, accounts receivable, other assets, accounts payable, due to affiliates, accrued liabilities and loan payable approximate their fair value at December 31, 2008, due primarily to their short-term nature. The fair value of the Partnership's bonds and term loans payable approximates the carrying value due to the variable nature of the interest obligations thereon.

8. Concentrations of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations. The Partnership primarily conducts business with counterparties in the energy industry. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated investment grade by a major credit rating agency or have a history of reliable performance within the energy industry.

The Partnership's credit risk is primarily concentrated with AE, DuPont and the Partnership's coal supplier. AE and DuPont provided 84.9% and 15.1%, respectively, of the Partnership's revenues for the year ended December 31, 2008 and accounted for approximately 81.1% and 18.9%, respectively, of the Partnership's accounts receivable balance at December 31, 2008. The Partnership has a coal supply contract with Consolidated Coal Company, Consolidated Pennsylvania Coal Company, Consolidated Coal Sales Company and Nineveh Coal Company (together "Consol") who are responsible for providing 100% of the Company's coal requirements through 2014. The Partnership's credit risk is also impacted by the credit risk associated with its issuing bank of the bond letter of credit, Dexia Credit Locale.

The Partnership is exposed to credit-related losses in the event of nonperformance by counterparties to the Company's interest rate swap agreements (Notes 2 and 5). The Partnership does not obtain collateral or other security to support such agreements, but continually monitors its positions with, and the credit quality of, the counterparties to such agreements.

9. Commitments and Contingencies

Power Purchase Agreement

The Partnership has a power purchase agreement ("PPA") with AE for sales of the Facility's power output during a 30-year period commencing in 1994. The PPA provides AE with dispatch rights over

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

9. Commitments and Contingencies (Continued)

the Facility. The pricing structure provides for both capacity and energy payments. Capacity payments are fixed over the life of the contract. Energy payments are based on a contractual formula which is adjusted annually, as defined in the PPA, based on a utility coal index.

Power Sales Agreement

The Partnership has entered into a supplemental power sales agreement ("PSA") with AE which provides the Partnership self-dispatch rights for both undispatched PPA and excess energy as well as the right to market excess capacity. The pricing structure provides for both capacity and energy payments. The Partnership shares margins on the self-dispatched energy with AE based on hourly wholesale prices. Excess capacity is sold in PJM's periodic auctions and the resulting revenue is shared between the Partnership and AE. The PSA expires on July 31, 2010.

Steam and Electricity Sales Agreement

The Partnership has a steam and electricity sales agreement with DuPont (the "DuPont Agreement") for a 30-year period commencing in 1994. Thereafter, the agreement will remain in effect unless terminated by either party upon at least 36 months' notice. DuPont is required to purchase a minimum of 525,600,000 pounds of process steam per year and no minimum amount of electricity. The steam price is adjusted quarterly based on coal price index formulas defined in the agreement. The electricity price is also adjusted quarterly based on coal price index formulas and the AE average retail rate, as defined in the agreement. The Partnership has an ongoing dispute with DuPont over electric energy payment calculation. Amounts under dispute have not been reflected in revenues in the accompanying consolidated statements of operations.

Lease Commitments

The Partnership leases certain equipment under noncancelable operating leases expiring at various dates through 2022. For the years ended December 31, 2008 and 2007, the Partnership incurred lease expense of approximately $252,000 and $251,000, respectively, which is included in operations and maintenance expense and general and administrative expense in the accompanying consolidated statements of operations.

Future minimum lease payments under the terms of the noncancelable operating agreements, as of December 31, 2008, are as follows:

(in thousands of dollars)	
2009	$ 202
2010	201
2011	196
2012	194
2013	192

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

9. Commitments and Contingencies (Continued)

Environmental

The Partnership is subject to the compliance provisions of Regional Greenhouse Gas Initiative ("RGGI"), a mandatory, market-based CO_2 emissions reduction program in ten Northeast and Mid- Atlantic states. Under RGGI the Partnership will be able to use CO_2 allowances issued by any of the ten participating states to demonstrate compliance with the state of New Jersey program. RGGI which is effective January 1, 2009, limits the Facility's CO_2 emissions and requires a 10 percent reduction in CO_2 emissions by 2018. RGGI also requires that the Partnership hold allowances covering the Facility's CO_2 emissions which as of December 31, 2008, the Partnership anticipates the compliance will cost approximately $5,000,000 for 2009 based on estimated CO_2 emissions of 2.0 million tons.

Litigation

In 2005 the Partnership filed a lawsuit in New Jersey against Consol for failure to perform under the coal supply agreement. Consol made counter claims seeking damages against the Partnership. On December 29, 2006 the Partnership and Consol entered into a settlement agreement which provides for a $0.77 per ton surcharge on future coal purchases until such surcharges total $4,750,000. In return, Consol acknowledges its obligation to provide the full coal requirements of Chambers, up to the maximum quantity defined in the coal purchase agreement, irrespective of the underlying PPA, PSA or Dupont Agreement. On February 2, 2007, the parties dismissed the case with prejudice.

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

10. Related Parties

The Partnership has a management services agreement with PSC to provide day-to-day management and administration of the Partnership's business relating to the Facility through September 20, 2018. Compensation to PSC under the agreement includes a monthly fee of $50,000, wages and benefits for employees working on behalf of the Partnership and other costs directly related to the Partnership. The Partnership recorded related expense of $1,971,000 and $1,927,000 in general and administrative expenses in the consolidated statements of operations in 2008 and 2007, respectively. As of December 31, 2008 and 2007, the Partnership owed PSC approximately $116,000 and $144,000, respectively, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, $50,000 of the amounts owed for each of 2008 and 2007 is subordinate to debt service for the Partnership's bonds payable and term loans.

The Partnership has an operations and maintenance agreement with OSC for operations and maintenance of the Facility through March 6, 2009. The agreement is automatically renewed for periods of 5-years until terminated by either party upon 12-months notice. Compensation to OSC under the agreement includes (i) reimbursement of direct and indirect operational expenses; (ii) a base fee of $600,000 per year; (iii) additional fees based on targeted facility performance; and (iv) a management performance bonus of up to $150,000 per year, primarily based on the safe operation of the facility as measured by accepted industry metrics. These fees are adjusted annually by a measure of inflation as defined in the agreement. If the targeted facility performance is not reached, OSC will pay liquidated

Chambers Cogeneration Limited Partnership

Notes to Consolidated Financial Statements (Continued)

December 31, 2008 and 2007

10. Related Parties (Continued)

damages to the Partnership. The related expense of approximately $9,556,000 and $9,024,000 is recorded in operations and maintenance expenses in the consolidated statements of operations in 2008 and 2007, respectively. As of December 31, 2008 and 2007, the Partnership owed OSC approximately $280,000 and $487,000 respectively, which is included in due to affiliates in the accompanying consolidated balance sheets. As of December 31, 2008 and 2007, the Partnership has accrued for fees and bonuses of $1,832,000 and $2,052,000, respectively, which is included in due to affiliates in the accompanying consolidated balance sheets. Included in the amounts owed at December 31, 2007 was $492,000 of capitalized software costs which is included in property and equipment on the accompanying consolidated balance sheet. Included in other current assets and other assets at December 31, 2008 are $160,000 and $240,000, respectively, of capitalized costs with affiliates. As of December 31, 2008 and 2007, approximately $549,000 and $607,000 had been advanced to OSC and is included in other current assets in the accompanying consolidated balance sheets. Under the terms of the agreement, approximately $591,000 and $765,000 of the amounts owed at December 31, 2008 and 2007, respectively, is subordinate to the debt service for the Partnership's bonds payable and term loans.

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Gregory Partners, LLC and Gregory Power Partners, L.P.

Combined Financial Statements

December 31, 2009 and 2008

The combined financial statements of Gregory Partners, LLC, and Gregory Power Partners, L.P., for the years ended December 31, 2009 and 2008, are presented herein without the related report of independent accountants.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Balance Sheets

December 31, 2009 and 2008

	2009	2008
Assets		
Current assets		
Cash and cash equivalents	$ 5,976,650	$ 5,189,868
Accounts receivable	11,333,532	9,641,457
Spare parts inventories	4,042,634	4,257,200
Prepaid expenses	401,758	1,751,253
Derivative asset gas swap contracts	8,560,010	12,971,861
Total current assets	30,314,584	33,811,639
Property, plant and equipment, net	153,936,483	161,859,053
Other assets		
Restricted cash and cash equivalents	35,777,376	43,788,715
Deposits	500,000	500,000
Deferred financing costs, net	1,407,574	1,782,763
Total assets	$ 221,936,017	$ 241,742,170
Liabilities and Partners' and Members' Capital		
Accounts payable and accrued liabilities	$ 14,770,444	$ 11,024,545
Current portion of long-term debt	9,424,991	9,644,306
Total current liabilities	24,195,435	20,668,851
Derivative liability interest rate swap contract	6,463,451	9,895,188
Long-term debt	84,632,202	101,435,444
Asset retirement obligation and other	2,258,306	1,926,091
Total liabilities	117,549,394	133,925,574
Commitments and Contingencies (See Note 14)		
Partners' and members' capital		
Contributed capital	30,330,329	30,330,329
Accumulated other comprehensive loss	(6,463,451)	(9,895,188)
Retained earnings	80,519,745	87,381,455
Total partners' and members' capital	104,386,623	107,816,596
Total liabilities and partners' and members' capital	$ 221,936,017	$ 241,742,170

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Statements of Operations

Years Ended December 31, 2009 and 2008

	2009	2008
Revenues		
Electricity	$ 103,436,357	$ 195,978,663
Steam	48,467,709	133,090,568
Other	3,407,688	7,727,498
Total revenue	155,311,754	336,796,729
Operating expenses		
Fuel purchased	109,578,737	279,552,454
Operation and maintenance	24,472,247	20,705,193
Depreciation, amortization and accretion	8,710,155	8,701,677
General and administrative	6,442,707	5,459,489
Total operating expenses	149,203,846	314,418,813
Income from operations	6,107,908	22,377,916
Other income (expense)		
Interest income	29,184	1,173,676
Interest expense	(5,847,066)	(8,278,857)
Gain on derivative contracts	6,756,649	7,529,777
Income before income taxes	7,046,675	22,802,512
Income tax expense	381,517	374,024
Net Income	6,665,158	22,428,488
Other comprehensive income (loss)		
Change in the fair value in the interest rate swap contracts	3,431,737	(4,992,609)
Comprehensive Income	$ 10,096,895	$ 17,435,879

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Statements of Changes in Partners' and Members' Capital

Years Ended December 31, 2009 and 2008

	Contributed Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance, December 31, 2007	$ 30,330,329	$ (4,902,579)	$ 126,205,446	$ 151,633,196
Net income			22,428,488	22,428,488
Distributions			(61,252,479)	(61,252,479)
Other comprehensive loss		(4,992,609)		(4,992,609)
Balance, December 31, 2008	30,330,329	(9,895,188)	87,381,455	107,816,596
Net income			6,665,158	6,665,158
Distributions			(13,526,868)	(13,526,868)
Other comprehensive gain		3,431,737		3,431,737
Balance, December 31, 2009	$ 30,330,329	$ (6,463,451)	$ 80,519,745	$ 104,386,623

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Statements of Cash Flows

Years Ended December 31, 2009 and 2008

	2009	2008
Cash flows from operating activities		
Net income	$ 6,665,158	$ 22,428,488
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and accretion	8,710,155	8,701,677
Amortization of deferred financing costs	375,189	412,707
Net derivative activity	(6,756,649)	(7,529,777)
Deferred tax liability	118,207	
Changes in assets and liabilities:		
Accounts receivable	(1,692,075)	12,360,399
Spare parts inventories	214,566	(741,647)
Prepaid expenses	1,349,495	246,913
Accounts payable and accrued liabilities	3,745,899	(1,284,512)
Net cash provided by operating activities	12,729,945	34,594,248
Cash flows from investing activities		
Purchases of property, plant and equipment	(573,577)	(778,689)
Net change in restricted cash	8,011,339	33,510,725
Cash flows from derivatives	11,168,500	157,500
Net cash provided by investing activities	18,606,262	32,889,536
Cash flows from financing activities		
Payment of long-term debt	(17,022,557)	(10,589,577)
Distributions to partners	(13,526,868)	(61,252,479)
Net cash used in financing activities	(30,549,425)	(71,842,056)
Net change in cash and cash equivalents	786,782	(4,358,272)
Cash and cash equivalents		
Beginning of the period	5,189,868	9,548,140
End of the period	$ 5,976,650	$ 5,189,868
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 5,476,768	$ 7,854,148

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements

December 31, 2009 and 2008

1. Organization

Gregory Partners, LLC, and Gregory Power Partners, L.P. (collectively, the "Company," the "Partnership" or "Gregory") were organized on June 1, 1998, as a Delaware limited liability company and a Texas limited partnership, respectively, for the sole purpose of developing, financing, constructing, owning and operating a 500-megawatt (equivalent) cogeneration facility (the "Facility") at the Sherwin Alumina, L.P. (formerly Reynolds Metal Company) (BPU Reynolds, Inc.) plant near Gregory, Texas. The Facility commenced commercial operations on July 15, 2000. The Company operates as a Qualifying Facility ("QF") pursuant to the Public Utility Regulatory Policies Act ("PURPA"). The Partnership is operated pursuant to the Gregory Partnership Agreement dated June 1, 1998 (the "Partnership Agreement"). The operation and maintenance services are provided by subsidiaries of Babcock & Wilcox Company ("B&W"), an unaffiliated company.

Partnership interests are owned by subsidiaries of Javelin Holding, LLC ("Javelin Holding"), a wholly owned subsidiary of Javelin Energy, LLC ("Javelin Energy") and a subsidiary of DPC KY Energy LLC a wholly owned subsidiary of Delta Power Company, LLC ("Delta") called KY Energy, LLC. KY Energy, LLC holds a 4% limited partner interest in Gregory Partners, LLC and Gregory Power Partners, L.P. KY Energy, LLC also holds through its subsidiaries KY Energy Power Gregory #1, Inc. and KY Energy Power Gregory #2, Inc. a 1% general partner interest in Gregory Partners, LLC and Gregory Power Partners, LP. Subsidiaries of Javelin Energy hold a 94% limited partnership interest and a 1% general partnership interest. Javelin Energy is owned by the following six entities: (1) DPC Javelin Energy, LLC, a wholly owned subsidiary of Delta; (2) John Hancock Variable Life Insurance Company; (3) Epsilon Power Funding, LLC (4) John Hancock Life Insurance Company (5) JH Partnership Holdings I, LP; and (6) JH Partnership Holdings II, LP.

Under the terms of the Partnership Agreement, the Partnership's profits, losses, and distributions are divided equally, based on ownership percentages, among the Gregory partners.

The following chart shows the general partners and members managers designated by an asterisk (*) and the Limited Partners and Members of the Company as of December 31, 2009 and December 31, 2008:

	Gregory Partners, LLC	Gregory Power Partners, LP
Javelin Holding, LLC		
* Javelin Gregory General Corporation		1%
Gregory Holdings #1, LLC		94%
* Javelin Gregory Remington Corporation	1%	
Gregory Holdings #2, LLC	94%	
KY Energy, LLC		
* KY Energy Power Gregory #1 Inc.		1%
KY Energy, LLC		4%
* KY Energy Power Gregory #2 Inc.	1%	
KY Energy, LLC	4%	

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

2. Business Risks

Several current issues in the power industry could have an effect on the Company's financial performance. Some of the business risks and uncertainties that could cause future results to differ from historical results include, but are not limited to:

- The uncertain length and severity of the current depressed general financial and economic downturn, the timing and strength of an economic recovery, if any, and their impacts on the Company's business, including demand for power, and the ability of contractual counterparties to perform under their contracts with the Company;
- The Company's ability to manage its customers and counterparty exposure and credit risk;
- Competition, including risks associated with marketing and selling power in the evolving energy markets;
- Regulation in the markets in which the Company participates and the Company's ability to effectively respond to changes in federal, state and regional laws and regulations;
- Natural disasters, such as hurricanes, earthquakes and floods, or acts of terrorism that may impact the Company's power plant or the market it serves;
- Seasonal fluctuations of the Company's results and exposure to variations in weather patterns;
- Disruptions in, or limitations on, the transportation of natural gas and transmission of power;
- Risks associated with the operation of a power plant including unscheduled outages and plant inefficiencies;
- Present and possible future claims, litigation and enforcement actions;
- The expiration or termination of the Company's Power Purchase Agreements and the related results on revenues.

3. Summary of Significant Accounting Policies

Basis of Presentation

The combined financial statements have been prepared in accordance with Generally Accepted Accounting Principles ("GAAP") and include the accounts of Gregory Partners, LLC, and Gregory Power Partners, L.P. All significant intercompany accounts and transactions have been eliminated upon combination. The combination results from the fact that the companies operate under common control and have significant financial interests in one another. The significant financial interests relate to the cross collateralization of the assets of the Company's debt agreement as described in Note 6.

Reclassifications

Certain reclassifications have been made to the combined balance sheets, combined statements of operations, and combined statements of cash flows, to conform to current year presentation.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

Use of Estimates

The preparation of the Company's financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue, expenses, and related disclosures included in the combined financial statements. Actual results could differ from these estimates.

Significant estimates made by the Company include reserves for doubtful accounts receivable, inventory obsolescence, accrued expenses, and estimates of discounted future cash flows used in evaluating assets for impairments.

Cash and Cash Equivalents

The Company considers all highly liquid investments with a term to maturity of three months or less at the date of purchase to be cash and cash equivalents.

Accounts Receivable and Accounts Payable

Accounts receivable and payable represent amounts due from customers and owed to vendors. Accounts receivable are recorded at invoiced amounts, net of reserves and allowances as applicable, and do not bear interest. Receivable balances greater than 30 days past due are individually reviewed for collectability, and if deemed uncollectible, are charged off against the allowance accounts after all means of collection have been exhausted and the potential recovery is considered remote. The Company uses an estimate to determine the required allowance for doubtful accounts based on a variety of factors, including the length of time receivables are past due, economic trends, significant one-time events, and historical write-off experience. Specific provisions are recorded for individual receivables when the Company becomes aware of a customer's inability to meet its financial obligations. Reserves and allowances are reviewed annually. No allowance was recorded as of December 31, 2009 and 2008.

Spare Parts Inventory

Spare parts inventories are valued at the lower of cost or market, with cost determined using a weighted average. The costs are expensed to plant operating costs as the parts are utilized and consumed.

Accounting for the Impairment of Long-Lived Assets

The Company evaluates long-lived assets, such as property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. When an impairment condition may have occurred, the Company is required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets or liabilities for long-lived assets that are expected to be held and used.

In order to estimate future cash flows, the Company considers historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable,

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

the assumptions are consistent with forecasts that the Company is otherwise required to make. The use of this method involves inherent uncertainty. The Company uses its best estimates in making these evaluations and considers various factors, including forward price curves for power, fuel costs, and operating costs. However, actual future market prices could vary from the assumptions used in the estimates, and the impact of such variations could be material.

During 2009 and 2008, long-lived assets were reviewed and it was determined that no impairment condition had occurred.

Property, Plant and Equipment

Property, plant and equipment are stated at cost and depreciated over their estimated useful lives using the straight-line method or machine-hours method. Property, plant and equipment accounts are relieved of the cost and related accumulated depreciation when assets are disposed of or otherwise retired.

Planned Major Maintenance Accounting

The Company recognizes all expenses related to the Long-Term Service Agreement ("LTSA") with General Electric International, Inc. when occurred. See more detail in Note 9.

Deferred Financing Costs

Financing costs incurred related to the debt issuance are deferred and amortized over the term of related debt using a method that approximates the effective interest rate method. When a debt is retired before its maturity, unamortized deferred costs are written off and other debt extinguishment costs related to retirement of debt are recognized in the period of extinguishment. For the years ended December 31, 2009 and 2008, the Company recorded amortization expense of $375,189 and $412,707, respectively and was recorded in interest expense on the accompanying combined statements of operations. As of December 31, 2009 and 2008, accumulated amortization was $4,545,591 and $4,320,402, respectively.

Restricted Cash and Cash Equivalents

The Company has established escrow accounts held by a trustee pursuant to the terms of the project financing arrangement as described in Note 6. These funds are held by trustees and are restricted as to payments for future maintenance on property and equipment, future operating costs and future principal and interest payments, subject to the terms of the project financing arrangement.

Accounting for Asset Retirement Obligations

The Company has recorded all known asset retirement obligations for which the liability's fair value can be reasonably estimated under Financial Accounting Standards Board "FASB" ASC Topic 410, Asset Retirement and Environmental Obligations. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. The Company's asset retirement obligations primarily relate to site restoration costs, including

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

removal costs, environmental remediation ground water monitoring, and the purchase of an environmental insurance policy.

Under these accounting methods, the Company recorded an asset of $829,112, representing the net present value of the Year 2030 asset retirement obligation utilizing a 10.0% risk free cost of capital and a liability of $1,023,595 for the asset retirement obligation as of January 1, 2003. In addition, the Company will expense an amount equal to (a) the straight-line depreciation of the site dismantlement asset of $829,112 and (b) an amount equal to the annual increase in the site dismantlement liability, assuming a 2.5% annual inflation rate through the end of the lease term. Accretion expense was $214,008 and $192,612 for the years ended December 31, 2009 and 2008, respectively.

Scheduled depreciation expense and accretion expense is as follows:

	Depreciation Expense	Accretion Expense
2010	$ 27,637	$ 237,787
2011	27,637	264,208
2012	27,637	293,564
2013	27,637	326,182
2014	27,637	362,425
After 2014	428,374	14,904,953
	$ 566,559	$ 16,389,119

Derivative Instruments

The Company follows applicable U.S. accounting standards in accounting for derivative instruments and hedging activities. These standards require all derivatives to be recognized on the balance sheet and measured at fair value. The Company records the fair value of derivatives in current assets, long-term assets, current liabilities or long-term liabilities, as appropriate. If a derivative is designed to meet hedge accounting criteria, the Company is required to measure the effectiveness of the hedge. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and, subsequently, reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative's change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

The Company is required by its project financing arrangement to utilize interest rate swap contracts to reduce its exposure to adverse fluctuations in interest rates on its long-term debt. Such swaps are accounted for as cash flow hedge transactions, with related gains (losses) being recorded in interest expense as realized and changes in the fair value are recorded in other comprehensive income (See Note 10).

The Company has entered into several natural gas swap contracts. These contracts are carried in the Company's Balance Sheet at fair value, with changes in fair value recorded in current earnings in other income on the income statement.

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Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

Revenue Recognition

Capacity revenue is recognized monthly, based on the Facility's availability. Revenues from the sale of power, steam, spray water, and ancillary services are recorded upon transmission and delivery to the customer.

Fuel Expense

During 2009 and 2008 the Company purchased about half of its gas from Kinder Morgan Tejas Pipeline, LLC. The remaining half of its gas during this period was delivered to the Company as payment for steam sales to Sherwin Alumina L.P.

Income Taxes

The Company is exempt from federal and state income taxes. Taxable income or loss from the Company is reportable by the partners and members on their respective income tax returns. Accordingly, there is no recognition of income taxes in the combined financial statements. However, Texas imposes its franchise tax at the Company level. Accordingly, a provision and accrual for current and deferred income taxes for Texas franchise tax have been included in our combined financial statements.

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities due to a change in tax rates is recognized in income in the period that includes the enactment date.

Comprehensive Income

The Company's comprehensive income consists of net income and other items recorded directly to the equity accounts. The objective is to report a measure of all changes in the partners' and members' capital that result form transactions and other economic events of the period other than transactions with owners. The Company's other comprehensive income consists principally of changes in the fair value of interest rate swap contracts that qualify for cash flow hedge treatment.

At December 31, 2009 and 2008, the balance of accumulated other comprehensive loss was $6,463,451 and $9,895,188, respectively, and consisted of the changes in the fair value of the interest rate swap agreements.

Fair Value of Financial Instruments

The Company uses the market and income approaches to determine the fair value of its financial assets and liabilities and considers the markets in which the transactions are executed. Effective in 2009, U.S. accounting standards require the application of fair value measurement criteria to include both financial and non-financial instruments. Inputs into the Company's fair value estimates include

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

market quoted prices, LIBOR, and other liquid money market instrument rates. The interest rates used to calculate the market value of our interest rate swaps are derived from three month LIBOR future rates. The Company considers the impact of counterparty credit risk on the fair value of derivative assets, as well as the Company's own credit risk for derivative liabilities, using the Company's credit spread.

The authoritative guidance related to fair value establishes the fair value hierarchy that prioritizes inputs to valuation techniques based on observable and unobservable data and categorizes the inputs into three levels, with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are described below:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities;

Level 2 Significant observable pricing inputs other than quoted prices included with Level 1 that are either directly or indirectly observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and

Level 3 Generally unobservable inputs, which are developed based on the best information available and may include our own internal data.

Determining the appropriate classification of fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. If prices change for a particular input from the previous measurement date to the current measurement date, the impact could result in the financial instrument being moved between Levels, depending upon management judgment of the significance of the price change of that particular input to the total fair value of the financial instrument.

The carrying amounts reported in the balance sheets of cash and cash equivalents, accounts receivable, accounts payable, and other payables approximate their respective fair values due to their short maturities. See Note 12 for disclosures regarding the fair value of other debt instruments and derivatives.

Concentration of Credit Risk

Financial instruments that potentially subject to the Company to credit risk consist primarily of cash and cash equivalents, restricted cash, accounts receivables, and derivatives. Cash and cash equivalents, as well as restricted cash balances, may exceed Federal Deposit Insurance Corporation ("FDIC") insured limits or are invested in money market accounts with investment banks that are not FDIC insured. The Company places cash and cash equivalents and restricted cash in what it believes to be credit-worthy financial institutions and certain of the money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. Government, its agencies or instrumentalities. Management does not believe there is significant risk to the Company relating to the financial institutions. The Company sells power to Sherwin Alumina, L.P. and Fortis Energy Marketing, Inc. under power purchase contracts and accounts receivable are concentrated with these customers. The Company has exposure to trends within the power industry, including declines in the creditworthiness of its significant customers. The Company generally has not collected collateral or

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

other security to support its power-related accounts receivable; however, the Company may require collateral in the future. Management does not believe there is significant credit risk to the Company associated with its significant customers.

The Company has significant customers for 2009 and 2008, as follows:

	2009	2008
Sherwin Alumina, L.P.		
Percentage of combined total revenue	36%	45%
Percentage of combined accounts receivable	21%	9%
Constellation Energy Commodities Group, Inc.		
Percentage of combined total revenue	0%	55%
Percentage of combined accounts receivable	0%	87%
Fortis Energy Marketing, Inc.		
Percentage of combined total revenue	62%	0%
Percentage of combined accounts receivable	79%	0%
Other		
Percentage of combined total revenue	2%	<1%
Percentage of combined accounts receivable	0%	4%

Accounting and Reporting Developments

Accounting Standards Codification and GAAP Hierarchy Effective for interim and annual periods ending after September 15, 2009, the Accounting Standards Codification and related disclosure requirements issued by the FASB became the single official source of authoritative, nongovernmental GAAP. The ASC simplifies GAAP, without change, by consolidating the numerous, predecessor accounting standards and requirements into logically organized topics. All other literature not included in the ASC is non-authoritative. We adopted the ASC as of December 31, 2009, which did not have any impact on our results of operations, financial condition or cash flows as it does not represent new accounting literature or requirements; however, it did change our references to authoritative sources of GAAP to the new ASC nomenclature.

Fair Value Measurements of Non-Financial Assets and Non-Financial Liabilities Effective for interim and annual periods beginning after November 15, 2008, GAAP established new standards related to fair value measurements for non-financial assets and liabilities. These new standards do not apply to assets and liabilities that were not previously required to be recorded at fair value, but do apply when other accounting pronouncements require fair value measurements. The new standards also define fair value, establish a framework for measuring fair value under GAAP and enhance disclosures about fair value measurements. We adopted the new standards with respect to non-financial assets and non-financial liabilities as of January 1, 2009, which had no effect on our results of operations, financial position or cash flows; however, adoption may impact measurements of asset impairments and asset retirement obligations if they occur in the future.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

3. Summary of Significant Accounting Policies (Continued)

Determining Fair Value in Inactive Markets Effective for interim and annual periods beginning after June 15, 2009, GAAP established new accounting standards for determining fair value when the volume and level of activity for the asset or liability have significantly decreased and the identifying transactions are not orderly. The new standards apply to all fair value measurements when appropriate. Among other things, the new standards:

- affirm that the objective of fair value, when the market for an asset is not active, is the price that would be received in a sale of the asset in an orderly transaction;
- clarify certain factors and provide additional factors for determining whether there has been a significant decrease in market activity for an asset when the market for that asset is not active;
- provide that a transaction for an asset or liability may not be presumed to be distressed (not orderly) simply because there has been a significant decrease in the volume and level of activity for the asset or liability, rather, a company must determine whether a transaction is not orderly based on the weight of the evidence, and provide a non-exclusive list of the evidence that may indicate that a transaction is not orderly; and
- require disclosure in interim and annual periods of the inputs and valuation techniques used to measure fair value and any change in valuation technique (and the related inputs) resulting from the application of the standard, including quantification of its effects, if practicable.

These new accounting standards must be applied prospectively and retrospective application is not permitted. We adopted these new standards during 2009, which resulted in a clarification of existing accounting guidance with no change to our accounting policies and had no effect on our results of operations, cash flows or financial position. See Note 11 for disclosure of our fair value measurements.

Disclosures About Derivative Instruments and Hedging Activities Effective for interim and annual periods beginning after November 15, 2008, GAAP established enhanced disclosure requirements relating to an entity's derivative and hedging activities to enable investors to better understand their effects on the entity's financial position, financial performance, and cash flows. We adopted the new disclosure requirements as of January 1, 2009. Adoption resulted in additional disclosures related to our derivatives and hedging activities including additional disclosures regarding our objectives for entering into derivative transactions, increased balance sheet and financial performance disclosures, volume information and credit enhancement disclosures. See Note 9 for our derivative disclosures.

Subsequent Events Effective for interim and annual periods ending after June 15, 2009, GAAP established general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The new requirements do not change the accounting for subsequent events: however, they do require disclosure, on a prospective basis, of the date an entity has evaluated subsequent events. We adopted these new requirements during 2009, which had no impact on our results of operations, financial condition or cash flows. We have evaluated subsequent events up to the time of issuance of this Report on April 9, 2010.

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Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

4. Restricted Cash and Cash Equivalents

Pursuant to the Depositary Agreement dated November 18, 1998 (as amended), the Company established certain reserve funds for the operation of the plant: operating account, debt payment account, major maintenance reserve account, DSR account, fuel account, distribution retention account, loss proceeds account, calculation holding account, PSA collateral account, IDR account, shortfall reserve account, and special reserve account. Restricted cash and cash equivalents consist of the following at December 31, 2009 and 2008, respectively:

	2009	2008
Debt Service Reserve	$ 10,000,200	$ 10,078,335
Distribution Retention	1,288,940	1,606,778
Calculation Holding	1,169,591	3,556,426
Major Maintenance	12,920,245	20,301,049
IDR	500,010	564,726
PSA Collateral		8,381
Javelin Equity Support	4	7,289,448
Project Equity Support		383,572
Special Reserve	9,898,386	
Total Restricted Cash and Cash Equivalents	$ 35,777,376	$ 43,788,715

5. Property, Plant and Equipment

Plant and equipment consist of the following at December 31, 2009 and 2008, respectively:

	Useful Lives	2009	2008
Plant and related equipment	5 - 30 years	$ 246,907,519	$ 246,498,709
Office and transportation equipment	3 - 10 years	1,333,292	1,168,525
		248,240,811	247,667,234
Less: Accumulated depreciation		(94,304,328)	(85,808,181)
Net plant and equipment		$ 153,936,483	$ 161,859,053

Depreciation expense for the years ended December 31, 2009 and 2008 amounted to $8,496,147 and $8,509,066, respectively. Approximately 14% of plant and related equipment is depreciated using the machine-hours method in 2009 and 2008.

6. Long-Term Debt

The Company has a 17 year loan, expiring September 30, 2017 with ING Capital, LLC that provides for quarterly principal payments and interest at LIBOR plus 1.375% during 2007 and through October 2, 2008. On October 2, 2008 the interest rate changed to LIBOR plus 1.5%. The effective interest rate at December 31, 2009 and 2008 was approximately 5.2% and 7.3% respectively.

Borrowings are obligations solely of the Company and the lender's collateral is substantially all of the assets of the Company. The lenders have no contractual recourse to the partners. The loan

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

6. Long-Term Debt (Continued)

agreement contains various affirmative and negative covenants involving the operation of the Facility, compliance with laws, and incurrence of additional debt and restricted payments.

The most restrictive covenants under the term loan are as follows:

(1) The Company must give prompt notice to ING Capital, LLC of any contractual obligations incurred by the Company exceeding $250,000 per year.

(2) The Company must give prompt notice to ING Capital, LLC of any potential litigation that may exceed $250,000.

Scheduled maturities of the long-term debt are as follows:

2010	$ 9,424,991
2011	10,194,379
2012	10,963,766
2013	11,829,326
2014	12,791,060
After 2014	38,853,671
	94,057,193
Less: Current portion	(9,424,991)
	$ 84,632,202

The fair value of the debt as of December 31, 2009 was approximately $87,148,838.

In November 2008, the Company provided a notice letter to ING Capital, LLC advising that it was in a state of default under the Credit Agreement. The default situation was the result of the expiration of the Texas state authorization in March 2008 for its Prevention of Signification Deterioration ("PSD") Air Permit. The Company signed an Agreed Order with the Texas Commission of Environmental Quality ("TCEQ") on March 24, 2009 which provided the state's authority to operate under the terms of the former PSD Air Permit until a new permit was issued. The Company concurrently provided notice to ING Capital, LLC that the default situation was cured. On March 15, 2010, the new permit was issued.

7. Income Taxes

Under federal income tax rules, the Company is treated as a partnership and is not subject to any entity level federal income tax. However, the Company is subject to the Texas franchise tax which generally imposes a tax at the "margin" level. Income tax expense consists of the following components:

Current	$ 263,310
Deferred	13,187
Prior year true up	105,020
Total income tax expense	$ 381,517

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

7. Income Taxes (Continued)

The federal statutory income tax rate that applies to the Company in the present form is 0%. The income tax provision of $381,517 attributable to continuing operations is the result of applying Texas franchise tax provisions and is the only difference from the amount of income tax expense determined by applying the federal statutory income tax rate. The income tax expense for the Texas franchise tax reflected on the Company's combined statement of operations for the year ended December 31, 2009, includes an expense of $105,020 to revise prior year deferred tax estimates. The Company has an effective tax rate of 5.4% for the year ended December 31, 2009. Excluding the income tax expense that was recorded in 2009 due to revisions of prior year estimate, the Company would have an effective tax rate of 3.9%.

Deferred tax liabilities of $118,207 at December 31, 2009, result from book versus tax basis differences attributable to property, plant, and equipment, and is included in asset retirement obligation and other in the accompanying combined balance sheets.

8. Related Party Transactions

The Company entered into an agreement as of January 1, 2001, whereby it reimburses Delta for salaries and benefits for the General Manager and staff that are assigned to the Company. Payments to Delta for salaries and benefits totaled $559,389 and $497,215 for the years ended December 31, 2009 and 2008, respectively and are included in general and administrative expense in the combined statements of operations. At December 31, 2009 and 2008, respectively, $137,099 and $138,978 were payable to Delta which was included in accounts payable and accrued liabilities in the accompanying combined balance sheets.

9. Significant Agreements with Third Parties

Power Purchase Agreements

Sherwin Alumina, L.P. ("Sherwin")

The Company and Reynolds Metals Company entered into an Energy Services Agreement ("ESA") for a term of 35 years effective June 30, 1998, and ending on the 35-year anniversary of the Commercial Operations Date, ("COD" as defined in the ESA as August 1, 2000). The ESA affords Reynolds the right to purchase a portion of the Company's steam and electricity production for a term ending on the 20-year anniversary of the COD, with a right to extend this term for up to three additional 5-year terms upon providing the Company with at least two years' notice prior to the expiration date. On December 31, 2000, the ESA was assigned to and assumed by BPU Reynolds. On August 1, 2001, the ESA was assigned to and assumed by Sherwin Alumina, L.P. The provisions of the ESA allow Sherwin to provide natural gas in lieu of a cash payment as compensation for the steam they purchase for their production needs. The Partnership records the related steam revenue in revenue and an equivalent natural gas expense recorded in fuel purchased in the accompanying combined statements of operations.

Constellation Energy Commodities Group, Inc ("CCG")

The Company and CCG entered into a power sales agreement ("CCG PSA") as of August 29, 2005, whereby the Company agrees to sell and CCG agrees to purchase certain quantities of electricity

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

9. Significant Agreements with Third Parties (Continued)

capacity and energy, as well as ancillary service capabilities. The CCG PSA has a term of three years and four months from September 1, 2005, ending December 31, 2008.

The CCG PSA expired on December 31, 2008, and was replaced with a power sales agreement with Fortis Energy Marketing & Trading GP.

Fortis Energy Marketing & Trading GP ("Fortis")

The Company and Fortis entered into a power sales agreement ("Fortis PSA") as of July 23, 2007, whereby the Company agrees to sell and Fortis agrees to purchase certain quantities of electricity capacity and energy, as well as ancillary service capabilities. The Fortis PSA has a term of five years beginning January 1, 2009.

The Fortis PSA calls for a fixed capacity component and a variable energy component. The Fortis PSA includes a provision that requires the Company to provide Credit Support which was delivered to Fortis by the Company in July 2007 in the form of a letter of credit for $10 million. The letter of credit expired on July 23, 2008 Currently, Arroyo DP Holdings, LP, Delta's parent, provides an approximate $1.4 million cash collateral as credit support for this agreement.

The Company is subject to operational and contractual risks associated with the Fortis PSA. Risks include, but are not limited to, output capacity and availability. Management has taken steps to manage physical and contractual risks; however, such risks cannot be eliminated.

Energy Management Agreements

Tenaska Power Services Co. ("TPS")

On December 6, 2006, the Company and TPS entered into an Energy Management Agreement ("EMA") whereby TPS is to provide energy management services for the Facility by acting as the Company's qualified scheduling entity with ERCOT and marketing the excess power (~5 to 55 MWhs) from the Facility generated above the volumes committed to Sherwin, CCG and Fortis. The agreement primary term expired on December 31, 2008. The agreement automatically renewed and will continue to automatically renew for successive one year terms unless terminated by either party by giving a written notice to the other party. No termination notice was produced by either party in 2008 or 2009. The Company provided TPS a cash deposit in lieu of an irrevocable letter of credit in the amount of $500,000 which is included in deposits in the accompanying combined balance sheets.

Gas Purchase and Transportation Agreements

Kinder Morgan

Coral Energy Resources, L.P., Coral Energy, L.P. (together, "Coral") and the Company entered into an Amended and Restated Gas Sales Agreement (the "GSA"), as of November 20, 1998, whereby Coral agrees to sell, at an agreed upon price. to the Company up to 62,000 MMBtu per day of natural gas, the Facility's estimated maximum daily fuel requirement (net of gas supplied by Sherwin). On February 28, 2002, the GSA was assigned to and assumed by Kinder Morgan Tejas Gas Pipeline, which underwent a name change to Kinder Morgan Tejas Pipeline, LLC ("Kinder Morgan"). The Company has no obligation to purchase any gas under the GSA beyond the first two contract years.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

9. Significant Agreements with Third Parties (Continued)

The GSA has a primary term of ten years from the COD (as defined in the ESA as August 1, 2000). The GSA includes a provision that requires the Company to provide additional credit support under certain circumstances.

Tejas Gas Pipeline L.P.

Tejas Gas Pipeline L.P., ("Tejas") and the Company entered into an Amended and Restated Intrastate Gas Transportation Agreement (the "Intrastate Agreement"), as of November 20, 1998, whereby Tejas agrees to provide firm transportation for the Facility of up to 62,000 MMBtu per day of gas.

The Intrastate Agreement has a primary term of ten years from the COD (as defined in the ESA as August 1, 2000), but the Company may terminate the Intrastate Agreement at the end of the fifth contract year upon at least 60 days notice to Tejas.

Constellation NewEnergy, Inc. ("CNE")

On April 27, 2006, the Company and CNE entered into a one year Master Retail Power Sales Agreement, whereby CNE agreed to supply full requirements for electric energy, including standby electricity and provide any additional energy and services as the Company may require in the event it is required to import electricity to support it and/or its steam hosts production requirements. The price of the electricity is the Market Clearing Price of Electricity plus $0.50, with a monthly fee of $3,000. On April 23, 2007, the agreement was extended until April 26, 2008. On February 6, 2008, the agreement was modified to change the term from one year to three years ending on April 26, 2009. On April 27, 2009, the agreement was extended for an additional one year term ending on April 26, 2010. The price of the electricity was also changed to ERCOT's applicable zonal market clearing price for energy for the Delivery Point as posted on its website plus $5.50.

San Patricio Municipal Water District

The Company and the San Patricio Municipal Water District ("SPMWD") entered into a Raw Water Contract (the "RWC") as of September 15, 1998, that provides, in part, that SPMWD will sell and deliver up to 2 million gallons of water per day to the Company. The initial term of the RWC is 20 years. Monthly billings for water sold to the Company are based on rates set annually to recover SPMWD's cost of service. Under the terms of the RWC, SPMWD will reserve specified capacity in its facilities to deliver water to the Facility.

General Electric International, Inc.

The Company and General Electric International, Inc. ("GE") entered into a Long-Term Service Agreement ("LTSA") as of September 30, 2001, whereby GE agrees to manage future planned maintenance and certain additional maintenance with respect to the two gas turbines at the Facility, including the combustion and turbine sections of the covered units and their Mark V control system. The initial term of the contract is the earlier of the time when covered units experience their second major inspection, as described under the contract or 17 years from the effective date of the contract. The contract was amended as of March 31, 2006 to extend the term of coverage until each covered unit

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

9. Significant Agreements with Third Parties (Continued)

reaches the later of 120,000 factored fired hours of operation or completion of the first hot path inspection after the second major inspection as defined in the contract.

Koch Supply & Trading, LP

On January 7, 2009 the Company entered into an agreement with Koch Supply & Trading, LP ("Koch") for the Company to sell 500 tons of 2009 CAIR Annual NOx Allowances at $5,000 per ton. The $2.5 million payment from Koch was received on February 6, 2009 and was a component of other revenues in the accompanying combined statement of operations.

10. Interest Rate Swap Contract

To protect the project lenders from the uncertainty of interest rate changes during the term of the loan, the Company was required by the project financing agreement to fix or hedge fifty percent (50%) of the original balance of the term loan by entering into an interest rate swap contract. The agreement with ING Capital LLC, dated November 23, 1998, requires the Company to make fixed interest payments at a rate of 5.95% for the term of the loan and the Company will receive interest at a variable rate equal to the rate on the debt hedged. The contract has a notional amount of approximately half of the outstanding principle balance of the loan. The interest rate swap contract matures at the time the related debt matures.

The effective portion of the unrealized gain or loss on an interest rate swap designated and qualifying as a cash flow hedging instrument is reported as a component of other comprehensive income ("OCI") and such gains and losses are reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on interest rate swaps are recognized currently in earnings as a component of interest expense. If it is determined that the forecasted transaction is probable of not occurring, then hedge accounting will be discontinued prospectively and the associated gain or loss previously deferred in OCI is reclassified into current income. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the gain or loss associated with the hedge instrument remains deferred in OCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is probable of not occurring.

As of December 31, 2009 and 2008, the Company had recorded cumulative losses of $6,463,451 and $9,895,188, respectively, in other comprehensive income. Upon termination of the loan and swap contract any amount recorded in other comprehensive income will be reclassified into earnings.

11. Natural Gas Swap Contracts

On June 15, 2007, the Company entered into a financial swap agreement with Sempra for a period of one year from January 1, 2008 through December 31, 2008. The agreement requires the Partnership to sell 4,500,000 MMBtu of gas during the year at a fixed price of $8.70 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

On March 3, 2008 the Company entered into another financial swap agreement with Sempra for a period of one year from January 1, 2009 through December 31, 2009. The agreement requires the

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

11. Natural Gas Swap Contracts (Continued)

Partnership to sell 2,100,000 MMBtu of gas during the year at a fixed price of $9.10 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

On June 9, 2008, the Company entered into another financial swap agreement with Sempra for a period of one year from January 1, 2010 through December 31, 2010. The agreement requires the Partnership to self 2,100,000 MMBtu of gas during the year at a fixed price of $9.91 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

These contracts are carried in the accompanying combined balance sheets at their fair value of $8,560,010 and $12,971,861 as of December 31, 2009 and 2008, respectively in derivative asset gas swap agreement, with changes in fair value recorded in current earnings in other income in the combined statements of operations.

12. Fair Value Disclosures

The Company adopted the provisions of FASB ASC 820, Fair Value Measurements and disclosures, effective January 1, 2008. FASB ASC 820 defines fair value, establishes a framework for measuring fair value under GAAP and enhances disclosures about fair value measurements.

Fair Value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used to measure fair value, as required by Topic 820 of the FASB ASC, must maximize the use of observable inputs and minimize the use of unobservable inputs.

The standard describes a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment, and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy.

The following table summarizes the fair values of the Company's derivatives based on the inputs used as of December 31, 2009 and 2008 in determining such fair values:

Description	Fair Market Value on 12/31/2009	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Natural gas swaps	$ 8,560,010		8,560,010	
Interest rate swaps	$ (6,463,451)		(6,463,451)	
Restricted cash and cash equivalents	$ 35,777,376	35,777,376		
	$ 37,873,935	$ 35,777,376	$ 2,096,559	$

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2009 and 2008

12. Fair Value Disclosures (Continued)

Description	Fair Market Value on 12/31/2008	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Natural gas swaps	$ 12,971,861		12,971,861	
Interest rate swaps	$ (9,895,188)		(9,895,188)	
Restricted cash and cash equivalents	$ 43,788,715	43,788,715		
	$ 46,865,388	$ 43,788,715	$ 3,076,673	$

For derivatives for which fair value is determined based on multiple inputs, fair value accounting standards require that the measurement for an individual derivative to be categorized within a single level based on the lowest-level input that is significant to the fair value measurement in its entirety.

Fair value inputs for natural gas swaps in Level 2 are market prices. Fair value inputs for interest rate swaps in Level 2 are three month LIBOR future rates. Fair value inputs for restricted cash and cash equivalents in Level 1 are the Company's money market accounts.

The carrying amount of cash and cash equivalents approximate their fair value principally due to the short-term nature of these instruments. The fair value of the Company's long-term debt approximates the carrying amounts by virtue of the variable rate interest arrangements associated with the debt (See Note 6). The fair values of the interest rate swap contract and natural gas swap contracts equal the carrying value and were determined using the estimated amount the Company would receive to terminate the contracts. See Notes 10 and 11 for additional disclosure regarding the Company's accounting for its interest rate swap contract and natural gas swap contracts, respectively.

13. Ground Lease

The Company leases the land where the Facility is located from Sherwin under a 35-year term operating lease. The annual rent is $1 per year. The Company is required to pay all taxes, assessments, and fees on the leased property during the lease term. If the agreement is terminated prior to the 35-year term, the Company shall pay rent in equal monthly installments in an amount based on the market value of the unimproved land as determined at the time the agreement is terminated.

14. Commitments and Contingencies

There are commitments and contingencies arising from the ordinary course of business to which the Company is party. It is management's belief that the ultimate resolution of those commitments and contingencies will not have a material adverse impact on the Company's financial position or results of operations.

15. Subsequent Events

The Company has evaluated events subsequent to December 31, 2009 through April 9, 2010, the date the financial statements were available to be issued, and identified no events to be disclosed.

Gregory Partners, LLC and Gregory Power Partners, L.P.

Combined Financial Statements

December 31, 2008 and 2007

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The combined financial statements of Gregory Partners, LLC, and Gregory Power Partners, L.P., for the years ended December 31, 2008 and 2007, are presented herein without the related report of independent accountants for the year ended December 31, 2008. The report of independent accountants is presented for the year ended December 31, 2007 pursuant to the requirements of Rule 3-09 of Regulation S-X.

PricewaterhouseCoopers LLP
300 Atlantic Street
Stamford CT 06901
Telephone (203) 539-3000
Facsimile (203) 207-3999

Report of Independent Auditors

To the Board of Managers of
Gregory Partners, LLC and
Gregory Power Partners, L.P.:

In our opinion, the accompanying combined balance sheet and the related combined statements of operations, of changes in partners' and members' capital and of cash flows present fairly, in all material respects, the combined financial position of Gregory Partners, LLC, and Gregory Power Partners, L.P., (the "Company") at December 31, 2007, and the combined results of their operations and their combined cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 2 to the combined financial statements, the Company has adopted a new method of accounting for planned major maintenance.

/s/ PricewaterhouseCoopers LLP

March 28, 2008

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Balance Sheets

December 31, 2008 and 2007

	2008	2007
Assets		
Current assets		
Cash and cash equivalents	$ 5,189,868	$ 9,548,140
Accounts receivable	9,641,457	22,001,856
Spare parts inventories	4,257,200	3,515,553
Prepaid expenses and other current assets	14,723,114	7,597,750
Total current assets	33,811,639	42,663,299
Property, plant and equipment, net	161,859,053	169,589,429
Other assets		
Restricted cash and cash equivalents	43,788,715	77,299,440
Deposits	500,000	500,000
Deferred financing costs, net	1,782,763	2,195,470
Total assets	$ 241,742,170	$ 292,247,638
Liabilities and Partners' and Members' Capital		
Accounts payable and accrued liabilities	$ 11,024,545	$ 12,309,057
Current portion of long-term debt	9,644,306	9,042,396
Total current liabilities	20,668,851	21,351,453
Derivative liability interest rate swap contract	9,895,188	4,902,579
Asset retirement obligation	1,926,091	1,733,479
Long-term debt	101,435,444	112,626,931
Total liabilities	133,925,574	140,614,442
Partners' and members' capital		
Contributed capital	30,330,329	30,330,329
Accumulated other comprehensive income (loss)	(9,895,188)	(4,902,579)
Retained earnings	87,381,455	126,205,446
Total partners' and members' capital	107,816,596	151,633,196
Total liabilities and partners' and members' capital	$ 241,742,170	$ 292,247,638

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Statements of Operations

Years Ended December 31, 2008 and 2007

	2008	2007
Revenues		
Electricity	$ 195,978,663	$ 158,248,249
Steam	133,090,568	107,778,817
Other	7,727,498	2,549,322
Total revenue	336,796,729	268,576,388
Operating expenses		
Fuel purchased	279,552,454	221,549,966
Operation and maintenance	20,705,193	15,396,854
Depreciation, amortization and accretion	9,114,384	9,133,264
General and administrative	5,833,513	5,660,521
Total operating expenses	315,205,544	251,740,605
Income from operations	21,591,185	16,835,783
Other income (expense)		
Interest income	1,173,676	4,150,787
Interest expense	(7,866,150)	(9,494,485)
Gain on derivative contract	7,529,777	6,398,161
Net Income	22,428,488	17,890,246
Other comprehensive income (loss)		
Change in the fair value in the interest rate swap contract	(4,992,609)	(1,852,692)
Comprehensive Income	$ 17,435,879	$ 16,037,554

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Statements of Changes in Partners' and Members' Capital

Years Ended December 31, 2008 and 2007

	Contributed Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
Balance, December 31, 2006	$ 30,330,329	$ (3,049,887)	$ 108,315,200	$ 135,595,642
Net income			17,890,246	17,890,246
Other comprehensive loss		(1,852,692)		(1,852,692)
Balance, December 31, 2007	30,330,329	(4,902,579)	126,205,446	151,633,196
Net income			22,428,488	22,428,488
Distributions			(61,252,479)	(61,252,479)
Other comprehensive loss		(4,992,609)		(4,992,609)
Balance, December 31, 2008	$ 30,330,329	$ (9,895,188)	$ 87,381,455	$ 107,816,596

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Combined Statements of Cash Flows

Years Ended December 31, 2008 and 2007

	2008	2007
Cash flows from operating activities		
Net income	$ 22,428,488	$ 17,890,246
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, amortization and accretion	9,114,384	9,133,264
Net derivative activity	(7,529,777)	(6,398,161)
Changes in assets and liabilities		
Accounts receivable	12,360,399	2,150,649
Spare parts inventories	(741,647)	(1,193,244)
Prepaid expenses and other current assets	246,913	1,135,144
Accounts payable and accrued liabilities	(1,284,512)	810,009
Net cash provided by operating activities	34,594,248	23,527,907
Cash flows from investing activities		
Purchases of plant and equipment	(778,689)	(651,713)
Net change in assets restricted as to use	33,510,725	(22,671,989)
Cash flows from derivatives	157,500	10,312,500
Net cash (used in)/provided by investing activities	32,889,536	(13,011,202)
Cash flows from financing activities		
Payment of long-term debt	(10,589,577)	(8,516,674)
Distributions to partners	(61,252,479)	
Net cash used in financing activities	(71,842,056)	(8,516,674)
Net change in cash and cash equivalents	(4,358,272)	2,000,031
Cash and cash equivalents		
Beginning of the period	9,548,140	7,548,109
End of the period	$ 5,189,868	$ 9,548,140
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 7,854,148	$ 9,538,497

The accompanying notes are an integral part of the combined financial statements.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements

December 31, 2008 and 2007

1. Organization

Gregory Partners, LLC, and Gregory Power Partners, L.P. (collectively, the "Company," the "Partnership" or "Gregory") were organized on June 1, 1998, as a Delaware limited liability company and a Texas limited partnership, respectively, for the sole purpose of developing, financing, constructing, owning and operating a 500-megawatt (equivalent) cogeneration facility (the "Facility") at the Sherwin Alumina, L.P. (formerly Reynolds Metal Company) (BPU Reynolds, Inc.) plant near Gregory, Texas. The Facility commenced commercial operations on July 15, 2000. The Company operates as a Qualifying Facility ("QF") pursuant to the Public Utility Regulatory Policies Act ("PURPA"). The Partnership is operated pursuant to the Gregory Partnership Agreement dated June 1, 1998 (the "Partnership Agreement"). The operation and maintenance services are provided by subsidiaries of Babcock & Wilcox Company ("B&W"), an unaffiliated company.

Partnership interests are owned by subsidiaries of Javelin Holding, LLC ("Javelin Holding"), a wholly owned subsidiary of Javelin Energy, LLC ("Javelin Energy") and a subsidiary of DPC KY Energy LLC a wholly owned subsidiary of Delta Power Company, LLC ("Delta") called KY Energy, LLC. KY Energy, LLC holds a 4% limited partner interest in Gregory Partners, LLC and Gregory Power Partners, L.P. KY Energy, LLC also holds through its subsidiaries KY Energy Power Gregory #1, Inc. and KY Energy Power Gregory #2, Inc. a 1% general partner interest in Gregory Partners, LLC and Gregory Power Partners, LP. Subsidiaries of Javelin Energy hold a 94% limited partnership interest and a 1% general partnership interest. Javelin Energy is owned by the following four entities: (1) DPC Javelin Energy, LLC (2) John Hancock Variable Life Insurance Company; (3) Epsilon Power Funding, LLC; and (4) John Hancock Life Insurance Company.

Effective January 1, 2007, the membership interest in DPC Javelin Energy, LLC and DPC KY Energy, LLC were acquired by Arroyo DP Holdings, LP, an indirect wholly owned subsidiary of JP Morgan Chase & Co.

Under the terms of the Partnership Agreement, the Partnership's profits and losses are divided equally, based on ownership percentages, among the Gregory partners. No distributions were allowed to be made without lender consent through December 31, 2007. Starting in 2008 all distributions are divided based on ownership percentages.

Javelin Gregory General Corporation and KY Energy Power Gregory #1, Inc. (the "general partners") are responsible for the management, operation and control of the business and affairs of the Partnership, except in certain matters requiring a vote by the limited partners. Each of the general partners designated two representatives ("Designated Representatives") to represent it for purposes of making management decisions regarding the business of the Partnership. Each such Designated Representative has the authority to act for and bind the designating general partner in the affairs of the Partnership. The general manager, appointed by the general partners, is responsible for conducting all aspects of the ordinary, day-to-day business affairs and operation of the Partnership in accordance with the business plan approved by the general partners.

Javelin Gregory Remington Corporation and KY Energy Power Gregory #2, Inc, (the "member managers") manage the business, property and affairs of Gregory Partners, LLC. Except for certain matters outlined in the Gregory Partners, LLC Operating Agreement, the member managers may make all decisions and take all actions for Gregory Partners, LLC. Each of the member managers designated two representatives to represent it for purposes of making management decisions regarding business

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

1. Organization (Continued)

matters. The general manager appointed by the member managers is responsible for conducting all aspects of the ordinary day-to-day and usual business affairs and operations of Gregory Partners, LLC in accordance with the business plan approved by the member managers.

The following chart shows the general partners and members managers designated by an asterisk (*) and the Limited Partners and Members of the Company as of December 31, 2008 and December 31, 2007:

		Gregory Partners, LLC	Gregory Power Partners, LP
Javelin Holding, LLC			
*	Javelin Gregory General Corporation		1%
	Gregory Holdings #1, LLC		94%
*	Javelin Gregory Remington Corporation	1%	
	Gregory Holdings #2, LLC	94%	
KY Energy, LLC			
*	KY Energy Power Gregory #1 Inc.		1%
	KY Energy, LLC		4%
*	KY Energy Power Gregory #2 Inc.	1%	
	KY Energy, LLC	4%	

2. Summary of Significant Accounting Policies

Basis of Presentation

The combined financial statements include the accounts of Gregory Partners, LLC, and Gregory Power Partners, L.P. All significant intercompany accounts and transactions have been eliminated upon combination. The combination results from the fact that the companies operate under common control and have significant financial interests in one another. The significant financial interests relate to the cross collateralization of the assets of the Company's debt agreement as described in Note 5.

Use of Estimates

The preparation of the Company's financial statements in conformity with generally accepted accounting principles necessarily requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the balance sheet dates and the reported amounts of revenue and expense during the reporting periods for certain accruals. Actual results could differ from these estimates.

Cash Equivalents

The Company considers all highly liquid investments with a term to maturity of three months or less at the date of purchase to be cash equivalents.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (Continued)

Revenue Recognition

Revenues are recorded based on power, steam, spray water, and ancillary services delivered to customers through period-end.

Included in 2007 revenues and net income is a $2.4 million charge relating to 2005 and 2006 billings to Constellation for ancillary services under the Power Purchase Agreement (Note 4). The Company and Constellation agreed to revise the rates for such services retroactive to 2005 as the PPA allows a 24-month true up for invoices. The Company refunded Constellation the amount in December 2007.

Spare Parts Inventory

Spare parts inventory of the Company is valued at the lower of cost or market.

Property, Plant and Equipment

Property, plant and equipment are stated at cost and depreciated over their estimated useful lives using the straight-line method or machine-hours method. Property, plant and equipment accounts are relieved of the cost and related accumulated depreciation when assets are disposed of or otherwise retired.

Planned Major Maintenance Accounting

Effective with the commencement of the Facility's operations, the Company expensed major maintenance expense costs as incurred and depreciated major maintenance component capital costs over the useful lives of the components, rather than the lives of the assets in which they are installed.

Until recently, the AICPA Industry Audit Guide, *Audits of Airlines* ("Airline Guide") was the primary guidance for accounting for planned major maintenance in all industries. The accrue-in-advance methodology was an acceptable method based on the accounting guidance prior to the issuance of FSP AUG AIR-1. In September 2006, FASB issued FSP AUG AIR-1 (effective for fiscal years beginning after December 15, 2006), which prohibits the use of the accrue in-advance method of accounting for planned major maintenance. The Company has adopted this new pronouncement on January 1, 2007, and has changed its accrue-in-advance method to the direct method, recognizing all expenses related to the Long-Term Service Agreement ("LTSA") with General Electric International, Inc. when incurred. See more detail in Note 4. The impact on 2006 and prior years financial statements was not material.

Accounting for the Impairment of Long-Lived Assets

The Company accounts for impairment of long-lived assets in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* SFAS No. 144 requires that long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that the book value of the asset may not be recoverable. The Company evaluates at each balance sheet date whether events and circumstances have occurred

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (Continued)

that indicate possible operational impairment. There was no impairment of long-lived assets at December 31, 2008 or 2007.

Deferred Financing Costs

The Company has deferred the finance costs associated with the development, construction and start-up of the Facility. The deferred financing costs are being amortized over the life of the loan using the loans outstanding method. In August 2005, the Company obtained a $5 million working capital letter of credit facility due to requirements for credit support under its Power Sales Agreement ("PSA"). The expiration of the facility at December 31, 2008 is coincident with the termination of the PSA (Note 4). The Company has deferred the finance costs associated with this credit facility. These costs are being amortized over the life of the PSA. Accumulated amortization was $4,320,402 and $3,907,695 at December 31, 2008 and 2007, respectively. Amortization expense was $412,707 and $438,438 in 2008 and 2007, respectively and was recorded in depreciation, amortization, and accretion expense on the accompanying combined statements of operations.

Restricted Cash and Cash Equivalents

The Company has established escrow accounts held by a trustee pursuant to the terms of the project financing arrangement as described in Note 5. These funds are held by trustees and are restricted as to payments for future maintenance on property and equipment, future operating costs and future principal and interest payments, subject to the terms of the project financing arrangement.

Derivative Instruments

The Company is required by its project financing arrangement to utilize interest rate swap contracts to reduce its exposure to adverse fluctuations in interest rates on its long-term debt. Such swaps are accounted for as cash flow hedge transactions, with related gains and losses being recorded in interest expense as realized and changes in the fair value are recorded in other comprehensive income (Note 6).

The Company has entered into several natural gas swap contracts. These contracts are carried in the Company's Balance Sheet at fair value, with changes in fair value recorded in current earnings in other income on the income statement.

The Company has certain commodity contracts for the physical delivery of purchase and sale quantities in the normal course of business. Since these activities qualify as normal purchase and normal sale activities, the Company has not recorded the value of the related contracts on the balance sheet as permitted under relevant accounting standards.

Accounting for Asset Retirement Obligations

The Company has recorded an asset retirement obligation under Statement of Financial Accounting Standard No. 143 ("SFAS 143"), *Accounting for Asset Retirement Obligations* and FIN 47, *Accounting for Conditional Asset Retirement Obligations.* Under these accounting methods, the Company recorded an asset of $829,112, representing the net present value of the Year 2030 asset retirement obligation utilizing a 10.0% risk free cost of capital and a liability of $1,023,595 for the asset retirement

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (Continued)

obligation as of January 1, 2003. In addition, the Company will expense an amount equal to (a) the straight-line depreciation of the site dismantlement asset of $829,112 and (b) an amount equal to the annual increase in the site dismantlement liability, assuming a 2.5% annual inflation rate through the end of the lease term.

Accounting and Reporting Developments

In March 2008, the FASB issued SFAS No. 161 *Disclosures About Derivative Instruments and Hedging Activities an Amendment of FASB Statement No. 133* ("SFAS 161"). SFAS 161 amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* by requiring expanded disclosures about an entity's derivative instruments and hedging activities. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative instruments. SFAS 161 is effective for the Company as of January 1, 2009. The adoption of SFAS 161 is not expected to have a material impact on the Company's financial statements.

3. Concentration of Credit Risk

Financial instruments, which potentially subject the Company to credit risk, consist primarily of cash and cash equivalents, accounts receivable, restricted cash and temporary investments. The Company maintains cash and cash equivalents with major financial institutions. Cash equivalents, restricted cash and temporary investments include investments in money market securities backed by the U.S. Government. At December 31, 2008 and 2007, substantially all of the deposits were in excess of the Federal Deposit Insurance Corporations Insured Limit of $250,000. The Company believes that no significant concentration of credit risk exists with respect to cash investments.

The Company has significant customers for 2008 and 2007, as follows:

	2008	2007
Sherwin Alumina, L.P.		
Percentage of combined total revenue	45%	45%
Percentage of combined accounts receivable	9%	5%
Constellation Energy Commodities Group, Inc.		
Percentage of combined total revenue	55%	53%
Percentage of combined accounts receivable	87%	94%
Tenaska Power Marketing, Inc.		
Percentage of combined total revenue	<1%	2%
Percentage of combined accounts receivable	4%	1%

Tenaska has provided security for their receivables in the form of a parent guaranty in the amount of $1.5 million as required by the contract.

During 2008 and 2007 the Company purchased about half of its gas from Kinder Morgan Tejas Pipeline, LLC. The remaining half of its gas during this period was delivered to the Company as payment for steam sales to Sherwin Alumina L.P.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

4. Contracts

The Company has entered into several contracts pertaining to revenues, costs of revenues, operations and marketing. The contracts are described as follows:

Power Purchase Agreements

Sherwin Alumina, L.P.

The Company and Reynolds Metals Company entered into an Energy Services Agreement ("ESA") for a term of 35 years effective June 30, 1998, and ending on the 35-year anniversary of the Commercial Operations Date, ("COD" as defined in the ESA as August 1, 2000). The ESA affords Reynolds the right to purchase a portion of the Company's steam and electricity production for a term ending on the 20-year anniversary of the COD, with a right to extend this term for up to three additional 5-year terms upon providing the Company with at least two years' notice prior to the expiration date. The remaining obligations of the contract remain in effect for the full 35 year term. On December 31, 2000, the ESA was assigned to and assumed by BPU Reynolds. On August 1, 2001, the ESA was assigned to and assumed by Sherwin Alumina, L.P. The provisions of the ESA allow Sherwin Alumina L.P. to provide natural gas in lieu of a cash payment as compensation for the steam they purchase for their production needs. The Partnership records the related steam revenue which is offset by an equivalent natural gas expense recorded in fuel purchased in the accompanying combined statements of operations.

Constellation Energy Commodities Group, Inc ("CCG")

The Company and CCG entered into a power sales agreement ("CCG PSA") as of August 29, 2005, whereby the Company agrees to sell and CCG agrees to purchase certain quantities of electricity capacity and energy, as well as Ancillary Service capabilities. The CCG PSA has a term of three years and four months from September 1, 2005, ending December 31, 2008.

The CCG PSA calls for a fixed capacity component and a variable energy component. However, not all of the Capacity Payment was realized as a cash receipt during 2006 and in January 2007. The CCG PSA includes a provision that requires the Company to provide a Required Additional Credit Support Amount under certain circumstances. Rather than increasing the security instrument provided to CCG PSA, the contract allows for Deferred Payment Obligations to be granted to Constellation to a maximum of $12,750,000. Accordingly, the Company has included $8,760,917 in accounts receivable in the current asset section of the accompanying balance sheet as of December 31, 2007. This represents the discounted value of $9 million contractual receivable using a discount rate of 5.0%. As of December 31, 2008, the entire balance of the receivable has been collected.

The Company is subject to operational and contractual risks associated with the Constellation PPA. Risks include, but are not limited to, output capacity and availability and heat rate guarantees. Management has taken steps to manage physical and contractual risks; however, such risks cannot be eliminated.

Fortis Energy Marketing & Trading GP ("Fortis")

The Company and Fortis entered into a power sales agreement ("Fortis PSA") as of July 23, 2007, whereby the Company agrees to sell and Fortis agrees to purchase certain quantities of electricity

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

4. Contracts (Continued)

capacity and energy, as well as Ancillary Service capabilities. The Fortis PSA has a term of five years from January 1, 2009.

The Fortis PSA calls for a fixed capacity component and a variable energy component. The Fortis PSA includes a provision that requires the Company to provide Credit Support which was delivered to Fortis by the Company in July 2007 in the form of a letter of credit for $10 million. The letter of credit expired on July 23, 2008 and was replaced by a cash deposit provided by the Company's partners.

The Company is subject to operational and contractual risks associated with the Fortis PPA. Risks include, but are not limited to, output capacity and availability. Management has taken steps to manage physical and contractual risks; however, such risks cannot be eliminated.

Energy Management Agreements

Tenaska Power Services Co. ("TPS")

On December 6, 2006, the Company and TPS entered into an EMA whereby TPS is to provide energy management services for the Facility by acting as the Company's qualified scheduling entity with ERCOT and marketing the excess power (~5 to 55 MWhs) from the Facility generated above the volumes committed to CCG. The agreement primary term expires on December 31, 2008. The agreement will automatically renew for successive one year terms unless terminated by either party by giving a written notice to the other party. No termination notice was produced by either party in 2008. The Company provided TPS a cash deposit in lieu of an irrevocable LOC in the amount of $500,000 which is included in deposits in the accompanying combined balance sheets.

Gas Purchase and Transportation Agreements

Kinder Morgan

Coral Energy Resources, L.P., Coral Energy, L.P. (together, "Coral") and the Company entered into an Amended and Restated Gas Sales Agreement (the "GSA"), as of November 20, 1998, whereby Coral agrees to sell, at an agreed upon price, to the Company up to 62,000 MMBtu per day of natural gas, the Facility's estimated maximum daily fuel requirement (net of gas supplied by Reynolds). On February 28, 2002, the GSA was assigned to and assumed by Kinder Morgan Tejas Gas Pipeline, which underwent a name change to Kinder Morgan Tejas Pipeline, LLC ("Kinder Morgan"). The Company has no obligation to purchase any gas under the GSA beyond the first two contract years.

The GSA has a primary term of ten years from the Commercial Operations Date (as defined in the ESA as August 1, 2000). The GSA includes a provision that requires the Company to provide additional credit support under certain circumstances.

Tejas Gas Pipeline L.P.

Tejas Gas Pipeline L.P., ("Tejas") and the Company entered into an Amended and Restated Intrastate Gas Transportation Agreement (the "Intrastate Agreement"), as of November 20, 1998, whereby Tejas agrees to provide firm transportation for the Facility of up to 62,000 MMBtu per day of gas.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

4. Contracts (Continued)

The Intrastate Agreement has a primary term of ten years from the Commercial Operations Date (as defined in the ESA as August 1, 2000), but the Company may terminate the Intrastate Agreement at the end of the fifth contract year upon at least 60 days notice to Tejas.

Constellation NewEnergy, Inc. ("CNE")

On April 27, 2006, the Company and CNE entered into a one year Master Retail Power Sales Agreement, whereby CNE agreed to supply full requirements for electric energy, including standby electricity and provide any additional energy and services as the Company may require in the event it is required to import electricity to support it and/or its steam hosts production requirements. The price of the electricity is the Market Clearing Price of Electricity ("MCPE") plus $0.50, with a monthly fee of $3,000. On April 23, 2007, the agreement was extended until April 26, 2008. On February 6, 2008, the agreement was modified to change the term from one year to three years ending on April 26, 2009.

San Patricio Municipal Water District

The Company and the San Patricio Municipal Water District ("SPMWD") entered into a Raw Water Contract (the "RWC") as of September 15, 1998, that provides, in part, that SPMWD will sell and deliver up to 2 million gallons of water per day to the Company. The initial term of the RWC is 20 years. Monthly billings for water sold to the Company are based on rates set annually to recover SPMWD's cost of service. Under the terms of the RWC, SPMWD will reserve specified capacity in its facilities to deliver water to the Facility.

General Electric International, Inc.

The Company and General Electric International, Inc. ("GE") entered into a Long-Term Service Agreement ("LTSA") as of September 30, 2001, whereby GE agrees to fund future planned maintenance and certain additional maintenance with respect to the two gas turbines at the Facility, including the combustion and turbine sections of the covered units and their Mark V control system. The initial term of the contract is the earlier of the time when covered units experience their second major inspection, as described under the contract or 17 years from the effective date of the contract. The contract was amended as of March 31, 2006 to extend the term of coverage until each covered unit reaches the later of 120,000 factored fired hours of operation or completion of the first hot path inspection after the second major inspection as defined in the contract.

5. Long-Term Debt

The Company has a 17 year loan, expiring September 30, 2017 with ING Capital, LLC that provides for quarterly principal payments and interest at LIBOR plus 1.375% during 2007 and through October 2, 2008. On October 2, 2008 the interest rate changed to LIBOR plus 1.5%.

Borrowings are obligations solely of the Company and the lender's collateral is substantially all of the assets of the Company. The lenders have no contractual recourse to the partners. The loan agreement contains various affirmative and negative covenants involving the operation of the Facility, compliance with laws, and incurrence of additional debt and restricted payments.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

5. Long-Term Debt (Continued)

The most restrictive covenants under the term loan are as follows:

(1) The Company must give prompt notice to ING Capital, LLC of any contractual obligations incurred by the Company exceeding $250,000 per year.

(2) The Company must give prompt notice to ING Capital, LLC of any potential litigation that may exceed $250,000.

Scheduled maturities of the long-term debt are as follows:

2009	$ 9,644,306
2010	10,162,817
2011	10,992,434
2012	11,822,052
2013	12,755,372
After 2013	55,702,769
	111,079,750
Less: Current portion	(9,644,306)
	$ 101,435,444

In November 2008 the Company provided a notice letter to ING Capital, LLC advising that it is in a state of default under the Credit Agreement. The default situation was the result of the expiration of the Texas state authorization in March, 2008 for its Prevention of Signification Deterioration ("PSD") Air Permit. The Company signed an Agreed Order with the Texas Commission of Environmental Quality ("TCEQ") on March 24, 2009 which gives it the state's authority to operate under the terms of the PSD Air Permit. The Company concurrently provided notice to ING Capital, LLC that the Default situation has been cured.

6. Interest Rate Swap Contract

To protect the project lenders from the uncertainty of interest rate changes during the term of the loan, the Company was required by the project financing agreement to fix or hedge fifty percent (50%) of the original balance of the term loan by entering into an interest rate swap contract. The agreement with ING Capital LLC, dated November 23, 1998, requires the Company to make fixed interest payments at a rate of 5.95% for the term of the loan and will receive interest at a variable rate equal to the rate on the debt hedged. The contract has a notional amount of approximately half of the outstanding principle balance of the loan. The interest rate swap contract matures at the time the related debt matures. As of December 31, 2008 and 2007, the Company had recorded cumulative losses of $9,895,188 and $4,902,579, respectively, in other comprehensive income. Upon termination of the loan and swap contract any amount recorded in other comprehensive income will be reclassified into earnings.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

7. Natural Gas Swap Contracts

On July 31, 2006, the Company entered into a financial swap agreement with Sempra for a period of one year from January 1, 2007 through December 31, 2007. The agreement requires the Partnership to sell 4,500,000 MMBtu of gas during the year at a fixed price of $8.8725 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

On June 15, 2007, the Company entered into another financial swap agreement with Sempra for a period of one year from January 1, 2008 through December 31, 2008. The agreement requires the Partnership to sell 4,500,000 MMBtu of gas during the year at a fixed price of $8.70 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

On March 3, 2008 the Company entered into another financial swap agreement with Sempra for a period of one year from January 1, 2009 through December 31, 2009. The agreement requires the Partnership to sell 2,100,000 MMBtu of gas during the year at a fixed price of $9.10 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

On June 9, 2008, the Company entered into another financial swap agreement with Sempra for a period of one year from January 1, 2010 through December 31, 2010. The agreement requires the Partnership to sell 2,100,000 MMBtu of gas during the year at a fixed price of $9.91 per MMBtu. The agreement also includes a coincident gas purchase contract to purchase a like amount of gas at a Houston Ship Channel/Beaumont, Texas price index through the same period.

These contracts are carried in the accompanying combined balance sheets at their fair value of $12,971,861 and $5,599,584 as of December 31, 2008 and 2007, respectively in prepaid expense and other current assets, with changes in fair value recorded in current earnings in other income in the combined statements of operations.

8. Fair Value Disclosures

In September 2006, the FASB issued SFAS 157, which provides a single definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Prior to SFAS 157, guidance for applying fair value was incorporated into several accounting pronouncements. SFAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and sets out a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources (observable inputs) and those based on an entity's own assumptions (unobservable inputs). Under SFAS 157, fair value measurements are disclosed by level within that hierarchy, with the highest priority being quoted prices in active markets. The Company adopted SFAS 157 on January 1, 2008.

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

8. Fair Value Disclosures (Continued)

The following table summarizes the fair values of the Company's derivatives based on the inputs used as of December 31, 2008 in determining such fair values:

Description	Fair Market Value on December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Natural gas swaps	$ 12,971,861	$	$ 12,971,861	$
Interest rate swaps	(9,895,188)		(9,895,188)	
	$ 3,076,673	$	$ 3,076,673	$

In February 2007 the FASB issued SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* SFAS 159 permits entities to elect to measure financial assets and liabilities (except for those that are specifically scoped out of the Statement) at fair value. The election to measure a financial asset or liability at fair value can be made on an instrument-by-instrument basis and is irrevocable. The difference between the carrying value and the fair value at the election date is recorded as a transition adjustment to opening retained earnings. Subsequent changes in fair value are recognized in earnings. The Company adopted SFAS 159 effective January 1, 2008 with no material impact on the financial statements.

The carrying amount of cash and cash equivalents approximate their fair value principally due to the short-term nature of these instruments. The fair value of the Company's long-term debt approximates the carrying amounts by virtue of the variable rate interest arrangements associated with the debt. The fair values of the interest rate swap contract and natural gas swap contracts equal the carrying value and were determined using the estimated amount the Company would receive to terminate the contracts. See Notes 6 and 7 for additional disclosure regarding the Company's accounting for its interest rate swap contract and natural gas swap contracts, respectively.

9. Property, Plant and Equipment

Plant and equipment consist of the following at December 31, 2008 and 2007, respectively:

	Useful Lives (Years)	2008	2007
Plant and related equipment	5 - 30	$ 246,498,709	$ 245,872,627
Office and transportation equipment	3 - 10	1,168,525	1,015,917
		247,667,234	246,888,544
Less: Accumulated depreciation		85,808,181	77,299,115
Net plant and equipment		$ 161,859,053	$ 169,589,429

Gregory Partners, LLC, and Gregory Power Partners, L.P.

Notes to Combined Financial Statements (Continued)

December 31, 2008 and 2007

10. Ground Lease

The Company leases the land where the Facility is located from the BPU Reynolds under an operating lease for a 35-year term. The annual rent is $1 per year. The Company is required to pay all taxes, assessments, and fees on the leased property during the lease term. If the agreement is terminated prior to the 35-year term, the Company shall pay rent in equal monthly installments in an amount based on the market value of the unimproved land as determined at the time the agreement is terminated.

11. Related Party Transactions

Delta Power Company, LLC ("DPC")

The Company entered into an agreement as of January 1, 2001, whereby it reimburses DPC for salaries and benefits for the General Manager and staff that are assigned to the Company. Payments to DPC for salaries and benefits totaled $497,215 and $548,508 for the years ended December 31, 2008 and 2007, respectively and are included in general and administrative expense in the combined statements of operations. At December 31, 2008 and 2007, respectively, $138,978 and $97,249 were payable to DPC which was included in accounts payable and accrued expenses in the accompanying combined balance sheets. On May 1, 2007, JP Morgan Chase & Co. began providing accounting services for the Company.

12. Income Taxes

The Company is exempt from federal and state income taxes. Taxable income or loss from the Company is reportable by the partners and members on their respective income tax returns. Accordingly, there is no recognition of income taxes in the combined financial statements. Beginning in 2007, the Company is subject to a franchise tax in the state of Texas, and has recorded an amount representing the obligation in accordance with the State of Texas franchise tax.

13. Commitments and Contingencies

There are commitments and contingencies arising from the ordinary course of business to which the Company is party. It is management's belief that the ultimate resolution of those commitments and contingencies will not have a material adverse impact on the Company's financial position or results of operations.

14. Subsequent Events

On January 7, 2009 the Company entered into an agreement with Koch Supply & Trading, LP ("Koch") for the Company to sell 500 tons of 2009 CAIR Annual NOx Allowances at $5,000 per ton. The $2.5 million payment from Koch was received on February 6, 2009.

PASCO COGEN, LTD.
Financial Statements
December 31, 2007
(With Independent Auditors' Report Thereon)

Independent Auditors' Report

The Partners
Pasco Cogen, Ltd.:

We have audited the accompanying balance sheet of Pasco Cogen, Ltd. as of December 31, 2007, and the related statement of operations and partners' capital and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Pasco Cogen, Ltd. as of December 31, 2007, and the results of its operations and its cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

March 7, 2008
Tampa, Florida
Certified Public Accountants

PASCO COGEN, LTD.

Statement of Operations and Partners' Capital

Year ended December 31, 2007

Operating revenues	$	57,331,633
Operating costs and expenses:		
Fuel expenses		22,111,732
Operating expenses		7,277,438
Depreciation and amortization		3,855,847
Total operating expenses		33,245,017
Income from operations		24,086,616
Other income (expense):		
Other income		299,415
Interest expense		(1,741,368)
Interest income		943,474
Other expense, net		(498,479)
Net income		23,588,137
Partners' capital, beginning of year		52,490,036
Partnership distributions		(18,395,423)
Partners' capital, end of year	$	57,682,750

See accompanying notes to financial statements.

PASCO COGEN, LTD.

Balance Sheet

December 31, 2007

Assets		
Current assets:		
Cash and cash equivalents	$	3,549,810
Accounts receivable		5,223,629
Prepaid expenses		458,015
Materials and supplies		1,704,661
Restricted investments, current portion		7,500,000
Total current assets		18,436,115
Restricted investments, net of current portion		5,365,678
Property, plant, and equipment, net		48,024,584
Other assets, net		708,187
Total assets	$	72,534,564
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable and accrued expenses	$	2,813,814
Current installment of notes payable		12,038,000
Total current liabilities		14,851,814
Partners' capital		57,682,750
Total liabilities and partners' capital	$	72,534,564

See accompanying notes to financial statements.

PASCO COGEN, LTD.

Statement of Cash Flows

Year ended December 31, 2007

Cash flows from operating activities:		
Net income	$	23,588,137
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation		3,082,056
Amortization		773,791
Changes in operating assets and liabilities:		
Accounts receivable		(589,068)
Prepaid expenses		(66,965)
Materials and supplies		(95,544)
Accounts payable and accrued expenses		55,446
Accrued maintenance		(322,560)
Net cash provided by operating activities		26,425,293
Cash from investing activities:		
Change in restricted investments		4,203,563
Purchases of property, plant, and equipment		(698,041)
Net cash provided by investing activities		3,505,522
Cash flows from financing activities:		
Principal payments of notes payable		(11,574,998)
Partnership distributions		(18,395,423)
Net cash used in financing activities		(29,970,421)
Net decrease in cash and cash equivalents		(39,606)
Cash and cash equivalents, at beginning of year		3,589,416
Cash and cash equivalents, at end of year	$	3,549,810
Supplemental disclosure of cash flow information:		
Cash paid for interest	$	1,741,368

See accompanying notes to financial statements.

PASCO COGEN, LTD.

Notes to Financial Statements

December 31, 2007

(1) Organizational History and Ownership

Pasco Cogen Ltd. (the Partnership) is a limited partnership formed during 1991 to develop and operate a 109-megawatt gas and oil fired cogeneration facility in Dade City, Florida, which was placed into commercial service on July 1, 1993. The term of the Partnership will continue until December 31, 2015, which can be shortened or extended in accordance with the Limited Partnership Agreement. The Partnership is a qualifying facility under the Public Utility Regulatory Policies Act of 1978 (PURPA) which entitles it to certain energy sales and purchase benefits as long as certain ownership and operating standards are maintained.

The facility's electricity is sold to Progress Energy Florida (PEF), and its steam was sold to the Pasco Beverage Company (PBC) and other steam users until March 2005 when PBC and the other steam users ceased steam purchases. Prior to the cessation of steam sales, the Partnership completed the installation of a water distillation system. Steam is used to manufacture distilled water, which is sold to an unaffiliated third party, ensuring compliance with the qualifying facility requirements set by the Public Utility Regulatory Policies Act of 1978.

Each partner shares in operating income or loss of the Partnership on a basis proportionate to the partners' respective ownership percentage. Effective December 24, 2007, NCP Dade Power, LLC (NCP) and Dade Investment, L.P. acquired all but 0.2% of the remaining interest in the Partnership and the ownership allocation among the partners was adjusted accordingly.

At December 31, 2007, the respective partnership ownership percentages are as follows:

General Partner:	
NCP Dade Power, LLC	2.0%
Limited Partners:	
DCC Project Finance Ten, Inc.	0.2%
Dade Investment, L.P.	97.8%

The limited partners do not participate in management control of the Partnership and are limited to voting on certain matters described in the Limited Partnership Agreement. Except as otherwise required by law, each limited partners' liability for any debts, liabilities, contracts, or obligations of the Partnership is limited to its capital contribution and its share of any undistributed assets of the Partnership. No partner shall be required to make any additional capital contributions unless approved by the general partner.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

The preparation of the financial statements requires management of the Partnership to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Significant items subject to such estimates and assumptions include the carrying amount and useful lives of property, plant, and equipment. Actual results could differ from those estimates.

PASCO COGEN, LTD.

Notes to Financial Statements (Continued)

December 31, 2007

(2) Summary of Significant Accounting Policies (Continued)

(b) Income Taxes

The partners are required to report their share of the Partnership's net income or loss on their respective tax returns. Accordingly, no provision for income tax is reflected in the accompanying financial statements.

(c) Concentration of Credit Risk

Financial instruments that potentially subject the Partnership to concentrations of credit risk consist principally of cash and cash equivalents, restricted investments, and accounts receivable. As of December 31, 2007, substantially all of the Partnership's cash and restricted investment balances were deposited with one financial institution assessed by management as being of high quality.

One customer, PEF, accounts for approximately 97% of the Partnership's revenue for the year ended December 31, 2007, and for approximately 93% of the accounts receivable (100% of the trade accounts receivable) as of December 31, 2007. The Partnership does not collateralize its accounts receivable.

One vendor supplied approximately 100% of the Partnership's gas purchases in 2007 and accounted for approximately 88% of the accounts payable as of December 31, 2007.

(d) Cash and Cash Equivalents

The Partnership considers all short-term highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

(e) Accounts Receivable

Accounts receivable are recorded at the invoiced amount and do not bear interest. Due to the limited number of customers and invoices, the Partnership determines the need for an allowance, if any, based on specific facts and circumstances. No such allowance was deemed necessary as of December 31, 2007.

(f) Materials and Supplies

Materials and supplies inventory consists of plant equipment components and recurring maintenance supplies required to be maintained in order to facilitate routine maintenance activities. Materials and supplies inventory is recorded at the lower of cost or market.

(g) Derivative Instruments and Hedging Activities

The Partnership accounts for derivative instruments and hedging activities in accordance with Statements of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 133, as amended, requires the fair value of derivative instruments to be recorded on the balance sheet as an asset or liability. Changes in the fair value of derivative financial instruments are either recognized periodically in income or partners' capital depending on whether the derivative is being used to hedge changes in fair value or cash flow. The Partnership identifies, and routinely analyzes various financial instruments and contracts. The Partnership had no

PASCO COGEN, LTD.

Notes to Financial Statements (Continued)

December 31, 2007

(2) Summary of Significant Accounting Policies (Continued)

derivative instruments as of and during the year ended December 31, 2007. The Financial Accounting Standards Board (FASB) continues to issue guidance that could affect the Partnership's application of SFAS No. 133 and require adjustments to the amounts and disclosures in the financial statements.

(h) Property, Plant, and Equipment

Property, plant, and equipment are stated at historical cost. Depreciation expense is provided on the straight-line method over the lesser of the useful lives of the asset or the lease term. The estimated useful lives of the plant and machinery are 30 years and 5 to 10 years, respectively. Leasehold improvements to the land site are amortized over the land lease commitment of 20 years.

(i) Restricted Investments

Restricted investments represent amounts set aside under the terms of the Disbursement Agreement (as amended and restated) and the Master Agreement (as amended and restated) between the Partnership and bank lenders, agent, and collateral agent (together, the Agreement) for future debt service, significant scheduled maintenance requirements, and distributions to partners pursuant to Section 3.5(e)(ii) of the Agreement. The three restricted accounts at December 31, 2007 are the Capital Expenditure Reserve Fund account, funded with $1,484,277; the Debt Service Reserve account, funded with $7,500,000; and the Special Reserve Account, funded with $3,881,401. All funds are held in highly rated money-market accounts, as determined by management, which approximates fair value at December 31, 2007.

(j) Revenue Recognition

Revenues from the sale of electricity consist of capacity payments and sale of energy to a single customer. Revenues are recorded at the time of billings and are based upon output delivered and capacity provided at rates specified under the contractual terms. Revenues for distilled water sales are recognized upon delivery.

Billings for electricity and distilled water sales are rendered monthly.

(k) Deferred Financing Costs

Financing costs, consisting primarily of commitment fees paid to the lenders, as well as legal fees and other direct costs incurred to obtain financing for the Partnership, are deferred and amortized over the term of the related loan. For the year ended December 31, 2007, amortization expense related to the deferred financing costs was approximately $317,000 per year.

(l) Asset Impairment

The Partnership accounts for its long-lived assets in accordance with SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). SFAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets. An impairment loss is recognized if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and is measured as the difference between the carrying amount and fair value of the asset. The Partnership periodically

PASCO COGEN, LTD.

Notes to Financial Statements (Continued)

December 31, 2007

(2) Summary of Significant Accounting Policies (Continued)

assesses whether there has been an impairment of its long-lived assets, held and used by the Partnership in accordance with SFAS 144. There were no impairment losses in 2007.

(m) Accrued Maintenance

Effective January 1, 2007, the Partnership adopted FASB Staff Position No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*. Upon adoption, the Partnership no longer accrues and expenses estimated major maintenance in advance, rather major maintenance items are expensed as incurred.

(n) Asset Retirement Obligations

On January 1, 2003, the Partnership adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement requires companies to record a liability relating to legal obligations to retire and remove assets used in their business. On January 1, 2005, the Partnership adopted FIN No. 47, *Accounting for Conditional Asset Retirement Obligations*, an interpretation of FASB Statement No. 143. FIN No. 47 clarifies the term "conditional asset retirement obligation" as used in SFAS No. 143. The adoption of SFAS No. 143 and FIN No. 47 did not have a material impact on the Partnership's financial position, results of operations, or cash flows as of and for the year ended December 31, 2007.

(3) Property, Plant, and Equipment

Property, plant, and equipment consist of the following at December 31, 2007:

Land and leasehold improvements	$	520,787
Machinery and equipment		184,979
Cogeneration plant		83,053,582
Accumulated depreciation		(35,734,764)
	$	48,024,584

Total depreciation expense for the year ended December 31, 2007 was approximately $3,082,000.

(4) Other Assets

Other assets consist of the following at December 31, 2007:		
Financing costs	$	5,760,063
Development costs		5,999,779
Accumulated amortization on financing and development costs		(11,085,155)
Utility deposit		33,500
	$	708,187

Development costs incurred during construction are amortized over the remaining terms of the sales contracts with PEF on a straight-line method, expiring on December 31, 2008. Financing costs are

PASCO COGEN, LTD.

Notes to Financial Statements (Continued)

December 31, 2007

(4) Other Assets (Continued)

amortized over the respective loan period. Total amortization expense was approximately $774,000 for the year ended December 31, 2007.

(5) Notes Payable

Long-term debt consists of the following at December 31, 2007:

Note payable to insurance company, 9.125%, interest due quarterly, with quarterly principal payments through December 31, 2008, secured by all of the Company's assets	$	10,990,836
Note payable to bank, interest due quarterly at LIBOR plus 1.50% (6.69% at December 31, 2007); with quarterly principal payments through December 31, 2008; secured by all of the Company's assets		1,047,164
		12,038,000
Less current installments of notes payable		(12,038,000)
	$	

In compliance with the terms of the Agreement, the Partnership has established a reserve to fund future debt service. Through December 31, 2006, the debt service reserve was $12,000,000. During 2007, the Partnership obtained a waiver from the lender allowing a reduction to $7,500,000 at December 31, 2007.

The Master Agreement contains various positive and negative covenants. As of December 31, 2007, the Partnership was in compliance with its loan covenants and had obtained a waiver associated with insurance deductible requirements from the lenders.

The Partnership has a renewable letter of credit in favor of PEF issued by a financial institution in the amount of $4,350,000 expiring effective January 1, 2009. This letter of credit is required by the power sales contract with PEF as a guaranty of the Partnership's commitment to sell electricity. The financial institution is committed through December 31, 2008 to issue a letter of credit in an amount up to $4.5 million, and a $^3/_8$ of 1% annual commitment fee is charged on the unutilized portion.

(6) Related Parties

Peaking gas supply and gas management services are provided by TECO Gas Services (TGS), a wholly owned subsidiary of TECO, which, until the December 24, 2007 sale transaction, indirectly owned the Pasco Project Investment Partnership, Ltd. (PPIP) partnership interest in the Partnership. The gas is transported by Florida Gas Transmission Company and Peoples Gas System Inc. (PGS).

The Partnership incurs fixed annual fees for administrative operating management functions payable to PPIP and NCP totaling approximately $465,000 in 2007. The total fees were split evenly between PPIP and NCP. Effective December 24, 2007, all of the fixed annual fees are paid to NCP. Related-party (income) expenses for gas sales and transportation for the year ended December 31, 2007 totaled approximately $(896,000) and $2,027,000 from TGS and PGS, respectively. Approximately $112,000 of accounts payables at December 31, 2007, were due to PGS. In addition, approximately $148,000 of accounts receivable at December 31, 2007, were due from PGS for imbalance book out gas.

PASCO COGEN, LTD.

Notes to Financial Statements (Continued)

December 31, 2007

(6) Related Parties (Continued)

Teton Operating Services (Teton OS) became the contractual operator of the facility beginning March 12, 2004, succeeding Aquila Generation Services. Teton OS is an affiliate of Teton East Coast Generation, Inc., which owns the NCP Dade Power, LLC and Dade Investment, LP partnership interest in the Partnership. For the year ended December 31, 2007, the Partnership incurred operation and maintenance costs to Teton OS of approximately $3,891,000. Approximately, $467,000 of accounts payable was due to Teton OS as of December 31, 2007.

During 2004, the Partnership's affiliates formed Pasco Cogen Realty, L.P. (Realty). On December 30, 2004, Realty purchased the land where the Partnership's facility is located, which was previously leased to the Partnership by PBC. PBC assigned the site lease to Realty, which will continue leasing the land to the Partnership for the remainder of the lease term. The annual amount of these site lease payments are approximately $20,100 through the term of the lease expiring July 31, 2013.

(7) Commitments and Contingencies

(a) Leases

The Partnership has noncancelable operating leases on land and other equipment. Total rent expense for the year ended December 31, 2007 was approximately $442,000.

Aggregate minimum annual rental commitments under noncancelable operating leases as of December 31, 2007 are as follows:

2008	$	471,814
2009		471,814
2010		471,814
2011		358,886
2012		20,100
Thereafter		11,725
	$	1,806,153

(b) Contingencies

The Partnership is subject to legal proceedings and claims which arise in the ordinary course of business. In the opinion of management, the amount of ultimate liability with respect to these actions will not materially affect the financial position, results of operations, or liquidity of the Partnership.

(8) Power Purchase Agreement

The Partnership sells all of the net electrical output of the facility to PEF pursuant to a $15^1/_2$ year Power Purchase Agreement (PPA) that commenced in July 1993. The PPA was restructured in October 1996, reducing the term (from 20 years to the $15^1/_2$ year term currently in effect) and providing for a special monthly payment through 2005. Revenue under the PPA is based on a payment for capacity, an energy payment, and an hourly performance adjustment for on-peak hours. Capacity payments have been contracted and range from $26.79/kW month in 2006 to $29.46/kW month in 2008. The capacity payment is subject to the Partnership maintaining an on-peak capacity during on-peak hours on a

PASCO COGEN, LTD.

Notes to Financial Statements (Continued)

December 31, 2007

(8) Power Purchase Agreement (Continued)

12-month rolling average basis. The energy payment component of the PPA comprises a fuel component and a voltage adjustment for each kWh of electricity produced. The performance adjustment is an hourly calculation based upon PEF's avoided cost of all electricity provided to the system during that hour. For the year ended December 31, 2007, the Partnership has recorded electricity revenue of approximately $57,321,000 under the PPA.

On August 14, 2007, the Partnership entered into a tolling agreement with Tampa Electric Company (TEC), a business unit of TECO Energy, Inc. (TECO). The term of the tolling agreement is from January 1, 2009 through December 31, 2018. Under the agreement, the Partnership will provide capacity and fuel conversion services.

(9) Fuel Agreements

PPM provides the Partnership with up to 20,472 MMBtu's of natural gas per day pursuant to a 15-year gas purchase agreement commencing in July 1993. The base purchase price under the agreement is adjusted monthly based on PEF's coal costs and capacity rates under the PPA between the Partnership and PEF.

Cdn$

% Series B Convertible Unsecured Subordinated Debentures due

PROSPECTUS

, 2010

BMO Capital Markets

ALTERNATE PAGE FOR CANADIAN PROSPECTUS

A copy of this preliminary short form prospectus has been filed with the securities regulatory authorities in each of the provinces and territories of Canada other than the province of Québec but has not yet become final for the purpose of the sale of securities. Information contained in this preliminary short form prospectus may not be complete and may have to be amended. The securities may not be sold until a receipt for the short form prospectus is obtained from the securities regulatory authorities.

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. Atlantic Power Corporation has filed a registration statement on Form S-1 with the United States Securities and Exchange Commission, under the United States Securities Act of 1933, as amended, with respect to these securities. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of Atlantic Power Corporation at 200 Clarendon Street, 25th Floor, Boston, Massachusetts, U.S.A., 02116, telephone 617.977.2400, and are also available electronically at www.sedar.com*

PRELIMINARY SHORT FORM PROSPECTUS

New Issue August 13, 2010

Atlantic Power Corporation

Cdn$

% Series B Convertible Unsecured Subordinated Debentures due

This short form prospectus qualifies the distribution of Cdn$ aggregate principal amount of % series B convertible unsecured subordinated debentures (the "**Debentures**") of Atlantic Power Corporation (the "**Company**") at the price of Cdn$1,000 per Cdn$1,000 principal amount of Debentures (the "**Offering**"). The Debentures have a maturity date of (the "**Maturity Date**") and bear interest at an annual rate of % payable semi-annually in arrears on the day of and in each year (each, an "**Interest Payment Date**") (or the immediately following business day if any Interest Payment Date would not otherwise be a business day) commencing on . The interest payment will represent accrued interest for the period from the closing date of the Offering up to, but excluding . Further particulars concerning the attributes of the Debentures are set out under "Description of Debentures" in the U.S. Prospectus (as defined below), which is included in this short form prospectus. The terms and offering price of the Debentures were determined by negotiation between the Company and BMO Nesbitt Burns Inc. (the "**Underwriter**"). See "Plan of Distribution". The registered office of the Company is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia, V6C 2G8 and the head office of the Company is located at 200 Clarendon Street, 25th Floor, Boston, Massachusetts, USA 02116.

A bank affiliate of BMO Nesbitt Burns Inc. is a lender to Atlantic Power Holdings, Inc. ("Holdings"), an indirect wholly-owned Subsidiary of the Company, under an existing credit facility. Consequently, the Company may be considered a "connected issuer" of BMO Nesbitt Burns Inc. under applicable securities laws in certain Canadian provinces and territories. See "Relationship Between the Company and Certain Persons".

Conversion Privilege

Each Debenture will be convertible into common shares of the Company ("**Common Shares**") at the option of the holder at any time prior to the close of business on the earlier of the Maturity Date and the business day immediately preceding the date specified by the Company for redemption of the Debentures at a conversion price of Cdn$ per Common Share (the "**Conversion Price**"), being a conversion rate of approximately Common Shares per Cdn$1,000 principal amount of Debentures, subject to adjustment in accordance with the trust indenture governing the terms of the Debentures. Holders converting their Debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their Debentures to, but not including, the date of conversion. Further particulars concerning the conversion privilege, including provisions for the adjustment of the Conversion Price in certain events, are set out under "Description of Debentures Conversion Privilege" in the U.S. Prospectus.

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The Debentures may not be redeemed by the Company on or before (except in certain limited circumstances following a Change of Control (as defined herein)). After and prior to , the Debentures may be redeemed by the Company, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the volume weighted average trading price of the Common Shares on the Toronto Stock Exchange (the "**TSX**") for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given is not less than 125% of the Conversion Price. On or after and prior to the Maturity Date, the Debentures may be redeemed in whole or in part at the option of the Company on not more than 60 days and not less than 30 days prior notice at a price equal to their principal amount plus accrued and unpaid interest. Further particulars of the interest, redemption, repurchase and maturity provisions of the Debentures are set out under "Description of Debentures" in the U.S. Prospectus.

The Company has filed a registration statement on Form S-1 (File No. 333) (the "**U.S. Registration Statement**") with respect to the Debentures and the Common Shares underlying the Debentures with the United States Securities and Exchange Commission (the "**SEC**") under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**"). The U.S. prospectus contained in the U.S. Registration Statement (the "**U.S. Prospectus**") is included in and forms a part of this short form prospectus. This short form prospectus qualifies the Debentures for distribution in each of the provinces and territories of Canada other than the province of Québec.

Concurrently with the Offering of Debentures, the Company is conducting a separate public offering of Common Shares (plus up to an additional Common Shares if the underwriters exercise an option to purchase additional Common Shares) at a price of US $ per Common Share (the "**Common Share Offering**"). This Offering is not conditional upon completion of the Common Share Offering. See "Description of Concurrent Offering of Common Shares" and "Use of Proceeds" in the U.S. Prospectus.

There is currently no market through which the Debentures may be sold and purchasers may not be able to resell the Debentures purchased under this short form prospectus. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures, and the extent of issuer regulation. See "Risk Factors" in the U.S. Prospectus.

The Underwriter, as principal, conditionally offers the Debentures, subject to prior sale, if, as and when issued by the Company and accepted by the Underwriter in accordance with the conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to approval of certain legal matters on behalf of the Company by Goodmans LLP and on behalf of the Underwriter by Blake, Cassels & Graydon LLP. The Debentures shall be taken up by the Underwriter, if at all, on or before a date not later than 42 days after the date of the receipt for the final short form prospectus.

	Price to the Public(1)	Underwriter's Fee	Net Proceeds(2)(3)
Per Debenture	Cdn$1,000	Cdn$	Cdn$
Total Offering	Cdn$	Cdn$	Cdn$

(1) The offering price of the Debentures has been determined through negotiation between the Company and the Underwriter.

(2) Net proceeds are before deducting the expenses of the Offering, which are estimated to be approximately Cdn$ million.

(3) The Company has granted to the Underwriter an option (the "**Over-Allotment Option**") to purchase up to an additional Cdn$ aggregate principal amount of Debentures at a price of Cdn$1,000 per Debenture on the same terms and conditions as the Offering, exercisable in whole or in part, at the sole discretion of the Underwriter at any one time on or prior to the 30th day after the closing of the Offering, for the purposes of covering the Underwriter's over-allotment position, if any. If the Over-Allotment Option is exercised in full, the "Price to the Public", "Underwriter's Fee" and "Net Proceeds" (before deducting expenses of the Offering) will be Cdn$, Cdn$ and Cdn$, respectively. See "Plan of Distribution". This short form prospectus also qualifies for distribution the grant of the Over-Allotment Option and the issuance of the Debentures upon exercise of the Over-Allotment Option. A purchaser who acquires any of the Debentures forming part of the over-allocation position acquires such Debentures under this short form prospectus regardless of whether the over-allocation

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position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. See "Plan of Distribution".

Underwriter's Position	Maximum Size or Number	Exercise Period	Exercise Price
Over-Allotment Option	Cdn$	30 days after closing of the Offering	Cdn$1,000 per Debenture

Subscriptions for the Debentures will be received subject to rejection or allotment, in whole or in part, and the right is reserved to close the subscription books at any time without notice. Book-entry only certificates representing the Debentures will be issued in registered form to CDS Clearing and Depository Services Inc. ("**CDS**") or its nominee as registered global securities and will be deposited with CDS on the date of issue of the Debentures, which is expected to occur on or about , 2010 or such later date as the Underwriter and the Company may agree, but in any event no later than , 2010. Holders of Debentures will not be entitled to receive physical certificates representing their Debentures.

In certain circumstances, the Underwriter may offer the Debentures at a price lower than the price stated above. The Underwriter may, in connection with the Offering, effect transactions that stabilize or maintain the market price of the Debentures at levels other than those that might otherwise prevail in the open market. Such transactions, if commenced, may be interrupted or discontinued at any time. See "Plan of Distribution".

The Company's earnings coverage ratios for the twelve month periods ending December 31, 2009 and June 30, 2010, calculated on the basis of the Company's financial statements prepared in accordance with United States generally accepted accounting principles and included in this short form prospectus, were less than one to one. See "Earnings Coverage Ratios".

An investment in the Debentures is subject to a number of risks that should be considered by a prospective investor. An investment in the Debentures should only be made by persons who can afford the total loss of their investment. See "Cautionary Statement Regarding Forward Looking Information" in this short form prospectus and "Risk Factors" in the U.S. Prospectus.

The Debentures 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.

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AGREEMENT TO PURCHASE SECURITIES

FOR PURPOSES OF U.S. SECURITIES LAWS, NO BINDING COMMITMENT TO PURCHASE THE DEBENTURES OFFERED PURSUANT TO THIS PROSPECTUS IS MADE BY ANY INVESTOR, AND NO SALE OF THE DEBENTURES OFFERED PURSUANT TO THIS PROSPECTUS IS MADE TO ANY INVESTOR, UNTIL 5:00 P.M. (TORONTO TIME) ON THE SECOND BUSINESS DAY AFTER SUCH INVESTOR RECEIVES THIS PROSPECTUS. UNTIL SUCH TIME, ANY INVESTOR MAY CANCEL HIS OR HER INTENTION TO PURCHASE THE DEBENTURES WITHOUT PENALTY BY CONTACTING ANY OF THE UNDERWRITERS NAMED IN THIS PROSPECTUS.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this short form prospectus from documents filed with the securities commissions or similar authorities in the provinces and territories of Canada. Copies of the documents incorporated in this short form prospectus by reference may be obtained on request without charge from the Corporate Secretary of the Company at 200 Clarendon Street, 25th Floor, Boston, Massachusetts, U.S.A., 02116, telephone 617.977.2400. In addition, copies of the documents incorporated by reference herein may be obtained from the securities commissions or similar authorities in Canada through SEDAR at www.sedar.com.

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The following documents of the Company, filed with the securities commissions or similar authorities in the provinces and territories of Canada, are specifically incorporated by reference into and form an integral part of this short form prospectus:

(a) the Company's annual information form dated March 29, 2010 for the year ended December 31, 2009;

(b) the consolidated financial statements of the Company as at and for each of the years ended December 31, 2009 and December 31, 2008, prepared in accordance with Canadian generally accepted accounting principles ("**Canadian GAAP**"), together with the notes thereto and the auditors' report thereon (the "**Annual Financial Statements**"), filed on SEDAR on March 29, 2010;

(c) management's discussion and analysis of the financial condition and results of operations of the Company for the year ended December 31, 2009 (the "**Annual MD&A**"), filed on SEDAR on March 29, 2010;

(d) the management information circular of the Company dated May 25, 2010, as supplemented by a supplement to the management information circular dated June 14, 2010, distributed in connection with the annual and special meeting of shareholders held on June 29, 2010;

(e) the unaudited consolidated interim financial statements of the Company for the three and six months ended June 30, 2010 and 2009, prepared in accordance with United States generally accepted accounting principles ("**U.S. GAAP**"), together with the notes thereto (the "**Q2 Financial Statements**"), filed on SEDAR on August 9, 2010;

(f) management's discussion and analysis of the financial condition and results of operations of the Company for the three and six months ended June 30, 2010 (the "**Q2 MD&A**"), filed on SEDAR on August 9, 2010; and

(g) the management information circular dated October 16, 2009, distributed in connection with the plan of arrangement of the Company pursuant to the *Business Corporations Act* (British Columbia) (the "**Arrangement Circular**") excluding the fairness opinion in Schedule "G" and all references to the fairness opinion, including under the heading "Background to and Reasons for the Conversion Fairness Opinion".

Any documents of the type required by section 11.1 of Form 44-101F1 of National Instrument 44-101 *Short Form Prospectus Distributions* to be incorporated by reference in a short form prospectus, if filed by the Company with the securities commissions or similar regulatory authorities in the provinces and territories of Canada in which this short form prospectus has been filed subsequent to the date of this short form prospectus and prior to the termination of the distribution, shall be deemed to be incorporated by reference in this short form prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference in this short form prospectus shall be deemed to be modified or superseded for the purposes of this short form prospectus to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that was required to be stated or that was necessary to make a statement not misleading in light of the

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circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this short form prospectus.

Concurrently with the filing of this short form prospectus, the Company has applied for and obtained an exemption from the requirement to incorporate by reference the fairness opinion contained in Schedule "G" of the Arrangement Circular and all references to the fairness opinion, including under the heading "Background to and Reasons for the Conversion Fairness Opinion" contained in the Arrangement Circular on the basis that the exempted sections are no longer relevant.

SUPPLEMENTAL CANADIAN DISCLOSURE

In accordance with the requirements of applicable securities laws in each province and territory of Canada other than the province of Québec, the disclosure in the U.S. Prospectus incorporated in this short form prospectus is supplemented with the following additional disclosure.

CURRENCY AND EXCHANGE RATE INFORMATION

In this short form prospectus, references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$", "US$" and "U.S. dollars" are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise stated.

The business of the Projects is conducted in major markets in the United States and their revenues and expenses are denominated, earned and incurred primarily in U.S. dollars. The following table sets forth, for each period indicated, the high and low exchange rates for one U.S. dollar, expressed in Canadian dollars, the average of such exchange rates on the last day of each month during such period and the exchange rate at the end of such period, based on the noon buying rate in Canadian dollars as quoted by the Bank of Canada (the "**Noon Buying Rate**"). On August 12, 2010, the Noon Buying Rate was US$1.00 = Cdn$1.0434.

	Six Months Ended June 30		Twelve Months Ended December 31	
	2010	**2009**	**2009**	**2008**
High	Cdn$1.0778	Cdn$1.3000	Cdn$1.3000	Cdn$1.2969
Low	Cdn$0.9961	Cdn$1.1827	Cdn$1.0292	Cdn$0.9719
Average	Cdn$1.0338	Cdn$1.2062	Cdn$1.1420	Cdn$1.0660
Period End	Cdn$1.0606	Cdn$1.1625	Cdn$1.0466	Cdn$1.2112

Source: Bank of Canada

NOTICE TO INVESTORS REGARDING GAAP

Beginning with the first quarter of 2010, the Company is now preparing its financial statements in accordance with U.S. GAAP. Prior to 2010, the Company prepared its financial statements in accordance with Canadian GAAP, including the Annual Financial Statements and the corresponding Annual MD&A incorporated by reference in this short form prospectus. The Q2 Financial Statements and the corresponding Q2 MD&A incorporated by reference in this short form prospectus, and the annual and interim financial statements included in the U.S. Prospectus, have been prepared in accordance with U.S. GAAP, which differ in certain material respects from Canadian GAAP. In accordance with Canadian securities laws, the Q2 Financial Statements and the corresponding Q2 MD&A incorporated by reference in this short form prospectus have been prepared with a reconciliation to Canadian GAAP.

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CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

Certain information in this short form prospectus may constitute "forward looking information", as such term is used in applicable Canadian securities legislation, about the Company including its business operations, strategy and future financial condition and results of operations. Prospective investors should refer to the heading, "Cautionary Statements Regarding Forward-Looking Statements" in the U.S. Prospectus for further detail on such forward-looking information and statements.

Material factors or assumptions that were applied in providing forward-looking information, include, but are not limited to, the Company's future growth potential, its results of operations, future cash flows, the continued performance and business prospects and opportunities of the Company and the Projects, third party projections of regional fuel and electric capacity and energy prices, the completion of certain transactions, including the Offering, the Company's future levels of indebtedness, the tax laws as currently in effect remaining unchanged and the current general regulatory environment and economic conditions remaining unchanged.

Forward-looking information contained in this short form prospectus reflects current expectations regarding future events and operating performance, and speaks only as of the date of this short form prospectus. Such forward-looking information is based on currently available competitive, financial and economic data and operating plans and are subject to known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company, or general industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking information. Recent events in global financial and credit markets have resulted in abnormally high market volatility and a level of uncertainty not seen in decades. Such uncertainty may continue to impact the global, North American and Canadian economies in unpredictable ways and may impact the results of the Company in a manner which is currently impossible to ascertain. Many other factors could also cause the Company's actual results, performance or achievements to vary from those expressed or inferred herein, including without limitation, a reduction in revenue upon expiration or termination of power purchase agreements, the dependence of the Projects on their electricity, thermal energy and transmission services customers, exposure of certain Projects to fluctuations in the price of electricity, Projects not operating to plan, the impact of significant environmental and other regulations on the Projects, increasing competition (including for acquisitions), the limited control by the Company over the operation of certain minority-owned Projects and changes in assumptions used in making such forward-looking statements. Many of these risks and uncertainties could affect the Company's actual results and could cause actual results to differ materially from those expressed or implied in any forward-looking information provided by the Company or on its behalf. The impact of any one factor on a particular piece of forward-looking information is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Should any risk factor affect the Company in an unexpected manner, or should assumptions underlying the forward-looking information prove incorrect, the actual results or events may differ materially from the results or events predicted. Unless otherwise indicated, forward-looking information does not take into account the effect that transactions or non-recurring or other special items announced or occurring after the date it is provided may have on the business of the Company. All of the forward-looking information reflected in this short form prospectus and the documents incorporated herein are qualified by these cautionary statements. There can be no assurance that the results or developments anticipated by the Company will be realized or, even if substantially realized, that they will have the expected consequences for the Company. Prospective investors should carefully consider the information contained under the heading "Risk Factors" in the U.S. Prospectus and other

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information included in this short form prospectus before making investment decisions with regard to the Debentures. Forward-looking information is provided and forward-looking statements are made as of the date of this short form prospectus and except as may be required by applicable law, the Company disclaims any intention and assumes no obligation to publicly update or revise such forward-looking information or forward-looking statements whether as a result of new information, future events or otherwise.

ELIGIBILITY FOR INVESTMENT

In the opinion of Goodmans LLP, counsel for the Company, and Blake, Cassels & Graydon LLP, counsel for the Underwriter, based on the provisions of the *Income Tax Act* (Canada) and the regulations thereunder (collectively, the "**Tax Act**") as of the date hereof, provided the Debentures, or, in the case of the Common Shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures, the Common Shares, are listed on a "designated stock exchange" as defined in the Tax Act, which currently includes the TSX, the Debentures being offered pursuant to this short form prospectus, and the Common Shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures, if issued on the date hereof, would be qualified investments under the Tax Act for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans (except, in the case of Debentures, a deferred profit sharing plan to which the Company, or an employer that does not deal at arm's length with the Company, has made a contribution), registered education savings plans, registered disability savings plans and tax-free savings accounts.

Notwithstanding the foregoing, if the Debentures or Common Shares are "prohibited investments" for the purposes of a tax-free savings account, a holder of such a tax-free savings account will be subject to penalty taxes as set out in the Tax Act. Provided that the holder of a tax-free savings account deals at arm's length with the Company for the purposes of the Tax Act, and does not hold a "significant interest" (within the meaning of the Tax Act) in the Company or any corporation, partnership or trust with which the Company does not deal at arm's length for the purposes of the Tax Act, the Debentures, and the Common Shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures, will not be "prohibited investments" for such tax-free savings account for the purposes of the Tax Act. Holders of tax-free savings accounts should consult their own tax advisors to ensure that the Debentures and Common Shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures would not be a "prohibited investment" for the purposes of the Tax Act in their particular circumstances.

PRIOR SALES

On December 17, 2009, the Company completed an offering of 6.25% convertible unsecured subordinated debentures due March 15, 2017 (the "**2009 Debentures**") at a price of Cdn$1,000 per 2009 Debenture for total gross proceeds of Cdn$75 million. On December 24, 2009, the underwriters exercised their over-allotment option in full to purchase an additional Cdn$11,250,000 aggregate principal amount of the 2009 Debentures at the same price.

On November 27, 2009 the Company completed its conversion from an Income Participating Security structure to a traditional common share structure, and issued 60,517,981 Common Shares in exchange for the previously outstanding Income Participating Securities and common shares of the Company.

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EARNINGS COVERAGE RATIOS

The *pro forma* earnings coverage ratios set forth below have been prepared using *pro forma* financial information which has been prepared on the basis of the U.S. GAAP financial statements included in this short form prospectus. The *pro forma* earnings assume that there are no additional earnings derived from indebtedness incurred in connection with this Offering. Earnings coverage is equal to net income before interest expense on all long-term debt and income taxes, divided by interest expense on long-term debt (after giving effect to the Offering).

In accordance with the presentation and measurement requirements of U.S. GAAP and after giving effect to the Offering, the Company's *pro forma* interest requirements for all long term debt, including the current portion, would have amounted to approximately $ million and approximately $ million for the 12 months ended December 31, 2009 and June 30, 2010, respectively. The Company's earnings before interest and income tax for the 12 months ended December 31, 2009 and June 30, 2010, respectively, was approximately $ million and $ million, which is $ and $ less than the Company's *pro forma* interest requirements for each respective period. The additional earnings required to achieve an earnings coverage ratio of 1.0 would have been approximately $ and approximately $ for the 12 months ended December 31, 2009 and June 30, 2010, respectively.

TRADING PRICE AND VOLUME

The Company's Common Shares began trading on the TSX on December 2, 2009, under the trading symbol "ATP" and on the NYSE on July 23, 2010 under the trading symbol "AT". The following table shows the monthly range of high and low prices per Common Share and the total volume of Common Shares traded on the TSX during the 12 month period before the date of this short form prospectus. On August 12, 2010, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the TSX was Cdn$13.25.

Date	**High**	**Low**	**Volume**
December 2 31, 2009	Cdn$11.90	Cdn$10.21	9,292,827
January 2010	Cdn$12.35	Cdn$11.52	5,207,417
February 2010	Cdn$12.79	Cdn$11.50	3,361,681
March 2010	Cdn$13.85	Cdn$12.10	11,976,401
April 2010	Cdn$12.90	Cdn$11.28	4,041,640
May 2010	Cdn$12.85	Cdn$11.20	4,147,728
June 2010	Cdn$12.85	Cdn$12.11	1,949,091
July 2010	Cdn$13.39	Cdn$12.11	1,873,091
August 1 12, 2010	Cdn$13.40	Cdn$13.00	696,079

The following table shows the range of high and low prices per Common Share and the total volume of Common Shares traded on the NYSE during the 12 month period before the date of this short form prospectus. On August 12, 2010, being the last day on which the Common Shares traded prior to the date of this short form prospectus, the closing price of the Common Shares on the NYSE was U.S.$12.69.

Date	**High**	**Low**	**Volume**
July 23 31, 2010	U.S.$12.97	U.S.$12.39	641,443
August 1 12, 2010	U.S.$13.48	U.S.$12.30	1,198,901

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The 2006 Debentures were listed for trading on the TSX on October 11, 2006, under the trading symbol "ATP.DB". The following table shows the range of high and low prices per Cdn$100 principal amount of 2006 Debentures and total monthly volumes traded on the TSX during the 12 month period before the date of this short form prospectus. On August 12, 2010, being the last day on which the 2006 Debentures traded prior to the date of this short form prospectus, the closing price of the 2006 Debentures on the TSX was Cdn$107.25.

Month	High	Low	Volume
May 2009	Cdn$100.00	Cdn$97.60	12,250
June 2009	Cdn$101.25	Cdn$98.00	10,990
July 2009	Cdn$103.50	Cdn$100.15	5,600
August 2009	Cdn$102.50	Cdn$101.50	5,660
September 2009	Cdn$102.50	Cdn$101.01	6,960
October 2009	Cdn$102.50	Cdn$100.01	10,980
November 2009	Cdn$103.00	Cdn$100.00	15,420
December 2009	Cdn$104.00	Cdn$101.50	5,980
January 2010	Cdn$106.00	Cdn$103.50	3,060
February 2010	Cdn$107.00	Cdn$104.70	5,260
March 2010	Cdn$110.00	Cdn$105.00	10,030
April 2010	Cdn$106.14	Cdn$103.00	11,560
May 2010	Cdn$106.00	Cdn$103.00	11,560
June 2010	Cdn$104.91	Cdn$103.00	3,650
July 2010	Cdn$107.00	Cdn$103.30	3,200
August 1 12, 2010	Cdn$108.00	Cdn$106.00	3,080

The 2009 Debentures were listed for trading on the TSX on December 17, 2009, under the trading symbol "ATP.DB.A". The following table shows the monthly range of high and low prices per Cdn$100 principal amount of 2009 Debentures and total monthly volumes traded on the TSX during the 12 month period before the date of this short form prospectus. On August 12, 2010, being the last day on which the 2009 Debentures traded prior to the date of this short form prospectus, the closing price of the 2009 Debentures on the TSX was Cdn$105.00.

Month	High	Low	Volume
December 17 31, 2009	Cdn$101.00	Cdn$99.90	86,010
January 2010	Cdn$103.00	Cdn$100.03	52,070
February 2010	Cdn$104.00	Cdn$102.05	25,630
March 2010	Cdn$107.50	Cdn$103.00	57,330
April 2010	Cdn$104.00	Cdn$101.50	27,920
May 2010	Cdn$106.97	Cdn$101.00	19,880
June 2010	Cdn$104.99	Cdn$101.00	17,540
July 2010	Cdn$105.49	Cdn$101.99	42,510
August 1 12, 2010	Cdn$105.50	Cdn$104.51	34,220

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PLAN OF DISTRIBUTION

Subject to the terms and conditions contained in the underwriting agreement dated as of , 2010 between the Company and the Underwriter (the "**Underwriting Agreement**"), the Company has agreed to issue and sell, and the Underwriter has agreed to purchase, as principal, on the closing date, being , 2010 or such other date as may be agreed upon by the Company and the Underwriter, but in any event not later than , 2010 an aggregate Cdn$ principal amount of Debentures at a price of Cdn $1,000 per Debenture, payable in cash against delivery by the Company of certificates evidencing the Debentures. The Debentures are being offered to the public in all of the provinces and territories of Canada other than the province of Québec. The terms and conditions were determined by negotiation between the Company and the Underwriter. The Underwriting Agreement provides that the Company will pay the Underwriter's fee of Cdn$ per Cdn$1,000 principal amount of Debentures in consideration for their services in connection with the Offering.

The Company has granted to the Underwriter the Over-Allotment Option to purchase up to an additional Cdn$ principal amount of the Debentures at a price of Cdn$1,000 per Debenture on the same terms and conditions as the Offering, exercisable in whole or in part, at the sole discretion of the Underwriter at any one time on or prior to the 30th day after the Closing, for the purposes of covering the Underwriter's over-allotment position, if any. If the Over-Allotment Option is exercised in full, the "Price to the Public", "Underwriter's Fee" and "Net Proceeds" (before deducting expenses of the Offering) will be Cdn$, Cdn$ and Cdn$, respectively. This short form prospectus also qualifies for distribution the grant of the Over-Allotment Option and the issuance of the Debentures pursuant to the exercise of the Over-Allotment Option. A purchaser who accepts any Debentures forming part of the Over-Allotment Option acquires such Debentures under the short form prospectus regardless of whether the over-allotment position is filled through the exercise of the Over-Allotment Option or secondary market purchases.

The obligations of the Underwriter under the Underwriting Agreement may be terminated at its discretion upon the occurrence of certain stated events. The Underwriter is, however, obligated to take up and pay for all Debentures if any Debentures are purchased under the Underwriting Agreement. The Underwriter proposes to offer the Debentures to the public initially at the Offering price and in the principal amount, respectively, specified on the cover page of this short form prospectus. After the Underwriter has made a reasonable effort to sell all of the Debentures offered hereby at the Offering price and in the principal amount, respectively, specified on the cover page, the Offering price for the Debentures may be decreased and may be further changed from time to time to amounts not greater than those set forth on the cover page. The compensation realized by the Underwriter will be decreased by the amount that the aggregate price paid by the purchasers of the Debentures is less than the amount paid by the Underwriter to the Company.

Pursuant to policy statements of certain securities regulators, the Underwriter may not, throughout the period of distribution, bid for or purchase the Debentures. The foregoing restriction is subject to exceptions, on the condition that the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in, or raising the price of, any of the Debentures. These exceptions include bids or purchases permitted under the Universal Market Integrity Rules for Canadian Marketplaces of Market Regulation Services Inc. relating to market stabilization and passive market making activities and bids or purchases made for and on behalf of a customer where the order was not solicited during the period of distribution. Under the first mentioned exception, in connection with this Offering, the Underwriter may effect transactions that stabilize or maintain the market price of the Debentures at levels other than those which might otherwise prevail in the open market. Those transactions, if commenced, may be interrupted or discontinued at any time.

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The Company and the senior officers of the Company have agreed with the Underwriter, subject to certain exceptions, not to issue, offer, sell, contract to sell or otherwise dispose of any of the Debentures or Common Shares of the Company or any securities convertible into or exercisable or exchangeable for any Debentures or Common Shares of the Company or financial instruments convertible into or exercisable or exchangeable for Debentures or Common Shares of the Company, or announce any intention to effect any of the foregoing, for a period of 90 days from the date of Closing without the prior written consent of the Underwriter, which consent may not be unreasonably withheld.

The Debentures will be issued in "book-entry only" form and must be purchased or transferred through a CDS Participant. At closing, the Company will cause global certificates representing the Debentures to be delivered to, and registered in the name of, CDS or its nominee. All rights of holders of Debentures must be exercised through, and all payments or other property to which such holder is entitled will be made or delivered by, CDS or the CDS Participant through which the holder of Debentures holds such Debentures. Each person who acquires Debentures will receive only a customer confirmation of purchase from the Underwriter or registered dealer from or through which the Debentures are acquired in accordance with the practices and procedures of that Underwriter or registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book-entry accounts for its CDS Participants having interests in the Debentures. See "Description of Debentures Book Entry, Delivery and Form" in the U.S. Prospectus.

INTERESTS OF EXPERTS

Certain Canadian legal matters in connection with the Offering will be passed upon on behalf of the Company by Goodmans LLP and on behalf of the Underwriter by Blake, Cassels & Graydon LLP. As at the date hereof, the partners and associates of Goodmans LLP, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares of the Company, and the partners and associates of Blake, Cassels & Graydon LLP, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares of the Company.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The discussion below is a general description of the Canadian federal income tax considerations generally applicable to an investment in the Debentures. It does not take into account the individual circumstances of any particular investor. Therefore, prospective investors are urged to consult their own tax advisors with respect to the tax consequences of an investment in the Debentures.

In the opinion of Goodmans LLP, counsel to the Company and Blake, Cassels & Graydon LLP, counsel to the Underwriter (collectively, "**Counsel**"), the following summary describes the principal Canadian federal income tax considerations pursuant to the Tax Act generally applicable to a holder who acquires Debentures pursuant to the Offering and who, for purposes of the Tax Act and at all relevant times is, or is deemed to be, resident in Canada, holds the Debentures and will hold Common Shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures (collectively, the "**Securities**") as capital property and deals at arm's length with the Company and the Underwriter and is not affiliated with the Company (a "**Holder**"). Generally, the Securities will be considered to be capital property to a Holder provided the Holder does not hold the Securities in the course of carrying on a business of trading or dealing in securities and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Holders who might not otherwise be considered to hold their Securities as capital property may, in certain circumstances, be entitled to have the Securities, and all other "Canadian securities" (as defined in the Tax Act) owned

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by such Holders, treated as capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act.

This summary is not applicable to (i) a Holder that is a "financial institution", as defined in the Tax Act for the purposes of the mark-to-market rules, (ii) a Holder an interest in which would be a "tax shelter investment" as defined in the Tax Act, (iii) a Holder that is a "specified financial institution" as defined in the Tax Act or (iv) a Holder who makes or has made a functional currency reporting election pursuant to section 261 of the Tax Act. Any such Holder should consult its own tax advisor with respect to an investment in the Securities. In addition, this summary does not address the deductibility of interest by a Holder who has borrowed money or otherwise incurred debt in connection with the acquisition of Securities.

This summary is based upon the provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act that have been publicly announced prior to the date hereof (the "**Proposed Amendments**"), and Counsel's understanding of the current administrative policies and assessing practices of the Canada Revenue Agency ("**CRA**") made publicly available prior to the date hereof. This summary assumes the Proposed Amendments will be enacted in the form proposed; however, no assurance can be given that the Proposed Amendments will be enacted in the form proposed, or at all. This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments, does not take into account any changes in the law or in administrative policies or assessing practices, whether by legislative, governmental or judicial action, nor does it take into account provincial, territorial or foreign tax considerations, which may differ significantly from those discussed in this short form prospectus.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular holder or prospective holder of Securities, and no representations with respect to the income tax consequences to any Holder or prospective Holder are made. Consequently, Holders and prospective Holders of Securities should consult their own tax advisors for advice with respect to the tax consequences to them of acquiring Securities pursuant to the Offering, having regard to their particular circumstances.

Taxation of Interest on Debentures

A Holder of Debentures that is a corporation, partnership, unit trust or any trust of which a corporation or a partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on the Debentures that accrues or is deemed to accrue to it to the end of the particular taxation year or that has become receivable by or is received by the Holder before the end of that taxation year, except to the extent that such interest was included in computing the Holder's income for a preceding taxation year.

Any other Holder, including an individual, will be required to include in computing income for a taxation year all interest on the Debentures that is received or receivable by the Holder in that taxation year (depending upon the method regularly followed by the Holder in computing income), except to the extent that the interest was included in the Holder's income for a preceding taxation year. In addition, if at any time a Debenture should become an "investment contract" (as defined in the Tax Act) in relation to a Holder, such Holder will be required to include in computing income for a taxation year any interest that accrues to the Holder on the Debenture up to any "anniversary day" (as defined in the Tax Act) in that year to the extent such interest was not otherwise included in the Holder's income for that year or a preceding year.

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A Holder of Debentures that throughout the relevant taxation year is a "Canadian-controlled private corporation", as defined in the Tax Act, may be liable to pay a refundable tax of $6^2/_3$% on its "aggregate investment income", which is defined in the Tax Act to include interest income.

Exercise of Conversion Privilege

Generally, a Holder who converts a Debenture into Common Shares or Common Shares and cash delivered in lieu of a fraction of a Common Share pursuant to the conversion privilege will be deemed not to have disposed of the Debenture for purposes of the Tax Act and, accordingly, will not be considered to realize a capital gain (or capital loss) on such conversion. Under the current administrative practice of the CRA, a Holder who, upon conversion of a Debenture, receives cash not in excess of $200 in lieu of a fraction of a Common Share may elect to either treat this amount as proceeds of disposition of a portion of the Debenture, thereby realizing a capital gain (or capital loss), or reduce the adjusted cost base of the Common Shares that the Holder receives on the conversion by the amount of the cash received.

Upon a conversion of a Debenture, interest accrued thereon to the date of conversion will be included in computing the income of the Holder as described above under "Taxation of Interest on Debentures".

The aggregate cost to a Holder of the Common Shares acquired on the conversion of a Debenture will generally be equal to the aggregate of the Holder's adjusted cost base of the Debenture immediately before the conversion, subject to the discussion above regarding cash in lieu of a fraction of a Common Share. The adjusted cost base to a Holder of Common Shares acquired at any time will be determined by averaging the cost of such Common Shares with the adjusted cost base of any other Common Shares owned by the Holder as capital property at the time.

Disposition of Debentures

A disposition or deemed disposition of a Debenture by a Holder, including upon a redemption, payment on maturity or purchase for cancellation or pursuant to an agreement by a converting Holder to receive cash in lieu of Common Shares, but not including upon the conversion of a Debenture into Common Shares pursuant to the Holder's right of conversion as described above, will generally result in the Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (computed as described below) are greater (or less) than the aggregate of the Holder's adjusted cost base thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "Taxation of Capital Gains and Capital Losses".

Where the Company elects to satisfy the redemption or purchase price or payment on maturity by issuing Common Shares to a Holder instead of paying cash, the Holder will be considered to have received proceeds of disposition equal to the fair market value of such Common Shares at the date of disposition of the Debenture. The Holder's adjusted cost base of the Common Shares so received will be equal to the fair market value of such Common Shares. The adjusted cost base to a Holder of Common Shares at any time will be determined by averaging the cost of such Common Shares with the adjusted cost base of any other Common Shares owned by the Holder as capital property at that time.

Any amount paid by the Company as a penalty or bonus because of the redemption or purchase for cancellation of a Debenture (for example, where the redemption price or purchase price is in excess of the principal amount) will generally be deemed to be interest received at the time of the payment by the Holder to the extent that such amount can reasonably be considered to relate to, and does not exceed the value, at the time of the payment, of the interest that, but for the redemption or purchase for cancellation, would have been paid or payable by the Company on the Debenture for a taxation year of the Company ending after the time of the payment.

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Upon a disposition or deemed disposition of a Debenture, a Holder will generally be required to include in income interest accrued on the Debenture to the date of disposition to the extent such amount has not otherwise been included in the Holder's income for the taxation year or a preceding taxation year, and such amount will be excluded in computing the Holder's proceeds of disposition of the Debenture.

If interest has accrued on a Debenture, a Holder who disposes of or converts the Debenture for consideration equal to its fair market value will generally be entitled to deduct in computing income for the year of disposition an amount equal to any such interest included in income for that or any preceding year to the extent that no amount was received or became receivable by the Holder in respect of the interest so accrued.

Receipt of Dividends on Common Shares

A Holder will be required to include in computing its income for a taxation year any dividends received (or deemed to be received) on the Common Shares, unless in the case of Canadian resident corporations, the application of a specific anti-avoidance rule re-characterizes such dividends as proceeds of disposition or a capital gain.

Dividends received or deemed to be received on the Common Shares by a Holder that is an individual (other than certain trusts) will be included in computing the individual's income for tax purposes and will be subject to the gross-up and dividend tax credit rules normally applicable to dividends received from taxable Canadian corporations (as defined in the Tax Act), including the enhanced gross-up and dividend tax credit for eligible dividends (as defined in the Tax Act) paid by taxable Canadian corporations such as the Company. A dividend will be eligible for the enhanced gross-up and dividend tax credit if the recipient receives written notice (which may include a notice published on the Company's website) from the Company designating the dividend as an "eligible dividend" (as defined in the Tax Act).

A Holder that is a corporation will include dividends received or deemed to be received on Common Shares in computing its income for tax purposes and generally will be entitled to deduct the amount of such dividends in computing its taxable income, with the result that no tax will be payable by it in respect of such dividends. Certain corporations, including a "private corporation" or a "subject corporation" (as such terms are defined in the Tax Act), may be liable to pay a refundable tax under Part IV of the Tax Act of $33^1/_3\%$ on dividends received or deemed to be received on Common Shares to the extent such dividends are deductible in computing taxable income. This tax will generally be refunded to the company at a rate of $1 for every $3 of taxable dividends paid while it is a private corporation.

Taxable dividends received by an individual (including certain trusts) may give rise to a liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act.

Disposition of Common Shares

A disposition or a deemed disposition of a Common Share by a Holder (except to the Company) will generally result in the Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of the Common Share are greater (or less) than the aggregate of the Holder's adjusted cost base thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "Taxation of Capital Gains and Capital Losses".

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Taxation of Capital Gains and Capital Losses

Generally, one-half of any capital gain (a "**taxable capital gain**") realized by a Holder in a taxation year must be included in the Holder's income for the year, and one-half of any capital loss (an "**allowable capital loss**") realized by a Holder in a taxation year must be deducted from taxable capital gains realized by the Holder in that year. Allowable capital losses for a taxation year in excess of taxable capital gains for that year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years, to the extent and under the circumstances described in the Tax Act.

The amount of any capital loss realized by a Holder that is a corporation on the disposition of a Common Share may be reduced by the amount of dividends received or deemed to be received by it on such Common Share (or on a share for which the Common Share has been substituted) to the extent and under the circumstances described by the Tax Act. Similar rules may apply where a company is a member of a partnership or a beneficiary of a trust that owns Common Shares, directly or indirectly, through a partnership or a trust.

A Holder that is, throughout the relevant taxation year, a "Canadian-controlled private corporation", as defined in the Tax Act, may be liable for a refundable tax of $6^{2}/_{3}$% on investment income, including taxable capital gains.

Capital gains realized by an individual (including certain trusts) may give rise to a liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act.

MATERIAL CONTRACTS

The only material contracts, other than contracts entered into in the ordinary course of business, to which the Company will become a party prior to or at the closing of the Offering are as follows:

(a) the Underwriting Agreement referred to under "Plan of Distribution";

(b) the Indenture referred to under "Description of Debentures" in the U.S. Prospectus;

(c) the First Supplement referred to under "Description of Debentures" in the U.S. Prospectus; and

(d) the underwriting agreement in respect of the Common Share Offering.

Copies of these agreements will be available at www.sedar.com or may be examined at the registered office of the Company, at 355 Burrard Street, Suite 1900, Vancouver, British Columbia, V6C 2G8, during normal business hours until the expiry of the 30-day period following the date of the final short form prospectus.

RELATIONSHIP BETWEEN THE COMPANY AND CERTAIN PERSONS

A bank affiliate of BMO Nesbitt Burns Inc. is a lender to Holdings, an indirect wholly-owned Subsidiary of the Company, under the Credit Facility. Consequently, the Company may be considered a connected issuer of BMO Nesbitt Burns Inc. under applicable securities laws in certain Canadian provinces and territories. As at August 12, 2010, outstanding borrowings under the Credit Facility totalled $20 million, which the Company intends to repay from the proceeds of this Offering and the concurrent Common Share Offering. See "Use of Proceeds" in the U.S. Prospectus. Holdings is in compliance with the terms of the Credit Facility. Since the execution of the Credit Facility, the lenders have not waived a breach, on the part of Holdings, of the Credit Facility. Except as otherwise disclosed in this short form prospectus, the financial position of the Company has not changed in any material manner since the Credit Facility was entered into. Indebtedness under the Credit Facility is secured by pledges of membership interests and capital stock of, and guarantees provided by certain subsidiaries of Holdings and by the Company and by Atlantic Power Generation, Inc., the direct parent of Holdings.

The decision to distribute the Debentures offered hereunder and the determination of the terms of the distribution were made through negotiations between the Company and the Underwriter. The lenders under the Credit Facility did not have any involvement in such decision or determination, but have been advised of the issuance and terms thereof. As a consequence of this issuance, the Underwriter will receive its share of the Underwriter's Fee.

AUDITORS, TRANSFER AGENT AND REGISTRAR AND DEBENTURE TRUSTEE

The auditors of the Company are KPMG LLP, Chartered Accountants, Bay Adelaide Centre, 333 Bay Street, Suite 4600, Toronto, Ontario, M5H 2S5.

The transfer agent and registrar for the Company's Common Shares is Computershare Investor Services Inc. at its principal office in Toronto, Ontario. The trustee of the 2006 Debentures, 2009 Debentures and the Debentures is Computershare Trust Company of Canada, at its principal office in Toronto, Ontario.

PURCHASERS' STATUTORY RIGHTS OF RESCISSION AND WITHDRAWAL

Securities legislation in certain of the provinces and territories of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right generally may be exercised within two business days after receipt or deemed receipt of a short form prospectus and any amendment. In several of the provinces and territories, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the short form prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for the particulars of these rights or consult with a legal advisor.

UNITED STATES PROSPECTUS

The text of the U.S. Prospectus, which forms part of the U.S. Registration Statement filed with the SEC, is attached and forms a part of this short form prospectus. All securities purchased under this short form prospectus, including securities purchased by Canadian investors, will also be registered pursuant to the U.S. Registration Statement under the U.S. Securities Act. The U.S. Securities Act affords certain protections in relation to the U.S. Prospectus.

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AUDITORS' CONSENT

We have read the short form prospectus of Atlantic Power Corporation (the "**Company**") dated , 2010 relating to the issue and sale of % Series B Convertible Unsecured Subordinated Debentures due . We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form prospectus of our report to the shareholders of the Company on the consolidated balance sheets of the Company as at December 31, 2009 and 2008 and the consolidated statements of income (loss) and deficit, comprehensive income (loss) and cash flows for each of the years then ended prepared in accordance with Canadian generally accepted accounting principles. Our report is dated March 29, 2010.

We also consent to the use in the above-mentioned short form prospectus of our report to the directors of the Company on the consolidated balance sheets of the Company as at December 31, 2009 and 2008 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2009 and the financial statement schedule "Schedule II. Valuation and Qualifying Accounts" prepared in conformity with U.S. generally accepted accounting principles. Our report is dated April 12, 2010 except as to notes 2(a), 4, 9, 19 and 21, which are as of May 26, 2010, and as to notes 2(a), 18 and 21, which are as of June 16, 2010.

(Signed) " "
Chartered Accountants,
Licensed Public Accounts

Toronto, Canada
, 2010

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GLOSSARY OF TERMS

In this short form prospectus, the following terms will have the meanings set forth below, unless otherwise indicated. Words importing the singular include the plural and vice versa and words importing any gender include all genders:

"**2006 Debentures**" means the 6.50% convertible secured debentures of the Company due October 31, 2014 issued pursuant to the trust indenture dated as of October 11, 2006 between the Company and the Debenture Trustee as amended by a first supplemental indenture dated as of November 27, 2009, and "**2006 Debenture**" means any one of them.

"**2009 Debentures**" means the 6.25% convertible unsecured subordinated debentures of the Company due March 15, 2017 issued pursuant to the trust indenture dated as of December 17, 2009 between the Company and the Debenture Trustee, and "**2009 Debenture**" means any one of them.

"**affiliate**" has the meaning ascribed thereto in the Securities Act.

"**allowable capital loss**" means one-half of any capital loss.

"**Annual Financial Statements**" means the consolidated financial statements of the Company as at and for each of the years ended December 31, 2009 and December 31, 2008, prepared in accordance with Canadian GAAP, together with the notes thereto and the auditors' report thereon, filed on SEDAR on March 29, 2010.

"**Annual MD&A**" means the management's discussion and analysis of the financial condition and results of operations of the Company for the year ended December 31, 2009, filed on SEDAR on March 29, 2010.

"**Arrangement Circular**" means the management information circular dated October 16, 2009, distributed in connection with the plan of arrangement of the Company pursuant to the *Business Corporations Act* (British Columbia).

"**Canadian GAAP**" means the accounting principles generally accepted in Canada.

"**CDS**" means CDS Clearing and Depository Services Inc.

"**CDS Participant**" means a participant in the CDS depository service.

"**Change of Control**" will be deemed to occur upon the occurrence of any of the following events:

(i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of the Securities Act) of ownership of, or voting control or direction over, 50% or more of the Common Shares; or

(ii) the sale or other transfer of all or substantially all the consolidated assets of the Company.

A Change of Control will not include a sale, merger, reorganization or other similar transaction if the previous holders of the Common Shares hold at least 50% of the voting control in such merged, reorganized or other continuing entity.

"**Closing**" means the closing of the Offering.

"**Common Share Offering**" means the Company's offering, concurrently with the Offering, of Common Shares at a price of U.S. $ per Common Share.

"**Common Shares**" means the common shares in the capital of the Company.

"**Company**" means Atlantic Power Corporation.

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"**Conversion Price**" means, with respect the conversion of Debentures to Common Shares, a price of Cdn$ per Common Share, equivalent to Common Shares per Cdn$1,000 principal amount of Debentures.

"**CRA**" means the Canada Revenue Agency.

"**Credit Facility**" means the revolving senior credit facility provided to Holdings pursuant to a credit agreement dated November 18, 2004, as amended to the date hereof, among, inter alia, Holdings, as borrower, the various financial institutions as are or may become parties thereto and a bank affiliate of BMO Nesbitt Burns Inc., as agent, as amended by a certain first amendment to credit agreement dated as of April 29, 2005, as further amended by a certain second amendment to credit agreement dated as of November 18, 2005, as further amended by a certain third amendment to credit agreement dated as of September 15, 2006, as further amended by a certain fourth amendment to credit agreement dated as of October 11, 2006, as further amended by a certain fifth amendment to credit agreement dated as of August 13, 2007, as further amended by a certain sixth amendment to credit agreement dated as of August 13, 2007, as further amended by a certain consent and seventh amendment to credit agreement dated as of April 21, 2008, as further amended by a certain consent and eighth amendment to credit agreement dated as of November 20, 2008, as further amended by a certain consent and ninth amendment to credit agreement dated as of November 27, 2009 and as further amended by a certain consent and tenth amendment to credit agreement dated as of July 1, 2010.

"**Debenture Trustee**" means Computershare Trust Company of Canada.

"**Debentures**" means the % series B convertible unsecured subordinated debentures of the Company offered under this short form prospectus and "**Debenture**" means one of them.

"**Holder**" has the meaning ascribed thereto herein under "Certain Canadian Federal Income Tax Considerations".

"**Holdings**" means Atlantic Power Holdings, Inc.

"**Interest Payment Date**" means the date that interest will be paid on the Debentures, payable semi-annually on the day of and in each year, commencing on computed on the basis of a 360-day year composed of twelve 30-day months.

"**Maturity Date**" means , the maturity date of the Debentures.

"**Noon Buying Rate**" means the noon buying rate of exchange between U.S. dollars and Canadian dollars as quoted by the Bank of Canada.

"**NYSE**" means the New York Stock Exchange.

"**Offering**" means the offering of the Debentures pursuant to this short form prospectus.

"**person**" includes an individual, corporation, company, partnership, joint venture, association, trust, trustee, unincorporated organization or government or any agency or political subdivision thereof.

"**Projects**" means the power projects described under "Business Our Power Projects" in the U.S. Prospectus, and "**Project**" means any one of them.

"**Q2 Financial Statements**" means the unaudited consolidated interim financial statements of the Company for the three and six months ended June 30, 2010 and 2009, prepared in accordance with U.S. GAAP, together with the notes thereto, filed on SEDAR on August 9, 2010.

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"**Q2 MD&A**" means the management's discussion and analysis of the financial condition and results of operations of the Company for the three and six months ended June 30, 2010, filed on SEDAR on August 9, 2010.

"**Securities**" means, collectively, the Debentures offered pursuant to this short form prospectus and the Common Shares issuable on the conversion, redemption, purchase for cancellation or maturity of the Debentures.

"**Securities Act**" means the *Securities Act* (Ontario), as amended.

"**Subsidiary**" has the meaning ascribed thereto in the Securities Act.

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder, in each case in effect on the date hereof.

"**taxable capital gain**" means one-half of any capital gain.

"**Transfer Agent**" means Computershare Investor Services Inc. or its successor.

"**TSX**" means the Toronto Stock Exchange.

"**Underwriter**" means BMO Nesbitt Burns Inc.

"**Underwriter's Fee**" means the fee of % of the principal amount of the Debentures paid to the Underwriter for its participation in the Offering.

"**Underwriting Agreement**" means the underwriting agreement among the Company and the Underwriter dated , 2010.

"**U.S. GAAP**" means the accounting principles generally accepted in the United States.

"**U.S. Securities Act**" means the *United States Securities Act of 1933*, as amended.

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CERTIFICATE OF THE COMPANY

Dated: August 13, 2010

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces and territories of Canada other than the province of Québec.

ATLANTIC POWER CORPORATION

By: (Signed) BARRY WELCH
Chief Executive Officer

By: (Signed) PATRICK WELCH
Chief Financial Officer

ATLANTIC POWER CORPORATION
On Behalf of the Board of Directors

By: (Signed) KEN HARTWICK
Director

By: (Signed) JOHN MCNEIL
Director

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CERTIFICATE OF THE UNDERWRITER

Dated: August 13, 2010

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces and territories of Canada other than the province of Québec.

BMO NESBITT BURNS INC.

By: (Signed) STEVEN A. BRAUN

PART II
INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution.

The following table sets forth the estimated costs and expenses payable by the registrant in connection with the registration of securities being registered under this Registration Statement. All amounts except the SEC registration fee are estimates.

SEC registration fee	$	3,931.48
Legal fees and expenses		*
Accounting fees and expenses		*
Printing and related expenses		*
Trustee fees and expenses		*
Miscellaneous expenses		*
Total	$	*

*
To be filed by amendment.

Item 14. Indemnification of Directors and Officers.

Under the *Business Corporations Act* (British Columbia), which we refer to as the "BC Act," we may indemnify a present or former director or officer or a person who acts or acted at our request as a director or officer of another corporation or one of our affiliates, and his or her heirs and personal representatives, against all costs, charges and expenses, including legal and other fees and amounts paid to settle an action or satisfy a judgment, actually and reasonably incurred by him or her including an amount paid to settle an action or satisfy a judgment in respect of any legal proceeding or investigative action to which he or she is made a party by reason of his or her position and provided that the director or officer acted honestly and in good faith with a view to the best interests of Atlantic Power Corporation or such other corporation, and, in the case of a criminal or administrative action or proceeding, had reasonable grounds for believing that his or her conduct was lawful. Other forms of indemnification may be made with court approval.

In accordance with our Articles, we shall indemnify every director or former director, or may, subject to the BC Act, indemnify any other person. We have entered into indemnity agreements with our directors and executive officers, whereby we have agreed to indemnify the directors and officers to the extent permitted by our Articles and the BC Act.

Our Articles permit us, subject to the limitations contained in the BC Act, to purchase and maintain insurance on behalf of any person, as the board of directors may from time to time determine. Our directors and officers liability insurance coverage consists of three policies with aggregate limits of $30 million.

The foregoing summaries are necessarily subject to the complete text of the statute and our Articles, and the arrangements referred to above are qualified in their entirety by reference thereto.

Item 15. Recent Sales of Unregistered Securities.

We completed our initial public offering on the TSX in November 2004 in a transaction exempt from registration pursuant to Regulation S under the Securities Act. At the time of the IPO, our public security was an IPS. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. We sold 32,000,000 IPSs in this offering, at a price of Cdn$10.00 per IPS, for gross proceeds of Cdn$320 million. The principal underwriter was BMO Nesbitt Burns Inc. and aggregate underwriting commissions were Cdn$16.8 million. In December 2004, the underwriters of our initial public offering exercised their over-allotment option to purchase 4,800,000 additional IPSs, at a price of Cdn$10.00 per IPS, for gross proceeds of Cdn$48 million. We used the proceeds from our initial public offering to acquire a 58% interest in Atlantic Power Holdings, Inc. ("Atlantic Holdings") from two private equity funds managed by ArcLight Capital Partners, LLC and from Caithness.

In October 2005, we issued 7,500,000 IPSs in a private placement to a Canadian pension fund and 39,500 IPSs to Barry Welch, our President and Chief Executive Officer, and to our then-current managing director in a transaction exempt from registration pursuant to Section 4(2) of the Securities Act. The IPSs were sold at a price of Cdn$10.00 per IPS for aggregate gross proceeds of Cdn$75.4 million. We used the net proceeds from this private placement to increase our interest in Atlantic Holdings to 70%.

In October 2006, we completed a follow-on public offering in Canada of IPSs and convertible debentures for gross proceeds of Cdn$150 million in a transaction exempt from registration pursuant to Regulation S under the Securities Act. The offering consisted of 8,531,000 IPSs sold at a price of Cdn$10.55 per IPS for gross proceeds of Cdn$90 million and Cdn$60 million aggregate principal amount of 6.25% convertible subordinated debentures due 2011. The terms of the debentures provide that they can be converted into IPSs at the option of the holder at a conversion price of Cdn$12.40 per IPS, or approximately 80.6452 IPSs per Cdn$1,000 principal amount of debentures, subject to adjustment in accordance with the trust indenture governing the terms of the debentures. The principal underwriter was BMO Nesbitt Burns Inc. and aggregate underwriting commissions were Cdn$6.9 million. The net proceeds of the offering were used to partially repay $37 million of the credit facility arranged in connection with our acquisition of an interest in the Path 15 project and to increase our ownership in Atlantic Holdings from 70% to approximately 86%.

In December 2006, we completed a private placement of 8,600,000 IPSs, at a price of Cdn$10.00 per IPS, and Cdn$3.0 million principal amount of separate subordinated notes in a transaction exempt from registration pursuant to Section 4(2) of the Securities Act to three institutional investors for aggregate gross proceeds of Cdn$89.0 million. In February 2007, we used the net proceeds of the private placement to increase our ownership in Atlantic Holdings to 100%, whereupon Atlantic Holdings became our wholly-owned subsidiary.

Since January 1, 2007, we have issued 87,701 IPSs to three employees pursuant to our LTIP. These issuances were exempt from registration either pursuant to Rule 701 under the Securities Act, as a transaction pursuant to a compensatory benefit plan, or pursuant to Section 4(2) of the Securities Act, as a transaction by an issuer not involving a public offering.

On November 27, 2009, we completed the conversion of all of our IPSs to common shares. The exchange of IPSs for common shares was exempt from registration pursuant to Section 3(a)(10) of the Securities Act, which exempts offers and sales of securities in exchange transactions where a reviewing court or authorized governmental entity approves the fairness of the exchange following an open hearing. The IPSs were exchanged for common shares and the Supreme Court of British Columbia approved the terms and conditions of the exchange after a hearing upon the fairness of such terms and conditions at which all holders of IPSs had the right to appear.

In December 2009, we completed a public offering in Canada of an aggregate of Cdn$86.25 million of our 6.25% convertible unsecured subordinated debentures due 2017 in a transaction exempt from registration pursuant to Regulation S under the Securities Act. The terms of the debentures provide that they can be converted into our common shares at the option of the holder at a conversion price of Cdn$13.00 per common share, or approximately 76.9231 common shares per Cdn$1,000 principal amount of debentures, subject to adjustment in accordance with the trust indenture governing the terms of the debentures. The principal underwriter was BMO Nesbitt Burns Inc. and aggregate underwriting commissions were Cdn$3.45 million. We used the net proceeds of the offering principally to redeem all or substantially all of our outstanding 11.0% subordinated notes, and the remainder for general corporate purposes, including acquisitions.

Item 16. Exhibits and Financial Statement Schedules.

(a) Financial Statements. See the accompanying consolidated financial statements.

(b) The following is a list of all exhibits filed as part of this Registration Statement, including those incorporated by reference.

Exhibit No.	Description
1.1*	Form of Underwriting Agreement
3.1	Articles of Continuance of Atlantic Power Corporation, dated November 24, 2009, as amended on June 29, 2010(2)
3.2	Certificate of Incorporation of Atlantic Power Corporation, dated June 18, 2004(1)
4.1	Form of common share certificate(1)
4.2	Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada(1)
4.3	First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada(1)
4.4	Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada(1)
4.5*	Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada
5.1	Opinion of Goodmans LLP(3)
10.1	Credit Agreement dated as of November 18, 2004 among Atlantic Power Holdings, Inc. as Borrower, Bank of Montreal as Administrative Agent, LC issuer and collateral agent and the Other Lenders party thereto, and Harris Nesbitt Corp. as arranger(1)
10.2	Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Barry Welch(1)
10.3	Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Patrick Welch(1)
10.4	Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Paul Rapisarda(1)
10.5	Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation(1)
10.6	Third Amended and Restated Long-Term Incentive Plan, adopted June 29, 2010(2)
10.7	Second Amended and Restated Long-Term Incentive Plan, adopted June 4, 2008(1)
21.2	Subsidiaries of Atlantic Power Corporation(1)
23.1	Consent of Goodmans LLP (included in Exhibit 5.1)(3)

Exhibit No.	Description
23.2	Consent of KPMG LLP(3)
23.3	Consent of PricewaterhouseCoopers LLP(3)
23.4	Consent of PricewaterhouseCoopers LLP(3)
23.5	Consent of PricewaterhouseCoopers LLP(3)
23.6	Consent of KPMG LLP(3)
24.1	Powers of Attorney, included on signature page of the Registrant's Form S-1(3)
25.1*	Form T-1 Statement of Eligibility

* To be filed by amendment.

(1) Incorporated by reference to our registration statement on Form 10-12B filed with the Commission on April 13, 2010.

(2) Incorporated by reference to our registration statement on Form 10-12B/A filed with the Commission on July 9, 2010.

(3) Incorporated by reference to our registration statement on Form S-1 (File No. 333-168856) filed with the Commission on August 16, 2010.

Item 17. Undertakings.

(a) Insofar as indemnification for liabilities arising under the Securities Act of 1933, as amended, may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(b) The undersigned registrant hereby undertakes that:

(i) For purposes of determining any liability under the Securities Act of 1933, as amended, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(ii) For the purpose of determining any liability under the Securities Act of 1933, as amended, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered herein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant certifies that it has reasonable grounds to believe that it meets all of the requirements for filing on Form S-1 and that it has duly caused this Amendment No. 1 to Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Boston, The Commonwealth of Massachusetts, on the 20th day of August, 2010.

Atlantic Power Corporation

By: /s/ PATRICK J. WELCH

Patrick J. Welch
Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Act of 1933, as amended, this Amendment No. 1 to Registration Statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
* Barry E. Welch	President, Chief Executive Officer and Director (principal executive officer)	August 20, 2010
/s/ PATRICK J. WELCH Patrick J. Welch	Chief Financial Officer (principal financial and accounting officer)	August 20, 2010
* Irving R. Gerstein	Chairman of the Board	August 20, 2010
* Kenneth M. Hartwick	Director	August 20, 2010
* Richard Foster Duncan	Director	August 20, 2010
* John A. McNeil	Director	August 20, 2010
* Holli Nichols	Director	August 20, 2010

*By: /s/ PATRICK J. WELCH

Patrick J. Welch
Attorney-in-Fact

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