



Management's Discussion and Analysis of

**FORT CHICAGO ENERGY
PARTNERS L.P.**

Year ended December 31, 2009

March 2, 2010

FORT CHICAGO ENERGY PARTNERS L.P.

Management's Discussion & Analysis

Year ended December 31, 2009

This Management's Discussion and Analysis dated March 2, 2010 provides a review of the significant events and transactions that affected our performance during 2009 relative to 2008. Some of the information contained in this MD&A is forward-looking information under Canadian securities laws. All information that addresses activities, events or developments which may or will occur in the future is forward-looking information. Forward-looking information typically contains statements with words such as may, estimate, anticipate, believe, expect, plan, intend, target, project, forecast or similar words suggesting future outcomes or outlook. Forward-looking statements in this MD&A include statements about:

- our plan to convert from a limited partnership structure to a taxable Canadian corporation;
- the timing under which our Glen Park acquisition will close;
- the sources of additional rich-gas supplies for transportation on the Alliance pipeline and for processing at Aux Sable's Channahon facility;
- the potential expansion related to Aux Sable's Septimus Gas Plant;
- the timing of in service and capital cost of Aux Sable's Septimus pipeline;
- the timing of future cash distributions from East Windsor Cogeneration;
- our ability to secure commercial commitments for the Jordan Cove LNG terminal and Pacific Connector gas pipeline projects;
- the sufficiency of our available committed credit facilities to fund distributions and planned capital expenditures;
- the ability of each of our businesses to generate distributable cash; and
- our ability to make cash distributions.

The risks and uncertainties that may affect our operations, performance, development and the results of our businesses include, but are not limited to, the following factors:

- our ability to successfully implement our strategic initiatives and achieve expected benefits;
- levels of oil and gas exploration and development activity;
- the status, credit risk and continued existence of contracted customers;
- the availability and price of capital;
- the availability and price of energy commodities;
- the availability of construction services and materials;
- fluctuations in foreign exchange and interest rates;
- our ability to successfully obtain regulatory approvals;
- changes in tax, regulatory, environmental, and other laws and regulations;
- competitive factors in the pipeline, NGL and power industries;
- operational breakdowns, failures, or other disruptions; and
- the prevailing economic conditions in North America.

Additional information on these and other risks, uncertainties and factors that could affect our operations or financial results are included in our filings with the securities commissions or similar authorities in each of the provinces of Canada, as may be updated from time to time. We caution readers that the foregoing list of factors and risks is not exhaustive. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are independent and management's future course of action would depend on its assessment of all information at that time. Although we believe the expectations conveyed by the forward-looking information are reasonable based on information available to us on the date of preparation, we can give no assurances as to future results, levels of activity and achievements. Readers should not place undue reliance on the information contained in this MD&A, as actual results achieved will vary from the information provided herein and the variations may be material. We make no representation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained herein are made as of the date hereof, and, except as required by law, we do not undertake any obligation to update publicly or to revise any forward-looking information, whether as a result of new information, future events or otherwise. We expressly qualify any forward-looking information contained in this MD&A by this cautionary statement.

All financial information is in Canadian dollars unless otherwise noted and, as it relates to our financial results, has been derived from information used to prepare our consolidated financial statements, which have been prepared in accordance with Generally Accepted Accounting Principles in Canada. Financial information pertaining to our jointly held businesses reflects our proportionate share unless otherwise noted. Capitalized terms used in this MD&A that have not been defined have the same meanings attributed to them in our 2009 consolidated financial statements. Additional information concerning our business is available on SEDAR at www.sedar.com or on our website at www.fortchicago.com.

Certain financial information contained in this MD&A may not be standard measures under GAAP in Canada and may not be comparable to similar measures presented by other entities. These measures are considered to be important measures used by the investment community and should be used to supplement other performance measures prepared in accordance with GAAP in Canada. For further information on non-GAAP financial measures used by us see the section entitled "Non-GAAP Financial Measures" contained in this MD&A.

OVERVIEW

We are a limited partnership committed to actively managing and growing our existing businesses and making targeted, strategic investments. We focus on high quality, long-life infrastructure assets that provide diversity and contribute toward stable and growing distributions. Our three principal business segments include:

- a pipeline transportation business comprised of a:
 - 50 percent ownership interest in Alliance Pipeline, and
 - 100 percent ownership interest in the Alberta Ethane Gathering System;
- an NGL extraction business comprised of a:
 - 42.7 percent ownership interest in Aux Sable Liquid Products,
 - 42.7 percent ownership interest in Alliance Canada Marketing, and
 - 50 percent ownership interest in Aux Sable Canada; and
- a power business comprised of a:
 - 100 percent ownership interest in Fort Chicago Power,
 - 50 percent ownership interest in NRGreen; and
 - 50 percent ownership interest in East Windsor Cogeneration.

Pipeline Business

Our pipeline business represented 80 percent of our total assets at December 31, 2009 and generated 69 percent of 2009 distributable cash inflows. Each of Alliance and AEGS are stable cash flow generators that are supported by long-term, take-or-pay transportation agreements.

Alliance owns and manages an integrated, high-pressure natural gas pipeline that extends approximately 3,000 kilometres across North America. With an extensive gathering system, Alliance delivers natural gas from the gas-rich regions of northeastern British Columbia and northwestern Alberta to delivery points near Chicago, Illinois, a major natural gas market hub. The system is capable of transporting 1.325 billion cubic feet per day of liquids-rich natural gas on a firm-service basis.

AEGS is an integrated 1,324-km pipeline that transports pure ethane from various Alberta ethane extraction plants to major petrochemical complexes located near Joffre and Fort Saskatchewan, Alberta. AEGS is a key component of Alberta's energy infrastructure and of vital importance to Alberta's NGL extraction and petrochemical industries. AEGS also interconnects with a third-party underground storage site and an export pipeline system.

NGL Business

Our NGL business, which represented 6 percent of our assets at December 31, 2009 and generated 23 percent of 2009 distributable cash inflows, consists of:

- a world-scale NGL extraction and fractionation facility, referred to as the "Channahon Facility", near the terminus of the Alliance pipeline, capable of recovering up to 80,000 barrels per day of ethane, propane, normal butane, iso-butane and natural gasoline;
- storage, downstream NGL pipelines and loading facilities (which together with the Channahon Facility are collectively referred to as the "NGL Facilities");
- NGL injection facilities in Alberta and British Columbia;
- long-term firm natural gas transportation capacity on the Alliance pipeline; and
- a natural gas processing plant, referred to as the "Septimus Gas Plant", in the liquids-rich Montney region of northeast British Columbia.

Our Channahon Facility has long-term product sales agreements in place that provide a base level of earnings as well as a significant share of margins in excess of specified levels.

Power Business

Our power business represented 13 percent of our assets at December 31, 2009 and generated 6 percent of 2009 distributable cash inflows. Each of our power facilities is underpinned with long-term capacity payment-based energy contracts.

Fort Chicago Power is comprised of our wholly owned power assets:

- three gas-fired cogeneration facilities: two in California and one in London, Ontario which was placed into service in December 2008;
- a combined cycle power generation facility in Colorado, which we acquired in September 2008; and
- two district energy systems located in London, Ontario and Charlottetown, Prince Edward Island.

In December 2009, we announced an agreement to acquire the Glen Park facility, a run-of-river hydro-power generation facility located on the Black River in New York. We expect this transaction to close in the first quarter of 2010.

Our power business also includes two jointly held businesses. NRGreen owns four waste heat electrical generation facilities located at Alliance's Saskatchewan compressor sites. East Windsor Cogeneration owns a gas-fired cogeneration facility in Windsor, Ontario, which commenced operations on November 6, 2009.

Project Development

We are also actively advancing our growth strategy through of a number of initiatives, including:

- building out Alliance and Aux Sable's infrastructure to target rich gas;
- establishing a significant footprint in processing off-gas produced by Alberta's oil sands upgraders;
- growing our power business;
- developing liquefied natural gas and pipeline facilities on the U.S. west coast; and
- developing a Nova Scotia-based underground natural gas storage facility.

Conversion to a Corporation

In November 2009, the board of directors of our General Partner announced that we will be restructured from a limited partnership to a taxable Canadian corporation before January 1, 2011.

FINANCIAL AND OPERATING HIGHLIGHTS

(\$ Thousands, except where noted)	2009	2008	2007
Operating Highlights			
Average daily volumes (100%)			
Pipeline			
Alliance – billion cubic feet per day	1,601	1,609	1,598
AEGS – thousand barrels per day ⁽¹⁾	277.8	299.8	308.6
NGL			
Aux Sable – thousand barrels per day	64.7	60.9	67.7
Power			
Fort Chicago Power – megawatt hours	492,935	505,988	157,746
NRGreen – megawatt hours	135,568	73,697	35,183
Financial Results			
Revenues	649,133	701,430	589,223
Net income	37,575	61,499	86,157
Per Unit (\$) – basic and diluted	0.28	0.46	0.66
Adjusted net income ^{(2) (3)}	83,539	72,104	78,019
Per Unit (\$) – basic and diluted	0.61	0.54	0.60
Cash from operating activities	210,743	262,612	204,852
Distributable cash ^{(2) (4)}	149,067	160,149	177,439
Per Unit (\$) – basic and diluted	1.10	1.20	1.35
Distributions paid/payable	136,079 ⁽⁷⁾	133,150	123,699
Per Unit (\$)	1.00	1.00	0.9416
Capital expenditures			
Growth ^{(2) (5)}	44,815	119,581	97,754
Maintenance and sustaining ^{(2) (5)}	6,072	19,445	1,843
Financial Position			
Cash and short-term investments	57,945	53,308	47,191
Total assets	2,864,899	3,127,679	2,871,364
Senior debt	1,679,703	1,842,276	1,712,570
Subordinated convertible debentures	24,054	23,909	46,647
Exchangeable debentures	25,248	25,717	23,919
Partners' equity	698,726	800,587	755,453
Total enterprise value ^{(2) (6)}	3,294,856	3,123,928	3,401,723
Units			
Units outstanding – as at year-end ⁽⁸⁾	138,955,646	134,110,877	131,668,086
Average daily volume (Units)	414,224	173,621	154,670
Price per Unit – close (\$)	9.98	7.22	10.84

(1) Average daily volume for AEGS is based on toll volumes.

(2) This item is not a standard measure under GAAP and may not be comparable to similar measures presented by other entities. See section entitled "Non-GAAP Financial Measures" in this MD&A.

(3) We have provided a reconciliation of adjusted net income to net income in the "Non-GAAP Financial Measures" section of this MD&A.

(4) We have provided a reconciliation of distributable cash to cash from operating activities in the "Non-GAAP Financial Measures" section of this MD&A.

(5) The sum of growth and maintenance and sustaining capital expenditures equals total capital expenditures on our consolidated statement of cash flows.

(6) We have provided a reconciliation of total enterprise value to total assets in the "Non-GAAP Financial Measures" section of this MD&A.

(7) Includes \$44.0 million of distributions satisfied through the issuance of Units under our Distribution Reinvestment Plan.

(8) As at the close of markets on February 26, 2010 we had 140,059,725 Units outstanding.

OVERALL PERFORMANCE

Net Income

	Three months ended		Year ended	
	December 31		December 31	
(\$ Thousands, except per Unit amounts)	2009	2008	2009	2008
Net income (loss) before tax				
Pipeline	25,383	26,096	105,923	113,897
NGL	27,393	(1,601)	50,805	63,926
Power	(82,866)	(26,658)	(81,346)	(17,001)
Fort Chicago – Corporate	(16,215)	(18,822)	(46,093)	(72,167)
	(46,305)	(20,985)	29,289	88,655
Tax recovery (expense)	21,851	3,036	8,286	(27,156)
Net income (loss)	(24,454)	(17,949)	37,575	61,499
Per Unit (\$)	(0.18)	(0.13)	0.28	0.46

For the three months ended December 31, 2009, we incurred a net loss of \$24.5 million or \$0.18 per Unit compared to a net loss of \$17.9 million or \$0.13 per Unit for the same period in 2008. The decrease is attributable to a non-cash asset impairment loss of \$78.1 million recorded in the fourth quarter of 2009. Our California cogeneration facilities were adversely affected by a regulatory energy pricing decision (See “Results of Operations – Power Business”). Consequently, under accounting standards we were required to write down the book value of these assets. The net loss for the fourth quarter of 2008 included an impairment loss of \$21.1 million arising from our write down of goodwill. The increased net loss for the fourth quarter of 2009 was partially offset by:

- a \$9.5 million gain relating to Aux Sable’s liability settlement in association with its off-gas facility;
- a net \$24.9 million tax recovery relating to the asset impairment loss and Aux Sable’s settlement gain; and
- a \$20.1 million increase in margin-based lease revenues recognized by Aux Sable, from \$0.3 million in the fourth quarter of 2008 to \$20.4 million in the fourth quarter of 2009. Fractionation margins for the fourth quarter of 2009 were considerably higher than during the same period last year, when the economic downturn severely weakened NGL market conditions.

For the year ended December 31, 2009, net income was \$37.6 million or \$0.28 per Unit compared to \$61.5 million or \$0.46 per Unit for 2008. In addition to the effect of the fourth quarter asset impairment loss discussed above, the decrease in net income reflects:

- an \$18.4 million decrease in margin-based lease revenues, from \$67.7 million in 2008 to \$49.3 million in 2009, as 2009 NGL market conditions did not reach the record levels of the first nine months of 2008; and
- the absence of non-recurring gains recognized in the first quarter of 2008 relating to Alliance’s cash settlement with Calpine Energy Services Canada Partnership and a non-cash gain arising from the dilution of our ownership interest in Pristine.

These decreases were partially offset by a \$19.8 million reduction in the deemed realization of corporate foreign exchange losses previously deferred and recorded in other comprehensive income.

Adjusted Net Income ⁽¹⁾

	Three months ended December 31		Year ended December 31	
(\$ Thousands, except per Unit amounts)	2009	2008	2009	2008
Adjusted net income (loss) before tax				
Pipeline	25,383	26,096	105,923	103,877
NGL	17,921	(1,601)	41,333	63,926
Power	(4,815)	(5,553)	(853)	(96)
Fort Chicago – Corporate	(16,215)	(18,822)	(46,093)	(72,167)
	22,274	120	100,310	95,540
Tax recovery (expense)	(3,052)	3,036	(16,771)	(23,436)
Adjusted net income	19,222	3,156	83,539	72,104
Per Unit (\$)	0.14	0.02	0.61	0.54

(1) See the reconciliation to net income in the “Non-GAAP Financial Measures” section of this MD&A.

Adjusted net income for the three months ended December 31, 2009, which excludes non-recurring items, was \$19.2 million or \$0.14 per Unit compared to \$3.2 million or \$0.02 per Unit for the same period last year, primarily reflecting a \$20.1 million increase in Aux Sable’s margin-based lease revenues. Fourth quarter adjusted net income from our pipeline and power businesses was consistent with the same period last year.

Adjusted net income for the year ended December 31, 2009 was \$83.5 million or \$0.61 per Unit compared to \$72.1 million or \$0.54 per Unit for 2008, primarily reflecting a significant decrease in the deemed realization of corporate foreign exchange losses previously deferred and recorded in other comprehensive income. This was partially offset by an \$18.4 million decrease in margin-based lease revenues from Aux Sable, reflecting the year-over-year change in NGL market conditions. 2009 adjusted net income from our pipeline and power businesses was consistent with last year.

Distributable Cash ⁽²⁾

	Three months ended December 31		Year ended December 31	
(\$ Thousands, except per Unit amounts)	2009	2008	2009	2008
Pipeline	32,650	33,151	134,413	137,228
NGL	18,934	579	45,584	69,504
Power	(2,006)	856	14,841	9,943
Fort Chicago - Corporate	(9,760)	(7,507)	(29,812)	(32,213)
Taxes	(5,817)	(4,595)	(15,959)	(24,313)
	34,001	22,484	149,067	160,149
Per Unit (\$)	0.25	0.17	1.10	1.20

(2) See the reconciliation to cash from operating activities in the “Non-GAAP Financial Measures” section of this MD&A.

Distributable cash for the three months ended December 31, 2009 was \$34.0 million or \$0.25 per Unit compared to \$22.5 million or \$0.17 per Unit for the same period in 2008. The increase primarily reflects:

- significantly higher distributions from Aux Sable, due to the recovery of NGL market conditions in 2009 from the severe downward shift experienced in the fourth quarter of 2008;

partially offset by:

- lower energy margins from the power business, which was adversely affected by a regulatory decision and higher maintenance capital expenditures at the California cogeneration facilities;
- higher corporate costs due to increased administration and business development activity and interest associated with the \$200 million senior notes we issued in July 2009; and
- higher cash taxes associated with increased Aux Sable earnings.

Distributions from our pipeline business approximated amounts generated during the same period last year.

Distributable cash for the year ended December 31, 2009 was \$149.1 million or \$1.10 per Unit compared to \$160.1 million or \$1.20 per Unit for 2008. The decrease primarily reflects:

- lower distributions from Aux Sable, which generated record levels of cash flows in the first nine months of 2008;
- lower distributions from Alliance due to the absence of funds received the first quarter of 2008 from the Calpine settlement, partially offset by the effect of the weaker Canadian dollar in 2009;

partially offset by:

- higher distributable cash from the power business, as incremental cash flows from the London cogeneration facility and Brush, combined with lower maintenance capital costs in 2009 more than offset the lower energy margins earned at the California facilities in the latter half of the year;
- lower corporate costs, primarily reflecting lower interest costs for the year and the impact of a realized foreign exchange gain; and
- lower cash taxes associated with decreased Aux Sable earnings.

Cash from Operating Activities

(\$ Thousands)	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Pipeline	29,003	34,594	205,705	210,982
NGL	25,402	9,808	48,168	74,161
Power	5,276	4,930	26,589	11,740
Fort Chicago - Corporate	(15,994)	(10,053)	(69,719)	(34,271)
	43,687	39,279	210,743	262,612

We generated cash from operating activities of \$43.7 million for the three months ended December 31, 2009, a \$4.4 million increase from the same period last year as increased operating cash flows from Aux Sable offset lower operating cash flows from Alliance and higher corporate cash outflows.

For the year ended December 31, 2009, we generated cash from operating activities of \$210.7 million compared to \$262.6 million for last year. This decrease reflects significantly lower operating cash flows from Aux Sable due to the overall NGL market conditions and increased cash outflows from our corporate activities, reflecting a significant income tax payment in the first quarter of 2009 related to Aux Sable's 2008 earnings.

RESULTS OF OPERATIONS – BY BUSINESS SEGMENT

Pipeline Business

(\$ Thousands, except where noted)	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Net income before tax				
Alliance Pipeline	24,229	24,735	101,289	108,392
AEGS	1,154	1,361	4,634	5,505
	25,383	26,096	105,923	113,897
Volumes				
Alliance Pipeline (100%) (bcf/d)	1.569	1.583	1.601	1.609
AEGS (mmbbls/d) ⁽¹⁾	274.9	290.1	277.8	299.8

(1) Average daily volumes for AEGS are based on toll volumes.

Alliance Pipeline

Alliance has firm-service transportation services contracts with primary terms extending to December 2015 with a group of 28 shippers. Under the transportation service contracts, each shipper is obligated to pay monthly demand charges based on their contracted firm volume, regardless of volumes actually transported. These transportation contracts provide toll revenues sufficient to recover the costs of providing transportation service to shippers, including depreciation, debt financing costs and an allowed return on equity. The portion of such costs

recovered each year is based on the percentage of the firm transportation capacity contracted. During 2009 and 2008, 98.5 percent, or 1.305 bcf/d, of firm capacity was contracted under long-term, firm-service transportation agreements and 1.5 percent, or 0.02 bcf/d, of firm capacity was contracted under a short-term, firm-service agreement that currently extends to March 31, 2010.

Operational Highlights

Since initiating operations, Alliance has concentrated on its core business and continued to meet its objectives in all key areas of operational performance: availability, reliability, safe operations, throughput and efficiency (as measured by Authorized Overrun Service, or "AOS", being the amount of gas transported in excess of firm contracted capacity). Alliance offered shippers a level of AOS that was 20.8 percent in excess of firm contracted capacity in 2009. In 2009, transportation deliveries, including AOS, averaged 1.601 bcf/d compared with 1.609 bcf/d in 2008. This achievement reflects Alliance's focus on continuous improvement in maintenance practices, line pack management and system scheduling, along with the implementation of several asset optimization projects where Alliance has set industry standards for pipeline technology and system optimization.

Financial Highlights

Transportation revenues for the three months ended December 31, 2009 were \$100.2 million, a \$7.9 million decrease compared to \$108.1 million for the same period last year. The decrease primarily resulted from the effect of the stronger Canadian dollar. Fourth quarter revenues also decreased due to lower cost of service recoveries, reflecting reduced operating costs, interest expense (resulting from the ongoing amortization of Alliance's long-term debt), and equity return (resulting from the ongoing depreciation of its investment base). This was partially offset by higher recoveries for income taxes.

Transportation revenues for the year ended December 31, 2009 were \$388.0 million, a \$7.8 million increase compared to \$380.2 million for last year. The increase primarily resulted from the effect of the weaker Canadian dollar. This was partially offset by lower cost of service recoveries resulting from the same factors that influenced fourth quarter recoveries.

Net income before tax for the three months ended December 31, 2009 was \$24.2 million, a \$0.5 million decrease compared to \$24.7 million for the same period last year, reflecting the effect of the stronger Canadian dollar and the reduced return on investment base, partially offset by higher income tax recoveries.

For the year ended December 31, 2009, net income before tax was \$101.3 million, a \$7.1 million decrease compared to \$108.4 million for last year. This decrease primarily reflects Alliance's first quarter 2008 receipt of \$10.3 million in full settlement of its claim in respect of Calpine's 2006 repudiation of its transportation contracts. The decrease in net income before tax also reflects the reduced equity return on investment base in 2009, partially offset by the effect of the weaker Canadian dollar and higher income tax recoveries.

Proposed Gathering Receipt Service and Canadian Delivery Service

From June 1, 2009 to July 15, 2009 Alliance held concurrent open seasons for two new services: Gathering Receipt Service ("GRS") and Canadian Delivery Service ("CDEL"). GRS will provide gathering service from northeast British Columbia to south-central Alberta. CDEL will provide delivery from northwestern Alberta and northeastern B.C. receipt points to Canadian markets.

Prospective shippers have signed agreements to develop three new receipt point interconnections, which will allow for initial GRS capacity of 42 million cubic feet per day. Alliance expects GRS to commence in the fourth quarter of 2011.

Pecan Pipeline (North Dakota), Inc. Receipt Point

Pecan Pipeline (North Dakota), Inc. has developed the Prairie Rose Pipeline, a gathering pipeline that connects with a new gas receipt point on the Alliance system near Towner, North Dakota. This project brings associated rich gas from the Bakken formation onto Alliance for transport to Aux Sable's Channahon fractionation facility. Alliance and Pecan have executed a ten-year firm transportation agreement, under which Pecan holds 40 mmcf/d of firm transportation capacity for the first year and 80 mmcf/d thereafter. The new receipt point was placed into service in February 2010.

AEGS

AEGS' revenues and earnings are based on long-term, take-or-pay ethane transportation agreements ("ETAs"), which extend to December 31, 2018. The ETAs provide for a minimum revenue stream based on specified committed volumes, the recovery of all operating costs, and the right for each shipper to transport ethane on the

AEGS pipeline up to their committed volumes. Therefore, AEGS is expected to generate a stable stream of earnings and distributable cash.

Operational Highlights

Toll volumes for the three and 12 months ended December 31, 2009 were 274.9 thousand barrels per day and 277.8 mbbls/d, respectively, reflecting decreases compared to the same periods last year. The decreases resulted from lower gas flows across Alberta during the year, which limited ethane production.

Financial Highlights

AEGS generated \$11.6 million in revenues for the three months ended December 31, 2009, a \$0.8 million increase compared to \$10.8 million for the same period last year. The increase reflects higher operating and overhead cost recoveries, partially offset by lower toll revenues from ethane receipts.

Revenues for the year ended December 31, 2009 were \$40.1 million, a \$2.5 million decrease compared to \$42.6 million for last year. The decrease reflects lower ethane receipts, and lower operating and overhead cost recoveries.

Net income before tax for the three and 12 months ended December 31, 2009 was \$1.2 million and \$4.6 million, respectively, reflecting decreases of \$0.2 million and \$0.9 million compared to \$1.4 million and \$5.5 million for the same periods last year. The decreases primarily reflect lower ethane receipts in 2009.

NGL Business

	Three months ended December 31		Year ended December 31	
(\$ Thousands, except where noted)	2009	2008	2009	2008
Net income (loss) before tax	27,393	(1,601)	50,805	63,926
Margin-based fees under NGL Sales Agreement				
Estimated amount generated during period	19,552	(410)	49,290	67,713
Margin recognized from prior period	890	698	-	-
Amount recognized as revenue	20,442	288	49,290	67,713
Average daily NGL sales volumes (100%) (mbbls/d)				
Ethane - indigenous	37.5	4.0	33.0	29.7
Propane plus	25.5	24.8	27.6	27.2
NGL injections	4.5	5.4	4.1	4.0
	67.5	34.2	64.7	60.9
Pricing Metrics				
Crude oil (US\$ per bbl)	76	58	62	100
Natural gas (US\$ per mmbtu)	4.26	6.39	3.92	8.85
Crude to natural gas ratio	17.8	9.1	15.7	11.3
Ethane margin (US\$ per US gallon)	0.38	(0.01)	0.22	0.31
Propane plus (US\$ per US gallon)	0.82	0.25	0.58	0.69
Mont Belvieu to Edmonton propane differential (US\$ per US gallon)	(0.04)	0.01	0.07	0.10

Pursuant to a long-term NGL Sales Agreement with BP Products North America Inc., Aux Sable sells all production from its Channahon NGL Facilities to BP. In return, BP pays Aux Sable a fixed annual fee and a percentage share of net margins in excess of the fixed fee that varies upon specified thresholds being reached. In addition, BP compensates Aux Sable for all associated operating, maintenance, and capitalized maintenance costs related to its NGL Facilities, subject to certain limits in the case of capitalized costs. In addition to supplying BP, Aux Sable is pursuing growth initiatives through the development or acquisition of pipeline and storage facilities, terminal and rail operations, as well as NGL supply and marketing opportunities.

In December 2008, we increased our ownership interest in Aux Sable Canada to 50 percent.

NGL Market Overview

The NGL business environment was favourable during 2009 as NGL fractionation margins improved steadily throughout the year. As a result of the economic downturn in the fourth quarter of 2008, ethane margins continued to be negative for the first six weeks of 2009. Aux Sable continued to reinject ethane during this period. Ethane margins turned positive in mid-February 2009, bringing production back on-line for the rest of the year. With declining natural gas values relative to crude oil, NGL margins continued to increase through the second half of the year.

Although it did not reach the record levels of 2008, crude oil prices strengthened throughout 2009, as demand for crude improved and the U.S. dollar weakened. On the other hand, natural gas prices did not recover to the same extent as crude. Increased drilling in the developing shale basins of the United States drove record-high natural gas inventory levels in 2009, which kept downward pressure on natural gas prices. Petrochemical demand for ethane and propane improved in 2009, with propane further enhanced by near-record crop drying demand in the third and fourth quarters of 2009. Heavier NGLs responded positively to the increase in crude prices.

Operational Highlights

In the three and 12 months ended December 31, 2009, Aux Sable processed 95.8 percent and 96.4 percent, respectively, (2008 – 90.9 percent and 96.5 percent) of the natural gas delivered by Alliance. In the fourth quarter of 2009, some minor downtime resulted from planned maintenance work combined with a project to increase ethane recoveries on one of its extraction trains. Aux Sable is planning to complete required inspection work in the second half of 2010 or sometime in 2011.

Aux Sable produced 67.5 mbbbls/d of NGLs during the fourth quarter of 2009, up from 34.2 mbbbls/d for the same period in 2008. Average ethane volumes increased from 4.0 mbbbls/day in the fourth quarter last year to 37.5 mbbbls in the same period of 2009. As a result of weak market conditions in the fourth quarter of 2008, Aux Sable reinjected ethane for most of that period.

Aux Sable produced 64.7 mbbbls/d of NGLs, including 33.0 mbbbls/d of ethane, in 2009. This compares to 60.9 mbbbls/d of NGLs, including 29.7 mbbbls/d of ethane, in 2008.

Financial Highlights

For the three months ended December 31, 2009, Aux Sable generated NGL revenues of \$57.5 million (2008 – \$28.3 million), including \$30.1 million of lease revenues (2008 - \$15.8 million). Aux Sable recognized \$20.4 million of margin-based lease revenues during the fourth quarter of 2009, representing all amounts generated during the quarter as well as \$0.9 million generated but not recognized previously in the year. Due to market conditions described above, Aux Sable did not generate any meaningful margin-based lease revenue during the fourth quarter of 2008. The increase in fourth quarter 2009 revenues was partially offset by the effect of the stronger Canadian dollar.

For the year ended December 31, 2009, Aux Sable generated NGL revenues of \$149.7 million (2008 – \$180.4 million), including \$90.6 million of lease revenues (2008 - \$120.6 million), reflecting lower margin-based lease revenues, partially offset by the effect of the weaker Canadian dollar. 2009 lease revenues include \$49.3 million of margin-based lease revenues compared to \$67.7 million in 2008.

Operations and maintenance, natural gas, NGL and transportation costs for the three months ended December 31, 2009 were \$24.7 million (2008 - \$22.9 million), primarily reflecting higher NGL input costs due to increased prices and volumes consumed. For the year ended December 31, 2009, these costs were \$77.4 million (2008 – \$96.9 million), reflecting lower power and fuel prices, partially offset by higher volumes consumed and the effect of the weaker Canadian dollar.

Net income (loss) before tax for the three and 12 months ended December 31, 2009 was \$27.4 million and \$50.8 million, respectively, compared to \$(1.6) million and \$63.9 million for the same periods last year. 2009 results include a \$9.5 million pre-tax gain recorded by Aux Sable Canada in the fourth quarter in respect of its off-gas facility settlement, more fully described below.

Off-gas Facility

In November 2008, Aux Sable Canada curtailed construction of its Heartland Off-gas facility as a result of its counterparty suspending the construction of its upgrader. As a result, the counterparty reimbursed Aux Sable Canada for all capital costs and commitments in respect of this facility. At December 31, 2008, these funds

were reflected as a long-term construction security deposit. In 2009, Aux Sable Canada and its counterparty entered into a settlement agreement. As a result, Aux Sable Canada recognized a non-recurring \$9.5 million pre-tax gain was recorded in interest and other income. Further, Aux Sable Canada retained full ownership of the off-gas facility. Aux Sable Canada is pursuing commercial arrangements for an alternate use of the facility.

Septimus Gas Plant and Pipeline

On December 18, 2009, Aux Sable purchased from Crew Energy Inc. the 25 mmcf/d Septimus Gas Plant in the liquids-rich Montney region of northeast British Columbia. The purchase price was \$9.6 million (100 percent - \$19.1 million). Crew operates the facility and pays Aux Sable capital throughput fees on a take-or-pay basis. Aux Sable and Crew are exploring other related initiatives, including expanding the capacity of the Septimus plant.

On January 15, 2010, Aux Sable received approval from the BC Oil and Gas Commission to construct a 20-inch, 20-kilometre rich-gas pipeline to interconnect with the Alliance pipeline. The pipeline is currently under construction. We expect the pipeline to be placed into service in the second quarter of 2010 at a capital cost of approximately \$10 million (100 percent - \$20 million). Aux Sable will collect a take-or-pay fee from Crew when the pipeline is operational.

Other Growth Projects

In addition to the Septimus projects, Aux Sable is focused on a number of initiatives to ensure the optimal level of rich gas is delivered into the Alliance pipeline for processing at the Channahon Facility. These developments have largely been focused on northwest Alberta and northeast B.C., but with new oil and gas developments in the Bakken region in North Dakota and Saskatchewan, Aux Sable is developing NGL-rich gas supply opportunities in these areas. A significant development in this area is the Prairie Rose Pipeline that Pecan Pipeline constructed and placed into operations in February 2010. Pecan is delivering high heat content gas on to Alliance's U.S. system, which is processed at Aux Sable's Channahon Facility under a long-term processing agreement.

Power Business

	Three months ended		Year ended	
	December 31		December 31	
(\$ Thousands, except where noted)	2009	2008	2009	2008
Net income (loss) before tax				
Fort Chicago Power	(84,124)	(25,876)	(80,423)	(20,984)
NRGreen	603	105	1,177	416
East Windsor Cogeneration	655	373	342	724
Other	-	(1,260)	(2,442)	2,843
	(82,866)	(26,658)	(81,346)	(17,001)
Electricity Volumes (MWh)				
Fort Chicago Power ⁽¹⁾	82,593	191,602	492,935	505,988
NRGreen	39,116	29,492	135,568	73,697

Fort Chicago Power

Fort Chicago Power is comprised of our wholly-owned power facilities.

The Ripon and San Gabriel cogeneration facilities are located in California. Each is a Qualifying Facility under the regulations of FERC and produce electricity, which is sold under a long-term power purchase agreement, or "PPA". The 49 MW Ripon facility sells capacity and electricity to Pacific Gas & Electric Company pursuant to a long-term PPA that expires in 2018. The 44.5 MW San Gabriel facility sells capacity and electricity to Southern California Edison Company under a long-term PPA that expires in 2016.

Brush is a gas-fired exempt wholesale generator. It previously sold capacity and electricity to Xcel Energy under a tolling PPA that expired in September 2009. Effective October 1, 2009, Brush has a 10-year and 3 month tolling PPA with Tri-State Generation and Transmission Association, Inc.

Construction of the London, Ontario cogeneration facility, a 17 MW electric generation facility, was completed in December 2008. The facility operates under a 20-year electricity contract with the Ontario Power Authority. The

cogeneration facility is integrated into the London district energy system and provides additional steam and chilled water capacity for the overall district energy system.

Our district energy systems in London and Charlottetown, Prince Edward Island consist of central production plants. These facilities convert fuel (such as natural gas, municipal waste, biomass and fuel oil) into steam, hot water and/or chilled water. These products are distributed through underground pipes to customers' buildings to provide heating, air conditioning and some industrial process uses. Customers include government offices, hospitals, educational institutions and apartment buildings, and commercial businesses. Over 70 percent of our district energy systems' revenues are generated under long-term agreements with government-funded entities and investment grade customers.

The majority of Fort Chicago Power's earnings are comprised of fixed capacity payments. As such, its earnings are not significantly influenced by the volume of electricity generated or by variability in commodity prices.

California Short Run Avoided Cost

In August 2009, the California Public Utilities Commission changed the Short Run Avoided Cost energy reimbursement formula applicable to Qualifying Facilities in California, including our Ripon and San Gabriel facilities. The CPUC changed the heat rate in the SRAC formula, a primary component in the calculation of energy payments, to partially reflect California energy market heat rates. As a result, we expect the aggregate cash flows of our California facilities to be lower by US\$3 to US \$4 million annually. Capacity payments, which comprise the majority of EBITDA generated by these facilities, were not affected by the change in the SRAC formula.

Termination of Ripon Steam Agreement

Neenah Paper FR, LLC, the purchaser of the process steam generated by the Ripon facility, suspended operations at its plant indefinitely on May 30, 2009. At that time, Fort Chicago Power and Neenah entered into a settlement, which compensates us for costs we will incur to maintain the Ripon facility's Qualifying Facility status. FERC granted a temporary waiver of the Ripon facility's QF requirements through December 31, 2010 to permit an alternative beneficial use to be implemented. Failure to find an alternative use for the Ripon facility's thermal energy could result in the loss of its QF status. We are currently exploring various alternatives in order to maintain the Ripon facility's QF status, including the installation of a distilled water facility. We do not believe this event will have a material impact on our financial results.

Operational Highlights

Fort Chicago Power produced lower energy volumes in the three and 12 months ended December 31, 2009 compared to the same periods last year.

For the three months ended December 31, 2009, the Ripon and San Gabriel cogeneration facilities generated electricity volumes of 78,089 MWh compared to 148,866 MWh during the same period last year. This decrease reflects economic dispatch decisions driven by the new SRAC formula and down-time related to equipment repairs at the San Gabriel facility in the fourth quarter of 2009. Brush volumes decreased to 3,619 MWh from 42,403 MWh in the fourth quarter of 2008, reflecting the dispatch profile under its new toll agreement. London cogeneration did not produce a significant amount of electricity in the fourth quarter of 2009 due to low electricity prices in the Ontario market.

For the year ended December 31, 2009, the Ripon and San Gabriel cogeneration facilities generated electricity volumes of 379,175 MWh compared to 454,850 MWh in 2008. Energy production in the first half of 2009 increased relative to the same period last year due to plant efficiencies resulting from recently overhauled equipment at Ripon. As well, energy production from the Ripon facility was down in the first half of 2008 due to major maintenance work. However, these volume increases were offset by lower dispatch in the latter part of the year due to the SRAC change. Brush produced 101,116 MWh of electricity compared to 50,291 MWh in 2008, reflecting a full year of our ownership. London cogeneration, which commenced operations in December 2008, generated 12,037 MWh in 2009.

Financial Highlights

For the three months ended December 31, 2009, Fort Chicago Power generated \$0.8 million of losses before interest, taxes, depreciation and amortization, and other non-cash charges compared to \$0.3 million of losses during the same period last year. Increased losses resulting from the change in SRAC, combined with the effect of the stronger Canadian dollar, were partially offset by EBITDA from London cogeneration. Fourth quarter

2009 EBITDA includes a \$0.7 million non-cash loss relating to our U.S. dollar-denominated exchangeable debentures (2008 - \$2.3 million loss).

EBITDA for the year ended December 31, 2009 was \$17.8 million compared to \$14.2 million for 2008, reflecting incremental earnings from the new facilities, lower operating costs at the California facilities, and the effect of the weaker Canadian dollar. These increases were partially offset by the effect of the change in SRAC and lower EBITDA from the PEI district energy system, due to lower fuel pricing in revenues without a corresponding decrease in actual fuel input costs. 2009 EBITDA includes a \$0.5 million non-cash gain relating to our U.S. dollar-denominated exchangeable debentures (2008 - \$2.3 million loss).

2009 net income before tax was severely impacted by an asset impairment loss we recorded in the fourth quarter of 2009. As a result of the change in SRAC, in accordance with our accounting policy, we tested the California power facilities and power customer relationships and agreements for impairment based on our current assumptions regarding operating revenues and costs, updated to reflect the change in the SRAC pricing formula. Based on these calculations, we determined the carrying value of the assets was impaired as it exceeded the sum of the estimated undiscounted future cash flows attributable to the assets. We calculated the amount of the impairment loss as the difference between the carrying value of the assets and their estimated fair value, using a discounted cash flow approach. As a result, we recorded a non-cash pre-tax impairment loss of \$78.1 million, allocating \$35.4 million to the power facilities and \$42.7 million to power customer relationships and agreements.

2008 net income before tax was negatively impacted by a \$19.9 million non-cash asset impairment charge. In the fourth quarter of 2008, we determined the value of goodwill which arose from our August 2007 acquisition of the Countryside assets was impaired. Consequently, the \$19.9 million goodwill balance was removed from our balance sheet as at December 31, 2008.

Net loss before tax was \$84.1 million and \$80.4 million for the three and 12 months ended December 31, 2009, respectively (\$25.9 million net loss before tax for the three months ended December 31, 2008 and \$21.0 net loss before tax for the 12 months ended December 31, 2008).

Glen Park Acquisition

In December 2009, we announced an agreement to acquire the Glen Park facility, a 33 MW run-of-river hydro-power generation facility on the Black River in upstate New York. We expect to fund the approximate US\$80 million purchase price by drawing on our existing bank credit facilities. The transaction is expected to close in the first quarter of 2010, subject to usual closing conditions.

NRGreen

NRGreen owns four five-MW waste heat electrical generation units situated at Alliance compressor stations in Saskatchewan. Each unit generates electricity for sale to the Saskatchewan Power Corporation under a PPA with a primary term of 10 years. The first unit, located at Kerrobert, was placed into service in December 2006. Each of the remaining three units was placed into service at various stages during 2008.

Operational Highlights

2009 saw improved reliability of the four units, each of which experienced outages due to equipment failures in 2008.

Financial Highlights

For the three and 12 months ended December 31, 2009 NRGreen revenues were \$1.5 million and \$5.0 million compared to \$1.3 million and \$2.7 million for the same periods last year. These increases reflect the full year of operations at the Loreburn, Estlin and Alameda units during 2009 and the effect of their improved reliability throughout the year. The revenue impact of the fourth quarter 2008 outages was a reduction of approximately \$0.3 million.

Net income before tax was \$0.6 million and \$1.2 million for the three and 12 months ended December 31, 2009, compared to \$0.1 million and \$0.4 million for the same periods last year. The increases in revenues discussed above were partially offset by higher operations and maintenance costs and depreciation, due to four units being operational for the full duration of 2009 compared to being operational for various periods during 2008, as well as incremental borrowing costs related to amounts drawn on NRGreen's credit facility.

Saskatchewan Power Corporation Request for Proposal – Base Load Generation

In September 2009, NRGreen submitted two binding proposals into SaskPower's Request for Proposals for medium to base load power generation. NRGreen proposed building, owning and operating an 84 MW facility at Kerrobert, Saskatchewan and a 42 MW facility at Loreburn, Saskatchewan. In February 2010, SaskPower announced the results of the RFP. NRGreen was not selected to move forward.

East Windsor Cogeneration

East Windsor Cogeneration owns an 86 MW gas-fired cogeneration facility in Windsor, Ontario. The facility, constructed over the course of two years at a capital cost of approximately \$107 million (100 percent - \$213 million), commenced operations on November 6, 2009. East Windsor Cogeneration has a 20-year combined heat and power agreement with the Ontario Power Authority, under which it generates capacity payments.

East Windsor Cogeneration's net income before tax for the three and 12 months ended December 31, 2009 was \$0.7 million and \$0.3 million, respectively, compared to \$0.4 million and \$0.7 million for the same periods last year.

We do not expect East Windsor Cogeneration to make cash distributions until late 2010 as, pursuant to its financing agreement, its available cash flow must first be used to build up a Debt Service Reserve Account.

Other

During the first quarter of 2009, we transferred a \$2.4 million non-cash pre-tax expense from other comprehensive income to net income, representing the fair value decrease of our investment in Pristine from its initial public offering in March 2008, as we considered the decline in fair value to be other than temporary. The fair value was determined based on the closing trading price for Pristine common shares on March 31, 2009.

In 2008 we recognized a \$1.2 million impairment charge with respect to our investment in an independent power company, where we considered the decline in fair value to be other than temporary. The loss was offset by a dilution gain of \$4.2 million recognized in the first quarter of 2008, which resulted from our non-participation in Pristine's March 2008 initial public offering of common shares.

Fort Chicago - Corporate

	Three months ended December 31		Year ended December 31	
(\$ Thousands)	2009	2008	2009	2008
Net expenses (income)				
Net expenses before taxes	16,215	18,822	46,093	72,167
Current tax expense	5,923	4,597	16,330	24,378
Future tax expense (recovery)	(27,774)	(7,633)	(24,616)	2,778
	(5,636)	15,786	37,807	99,323

During the three months ended December 31, 2009 we incurred \$16.2 million of net corporate expenses before taxes compared to \$18.8 million during the same period last year. The variance resulted primarily from a \$3.7 million decrease in unrealized foreign exchange losses and a \$1.1 million decrease in project development costs. These decreases were partially offset by a \$1.3 million increase in interest and other finance costs resulting from our issuance of \$200 million of senior notes in July 2009, and a \$0.7 million increase in general and administrative expenses. Net tax recoveries increased by \$18.8 million, primarily reflecting the tax effect of the 2009 impairment loss recorded in relation to the California cogeneration facilities, partially offset by higher Aux Sable earnings.

For the year ended December 31, 2009 we incurred net corporate expenses before taxes of \$46.1 million compared to \$72.2 million for last year. The variance resulted primarily from a \$25.9 million decrease in foreign exchange losses. Reduced amounts of cash distributed by our U.S. businesses resulted in lower amounts of foreign exchange losses, previously deferred and recorded in other comprehensive income, recognized in income. Interest and other finance costs decreased by \$1.9 million, resulting from lower average interest rates and balances outstanding. These decreases were partially offset by a \$2.3 million increase in general and administrative costs, reflecting higher personnel costs and increased business development activity. We recorded a net tax recovery of \$8.3 million for 2009, primarily reflecting the tax recovery related to the asset impairment loss, compared to a net expense of \$27.2 million in 2008, due to higher Aux Sable earnings.

Development Projects

In December 2009, FERC issued an order authorizing Jordan Cove to site, construct and operate the Jordan Cove Energy liquefied natural gas import and regasification terminal at Coos Bay, Oregon. FERC also issued a certificate approving an application to construct and operate the related Pacific Connector Gas Pipeline that will connect Jordan Cove to various natural gas markets and pipelines through to Malin, Oregon. We expect these certifications to strengthen our ability to secure necessary commercial commitments to move the projects forward. Under our accounting policy, we continue to expense development costs associated with these projects.

SELECTED QUARTERLY FINANCIAL INFORMATION

(\$ Thousands, except where noted)	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	185,873	163,166	149,290	150,804	168,629	180,900	178,684	173,217
Net income (loss)	(24,454)	30,766	19,959	11,304	(17,949)	27,286	20,117	32,045
Net income (loss) per Unit (\$)	(0.18)	0.23	0.15	0.08	(0.13)	0.20	0.15	0.24
Distributable cash	34,001	45,435	38,619	31,010	22,484	53,285	41,565	44,145
Distributable cash per Unit (\$)	0.25	0.33	0.29	0.23	0.17	0.40	0.31	0.32
Cash from operating activities	43,867	89,449	33,227	44,380	39,279	88,222	39,512	95,599

Significant items that affected quarterly financial results include the following:

- Fourth quarter 2009 net income reflects the \$50.8 million (after-tax) asset impairment loss recorded in relation to our California cogeneration facilities; distributable cash and cash from operating activities reflect strong cash flow generation from Aux Sable.
- Third quarter 2009 reflected continued strengthening of NGL market conditions resulting in \$22.1 million of NGL margin-based lease revenues recognized in net income and distributable cash.
- Second quarter 2009 reflected a strengthening of NGL market conditions resulting in \$6.8 million of NGL margin-based lease revenues recognized in net income and distributable cash.
- First quarter 2009 reflected no NGL margin-based lease revenues recognized in net income or distributed to us.
- Fourth quarter 2008 reflected a \$21.1 million asset impairment loss related to power assets, as well as the significant weakening of NGL market conditions, resulting in pre-tax losses and a small distributable cash contribution from our NGL business segment. Cash from operating activities reflected Alliance's scheduled semi-annual interest payments.
- Third quarter 2008 reflected strong NGL margins, resulting in increased amounts of margin-based lease revenues generated and recognized by Aux Sable during the period, and strong earnings and cash flows from Fort Chicago Power.
- Second quarter 2008 reflected the recognition of all margin-based lease revenues generated by Aux Sable during the period, as well as amounts generated but not recognized in the first quarter of 2009, partially offset by higher corporate costs, including foreign exchange losses and taxes. Distributable cash was also impacted by increased cash taxes as a result of Aux Sable's earnings becoming fully taxable. As is the case each second and fourth quarter, cash from operating activities reflected Alliance's scheduled semi-annual interest payments.
- First quarter 2008 reflected incremental earnings and cash flows resulting from the Calpine settlement and the recognition of a portion of the record first quarter margin-based lease revenues generated by Aux Sable during the period. The increase to net income also reflected the Pristine dilution gain, partially offset by higher foreign exchange losses due to increased distributions from our U.S. investments. Cash from operating activities was also impacted by changes in non-cash working capital.

LIQUIDITY AND CAPITAL RESOURCES

(\$ Thousands, except where noted)	Year ended December 31			
	2009		2008	
Cash flows				
Operating activities	210,743		262,612	
Financing activities	(161,239)		(135,727)	
Investing activities	(39,818)		(127,532)	
Cash and short-term investments	57,945		53,308	
Capitalization				
Senior debt ^(1,2)	1,704,951	69%	1,867,993	68%
Subordinated convertible debentures ⁽¹⁾	24,054	1%	23,909	1%
Other long-term liabilities	44,211	2%	66,001	2%
Partners' equity	698,726	28%	800,587	29%
	2,471,942	100%	2,758,490	100%

(1) Includes current portion.

(2) Includes Exchangeable Debentures.

Overall, there has not been any significant change in our financial condition or that of our businesses compared with our position as at December 31, 2008. We and each of our operating businesses maintain prudent capital structures and are well positioned to withstand the impact of the current economic environment. We expect cash from operations and from available committed credit facilities will be sufficient to fund distributions and planned capital expenditures. Furthermore, substantially all of our consolidated debt is long-term with amortization periods that provide for the orderly repayment of all principal over the estimated useful economic life of our assets. This debt has generally been issued by each of the operating businesses, on a non-recourse basis, bearing fixed rates of interest, insulating us and our operating businesses from a potential higher long-term interest rate environment and reducing the default risk associated with any one operating entity. On December 31, 2009, all credit facilities were in good standing.

Cash and short-term investments at December 31, 2009 totaled \$57.9 million (2008 - \$53.3 million), of which \$23.3 million (2008 - \$21.6 million) represents funds held in trust accounts pursuant to applicable security and financing agreements. The majority of these trust funds are used by Alliance for current operating and working capital purposes, including scheduled principal and interest payments each June and December.

At December 31, 2009 we had a working capital deficiency of \$152.3 million (December 31, 2008 - \$81.7 million). Our working capital will generally be in a negative position, as the majority of our long-term debt is amortizing debt, resulting in a significant amount of debt due within one year. A large portion of our debt relates to Alliance, for which scheduled repayments of long-term debt have been designed to match the depreciation of its rate base. Depreciation is recovered through Alliance's firm transportation toll and is utilized to fund the debt repayments. Further, our series B convertible debentures are classified as current as they mature on December 31, 2010. At that time, debenture holders have the option of exchanging these debentures for Units. Consequently, we do not believe this balance sheet condition affects our liquidity.

Cash from Operating Activities

(\$ Thousands)	Three months ended December 31		Year ended December 31	
	2009	2008	2009	2008
Alliance	26,598	31,843	186,608	195,332
AEGS	2,405	2,751	19,097	15,650
Aux Sable	25,402	9,808	48,168	74,161
Fort Chicago Power	5,390	4,192	24,976	11,533
Other Power	(114)	738	1,613	207
Corporate	(15,994)	(10,053)	(69,719)	(34,271)
	43,687	39,279	210,743	262,612

For the three and 12 months ended December 31, 2009, cash generated from operating activities was \$43.7 million and \$210.7 million, respectively, compared to \$39.3 million and \$262.6 million for the same periods last year.

Alliance's operating cash flows decreased for the three and 12 months ended December 31, 2009 compared to the same periods last year. The fourth quarter decrease reflects the effect of the stronger Canadian dollar partially offset by increased income tax recoveries. The decrease in annual operating cash flows reflects the absence of the first quarter 2008 receipt of the \$10.3 million Calpine settlement, partially offset by the effect of the weaker Canadian dollar and increased income tax recoveries.

AEGS' fourth quarter cash from operating activities approximated amounts generated during the same period last year. Operating cash flows increased for the year compared to 2008, reflecting the impact of changes in non-cash working capital.

Aux Sable's cash from operating activities for the three months ended December 31, 2009 increased significantly compared to the same period last year as improved NGL market conditions resulted in higher margin-based lease revenues. For the year ended December 31, 2009, cash from operating activities decreased from amounts generated last year reflecting lower margin-based lease revenues due to weaker overall NGL market conditions.

Fort Chicago Power generated higher operating cash flows for the three and 12 months ended December 31, 2009 compared to the same periods last year. The increases reflect cash flows from the London cogeneration facility and Brush, as well as changes in operating non-cash working capital items, partially offset by lower cash flows generated by the U.S. cogeneration facilities. In addition, the year-to-date increase reflects the receipt of funds previously held by Brush's customer in the form of a security deposit.

Our other Power businesses did not generate a significant amount of operating cash flows. The year-to-date 2009 amount reflects increased operating activity at NRGreen, as all four waste heat facilities were operational for the duration of the year.

For the three months ended December 31, 2009, cash flows used for corporate operating activities increased to reflect our payment of income tax installments. Increased cash outflows for 2009 reflect the timing of income tax payments which relate primarily to Aux Sable earnings. Aux Sable's earnings became currently taxable in 2008. This, in conjunction with the record earnings generated by Aux Sable in 2008, resulted in a significant tax payment in the first quarter of 2009.

Financing Activities

For the year ended December 31, 2009, our financing activities included:

- issuance of \$263.0 million of long-term debt, including our issuance of \$200.0 million of senior notes and Alliance's issuance of \$60.0 million of senior notes, in each case net issue costs;
- repayment of \$73.2 million of long-term debt relating to scheduled principal repayments on senior debt (\$66.4 million – Alliance; \$2.6 million – AEGS; \$3.5 million – Fort Chicago; \$0.6 million – East Windsor Cogeneration);
- net decrease of \$249.4 million in credit facilities (\$193.7 million – Fort Chicago; \$56.5 million – Alliance; \$0.5 NRGreen; offset by \$1.3 million increase – Aux Sable);
- \$96.9 million of cash distributions paid by us; and
- \$4.6 million buyout of capital leases by Aux Sable.

Financing activities for 2008 included:

- repayment of \$68.6 million of long-term debt;
- net increase of \$50.0 million in credit facilities;
- \$132.9 million of cash distributions paid by us; and
- \$15.8 million received by Aux Sable from BA Energy in reimbursement of capital costs incurred to construct the Heartland Off-gas facility.

Investing Activities

Investing activities for the year ended December 31, 2009 reflect:

- Capital expenditures of \$50.9 million, primarily related to:
 - Aux Sable's Septimus Gas Plant and pipeline (\$12.1 million) and other additions (\$4.3 million),
 - Fort Chicago Power's steam and chilled water expansion projects at its London district energy system (\$9.0 million) and maintenance capital expenditures at the San Gabriel facility, including the purchase of a spare turbine, and
 - the East Windsor Cogeneration facility (\$18.1 million); and

- \$19.1 million drawdown of restricted cash, mostly related to the funding of construction costs related to the East Windsor Cogeneration facility.

Investing activities for the year ended December 31, 2008 reflect:

- \$34.0 million acquisition of Brush II;
- capital expenditures of \$139.0 million;
- \$56.6 million drawdown of restricted cash to fund construction costs for the East Windsor Cogeneration facility; and
- our \$11.3 million investment in a private solar power company.

Capitalization

The following provides an overview of significant changes to our consolidated capitalization which have occurred in the years ending December 31, 2009 and 2008.

Partnership

On March 19, 2009 we announced the reinstatement of an amended and restated Premium Distribution and Distribution Reinvestment Plan, wherein Unitholders enrolled in the Plan could direct that a portion of their distributions be reinvested at a 5 percent discount in additional Class A Units held for their account under the Plan, or have them delivered to a designated plan broker in exchange for a premium cash payment equal to 102 percent of the reinvested amount under the Premium Distribution component of the Plan. For the year ended December 31, 2009, we issued 5.4 million Units or \$44.0 million under the DRIP to satisfy a portion of our distributions.

On May 2, 2008 we filed with Canadian securities regulators a short form base shelf prospectus which allows us to offer for sale, from time to time, over a 25-month period, up to \$1.5 billion of debt and equity, or a combination thereof. We expect to use proceeds to reduce outstanding indebtedness, to finance future growth opportunities (including acquisitions and investments) and/or for general partnership purposes. We may offer these securities for sale separately or together. We will set forth the specific terms of any offering under this prospectus in one or more prospectus supplements.

In July 2008, we extended the term of our unsecured committed revolving credit agreement (“2004 Revolving Credit Facility”) with three Canadian chartered banks to April 1, 2011. The maturity date may, from time to time, be extended for further one-year periods, subject to lender consent. The maximum principal amount available under this facility is \$300 million, which we can use for general purposes, including acquisitions and distributions. On December 31, 2009, we had drawings of \$78.6 million (2008 – \$278.0 million), including \$11.8 million (2008 - \$1.6 million) in letters of credit, under this facility.

On December 24, 2008, we entered into an additional 364-day revolving credit and letter of credit facility (“2008 Revolving Credit Facility”) with a United States-based financial institution. The maximum principal amount available under this facility was \$25 million that can be used for general corporate purposes, including working capital needs and the issuance of up to \$5 million of stand-by letters of credit. On July 15, 2009 we amended this credit agreement by adding a \$25 million term facility (“2009 Term Facility”, and collectively with the 2008 Revolving Credit Facility referred to as the “2008 Credit Facility”) and extending the term of the agreement such that the 2008 Credit Facility now matures on July 14, 2010. We have fully drawn on the 2009 Term Facility and have used the proceeds to repay a portion of the outstanding indebtedness under our 2004 and 2008 Revolving Credit Facilities. The 2008 Credit Facility include covenants customary to bank credit facilities of this nature including meeting specified financial covenants on an ongoing basis.

On July 28, 2009, we issued \$200 million of senior unsecured notes series 1 (“Senior Notes”) pursuant to a public offering under our short form base shelf prospectus and a prospectus supplement dated July 23, 2009. The Senior Notes bear interest at the rate of 5.60 percent per annum, payable semi-annually in arrears on January 28 and July 28 of each year commencing on January 28, 2010 and mature on July 28, 2014. We used the net proceeds from this note offering to repay a portion of the outstanding indebtedness under our 2004 Revolving Credit Facility. The Senior Notes include covenants customary to debt instruments of this nature including meeting specified financial covenants on an ongoing basis.

We previously had issued two series of convertible debentures, the Series A and Series B debentures. The 7.5 percent Series A convertible debentures, which were convertible at the holder’s option into Units at a conversion price of \$9.00 per Unit, matured on June 30, 2008. During the period of January 1, 2008 to June 30, 2008, \$22.0 million of Series A convertible debentures, before issue costs, were converted into Units. The remaining

\$1.0 million of Series A convertible debentures not tendered for conversion by June 30, 2008 were extinguished with a cash payment.

The 6.75 percent Series B convertible debentures are due on December 31, 2010 and are convertible at the holder's option into Units at a conversion price of \$10.70 per Unit. During the year ended December 31, 2009, no amounts were converted into Units (2008 – \$20 thousand). On December 31, 2009, these convertible debentures are classified with current liabilities and have a balance of \$\$24.1 million.

Alliance

Alliance's credit facilities comprise a Canadian and a U.S. extendible five-year committed revolving credit facility. These facilities provide Alliance with up to \$100 million (100 percent - \$200 million) and US \$62.5 million (100 percent – US \$125 million), respectively. Each facility has an expansion provision that would facilitate the timely increase in the Canadian and U.S. credit facilities to \$150 million (100 percent - \$300 million) and US \$100 million (100 percent – US \$200 million), respectively. In June 2008, Alliance extended the terms of these facilities by one year such that they now mature on June 28, 2012. On December 31, 2009, \$40 million (2008 - \$40 million) of letters of credit and \$1.0 million (2008 - \$57.5 million) of borrowings were outstanding under the Canadian facility. Under the U.S. facility US \$30 million (2008 – US \$30 million) of letters of credit and US \$1.0 million (2008 – US \$1.0 million) of borrowings were outstanding on December 31, 2009. Alliance uses the letters of credit to satisfy debt service reserve requirements under its financing agreements.

On December 16, 2009, Alliance issued \$60 million (100 percent - \$120 million) of senior unsecured notes ("Alliance 2009 Notes") pursuant to a public offering under its short form base shelf prospectus and prospectus supplement, each dated December 9, 2009. The Alliance 2009 Notes bear interest at the rate of 4.928 percent per annum, payable semi-annually in arrears on June 16 and December 16 of each year commencing on June 16, 2010, and mature on December 16, 2019. The net proceeds from this note offering were used to repay a portion of the outstanding indebtedness under Alliance's Canadian revolving credit facility and for general partnership purposes. The Alliance 2009 Notes include covenants customary to debt instruments of this nature including meeting specified financial covenants on an ongoing basis.

Aux Sable

On December 16, 2009, Aux Sable Canada entered into a two-year, extendable secured non-revolving credit agreement with a Canadian chartered bank and an affiliate of Aux Sable Canada. The maximum principal available under this facility is \$5.8 million (100 percent - \$11.6 million). Aux Sable Canada used the proceeds from this facility, in addition to equity contributions from its owners, to fund the purchase of the Septimus Gas Plant. This credit agreement includes covenants customary to bank credit facilities of this nature including meeting specified financial covenants on an ongoing basis.

NRGreen

In March 2008, NRGreen entered into credit facilities comprised of a \$26.3 million (100 percent - \$52.5 million) construction credit facility and a \$2.5 million (100 percent - \$5.0 million) operating facility. Upon the commercial completion of the Loreburn, Estlin, Alameda waste heat facilities in November 2008, the construction facility converted to a two-year revolving credit facility. The operating facility is an extendible revolving facility, which matures on August 31, 2011 subject to one-year extension requests on August 31 of each year. These credit agreements include covenants customary to debt instruments of this nature including meeting specified financial covenants on an ongoing basis.

These facilities are secured by a first ranking floating charge over all real property of NRGreen forming part of the NRGreen credit facilities as well as an assignment of material contracts. On December 31, 2009, \$24.1 million (100 percent - \$48.1 million) was drawn on these facilities.

CREDIT AND STABILITY RATINGS

Maintaining strong and stable ratings is a key aspect of our financing strategy, which provides for long-term ready access to the capital markets on attractive terms and conditions. Our current ratings and those applicable to Alliance are set out below.

	DBRS	S&P	Moody's
Fort Chicago			

Senior debt ratings	BBB (high)	BBB	N/A
Stability ratings	STA-2 (low)	SR-2	N/A
Alliance			
Senior debt ratings (excluding Alliance 2009 Notes)	A (low)	BBB+	A3
Alliance 2009 Notes	BBB (high)	N/A	Baa1

In July 2009, DBRS assigned a rating of BBB (high) to our Senior Notes and reaffirmed our stability rating of STA-2(low). Also in July, S&P reaffirmed its rating of BBB on our senior debt and our stability rating of SR-2. These ratings remained unchanged during 2009. Alliance's senior note credit ratings (excluding the Alliance 2009 Notes) remained unchanged during 2009. Ratings for the Alliance 2009 Notes were issued in December 2009. The credit ratings represent long-term investment grade credit ratings in respect of our senior unsecured debt and Alliance's senior notes.

DISTRIBUTIONS

Policy

We pay distributions on a monthly basis to Unitholders of record as at the last business day of each month on the 23rd day of the month following such record date, or if not a business day, then on the preceding business day.

Our general distribution policy is to establish and maintain a sustainable and stable monthly distribution over time, having regard for forecast distributable cash and our growth capital requirements.

Sustainability of Distributions and Productive Capacity

We intend to continue to make cash distributions although such distributions are not guaranteed and do not represent a legal obligation. The sustainability of distributions is a function of several factors including, among other things the:

- earnings and cash flows we and our businesses generate, including Alliance Pipeline, a rate-regulated business;
- ongoing maintenance of each business' physical and economic productive capacity; and
- ability to comply with debt covenants and refinance debt as it comes due.

For a complete discussion of the significant risks and uncertainties affecting us and each of our businesses, see "Risks" contained elsewhere in this MD&A.

Distributions Paid/Payable Relative to Cash from Operating Activities and Net Income

(\$ Thousands)	Three months ended		Year ended	
	December 31		December 31	
	2009	2008	2009	2008
Cash from operating activities	43,687	39,279	210,743	262,612
Net income (loss)	(24,454)	(17,949)	37,575	61,499
Distributions paid/payable	34,591	33,513	136,079	133,150
Less distributions paid in Units under DRIP	(14,895)	-	(43,961)	-
Net distributions paid/payable	19,696	33,513	92,118	133,150
Excess of cash from operating activities over net distributions paid/payable	23,991	5,766	118,625	129,462
Shortfall of net income (loss) over net distributions paid/payable	(44,150)	(51,462)	(54,543)	(71,651)

The excess of cash from operating activities over net distributions paid/payable generally represents the cash we use for maintenance capital expenditures, scheduled amortization of any long-term debt, and cash we retain to fund growth, including cash held in trust.

Net distributions paid/payable are generally greater than net income as our net income includes certain non-cash expenses such as foreign exchange gains and losses, asset impairment losses, depreciation and future income taxes, which are not reflected in calculating the amount of cash available for distribution.

Determination of Distributable Cash

The amount of distributable cash we earn is comprised of and will vary depending on:

- distributions received/receivable from our operating businesses, which, in each case, are after providing for scheduled amortization of long-term debt and capital expenditures that are not growth-oriented or recoverable;
- operating support payments required by of our businesses;
- cash taxes and financing costs we incur, including scheduled principal repayments on long-term debt;
- our general and administrative costs; and
- cash we hold in reserve.

The calculation of distributable cash for the three and 12 months ended December 31, 2009 and 2008 is set out below.

	Three months ended December 31		Year ended December 31	
(\$ Thousands, except where noted)	2009	2008	2009	2008
Cash inflows				
Alliance distributions, prior to withholdings for capital expenditures and net of debt service	28,960	29,229	119,536	121,439
AEGS distributable cash, after non-recoverable capital expenditures and debt service	3,690	3,922	14,877	15,789
Aux Sable distributions, net of support payments, non-recoverable debt service costs and maintenance capital	18,934	579	45,584	69,504
Fort Chicago Power distributable cash, after maintenance capital expenditures and debt service	(2,596)	856	12,931	8,918
NRGreen distributions, prior to withholding for project development costs	590	-	1,910	1,025
Interest income and other	41	127	4,029	576
	49,619	34,713	198,867	217,251
Cash outflows				
General and administrative	4,231	3,143	16,148	13,362
Interest and other finance	4,762	3,580	14,248	16,170
Taxes	5,817	4,595	15,959	24,313
Principal repayments on senior debt	808	911	3,445	3,257
	15,618	12,229	49,800	57,102
Distributable cash ⁽¹⁾	34,001	22,484	149,067	160,149
Distributable cash per Unit (\$) ⁽²⁾	0.25	0.17	1.10	1.20
Distributions paid/payable ⁽³⁾	34,591	33,513	136,079	133,150
Distributions paid/payable per Unit (\$) ⁽³⁾	0.25	0.25	1.00	1.00

(1) See "Non-GAAP Financial Measures" for reconciliation of distributable cash to cash flows from operating activities.

(2) The number of Units used to calculate distributable cash per Unit is based on the average number of Units outstanding at each record date. For the three months ended December 31, 2009 the average number of Units outstanding for this calculation was 138,420,675

(2008 – 134,110,877) and 140,682,296 (2008 – 136,372,498) on a basic and diluted basis, respectively. For the year ended December 31, 2009 the average number of Units outstanding for this calculation was 136,133,938 (2008 – 133,206,799) and 138,395,559 (2008 – 136,418,546) on a basic and diluted basis, respectively. The number of Units outstanding would increase by 2,261,621 (2008 – 2,261,621) Units if the outstanding Convertible Debentures on December 31, 2009 were converted into Units.

- (3) Includes \$14.9 million (2008 – nil) and \$44.0 million (2008 – nil) of distributions for the three and 12 months ended December 31, 2009, respectively, satisfied through the issuance of Units under our Distribution Reinvestment Plan.

Distributable cash for the three months ended December 31, 2009 was \$34.0 million or \$0.25 per Unit compared to \$22.5 million or \$0.17 per Unit for the same period in 2008. The increase reflects:

- comparable distributions from Alliance and AEGS;
- higher distributions from Aux Sable, which recovered from a severe downward shift in NGL markets in the last quarter of 2008, offset by increased current taxes relating to these earnings;
- lower distributable cash from Fort Chicago Power, reflecting lower energy margins from the California cogeneration facilities and increased maintenance capital costs;
- higher distributions from NRGreen, which did not generate any distributable cash in the fourth quarter of 2008 due to system outages; and
- increased corporate interest costs, due primarily to the senior notes issued in July 2009, and general and administrative costs.

Distributable cash for the year ended December 31, 2009 was \$149.1 million or \$1.10 per Unit compared to \$160.1 million or \$1.20 per Unit for 2008. The decrease reflects:

- lower distributions from Alliance, primarily reflecting funds received from the settlement of its claim against Calpine in the first quarter of 2008, offset by the effect of the weaker Canadian dollar;
- lower distributable cash from AEGS, reflecting lower ethane receipts in 2009;
- lower distributions from Aux Sable, reflecting the record levels of distributable cash generated during the first nine months of 2008 as compared to 2009, and correspondingly lower current taxes;
- lower distributable cash from Fort Chicago Power as reduced energy margins from the California cogeneration facilities and the PEI district energy facility offset the effect of cash flows from the London cogeneration facility and Brush, and lower maintenance costs;
- higher distributions from NRGreen, reflecting increased output from its four facilities; and
- lower corporate costs, as increased general and administrative expenses were more than offset by lower interest costs arising from lower average debt balances and interest rates and a realized foreign exchange gain.

Distributions Paid

The table below summarizes the distributions we declared and paid to Unitholders in 2009 and 2008.

(\$ Thousands, except where noted)

Record date	Payment date	Distribution per Unit (\$)	Distribution paid/payable in cash	Distribution paid in Units under DRIP	Total distribution paid/payable
2009					
January 30, 2009	February 23, 2009	0.0833	11,171	-	11,171
February 27, 2009	March 23, 2009	0.0833	11,171	-	11,171
March 31, 2009	April 23, 2009	0.0833	7,408	3,763	11,171
April 30, 2009	May 22, 2009	0.0833	7,495	3,723	11,218
May 29, 2009	June 23, 2009	0.0833	7,137	4,126	11,263
June 30, 2009	July 23, 2009	0.0833	7,235	4,073	11,308
July 31, 2009	August 21, 2009	0.0833	7,089	4,262	11,351
August 31, 2009	September 23, 2009	0.0833	6,932	4,463	11,395
September 30, 2009	October 23, 2009	0.0833	6,784	4,656	11,440
October 30, 2009	November 23, 2009	0.0833	6,745	4,741	11,486
November 30, 2009	December 23, 2009	0.0833	6,536	4,994	11,530
December 31, 2009	January 22, 2010	0.0833	6,415	5,160	11,575
		1.0000	92,118	43,961	136,079

2008						
January 31, 2008	February 22, 2008	0.0833	10,975	-	10,975	
February 29, 2008	March 20, 2008	0.0833	10,978	-	10,978	
March 31, 2008	April 23, 2008	0.0833	10,988	-	10,988	
April 30, 2008	May 23, 2008	0.0833	10,998	-	10,998	
May 30, 2008	June 23, 2008	0.0833	11,014	-	11,014	
June 30, 2008	July 23, 2008	0.0833	11,171	-	11,171	
July 31, 2008	August 22, 2008	0.0833	11,171	-	11,171	
August 29, 2008	September 23, 2008	0.0833	11,171	-	11,171	
September 30, 2008	October 23, 2008	0.0833	11,171	-	11,171	
October 31, 2008	November 21, 2008	0.0833	11,171	-	11,171	
November 28, 2008	December 23, 2008	0.0833	11,171	-	11,171	
December 31, 2008	January 23, 2009	0.0833	11,171	-	11,171	
		1.0000	133,150	-	133,150	

Restrictions on Distributions

Our ability to make cash distributions to Unitholders is dependent on the applicable terms of certain financing and security agreements applicable to us, certain intermediary subsidiaries and our businesses. On December 31, 2009 no Default or Event of Default under any of these arrangements had occurred or was continuing that would restrict distributions being paid.

Our revolving credit facilities restrict us from making a cash distribution to Unitholders when a Default or an Event of Default has occurred or is continuing.

Our investments in our operating businesses have been made through debt and equity investments in subsidiary partnerships and corporations. In general, there are no legal or practical restrictions on such subsidiary partnerships or corporations from transferring funds received from the operating businesses to us except that the subsidiary corporations must meet liquidity and solvency tests under applicable corporate law. Two of our subsidiaries, which hold direct investments in Alliance, are issuers of the Series A and Series B Senior Notes. The ability of each such issuer to make distributions to its parent is, at the time of each payment, dependent upon there not being any Event of Default, as defined in the related note agreements, or any event or condition the occurrence or existence of which would, with the lapse of time or the giving of notice or both, become an Event of Default.

AEGS' ability to make distributions to its parent is subject to the terms of a note purchase agreement relating to the AEGS Notes issued in May 2005. Under this agreement, AEGS is permitted to make distributions provided certain conditions are met including, among other things:

- no Default or Event of Default has occurred and is continuing and no Default or Event of Default will occur as a result of such distribution; and
- certain debt and debt service coverage ratios are being met.

Fort Chicago Power's ability to make distributions to its parent is subject the terms of the Indenture of the Exchangeable Debentures. Under the Indenture, funds are required to first satisfy interest payable on the Exchangeable Debentures. Further, funds required for redemption at maturity or upon an Event of Default will be deducted and withheld from the amount that would otherwise be available for distribution.

The ability of each of our jointly held businesses to make distributions is subject to their respective financing agreements. Generally, under these agreements, distributions are permitted provided certain conditions are met including, among other things:

- no Event of Default or event, which, with the giving of notice or passage of time or both, could become an Event of Default, has occurred and is continuing;
- certain debt service coverage ratios and, in the case of Alliance, projected debt service coverage ratios are met; and
- except in the case of NRGreen, certain debt service accounts and debt service reserve accounts are fully funded.

In addition to the above listed conditions, East Windsor Cogeneration may not make distributions in the first year following its commercial operating date of November 9, 2009.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Fort Chicago Power and East Windsor Cogeneration have each entered into agreements with natural gas suppliers to purchase, in aggregate, a minimum of approximately 20 million cubic feet per day, or approximately \$48.9 million per year, until 2013. We pledged security for East Windsor Cogeneration's agreement as a guarantee to the supplier.

In 2008, Alliance and Aux Sable each entered into equipment maintenance agreements expiring in 2017. On December 31, 2009, outstanding commitments in respect of these agreements amounted to \$79.4 million.

Payments due for contractual obligations in each of the next five years and thereafter are as follows:

Payments due by period					
(\$ Thousands)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 Years
Long-term senior debt	1,671,451	145,014	250,650	367,382	908,405
Subordinated convertible debentures and exchangeable debentures	49,447	24,199	25,248	-	-
Operating leases	51,008	4,390	10,955	8,749	26,914
Other long-term obligations	138,337	18,426	44,148	25,301	50,462
	1,910,243	192,029	331,001	401,432	985,781

RISKS

In the course of operating our businesses, we are subject to various risks and uncertainties, which can affect our financial condition and operating results. Our objective is to manage these risks and uncertainties in a balanced manner with a view to maximizing total Unitholder returns. It is senior management's and the applicable business functional head's responsibility to effectively manage the risks of each business. This includes developing risk management strategies, policies, processes and systems. The approach taken by each business will not necessarily identify and eliminate all risks. Further, the risk-mitigating strategies adopted and actions taken may not be successful. In some circumstances, we may choose to reduce our financial risk through specific insurance or hedging programs where the cost is considered reasonable in relation to the associated risks and rewards. In other circumstances, the appropriate risk management strategy may be more fundamental or strategic in nature, based on longer-term considerations. Some risks and uncertainties are market-related risks, while others are either common to all of our businesses or unique to our pipeline, NGL or power businesses. Set out below are the more significant business risks and uncertainties affecting our businesses.

Market Pricing Risks

Commodity Price

Our earnings, cash flows and capital project costs are subject to movements in certain commodity prices. Our most significant commodity price exposures are in our NGL business where NGL margins are driven primarily by the relationship between the price of natural gas and the prices of ethane, propane, butane and condensate. Natural gas is the largest cost component of producing NGL. The prices of ethane, propane, butane and condensate are impacted by a variety of factors, including supply and demand for these products, and the price of crude oil. We are also exposed to movements in energy costs in some of our non-rate-regulated power businesses where the cost of fuel is not fully recoverable. In 2005, we made a strategic decision to enter into a long-term NGL Sales Agreement with BP Products North America Inc. which eliminated the downside risk of low NGL prices while retaining significant upside when NGL margins are strong. To further reduce our exposure to commodity price movements, we may occasionally use derivative instruments, including swaps, futures, and options, to hedge such exposures. These activities are subject to senior management or risk committee oversight as well as specific risk management policies and controls. To the extent these hedges are deemed to be effective, any such gains or losses are recorded in other comprehensive income.

Capital Funding and Liquidity

To fund our existing businesses and future growth, we rely on cash flows generated by our businesses and on the availability of competitive and reasonably-priced debt and equity from capital markets. Conditions within these markets can change dramatically, affecting both the availability and cost of this capital. Higher capital costs directly affect our earnings and cash flows and, in turn, may affect total Unitholder returns. To reduce these risks, we prepare forecasts to confirm our capital requirements and adhere to a financing strategy that supports being able to access capital on a timely and cost-effective basis. This strategy includes:

- maintaining a prudent capital structure supported by investment grade credit ratings;
- ready access to public capital markets by maintaining a current shelf prospectus with securities regulators; and
- sufficient liquidity through cash balances, excess cash flow, and committed revolving credit facilities to meet our obligations.

Through this strategy, we strive to avoid having to raise additional capital where the costs or terms of which would be regarded as being unacceptable. We have summarized the components of our capital in the "Liquidity and Capital Resources" section of this MD&A.

Foreign Currency

Significant portions of our assets, net earnings and cash flows are denominated in U.S. dollars. As a result, their accounting and economic values vary with changes in the U.S./Canadian exchange rate. To reduce this risk, we funded a portion of our U.S. assets with U.S. dollar-denominated debt to serve as a natural hedge against movements in the U.S./Canadian dollar exchange rate. To date, we have not entered into any foreign currency hedges to reduce our currency risk further in respect of our net U.S. dollar investment and net cash flows. We have, from time to time, entered into short-term foreign currency transactions to hedge the Canadian cost of certain capital investments.

We generally use net cash flows from our foreign operations, supplemented where necessary with U.S. dollar borrowings, to fund our U.S. dollar capital expenditures and debt service requirements. Where applicable, we have designated U.S. dollar borrowings as a hedge against our U.S. dollar net investment in self-sustaining foreign operations. To the extent these hedges are deemed to be effective, we record any such gains or losses in other comprehensive income.

On December 31, 2009, approximately 52 percent of our net assets were denominated in U.S. dollars. For the year ended December 31, 2009 foreign exchange gains (losses) of \$(72.1) million and \$7.2 million were recognized in other comprehensive income and net earnings, respectively. At December 31, 2009, if the Canadian currency had strengthened or weakened by one cent against the U.S. dollar, with all other variables constant, total assets, net income, and distributable cash would have been \$10.4 million, \$0.1 million, and \$1.0 million, respectively, lower or higher.

Interest Rate

We have financed portions of our assets with debt, including floating-rate debt. To the extent interest is not recoverable, we are exposed to fluctuations in interest rates on floating-rate debt and to potentially higher fixed rates at the time existing debt obligations need to be refinanced. To reduce this exposure, we maintain investment grade credit ratings and generally fund long-term assets utilizing long-term, fixed rate debt. Our floating-rate debt is comprised of drawdowns under various committed bank credit facilities, which, if more permanent in nature, we will refinance over time. To reduce our exposure to interest rate fluctuations further, we may occasionally use derivative instruments, including interest rate swaps, collars and forward rate agreements, to hedge against the effect of future interest rate movements. To the extent these hedges are deemed to be effective, we record any such gains or losses in other comprehensive income. On December 31, 2009, seven percent of our consolidated long-term debt was floating-rate debt. At December 31, 2009, if interest rates applied to floating-rate debt were 100 basis points higher or lower with all other variables constant, net income before tax and distributable cash each would have been \$1.2 million lower or higher.

Financial Instruments

The following table summarizes our financial instrument carrying and fair values on December 31, 2009:

	Held-for-trading	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total	Fair value ⁽¹⁾
Assets							
Cash and short-term investments	57,945					57,945	57,945
Restricted cash	3,084					3,084	3,084

Transportation security deposits and revenue adjustments		8,538			8,538	8,538
Receivables		59,155			59,155	59,155
Long-term receivables		4,201		347,428	351,629	4,201
Other assets	4,500		17,795	1,432	23,727	21,644
Liabilities						
Payables				88,822	2,442	88,822
Transportation security deposits				4,008		4,008
Distribution payable				6,406		6,406
Exchangeable debentures	25,248					25,248
Subordinated convertible debentures				24,199	(145)	25,409
Senior debt				1,671,543	8,160	1,768,327
Other long term liabilities				13,663	30,548	44,211

The following table summarizes our financial instrument carrying and fair values on December 31, 2008:

	Held-for-trading	Loans and receivables	Available-for-sale	Other financial liabilities	Non-financial instruments	Total	Fair value ⁽¹⁾
Assets							
Cash and short-term investments	53,308					53,308	53,308
Restricted cash	23,036					23,036	23,036
Transportation security deposits and revenue adjustments		7,989				7,989	7,989
Receivables		61,935				61,935	61,935
Prepaid expenses and other	250	4,009			8,090	12,349	4,259
Long-term receivables		11,314			262,078	273,392	11,314
Other assets	4,975		16,684		1,130	22,789	21,659
Liabilities							
Payables				110,181	2,442	112,623	110,181
Transportation security deposits				5,581		5,581	5,581
Distribution payable				11,162		11,162	11,162
Exchangeable debentures	25,717					25,717	25,717
Senior debt				1,834,629	7,647	1,842,276	1,881,026
Subordinated convertible debentures				24,199	(290)	23,909	24,922
Other long term liabilities				29,859	36,142	66,001	29,859

(1) Fair value excludes non-financial instruments.

For the years ended December 31, 2009 and 2008, we recognized the following amounts in income:

	2009	2008
Interest revenue related to loans and receivables	-	-
Fair value loss on assets held-for-trading recognized in net income before tax	(274)	(1,101)
Fair value gain (loss) on assets available-for-sale recorded in other comprehensive income, net of tax	2,347	(1,427)

Fair value loss on assets available-for-sale reclassified from cumulative other comprehensive income to net income	(1,427)	-
Fair value gain (loss) on liabilities held-for-trading recognized in net income before tax	469	(2,347)
Total interest expense, recorded with respect to other financial liabilities, calculated using the effective rate method	101,822	107,077

Fair Values

Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

The fair values of financial instruments included in cash and short-term investments, restricted cash, transportation security deposits and revenue adjustments, receivables, long-term receivables, payables, transportation security deposits, distribution payable, and other long-term liabilities approximate their carrying amounts due to the nature of the item and/or the short time to maturity.

The fair values of other assets which are investments in quoted equity instruments, Exchangeable Debentures and subordinated convertible debentures are measured at quoted market prices.

The fair value of senior debt is calculated by discounting future cash flows using discount rates estimated based on government bond rates plus expected spreads for similarly rated instruments with comparable risk profiles.

CICA Handbook Section 3862 "*Financial Instrument – Disclosures*" establishes a fair value hierarchy that distinguishes between fair values developed based on market data obtained from sources independent of the reporting entity, and fair values developed using the reporting entity's own assumptions based on the best information available in the circumstances. The levels of the fair value hierarchy are:

Level 1: Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2: Inputs are other than the quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3: Inputs are not based on observable market data.

Financial Instruments measured at fair value on December 31, 2009 were:

	Level 1	Level 2	Level 3	Total
Financial assets held-for-trading measured at fair value through net income				
Cash and short-term investments	57,945			57,945
Restricted cash	3,084			3,084
Other assets		4,500		4,500
Financial assets available-for-sale measured at fair value through other comprehensive income				
Other assets	9,161			9,161
Financial liabilities held-for-trading measured at fair value through net income				
Exchangeable debentures	25,248			25,248

Maturity Analysis Financial Liabilities

The table below analyses our financial liabilities into relevant maturity groupings based on the remaining period at December 31, 2009 to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within one year equal their carrying balances as the impact of discounting is not significant.

	<1 year	1 - 3 years	4 - 5 years	Over 5 years
Payables	88,822			
Transportation security deposits	4,008			
Distribution payable	6,406			
Subordinated convertible debentures and exchangeable debentures	24,199	25,248		
Long-term debt	145,014	250,650	367,382	908,407

We calculated the fair values of senior debt by discounting future cash flows using estimated discount rates based on Government of Canada bond rates plus expected spreads for similarly rated instruments with comparable risk profiles.

Common Business Risks

Investment

Our business strategy includes optimizing the value of our existing assets and investing in new and existing long-life energy infrastructure assets. Our ability to achieve accretive growth is influenced by a variety of risks, including our ability to:

- secure necessary regulatory and environmental approvals and permits;
- integrate acquisitions in an optimal manner and achieve expected synergies;
- access capital on a cost competitive basis;
- complete greenfield projects on time and within budget; and
- achieve expected operating and financial performance.

To reduce these risks we utilize our key personnel and outside experts, where necessary, to perform a detailed assessment of the risks and rewards associated with all significant investments, including detailed financial modeling and an assessment of its impact on our financial results, risk profile and capital structure. Each major investment is reviewed by senior management and the applicable board of directors to ensure it meets our key investment criteria. These activities require substantial management resources, which, from time to time, may strain our ability to manage existing operations and possibly other strategic opportunities. Periodic assessments of previous investments are undertaken to enhance our execution of future growth initiatives.

Counterparty

Through the course of operating our businesses and managing our financial risks, we are exposed to counterparty risks. We are exposed to market pricing and credit-related risks in the event any counterparty, whether a customer, debtor, financial intermediary or otherwise, is unable or unwilling to fulfill their contractual obligations or where such agreements are otherwise terminated and not replaced with agreements on substantially the same terms.

Our trade credit exposures are spread across numerous counterparties, the majority of which are with investment grade entities operating within the energy sector and are subject to the normal credit risks associated with this sector. In most cases, the contractual arrangements with our customers and the related exposures are long-term in nature. In the case of Alliance, this exposure has been reduced by requiring shippers to provide letters of credit or other suitable security unless they maintain specified credit ratings or a suitable financial position. In the case of AEGS, we are primarily dependent on two customers, NOVA Chemicals Corporation and Dow Chemical Canada Inc., both large petrochemical companies. AEGS represents a critical component in securing ethane feedstock for NOVA Chemicals' low-cost, world-scale petrochemical facilities located at Joffre, Alberta. In the case of our NGL business, earnings and cash flows are primarily dependent upon the long-term NGL Sales Agreement with BP, a strong investment grade company and one of the largest integrated energy companies in the world. The counterparty exposures associated with our power business are diverse and are spread across numerous entities (including a number of government entities in the case of our district energy facilities), and individual counterparties with investment grade ratings.

We undertake additional measures to manage our credit risks. These measures are generally guided by short-term investment policies and counterparty credit policies and include:

- assessing the financial strength of new and existing counterparties;
- setting limits on exposures to individual counterparties;
- seeking collateral; and
- using agreements that permit netting of exposures associated with a single counterparty as well as other remedies.

Operations

All of our businesses are subject to risks in the operation of their facilities. Operating risks include:

- the breakdown or failure of equipment, information systems or processes;
- the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects);
- failure to maintain adequate supplies of spare parts;
- operator error; and
- labour disputes, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond our control.

The occurrence or continuance of any of these events could reduce earnings and cash flows.

We and our businesses employ various inspection and monitoring methods to manage the integrity of our facilities and to minimize system disruptions. Further, we and our businesses maintain safety policies, disaster recovery procedures and insurance coverage at industry acceptable levels in the case of an incident.

Competition

All of our businesses participate in competitive markets and compete with other companies. All of our businesses have entered into long-term contractual agreements with varying maturities that serve to reduce the potential impact of this competition. However, we can give no assurances that such agreements will remain in effect or will be replaced with agreements on substantially the same terms. As a result, our future earnings and cash flows are exposed to competitive market forces, particularly at the time any of our existing contracts mature.

Income Tax

Our businesses operate in Canada and the U.S., are generally owned indirectly through a number of subsidiary intermediary entities, and in some instances utilize inter-company interest-bearing debt. As a result, we are subject to potential changes in tax laws, judicial interpretations in respect thereof, and the administrative and/or assessing practices of tax authorities in each jurisdiction. These tax changes may negatively affect our earnings and cash flows. With our structure as a partnership, the amount of taxable income allocated to Unitholders and the amount of tax payable in respect of distributions to Unitholders may also be affected by these tax changes. These tax risks are proactively managed and monitored by in-house tax professionals and outside tax experts. As a result of the changes affecting the taxation of specified investment flow-through entities, structural changes have and will continue to be made prior to 2011 in order to preserve tax pools and ensure we maintain an optimal organizational structure. We will convert to a taxable Canadian corporation before January 1, 2011.

Environmental, Health and Safety

Our businesses are subject to extensive environmental, health and safety laws and regulations typical for the industries and jurisdictions within which they operate. Failure to maintain compliance with these laws and regulations could result in:

- operational interruptions;
- physical injury to our employees, contractors, or general public;
- fines or penalties;
- environmental contamination clean-up costs; and
- additional costs being incurred to achieve compliance.

We are also exposed to potential changes in future laws and regulations, such as those related to greenhouse gas emissions, which could result in more stringent and costly compliance requirements. We are committed to complying with all applicable laws and regulations and maintaining a healthy and safe work environment for our employees and the communities within which we operate. To support this commitment, we have established policies, programs, practices, including performance targets and reporting to senior management and applicable boards. Our policies, programs and practices are managed by experienced personnel and periodically reviewed and modified to ensure they conform with current laws, regulations, and industry practices.

Abandonment

Each of our businesses is responsible for monitoring and complying with all laws and regulations concerning the abandonment of its facilities at the end of their respective economic lives and are therefore exposed to the costs associated with any future such abandonment. The costs of abandonment will be a function of then applicable regulatory requirements, which we cannot accurately predict. Where reasonably determinable, we accrue the costs associated with these legal obligations.

Insurance

In the normal course of managing our businesses, we purchase and maintain insurance coverage to reduce certain risks with limits and deductibles that are considered reasonable and prudent. Our insurance does not cover all eventualities because of customary exclusions and/or limited availability and in some instances, our view that the cost of certain insurance coverage is excessive in relation to the risk or risks being covered. Further, there can be no assurance insurance coverage will continue to be available on commercially reasonable terms, that such coverage will ultimately be sufficient, or that insurers will be able to fulfill their obligations should a claim be made.

Joint Ownership

Some of our businesses are jointly held and are governed by partnership and shareholder agreements. As a result, certain decisions regarding these businesses require a simple majority, while others require 66 2/3 percent, 75 percent, 80 percent or 100 percent approval of the owners. In the case of Alliance, NRGreen and East Windsor Cogeneration, all decisions require the agreement of both owners. In the case of Aux Sable U.S., most decisions are made with the agreement of the two controlling owners, of which we are one.

Risks Specific to Our Pipeline Business

Extension of Transportation Contracts; Supply and Demand

Alliance Pipeline and AEGS derive revenues from long-term transportation contracts, the vast majority of which have primary terms ending on November 30, 2015 and December 31, 2018, respectively, unless extended. Beyond such terms, the transportation commitments and the associated revenues will depend on various factors, including the supply of, and the demand for, natural gas and ethane, respectively, produced from western Canada and the ability of Alliance and AEGS to compete at the supply and demand ends of their respective systems. Supply depends on a number of factors including the:

- level of exploration, drilling, reserves and production of natural gas;
- price of natural gas;
- price and composition of natural gas available from alternative Canadian and United States sources;
- availability of natural gas in excess of domestic demand for export; and
- regulatory environments in Canada and the United States.

Demand for natural gas in the Midwestern and northeastern United States depends, among other things, on weather, price and consumption, and alternative energy sources. Upon maturity of the existing transportation contracts, Alliance faces competition in pipeline transportation to Chicago area delivery points from both existing and proposed projects.

The demand for ethane shipped on AEGS is driven by two large petrochemical companies, each of whom own and operate world-class petrochemical facilities in Alberta. If, for any reason, either of these customers, or their successors, ceased to operate these facilities or otherwise reduced or eliminated the quantities of ethane purchased by them, this could have a negative effect on the quantity of ethane transported on AEGS and our earnings and cash flows.

Alliance and AEGS may be forced to lower their respective rates and/or shorten contract duration to retain such shippers if supply and demand dynamics or other general market conditions result in shippers not extending their respective transportation contracts.

Rate Regulation

Alliance is subject to Canadian and United States federal regulation by the NEB and FERC, respectively. AEGS is subject to Canadian provincial regulation by the Alberta Utilities Commission. Our pipelines' ability to generate earnings and cash flows could be adversely affected by changes in pipeline regulation, including:

- changes in interpretations of existing regulations by courts or regulators;
- the exclusion of any cost of service amounts;

- any other adverse change to the rates on the respective rate structures or terms and conditions of service; and
- in the case of Alliance, a reduction in the negotiated rate of return on equity.

Risk Specific to Alliance and Aux Sable

Interdependency

There is a significant degree of interdependency between Alliance and Aux Sable, which are related parties through common controlling ownership interests. On one hand, should Aux Sable for any reason fail to provide heat content management services to Alliance U.S., Alliance pipeline and its shippers may experience operational issues, including in certain circumstances an interruption or curtailment of transportation service on the Alliance pipeline. On the other hand, the volume and composition of inlet natural gas available to Aux Sable is dependent on the volumes transported on the Alliance pipeline, which is subject to supply and demand factors, including competitive pressures from other pipeline systems, and the operating performance of the Alliance pipeline.

Risks Specific to the Power Business

SRAC Pricing

Each of the Ripon and San Gabriel facilities sells power pursuant to long-term power purchase agreements. Under the agreements, these facilities receive energy payments based upon the full short-run avoided cost (SRAC) energy pricing formula, which is generally based on California natural gas price indexes, utility system heat rates and applicable time-of-use factors. The SRAC energy pricing formula is subject to regulation by the California Public Utilities Commission and may be modified from time to time, including on a retroactive basis. Our earnings from these facilities may be reduced if the SRAC energy pricing formula changes such that the price we receive for energy payments is reduced. A facility may be de-rated and its capacity payment reduced or suspended if it fails to meet specified performance criteria. This could expose the facility to refund obligations plus interest, which in turn may reduce earnings and cash flows.

Qualifying Facility Status

Each of the Ripon and San Gabriel facilities is a Qualifying Facility as defined under legislation implemented by FERC. A temporary or permanent loss of status as a Qualifying Facility may trigger defaults under the each facility's power purchase agreement and result in penalties plus interest. Furthermore, a regulated utility could refuse to purchase electricity at the SRAC rate and may be entitled to certain remedies, including the right to terminate the power purchase agreement. FERC could also order the refund of payments previously made to a Qualifying Facility under a power purchase agreement during periods when the facility was not in compliance. The loss of Qualifying Facility status could also result in the loss of the exemption from utility-type regulation and expose a facility to regulation by FERC under other legislation, which could result in substantial regulatory burdens and other impediments, and may increase the costs of operation and reduce earnings. In addition, earnings and cash flows may be reduced by a repeal or amendment of the current legislation, which governs Qualifying Facilities, without "grand-fathering" protection to ensure that such change would not affect the obligation of our customers to purchase electricity from such facilities under the existing power purchase agreements.

The utilization of thermal energy is required in order for each of the Ripon and San Gabriel facilities to maintain its status as a Qualifying Facility. During 2007 and 2009, the respective steam hosts of the San Gabriel and Ripon facilities terminated their steam sales agreements. During 2008, while operating under a FERC-issued waiver of certain Qualifying Facility requirements, we installed a distilled water plant to utilize the San Gabriel facility's thermal energy and commenced sales of distilled water to a local manufacturing plant. In 2009, we made a filing with FERC to self-certify the San Gabriel facility's status as a Qualifying Facility reflecting the distillation plant and distilled water sales arrangements. We are currently operating the Ripon facility under a FERC-issued waiver that grants a waiver from QF performance and efficiency standards through December 31, 2010 while we develop an alternate thermal host arrangement to secure continued QF compliance by year-end 2010.

CRITICAL ACCOUNTING POLICIES

Alliance Pipeline is subject to rate regulation in Canada and the United States. Our consolidated financial statements are prepared in accordance with GAAP, which include specific provisions applicable to rate-

regulated businesses, such as Alliance. As a consequence, these principles may differ from those used by non-rate-regulated entities. In order to achieve a proper matching of revenues and expenses, certain revenues and expenses are recognized differently than would otherwise be expected under GAAP applicable to non-regulated businesses.

Alliance transportation contracts are designed to provide toll revenues sufficient to recover all prudently incurred costs, including an 11.26 percent return on equity in Canada and a 10.88 percent return on equity in the United States. The period in which costs are recovered from toll receipts may differ from the period when these costs are expensed under GAAP. Differences between the recorded toll revenue and actual toll receipts give rise to receivable or payable balances. In the case of Alliance's Canadian rate-regulated business, the taxes payable method is used to recover tax expense and, as such, Alliance's Canadian tolls do not include the recovery of future income taxes. For purposes of calculating tolls, depreciation of the Alliance pipeline is based on negotiated rates contained in the transportation contracts, while depreciation expense under GAAP is recorded on a straight-line basis at a rate of four percent per annum commencing on the in-service date. The negotiated depreciation rates are generally less than the straight-line rate in earlier years resulting in accrued revenues and receivables in those years. These receivables are expected to be recovered from shippers in subsequent years when the negotiated depreciation in the toll exceeds the depreciation recorded for financial statement purposes.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our consolidated financial statements requires us to make judgements, estimates and assumptions about future events when applying GAAP that affect the recorded amounts of certain assets, liabilities, revenues and expenses. These judgements, estimates and assumptions are subject to change as the events occur or new information becomes available. The following highlights our more significant accounting estimates. Readers should also refer to note three of our consolidated financial statements for a list of significant accounting policies.

Impairment of Long-lived Assets

We evaluate, at least annually, our long-term assets for impairment when events or changes in circumstances indicate, in our judgement, the carrying value of such assets may not be recoverable. If we determine the recoverability of the asset's carrying value has been impaired, the amount of the impairment is determined by estimating the fair value of the assets and recording a loss for the amount the carrying value exceeds the estimated fair value. Judgements and assumptions are inherent in the determination of the recoverability of such assets and the estimate of their fair value.

In December 2009, we recognized pre-tax impairment losses of \$78.1 million with respect to our California cogeneration facilities, and \$2.4 million with respect to our investment in Pristine. In December 2008, we recognized pre-tax impairment losses of \$19.1 million with respect to goodwill, which arose from our acquisition of power assets in August 2007, and \$3.4 million with respect to our investment in a private power company. In our view, at December 31, 2009 there has not been impairment in the carried value of our other assets.

Asset Retirement Obligation

The estimated fair value of legal obligations associated with the retirement of tangible long-lived assets is to be recognized in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The asset retirement cost, deemed to be the fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived assets and is amortized over the remaining life of these assets. This amortization is included in depreciation and amortization in the consolidated statement of income and cumulative income. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion expense in depreciation and amortization in the consolidated statement of income and cumulative income, over the estimated time period until settlement of the obligation. Actual expenditures incurred are charged against the accumulated asset retirement obligation.

We have recognized provisions for asset retirement obligations in our consolidated financial statements with respect to AEGS, Aux Sable Canada, NRGreen and East Windsor Cogeneration. We have not recognized provisions for asset retirement obligations with respect to the Alliance pipeline or Aux Sable U.S. It is not currently possible to make a reasonable estimate of the fair value of the liability for these businesses due to the indeterminate timing and scope of the respective asset retirements and, with respect to Aux Sable U.S. the

expected legal obligations are not material. We believe it is reasonable to assume that all asset retirement obligations associated with the Alliance pipeline will be recoverable through future tolls.

Depreciation and Amortization

Our pipeline, plant and other capital assets and intangible assets are depreciated and amortized based on their estimated useful lives. A change in the estimation of useful lives could have a material impact on our consolidated financial statements, including transportation revenue and receivables.

Regulatory Asset

We have recorded a long-term receivable for the cumulative difference between depreciation expense included in our consolidated financial statements and depreciation expense included in Alliance's transportation tolls. The carrying value of this asset reflects our assessment as to the ultimate recoverability of this receivable.

NEW ACCOUNTING STANDARDS ADOPTED IN 2009

Accounting for the Effects of Rate Regulation

Effective January 1, 2009, the exemption from the requirement for rate-regulated entities to record future income taxes was removed. We adopted these changes effective January 1, 2009 and the principal effect was the balance sheet recognition of \$106.7 million in future Canadian income tax liabilities associated with Alliance, equally offset by regulatory assets recorded as long-term receivables.

FUTURE ACCOUNTING STANDARDS

International Financial Reporting Standards

Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards. Some Canadian standards will change to converge with IFRS prior to the conversion date. We will continue to prepare our consolidated financial statements for periods up to and including the year ending December 31, 2010 in accordance with Canadian GAAP as it exists at each reporting date. Financial statements for the three months ended March 31, 2011, including comparative amounts, will be reported in accordance with IFRS.

In order to transition to IFRS, we have established a project team and formed an executive steering committee. We are implementing a plan to convert our consolidated financial statements to IFRS. We are providing training to key employees and training will be ongoing throughout the conversion process. We continue to monitor the effect of the transition on information systems, internal controls over financial reporting and disclosure controls and procedures and are updating each of these as needed. We are currently reviewing debt covenants and other agreements to determine what changes may be required upon IFRS adoption. Where changes are necessary we anticipate amending agreements prior to IFRS adoption on January 1, 2011.

We continue to analyze differences between IFRS and our current accounting policies and to assess the impact of various alternatives. There are several accounting policy changes which may materially impact our consolidated financial statements. Changes in IFRS and our continued assessments between now and December 31, 2011 may result in further accounting policy changes with material impacts on our consolidated financial statements.

IFRS Accounting Policies

Several of our investments, including Alliance and Aux Sable, are entities that we control jointly with other owners. We currently proportionately consolidate these entities so each line of our financial statements includes our proportionate share of amounts recorded by each joint venture. Under current IFRS standards, we can choose between using proportionate consolidation and the equity method to account for joint ventures. There is presently an IFRS Exposure Draft outstanding that would eliminate the use of proportionate consolidation and require the use of equity accounting for interests in jointly controlled entities. Under the equity method, investments in jointly controlled entities and income are recorded on one line on each of the balance sheet and income statement. Similarly, the statement of cash flows reflects investments in and distributions received from

jointly controlled entities rather than our proportionate share of their cash flows on a line-by-line basis. While this change in policy would not, in and of itself, change the amount of net assets or net income we would expect almost every line item on the balance sheet, income statement and statement of cash flows to change, many by a material amount. The impact of all other accounting policy changes resulting from the adoption of IFRS cannot be quantified until the accounting standard for jointly controlled entities is known. We will determine our IFRS accounting policy after the Exposure Draft is finalized and an adoption date and transition rules are published with the final standard.

Alliance has certain rate-regulated accounting policies that vary from policies otherwise permitted under Canadian GAAP. IFRS does not presently address rate-regulated entities. An IFRS Exposure Draft is outstanding which would permit rate-regulated entities to use certain accounting policies not otherwise permitted under IFRS. The Exposure Draft as currently published differs from our current accounting policies in some respects. In February 2010, the IASB published an analysis of comment letters received related to the Exposure Draft. We currently expect the review of these comments will delay the introduction of a final standard until after we have adopted IFRS. While we continue to monitor developments regarding rate-regulated accounting under IFRS, at this time we cannot determine the impact of adopting IFRS for our rate-regulated businesses. The following paragraphs do not consider the potential impact of rate-regulated accounting on our policy choices.

Accounting for asset impairments differs under IFRS and Canadian GAAP. Under Canadian GAAP, an asset impairment test is a two-step process. A reporting unit's carrying value is first compared to the undiscounted forecast future cash flows. If the carrying value exceeds the undiscounted forecast future cash flows, the second step, comparing the carrying value to discounted forecast future cash flows, is used to determine the amount of impairment to be recorded. Under IFRS, an impairment test is performed when there are indicators of impairment existing for a specific asset or Cash Generating Unit. This impairment test is a one-step test where the carrying value of the asset or group of assets is compared to the higher of Fair Value Less Costs to Sell and Value-In-Use. This can result in an asset impairment being recorded under IFRS when it would not be recorded under Canadian GAAP, or an asset impairment being recorded at a different amount under IFRS than was recorded under Canadian GAAP. We have not yet determined the amount of impairment that would have been recorded in 2009 in relation to the Ripon and San Gabriel facilities if the impairment was calculated on an IFRS basis. Unlike under Canadian GAAP, asset impairment losses on assets other than goodwill will be reversed under IFRS if facts and circumstances change such that the asset is no longer deemed to be impaired.

Accounting for business combinations also differs between Canadian GAAP and IFRS. Business combinations prior to January 1, 2010 will not be restated on adoption of IFRS. Business combinations recorded during 2010 will be restated on adoption of IFRS. Under IFRS, transaction costs which are included in the determination of the purchase price under Canadian GAAP will be included in net income. As well, all liabilities, including those which would not meet recognition requirements under Canadian GAAP, will be recorded at fair value at the date of acquisition. Under IFRS, when a business combination occurs, all significant contracts are assessed to determine whether they are arrangements containing a lease using the facts and circumstances in existence at the date the contract was entered into. Under Canadian GAAP, this assessment is made using facts and circumstances as at the date of acquisition. Given the nature of our business, this change could be significant in future business acquisitions. Arrangements which are deemed to be leases are then assessed to determine whether the lease is operating or capital in nature, a determination which could materially impact net income and non-GAAP measures such as EBITDA.

Both Canadian GAAP and IFRS use a liability approach where future taxes are provided for differences between the tax basis and accounting basis of certain assets and liabilities. There are differences in how future taxes are calculated under IFRS and these differences could be material. The impact of these differences cannot be determined until other accounting policies, including initial adoption decisions, are finalized.

Initial Adoption Accounting Policies

In general, on adoption of IFRS, accounting policies must be changed retroactively with comparative financial statements prepared as if the current IFRS accounting policies had always been our accounting policies. There are several one-time elections available on adoption of IFRS in some areas that are potentially complex and where the calculations otherwise required could be onerous. We will elect to use some, but not all, of these first-time adoption exceptions. Significant items, in addition to business combinations described above, which have been assessed, are discussed here.

Fixed assets can be restated to fair value at the date of adoption. We will not use this election and will instead, where necessary, restate our fixed asset balances to an IFRS cost basis. The impact of these changes has not yet been determined.

IFRS has different rules than Canadian GAAP regarding the capitalization of interest on constructed assets. We will adopt these rules for projects commencing after January 1, 2010 for IFRS reporting purposes, and will not retroactively capitalize interest on an IFRS basis on projects that commenced prior to then. As a result, interest previously capitalized under Canadian GAAP will be reversed on adoption of IFRS with a corresponding reduction in Retained Earnings.

Asset Retirement Obligations (ARO) are calculated differently under IFRS than under Canadian GAAP. Significant differences include the discount rate used and the accounting for changes in estimates, including the estimated discount rates. Under IFRS all changes are accounted for on a prospective basis with the asset and liability recorded being adjusted for changes in estimates. We will take advantage of the adoption election that permits a simplified calculation to be used as at January 1, 2010. The impact of these changes has not been quantified.

The Cumulative Translation Adjustment loss in Cumulative Other Comprehensive Loss at December 31, 2009 will be reset to zero on IFRS adoption, with a corresponding decrease to Retained Earnings.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this MD&A are not measures recognized under GAAP. These non-GAAP financial measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. We caution investors not to construe these non-GAAP financial measures as alternatives to other measures of financial performance calculated in accordance with GAAP. We further caution investors not to place undue reliance on any one financial measure.

We provide the following non-GAAP financial measures to assist investors with their evaluation of us, including their assessment of our ability to generate distributable cash to fund monthly distributions. We consider these non-GAAP financial measures, together with other financial measures calculated in accordance with GAAP, to be important factors that assist investors in assessing performance.

Adjusted Net Income – represents net income adjusted for specific items that are significant, but are not reflective of our underlying operations. Specific items are subjective, however, we use our judgement and informed decision-making when identifying items to be included or excluded in calculating adjusted net income. Specific items may include, but are not limited to, certain income tax adjustments, bankruptcy settlements, gains or losses on sales of assets, certain fair value adjustments, and asset impairment losses. We believe our use of adjusted net income provides useful information to us and our investors by improving the ability to compare financial results among reporting periods, and by enhancing the understanding of our operating performance and our ability to fund distributions. The following is a reconciliation of adjusted net income to net income.

	Three months ended December 31		Year ended December 31	
(\$ Thousands, except per Unit amounts)	2009	2008	2009	2008
Net income (loss)	(24,454)	(17,949)	37,575	61,499
Adjustments to net income for non-recurring (gains) losses				
Pipeline – Alliance shipper claim settlement ⁽¹⁾	-	-	-	(10,020)
NGL – Aux Sable settlement ⁽²⁾	(9,472)	-	(9,472)	-
Power – asset impairment loss ^{(3) (4)}	78,051	21,105	78,051	21,105
Power – fair value loss reclassified from other comprehensive income ⁽⁵⁾	-	-	2,442	-
Power – gain on dilution of investment ⁽¹⁾	-	-	-	(4,200)
Taxes ⁽⁶⁾	(24,903)	-	(25,057)	3,720
	43,676	21,105	45,964	10,605
Adjusted net income	19,222	3,156	83,539	72,104

- (1) 2008 net income included Alliance's settlement with Calpine Energy Services Canada Partnership and a non-cash dilution gain related to our investment in Pristine Power Inc. We do not expect these items to recur and, as such, have deducted them from net income in arriving at adjusted net income.
- (2) Net income for the three and 12 months ended December 31, 2009 included Aux Sable's off-gas facility settlement. We do not expect this item to recur and, as such, have deducted it from net income in arriving at adjusted net income.
- (3) Net income for the three and 12 months ended December 31, 2009 included a \$78.1 million asset impairment loss. We recorded this non-cash charge in relation to our California cogeneration facilities, which were adversely impacted by a regulatory decision. We do not expect this item to recur and, as such, have deducted it from net income in arriving at adjusted net income.
- (4) Net income for the three and 12 months ended December 31, 2008 included a \$21.1 million asset impairment loss. This non-cash charge related primarily to goodwill, the value of which was deemed to be impaired and written down to nil. We do not expect this item to recur and, as such, have added it back to net income in arriving at adjusted net income.
- (5) Net income for the year ended December 31, 2009 included a non-cash expense transferred from other comprehensive income to net income in the first quarter of 2009, representing the fair value decrease of our investment in Pristine Power Inc. from Pristine's initial public offering in March 2008. As we consider such permanent decreases in the fair value of our investments to be non-typical, we have added this amount back to net income in arriving at adjusted net income.
- (6) This represents the related taxes on the adjusting items described above.

Distributable Cash - represents the cash we have available for distribution to Unitholders after providing for debt service obligations and any maintenance and sustaining capital expenditures. Distributable cash does not include distribution reserves, if any, available in jointly held businesses or project development costs. Project development costs are discretionary, non-recoverable costs incurred to assess the commercial viability of greenfield business initiatives unrelated to our operating businesses. The investment community uses distributable cash to assess the source and sustainability of our cash distributions. The following is a reconciliation of distributable cash to cash flow from operating activities.

	Three months ended December 31		Year ended December 31	
(\$ Thousands)	2009	2008	2009	2008
Consolidated cash flow from operating activities	43,687	39,279	210,743	262,612
Deduct: Cash flow generated from operating activities applicable to jointly held businesses ⁽¹⁾	(8,133)	(2,347)	(90,164)	(70,236)
Cash flow from operating activities applicable to wholly-owned businesses ⁽²⁾	35,554	36,932	120,579	192,376
Add (deduct) amounts applicable to wholly-owned businesses:				
Project development costs ⁽³⁾	2,224	3,506	10,632	11,628
Change in non-cash working capital	(4,137)	(5,512)	10,019	(19,293)
Principal repayments on senior notes	(1,457)	(1,523)	(6,001)	(5,657)
Maintenance capital expenditures	(2,913)	(685)	(3,498)	(7,330)
Distributions earned greater (less) than distributions received ⁽⁴⁾	4,730	(10,234)	17,336	(11,575)
Distributable cash	34,001	22,484	149,067	160,149

- (1) Represents cash flow from operating activities applicable to jointly held businesses which is not under our sole control and, consequently, is not included in distributable cash until distributions are declared by the jointly held businesses.
- (2) Net of support payments made to Alliance Canada Marketing of \$3.6 million and \$10.0 million for the three and 12 months ended December 31, 2009, respectively (2008 – \$0.8 million and \$3.0 million, respectively).
- (3) Represents costs incurred by us and our wholly owned businesses in relation to projects where the recoverability of such costs has not yet been established. Amounts incurred for the three and 12 months ended December 31, 2009 relate primarily to the Jordan Cove LNG terminal project, the Pacific Connector Gas Pipeline project, and the Alton Gas Storage project.
- (4) Represents the difference between distributions declared by jointly held businesses and distributions received.

Distributable Cash per Unit - reflects the per Unit amount of distributable cash calculated based on the average number of Units outstanding on each record date.

EBITDA - refers to earnings before interest, taxes, depreciation and amortization. EBITDA is reconciled to net income before tax by deducting interest, depreciation and amortization, and asset impairment losses, if any. The investment community uses this measure, together with other measures, to assess the source and sustainability of cash distributions.

Enterprise Value - represents our assets' aggregate market value, on the applicable date. It is calculated based on the total assets reported in the consolidated financial statements adjusted to reflect any differences between the market value and book value of our consolidated debt and Units. The investment community uses this measure, together with other measures, to assess the overall market value of a business. The following is a reconciliation of enterprise value to total assets.

(\$ Thousands)	As at December 31		
	2009	2008	2007
Total assets	2,864,899	3,127,679	2,871,364
Market value over (under) book value:			
Long-term debt	96,917	41,744	87,257
Subordinated convertible debentures	3,501	(498)	7,114
Equity	329,538	(44,997)	435,988
Enterprise value	3,294,856	3,123,928	3,401,723

Growth Capital Expenditures - are generally defined as capital expenditures that expand existing capacity and/or increase earnings. The investment community uses this measure to assess the extent of discretionary capital spending.

Maintenance and Sustaining Capital Expenditures - are generally defined as expenditures that enhance existing assets or support operations without any associated increase in earnings. The investment community uses this measure to assess the extent of non-discretionary capital spending.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President & Chief Executive Officer ("CEO") and Vice President, Finance and Chief Financial Officer ("CFO"), on a timely basis so appropriate decisions can be made regarding public disclosure.

We have evaluated the effectiveness of the design and operation of our disclosure controls and procedures, under the supervision of our CEO and CFO. Based on this evaluation, we concluded the disclosure controls and procedures, as defined in National Instrument 52-109, were effective as of December 31, 2009.

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are responsible for establishing and maintaining adequate internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. We assessed the design and effectiveness of internal controls over financial reporting as at December 31, 2009, and, based on that assessment, determined the design and operating effectiveness of internal controls over financial reporting was effective. However, because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements on a timely basis.

No changes were made to internal control over financial reporting during the year ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.