

# VERESEN

Management's Discussion and Analysis of

**VERESEN INC.**

For the three and nine months ended September 30, 2014

November 3, 2014

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**VERESEN INC.**  
**Management's Discussion and Analysis**  
Three and nine months ended September 30, 2014

**FINANCIAL AND OPERATING HIGHLIGHTS**

(\$ Millions, except where noted)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
<b>Operating Highlights (100%)</b>				
Pipeline				
Alliance – billion cubic feet per day	1.501	1.514	1.567	1.569
AEGS – thousand barrels per day <sup>1</sup>	280.2	285.8	286.6	290.5
Midstream				
Hythe/Steeprock – million cubic feet per day <sup>2</sup>	400.1	427.2	400.1	413.8
Aux Sable – thousand barrels per day	79.3	67.6	70.9	64.3
Power – gigawatt hours (net)	164.7	201.1	653.8	620.2
<b>Financial Results</b>				
Equity income	33.8	50.6	113.1	120.2
Operating revenues	82.0	84.5	263.3	245.9
Net income attributable to Common Shares	2.5	27.9	31.4	40.6
Per Common Share (\$) – basic and diluted	0.01	0.14	0.15	0.20
Cash from operating activities	50.4	44.0	143.3	136.4
Distributable cash <sup>3, 4</sup>	54.9	69.3	184.2	173.1
Per Common Share (\$) – basic and diluted	0.25	0.35	0.86	0.87
Dividends paid/payable <sup>5</sup>	55.4	50.0	160.8	149.4
Per Common Share (\$)	0.25	0.25	0.75	0.75
Capital expenditures <sup>6</sup>	31.4	14.4	111.9	38.5

	September 30, 2014	As at Dec. 31, 2013
<b>Financial Position</b>		
Cash and short-term investments	26.2	26.6
Total assets	3,025.3	2,973.4
Senior debt	1,011.6	1,187.5
Subordinated convertible debentures	51.7	86.2
Shareholders' equity	1,552.2	1,305.7
<b>Common Shares</b>		
Outstanding – as at period end <sup>7</sup>	223,456,044	201,476,244
Average daily volume	561,101	302,801
Price per Common Share – close (\$)	17.03	14.27

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

2. Average daily volume for Hythe/Steeprock is based on fee volumes.

3. This item is not a standard measure under US GAAP and may not be comparable to similar measures presented by other entities. See section entitled "Non-GAAP Financial Measures" in 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. Includes \$13.9 million and \$38.8 million of dividends satisfied through the issuance of Common Shares under our Premium Dividend™ and Dividend Reinvestment Plan (trademark of Canaccord Genuity Corp.) for the three and nine months ended September 30, 2014 (2013 - \$11.4 million and \$33.2 million).

6. Capital expenditures for wholly-owned and majority-controlled businesses, as presented on the consolidated statement of cash flows.

7. As at the close of markets on October 30, 2014 we had 227,243,892 Common Shares outstanding.

This MD&A, dated November 3, 2014, provides a review of the significant events and transactions that affected our performance during the three and nine months ended September 30, 2014 relative to the same periods last year. It should be read in conjunction with our consolidated financial statements and notes as at and for the three and nine months ended September 30, 2014 and as at and for the year ended December 31, 2013, prepared in accordance with accounting principles generally accepted in the United States.

## **ACCOUNTING STANDARDS AND BASIS OF PRESENTATION**

Our consolidated financial statements as at and for the three and nine months ended September 30, 2014 have been prepared by management in accordance with US GAAP. 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 US GAAP consolidated financial statements. Capitalized terms used in this MD&A that have not been defined have the same meanings attributed to them in our 2013 consolidated financial statements. Additional information concerning our business is available on SEDAR at [www.sedar.com](http://www.sedar.com) or on our website at [www.vereseninc.com](http://www.vereseninc.com).

## **FORWARD-LOOKING AND NON-GAAP INFORMATION**

*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:*

- *the ability of Alliance to successfully realize its proposed new services framework and the timing thereof;*
- *Aux Sable's ability to realize upon the extraction agreements with producers and to attract volumes into the Alliance pipeline;*
- *the 2014 pricing environment for ethane and propane;*
- *producer responses to the expansion of the Hythe gas processing facility;*
- *the projected in-service date of NRGreen's Whitecourt Recovered Energy Project;*
- *the projected in-service date of the Dasque-Middle run-of-river facility;*
- *the projected in-service date of the St. Columban wind project;*
- *the sufficiency of our liquidity;*
- *the sufficiency of our available committed credit facilities to fund working capital, dividends and capital expenditures;*
- *the ability of each of our businesses to generate distributable cash and the timing under which distributable cash will be generated;*  
*and*
- *our ability to pay dividends.*

*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;*
- *status, credit risk and continued existence of contracted customers;*
- *availability and price of capital;*
- *availability and price of energy commodities;*
- *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, midstream and power industries;*
- *operational breakdowns, failures, or other disruptions; and*
- *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.*

*Certain financial information contained in this MD&A may not be standard measures under GAAP in the United States 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 the United States. For further information on non-GAAP financial measures used by us see the section entitled "Non-GAAP Financial Measures" contained in this MD&A.*

## OVERALL FINANCIAL PERFORMANCE

### Net Income attributable to Common Shares

(\$ Millions, except per Common Share amounts)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Net income (loss) before tax				
Pipeline	30.6	27.8	92.1	80.1
Midstream	17.9	33.6	60.5	60.6
Power	2.8	6.2	0.8	16.7
Veresen–Corporate	(43.2)	(29.9)	(112.5)	(83.4)
Gain on sale of assets	-	-	14.3	-
Tax expense	(1.5)	(7.6)	(11.5)	(26.8)
<b>Net income</b>	<b>6.6</b>	<b>30.1</b>	<b>43.7</b>	<b>47.2</b>
<b>Preferred Share dividends</b>	<b>(4.1)</b>	<b>(2.2)</b>	<b>(12.3)</b>	<b>(6.6)</b>
<b>Net income attributable to Common Shares</b>	<b>2.5</b>	<b>27.9</b>	<b>31.4</b>	<b>40.6</b>
<b>Per Common Share (\$)</b>	<b>0.01</b>	<b>0.14</b>	<b>0.15</b>	<b>0.20</b>

For the three and nine months ending September 30, 2014, we generated net income attributable to Common Shares of \$2.5 million or \$0.01 per Common Share and \$31.4 million or \$0.15 per Common Share, respectively. For the same periods last year, we generated income of \$27.9 million or \$0.14 per Common Share and \$40.6 million or \$0.20 per Common Share.

Solid third quarter operating earnings from our pipeline, independent midstream, and power businesses were offset by reduced earnings from our Aux Sable midstream business, reflecting the continued weak NGL market environment.

These same factors are reflected in our year-to-date operating results. However, lower NGL margins at Aux Sable were offset by strong earnings in the first quarter due to the significant widening of the Chicago - AECO gas price differential driven by the extreme cold weather in the U.S. Mid-West.

Both quarter and year-to-date earnings were impacted by higher project development spending relating to our Jordan Cove project. In March 2014, our proposed Jordan Cove LNG project received a conditional order from the U.S. Department of Energy to export LNG to countries that do not have Free Trade Agreement status with the United States. With the reduction in risk resulting from receipt of this conditional order, we dedicated additional resources towards our commercial, engineering, and financing work efforts. Consequently, as anticipated, our development spending increased accordingly.

Our Power segment was impacted by the revaluation of the York Energy Centre interest rate hedge, which resulted in a \$2.7 million and \$20.3 million reduction in Power net income before tax for the three and nine months periods, respectively, compared to the same periods last year.

## Distributable Cash

	Three months ended September 30		Nine months ended September 30	
(\$ Millions, except per Common Share amounts)	2014	2013	2014	2013
Pipeline	40.7	39.9	122.3	116.3
Midstream	27.1	43.4	96.8	94.3
Power	14.8	12.2	39.7	29.1
Veresen–Corporate	(15.9)	(18.1)	(47.9)	(52.4)
Current tax	(7.7)	(5.9)	(14.4)	(7.6)
Preferred Share dividends	(4.1)	(2.2)	(12.3)	(6.6)
<b>Distributable Cash</b> <sup>(1)</sup>	<b>54.9</b>	69.3	<b>184.2</b>	173.1
<b>Per Common Share (\$)</b>	<b>0.25</b>	0.35	<b>0.86</b>	0.87

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

For the three and nine months ended September 30, 2014, we generated distributable cash of \$54.9 million and \$184.2 million or \$0.25 and \$0.86 per Common Share, compared to \$69.3 million and \$173.1 million or \$0.35 and \$0.87 per Common Share for the same periods last year.

Solid cash flows generated by our pipeline and power businesses on both a quarter and year-to-date basis were offset by the effect of continued weak NGL fractionation margins. Distributable cash from our Midstream segment for the nine months ending September 30 benefited from the strength of first quarter 2014 cash flows, more than offsetting the weaker fractionation margins. Distributions from Hythe/Steepprock remained consistent compared to the same periods last year.

Alliance generated an additional \$0.8 million this quarter and \$5.1 million over the first three quarters of the year which was largely driven by higher negotiated depreciation rates and contributions from the Tioga Lateral pipeline.

Higher distributable cash from our power business during the third quarter was driven by strong operating performance at our gas-fired facilities. On a year-to-date basis, distributable cash increased as a result of higher earnings at York Energy Centre which benefited from a one-time retroactive revenue settlement adjustment, and higher cash flows at our other Ontario gas-fired facilities and our Glen Park run-of-river facility.

Current tax was higher in the current year due primarily to higher U.S.-based taxable earnings from our Pipeline business.

Higher Preferred Share dividends reflect the October 2013 issuance of Preferred Shares.

## Cash from Operating Activities

	Three months ended September 30		Nine months ended September 30	
(\$ Millions)	2014	2013	2014	2013
Pipeline	41.6	39.6	123.9	116.8
Midstream	24.9	30.9	90.9	87.1
Power	26.6	15.6	44.9	39.9
Veresen–Corporate	(42.7)	(42.1)	(116.4)	(107.4)
	<b>50.4</b>	44.0	<b>143.3</b>	136.4

For the three and nine months ended September 30, 2014, we generated \$50.4 million and \$143.3 million of cash from operating activities compared to \$44.0 million and \$136.4 million for the same periods last year. The higher operating cash flows during the third quarter from our pipeline and power businesses, partially offset by a decrease in our midstream businesses, generally reflect the same factors impacting distributable cash and changes in power non-cash working capital. Corporate cash outflows remained consistent compared to the same period last year as higher project development costs and current taxes were offset by lower interest costs and changes in non-cash working capital.

Cash from operating activities on a year-to-date basis increased over the prior year, with the changes by business segment generally reflecting the same factors impacting distributable cash. Corporate cash outflows were mainly driven by the same factors impacting the third quarter.

## RESULTS OF OPERATIONS – BY BUSINESS SEGMENT

### Pipeline Business

(\$ Millions, except where noted)	Three months ended September 30, 2014			Three months ended September 30, 2013		
	Total	Alliance	AEGS	Total	Alliance	AEGS
<b>Earnings before interest, tax depreciation and amortization (“EBITDA”)</b> <sup>(1)</sup>	<b>6.9</b>	-	6.9	6.8	-	6.8
Depreciation and amortization	(3.5)	-	(3.5)	(3.5)	-	(3.5)
Interest and other finance	(1.2)	-	(1.2)	(1.3)	-	(1.3)
Equity income	28.4	28.4	-	25.8	25.8	-
<b>Net income before tax</b>	<b>30.6</b>	28.4	2.2	27.8	25.8	2.0
<b>Distributable cash</b>	<b>40.7</b>	36.0	4.7	39.9	35.2	4.7
<b>Volumes (100%)</b>		<b>1.501</b>	<b>280.2</b>		1.514	285.8
		bcf/d	mbbls/d <sup>(2)</sup>		bcf/d	mbbls/d <sup>(2)</sup>

### Pipeline Business

(\$ Millions, except where noted)	Nine months ended September 30, 2014			Nine months ended September 30, 2013		
	Total	Alliance	AEGS	Total	Alliance	AEGS
<b>Earnings before interest, tax depreciation and amortization (“EBITDA”)</b> <sup>(1)</sup>	<b>20.5</b>	-	20.5	19.6	-	19.6
Depreciation and amortization	(10.5)	-	(10.5)	(10.5)	-	(10.5)
Interest and other finance	(3.7)	-	(3.7)	(3.8)	-	(3.8)
Equity income	85.8	85.8	-	74.8	74.8	-
<b>Net income before tax</b>	<b>92.1</b>	85.8	6.3	80.1	74.8	5.3
<b>Distributable cash</b>	<b>122.3</b>	108.0	14.3	116.3	102.8	13.5
<b>Volumes (100%)</b>		<b>1.567</b>	<b>286.6</b>		1.569	290.5
		bcf/d	mbbls/d <sup>(2)</sup>		bcf/d	mbbls/d <sup>(2)</sup>

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

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

### Alliance Pipeline

#### Operational Highlights

Transportation deliveries for the three and nine months ended September 30, 2014 averaged 1.501 bcf/d and 1.567 bcf/d, compared to 1.514 bcf/d and 1.569 bcf/d for the same periods last year.

#### Financial Highlights

Distributable cash for the three and nine months ended September 30, 2014 was \$36.0 million and \$108.0 million compared to \$35.2 million and \$102.8 million for the same periods last year. The increases reflect higher revenues due to an increase in negotiated depreciation rates and contributions from the Tioga Lateral, along with a weakening of the Canadian dollar throughout 2014.

Net income before tax for the three and nine months ended September 30, 2014 was \$28.4 million and \$85.8 million compared to \$25.8 million and \$74.8 million for the same periods last year. The increases reflect the factors impacting distributable cash and a first quarter 2013 reduction in the recoverable toll costs.

## Outlook

Subject to regulatory approval, Alliance is offering capacity for transportation commencing December 1, 2015, under a proposed new services framework. The new services framework, which includes both fixed and flexible tolling options, responds to current market requirements and the diverse needs of existing and prospective shippers. The new service offering includes both full-path and segmented services with a new Canadian trading pool and a revised hydrocarbon dewpoint specification, which will facilitate the transportation of higher heat content natural gas. The services offer shippers competitive fixed tolls for medium and long-term services and biddable tolls for interruptible and seasonal service.

On May 22, 2014, Alliance Canada filed an application with Canada's National Energy Board for regulatory approval of the tolls and tariff provisions Alliance needs to implement its new services offering effective December 1, 2015. Similarly, Alliance USA will be applying to the U.S. Federal Energy Regulatory Commission in 2015 for regulatory approval. On August 20, 2014 the NEB issued a Hearing Order establishing a written proceeding for the review of Alliance Canada's new services offering application. The hearing concludes with oral final argument scheduled to start April 15, 2015. A decision by the NEB is expected mid-year 2015.

During the first three quarters of 2014, Alliance placed into service several new receipt interconnection facilities that increased the pipeline's receipt capacity by up to 470 mmcf/d from developing liquids-rich sources of natural gas in northeastern British Columbia and northwestern Alberta. The cost to provide these receipt facilities is funded by the requesting customer. A number of additional receipt interconnection facilities are in the planning and design stage.

## 2015 Tolls

Alliance made its 2015 Canadian toll filing to the NEB on October 31, 2014, and is expected to make its 2015 U.S. negotiated rate filing with the Federal Energy Regulatory Commission on November 28, 2014. The firm transportation toll is expected to increase from \$0.96/mcf in 2014 to \$1.00/mcf in 2015 on Alliance Canada, but decrease from US\$0.60/mcf to US\$0.58/mcf on Alliance U.S., resulting in a system-wide net toll increase of approximately \$0.02/mcf.

## **AEGS**

### Operational Highlights

Toll volumes for the three and nine months ended September 30, 2014 were 280.2 mbbbls/d and 286.6 mbbbls/d, respectively, compared to 285.8 mbbbls/d and 290.5 mbbbls/d for the same periods last year. An unplanned outage by a major petrochemical plant served by AEGS resulted in lower ethane deliveries in the current quarter relative to last year.

### Financial Highlights

For the three and nine months ended September 30, 2014, AEGS generated \$4.7 million and \$14.3 million in distributable cash, respectively, and \$2.2 million and \$6.3 million in net income before tax. Current year results reflect higher toll revenues.

## **Ruby Pipeline**

On September 22, 2014, we entered into an agreement with Global Infrastructure Partners to acquire its 50% convertible preferred interest in the Ruby pipeline system for US \$1.425 billion. The acquisition will be made through a wholly-owned subsidiary of Veresen. Ruby is a newly-built, large-scale natural gas transmission system delivering U.S. Rockies natural gas production to markets in the western United States. The 680-mile, 42-inch pipeline has a current capacity of approximately 1.5 bcf/d, with expansion potential to 2.0 bcf/d through the addition of compression. Ruby originates at the Opal hub in Wyoming and extends to the Malin hub in Oregon. The Malin hub is the main interconnect to the proposed Pacific Connector Gas Pipeline (50% owned by Veresen), which would supply our proposed Jordan Cove LNG terminal. El Paso Pipeline Partners, an affiliate of Kinder Morgan Inc., holds the remaining 50% ownership interest in Ruby through a common equity interest. Kinder Morgan, North America's largest natural gas pipeline operator, will continue to operate Ruby on a day-to-day basis.

The acquisition will be funded by proceeds from a \$920 million subscription receipt offering and from new credit facilities (details of the financing is discussed in the Liquidity and Capital Resources section of this MD&A). On November 3, 2014, we received notice from the Committee on Foreign Investment in the United States ("CFIUS") that there are no unresolved national security issues relating to Veresen's acquisition of Ruby. The

clearance by CFIUS was without conditions and terminates the review of the transaction. The completion of the Ruby acquisition remains subject to customary closing conditions. Closing is expected to occur on November 6, 2014.

Following the announcement of the acquisition, on September 22, 2014, Standard & Poor's Rating Services affirmed its ratings, including its 'BBB' long-term corporate credit rating. On September 23, 2014, Dominion Bond Rating Service placed our Issuer Rating and Senior Unsecured Notes rating of BBB (high) and our Preferred Shares rating of Pfd-3 (high) Under Review with Negative Implications, with ratings to be finalized upon completion of the acquisition.

### Midstream Business

(\$ Millions, except where noted)	Three months ended September 30, 2014			Three months ended September 30, 2013		
	Total	Hythe/ Steeprock	Aux Sable	Total	Hythe/ Steeprock	Aux Sable
<b>EBITDA</b>	<b>18.9</b>	18.9	-	19.3	19.3	-
Depreciation and amortization	(9.9)	(9.9)	-	(9.8)	(9.8)	-
Equity income	8.9	-	8.9	24.1	-	24.1
<b>Net income before tax</b>	<b>17.9</b>	9.0	8.9	33.6	9.5	24.1
<b>Distributable cash</b>	<b>27.1</b>	19.0	8.1	43.4	19.8	23.6
<b>Volumes (100%)</b>						
Fee Volumes <sup>(1)</sup>	<b>400.1</b> mmcf/d			427.2 mmcf/d		
Ethane				27.2		
Propane plus				52.1		
				79.3		
				mbbls/d		

### Midstream Business

(\$ Millions, except where noted)	Nine months ended September 30, 2014			Nine months ended September 30, 2013		
	Total	Hythe/ Steeprock	Aux Sable	Total	Hythe/ Steeprock	Aux Sable
<b>EBITDA</b>	<b>54.9</b>	54.9	-	55.3	55.3	-
Depreciation and amortization	(29.7)	(29.7)	-	(29.5)	(29.5)	-
Equity income	35.3	-	35.3	34.8	-	34.8
<b>Net income before tax</b>	<b>60.5</b>	25.2	35.3	60.6	25.8	34.8
<b>Distributable cash</b>	<b>96.8</b>	56.3	40.5	94.3	55.1	39.2
<b>Volumes (100%)</b>						
Fee Volumes <sup>(1)</sup>	<b>400.1</b> mmcf/d			413.8 mmcf/d		
Ethane				23.2		
Propane plus				47.7		
				70.9		
				mbbls/d		

(1) Hythe/Steeprock fee volumes represent (i) either the minimum commitment volumes for which we earned processing fees or actual volumes processed if in excess of the minimum threshold in respect of the Midstream Services Agreement with our primary customer, and (ii) fees for volumes processed for other producers.

### Hythe/Steeprock

Hythe/Steeprock earnings are primarily generated from a 20-year midstream services agreement, referred to as the "MSA", entered into on February 9, 2012 with our primary customer, a major natural gas producer. The MSA provides for minimum monthly fees based on specific committed volumes and unit fees, as well as the recovery of operating and maintenance costs. Volume commitments and unit fees are adjusted annually based on a pre-determined schedule to reflect anticipated production profiles and moderate fee escalation.

### Operational Highlights

For the three and nine months ended September 30, 2014, fee volumes at Hythe/Steeprock averaged 400.1 mmcf/d, which is comprised of the minimum volume commitment from our primary customer and natural gas from third party producers. Fee volumes decreased six percent compared to the third quarter last year due to higher actual volumes processed post-Hythe turnaround last year combined with lower actual volumes being processed this year as a result of downstream pipeline pressure restrictions impacting our Hythe plant.

As part of our ongoing commitment to asset integrity and reliability, we successfully completed the Steeprock facility turnaround in the month of June. The full scope of the turnaround was completed under budget and ahead of schedule. The minimum volume commitment under the MSA remained applicable during the turnaround period. A turnaround of this scale for the Steeprock facility is currently planned to be completed every three years.

During the third quarter of 2014, the Hythe and Steeprock facilities operated at reliability factors of 100% and 99%, respectively, exceeding the target factors under the MSA.

### Financial Highlights

For the three and nine months ended September 30, 2014, distributable cash for Hythe/Steeprock was \$19.0 million and \$56.3 million, respectively, compared to \$19.8 million and \$55.1 million for the same periods last year. The reduction in distributable cash for the quarter resulted from lower third party revenues. The increase in distributable cash for the nine months ended September 30, 2014 was due to higher revenues attributed to recovery of maintenance capital expenditures from our primary customer and the annual fee escalation as per the MSA.

Net income before tax for the three and nine months ended September 30, 2014 decreased by \$0.5 million and \$0.6 million, respectively, to \$9.0 million and \$25.2 million primarily due to lower third party revenue.

### **Aux Sable**

#### NGL Market Overview

	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Average USGC ethane margin (US\$/gallon)	<b>(0.03)</b>	0.01	<b>(0.01)</b>	0.02
Average USGC propane plus margin (US\$/gallon)	<b>0.79</b>	0.85	<b>0.82</b>	0.80
Average Henry Hub natural gas (US\$/mmbtu)	<b>3.94</b>	3.55	<b>4.53</b>	3.68
Average Chicago Citygate natural gas (US\$/mmbtu)	<b>3.99</b>	3.64	<b>6.13</b>	3.79
Average WTI crude oil (US\$/bbl)	<b>97.17</b>	105.90	<b>99.61</b>	98.16
Average Chicago - AECO differential (\$/mmbtu)	<b>0.33</b>	1.34	<b>1.86</b>	0.83

General weakness in U.S. Gulf Coast ethane margins continued in the third quarter of 2014 as ethane remained oversupplied with widespread rejection, particularly in the Rockies and Appalachian regions, keeping prices depressed while completely offset by the cost of make-up gas.

USGC propane plus margins weakened during the third quarter of 2014 relative to the same period last year. Propane plus margins were slightly higher on a year-to-date basis on the strength of the first half of the year. While the pricing environment remained strong through most of 2014, margins realized by Aux Sable were less favourable due to higher make-up gas costs, which is priced at Chicago.

Propane storage levels in the U.S. increased significantly throughout the third quarter, reaching a record-level 77 million barrels at the end of third quarter 2014, a 45% increase from the second quarter. Propane prices remained relatively firm due to the expectations of higher seasonal demand heading towards winter, particularly for crop drying.

Following the volatile natural gas price environment in the first quarter created by extremely cold temperatures in the U.S. Mid-West, prices moderated in the second quarter and continued to stabilize in the third quarter of

2014. The Chicago Citygate gas price averaged US\$3.99 per mmbtu in the third quarter, down from US\$4.65 per mmbtu in the second quarter of 2014 but up compared to US\$3.64 per mmbtu for the third quarter in 2013.

### Operational Highlights

	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Average volume receipts				
Prairie Rose Pipeline (mmcf/d)	<b>105.8</b>	110.0	<b>97.4</b>	104.6
Average sales				
Ethane (mmbbls/d)	<b>27.2</b>	22.0	<b>23.2</b>	20.3
Propane plus (mmbbls/d)	<b>52.1</b>	45.6	<b>47.7</b>	44.0
Total NGLs (mmbbls/d)	<b>79.3</b>	67.6	<b>70.9</b>	64.3

During the three and nine months ended September 30, 2014, Aux Sable processed 98% of the natural gas delivered by Alliance compared to 99% for the same periods last year. The slight decrease is attributed to uneconomic ethane margins coupled with brief operational downtime for maintenance.

Receipts into the Prairie Rose Pipeline in North Dakota averaged 106 mmcf/d and 97 mmcf/d during the three and nine months ended September 30, 2014, respectively, compared to 110 mmcf/d and 105 mmcf/d for the same periods last year. The average heat content of the natural gas delivered to the Alliance interconnection at Bantry, North Dakota was approximately 1,355 btu/ft<sup>3</sup> and 1,366 btu/ft<sup>3</sup> for the three and nine months ended September 30, 2014, respectively, compared to 1,394 btu/ft<sup>3</sup> and 1,382 btu/ft<sup>3</sup> for the same periods last year. Prairie Rose Pipeline's volumes and heat content have been reduced due to the movement of certain volumes to the Tioga Lateral, commencing in the second quarter of 2014. The heat content of the liquids-rich natural gas stream being delivered out of the Bakken continues to be very high. In comparison, the heat content including western Canadian natural gas delivered on the Alliance system for the nine months ended September 30, 2014 averaged 1,125 btu/ft<sup>3</sup>.

Aux Sable sold 79.3 mmbbls/d and 70.9 mmbbls/d of NGLs during the three and nine months ended September 30, 2014, respectively, compared to 67.6 mmbbls/d and 64.3 mmbbls/d for the same periods last year. Average ethane volumes sold increased to 27.2 mmbbls/d and 23.2 mmbbls/d for the three and nine months ended September 30, 2014, respectively, from 22.0 mmbbls/d and 20.3 mmbbls/d for the same periods last year. Increased ethane sales volumes are attributable to lower reinjection, although margins remain very low.

Propane plus sales volumes were 52.1 mmbbls/d and 47.7 mmbbls/d for the three and nine months ended September 30, 2014, respectively, compared to 45.6 mmbbls/d and 44.0 mmbbls/d for the same periods last year due primarily to the success Aux Sable has achieved through its Rich Gas Premium Agreement initiative, and the commencement of the Tioga Lateral in the second quarter of 2014.

## Financial Highlights

### Components of Aux Sable Equity Income:

(Veresen's share; \$ Millions)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Margin based lease revenues				
Amount generated during period	8.3	11.3	18.2	26.7
Margin recognized from prior period	6.2	10.5	-	-
(Unrecognized margin generated in period)	(3.3)	(1.8)	(3.3)	(1.8)
Amount recognized as revenue	11.2	20.0	14.9	24.9
Pipeline capacity margin	(5.0)	(0.5)	5.5	(8.2)
Other margin based activities	1.8	4.1	11.7	12.5
Fixed fee activities	8.3	9.0	26.8	28.5
General, administrative, operating and maintenance	(4.7)	(5.7)	(15.1)	(15.6)
Depreciation and amortization	(2.7)	(2.6)	(8.1)	(7.6)
Interest and other finance	-	(0.2)	(0.4)	0.3
Net income before tax / equity income	8.9	24.1	35.3	34.8

For the three months ended September 30, 2014, Aux Sable generated \$8.1 million of distributable cash and \$8.9 million in net income before tax, compared to \$23.6 million of distributable cash and \$24.1 million in net income before tax during the same period last year. For the nine months ended September 30, 2014, Aux Sable generated \$40.5 million of distributable cash and \$35.3 million of net income before tax, compared to \$39.2 million of distributable cash and \$34.8 million of net income before tax during the same period last year.

Net income and distributable cash decreased in the current quarter primarily due to lower fractionation margins driven by higher make-up gas prices, lower volumes flowing through Aux Sable's Palermo Conditioning Plant as a result of the Hess Tioga Gas Plant commencing service in May 2014, and lower pipeline capacity margins relating to the purchase and sale of natural gas by certain Aux Sable entities utilizing Alliance pipeline capacity. Net income and distributable cash on a year-to-date basis increased slightly, as lower fractionation margins were more than offset by positive pipeline capacity margins benefiting from the significant widening Chicago - AECO gas price differential driven by the extreme cold winter weather in the U.S. Mid-West during the first quarter.

For the nine months ended September 30, 2014, Aux Sable's Channahon fractionation facility generated \$12.0 million of margin-based lease revenues, of which \$8.7 million has been recognized in income. During the same period last year, the facility generated \$21.0 million, of which \$19.2 million was recognized in that period. The decrease from the prior year reflects the high cost of make-up gas eroding NGL margins, particularly in the first quarter of 2014.

### Outlook

As part of Aux Sable's strategy to attract liquids-rich natural gas to its Channahon Facility for the period following December 1, 2015, efforts have focused on working with producers developing liquids-rich fields in the Montney and Duvernay which are not yet connected to the Alliance Pipeline system. Aux Sable has offered Rich Gas Premium agreements which share natural gas liquids margins with producers. These agreements allow producers to avoid immediate capital investment and provide NGL value tied to large, liquid U.S. Midwest markets. Aux Sable has executed several RGP agreements and, as a result, Aux Sable's ability to extract additional NGLs at the Channahon Facility has reached the plant's capacity. In response to customer demand, the owners of Aux Sable, including us, have approved an expansion of the Channahon Facility which will allow for approximately 24,500 barrels per day of additional fractionation capacity, over and above the plant's current nameplate capacity of 107,000 barrels per day. The Channahon Facility expansion, which will increase the propane and butane processing capacity, has an estimated capital cost of US\$130 million (gross) and is expected to be completed in mid-2016.

## Power Business

(\$ Millions, except where noted)	Three months ended September 30, 2014				Three months ended September 30, 2013			
	Total	Gas-Fired/ District Energy	Renewables	Power- Corporate	Total	Gas-Fired/ District Energy	Renewables	Power- Corporate
<b>EBITDA</b>	<b>16.3</b>	14.8	3.0	(1.5)	16.5	14.4	3.7	(1.6)
Depreciation and amortization	(10.6)	(8.2)	(2.4)	-	(9.2)	(6.8)	(2.3)	(0.1)
Interest and other finance	(2.9)	(2.5)	(0.4)	-	(3.7)	(2.5)	(1.2)	-
Equity income	0.1	0.2	(0.1)	-	2.6	2.8	(0.2)	-
Foreign exchange and other	(0.1)	-	-	(0.1)	-	-	-	-
<b>Net income (loss) before tax</b>	<b>2.8</b>	4.3	0.1	(1.6)	6.2	7.9	-	(1.7)
<b>Distributable cash</b>	<b>14.8</b>	13.0	3.3	(1.5)	12.2	11.8	2.0	(1.6)
<b>Volumes (GWh)</b>								
Gross	187.7	81.8	105.9	-	236.1	125.5	110.6	-
Net	164.7	77.8	86.9	-	201.1	108.2	92.9	-

## Power Business

(\$ Millions, except where noted)	Nine months ended September 30, 2014				Nine months ended September 30, 2013			
	Total	Gas-Fired/ District Energy	Renewables	Power- Corporate	Total	Gas-Fired/ District Energy	Renewables	Power- Corporate
<b>EBITDA</b>	<b>42.1</b>	36.3	11.7	(5.9)	38.6	34.1	10.9	(6.4)
Depreciation and amortization	(31.4)	(24.4)	(7.0)	-	(26.1)	(19.0)	(6.8)	(0.3)
Interest and other finance	(10.2)	(7.4)	(2.8)	-	(10.9)	(7.5)	(3.4)	-
Equity income	0.1	(1.8)	1.9	-	15.1	13.7	1.4	-
Foreign exchange and other	0.2	-	-	0.2	-	-	-	-
<b>Net income (loss) before tax</b>	<b>0.8</b>	2.7	3.8	(5.7)	16.7	21.3	2.1	(6.7)
<b>Distributable cash</b>	<b>39.7</b>	33.1	12.6	(6.0)	29.1	28.0	7.5	(6.4)
<b>Volumes (GWh)</b>								
Gross	751.0	357.8	393.2	-	711.6	320.5	391.1	-
Net	653.8	326.0	327.8	-	620.2	290.4	329.8	-

### Operational Highlights and Project Updates

For the three months ended September 30, 2014, our power facilities operated in line with our expectations, providing consistent earnings compared to the same period last year.

We continue to progress construction of the Dasque-Middle run-of-river hydro facility in northwest British Columbia. Commercial in-service is expected in the fourth quarter of 2014.

The 13-MW Whitecourt waste heat facility, currently being constructed by NRGreen, is nearing completion. The commercial in-service date is expected in the fourth quarter of 2014.

Construction of the 33 MW St. Columban wind project commenced during the first quarter of 2014, with completion and in-service date expected in Q1 2015.

Our proposed Grand Valley III wind project, currently under development, received its Renewable Energy Approval from the Ontario Minister of Environment and Climate Change on October 15, 2014. The 40 megawatt wind project will be located near the Town of Grand Valley. We continue to advance this project and expect to make a final investment decision in the fourth quarter of 2014.

## Financial Highlights

For the three and nine months ended September 30, 2014, distributable cash was \$14.8 million and \$39.7 million, respectively, representing an increase of \$2.6 million and \$10.6 million compared to the same periods last year.

The current quarter increase reflects strong operational performance across our gas-fired and renewable energy facilities.

Our gas-fired, district energy and renewable energy facilities generated higher cash flows during the nine months ending September 30, 2014 compared to the same period last year. In addition to its strong operating performance, York Energy Centre results reflect a \$3.9 million retroactive adjustment from the Ontario Power Authority recognized in the second quarter of 2014. Our district energy systems benefited from stronger operational performance and lower maintenance costs. Renewable power facilities provided higher cash flows as our Glen Park run-of-river hydro facility benefited from robust energy prices in the first quarter of 2014 and higher water flows throughout 2014.

Net income before tax was \$2.8 million and \$0.8 million for the three and nine months ended September 30, 2014, decreasing by \$3.4 million and \$15.9 million over the same periods last year. Higher operating earnings were offset by higher depreciation at our California cogeneration facilities, and by the revaluation of the York Energy Centre interest rate hedge which resulted in a \$2.7 million and \$20.3 million reduction in Power net income before tax for the three and nine month periods, respectively, compared to the same periods last year.

### Veresen-Corporate

(\$ Millions)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Equity loss	3.5	1.8	8.0	4.4
General & administrative	7.6	7.8	21.8	22.0
Project development	28.5	8.1	58.8	23.9
Depreciation and amortization	0.6	0.5	1.9	1.6
Interest and other finance	9.0	10.8	28.0	32.2
Foreign exchange and other	(6.0)	0.9	(6.0)	(0.7)
<b>Net expenses before tax</b>	<b>43.2</b>	29.9	<b>112.5</b>	83.4
Current tax	9.3	6.8	19.2	10.2
Deferred tax	(7.8)	0.8	(7.7)	16.6
<b>Net expenses</b>	<b>44.7</b>	37.5	<b>124.0</b>	110.2
<b>Effective rate</b>	<b>18.5%</b>	20.2%	<b>20.8%</b>	36.2%
<b>Distributable cash</b>	<b>(15.9)</b>	(18.1)	<b>(47.9)</b>	(52.4)

For the three and nine months ended September 30, 2014, we incurred \$43.2 million and \$112.5 million, respectively, of net corporate expenses before taxes, a \$13.3 million and \$29.1 million increase compared to the same periods last year. The increase largely reflects higher project development spending related to our Jordan Cove LNG and Pacific Connector Gas Pipeline projects, partially offset by a \$4.9 million unrealized gain on forward foreign exchange contracts entered into to manage the fluctuating Canadian to US dollar exchange rate relating to the Ruby acquisition (the forward exchange contracts are discussed in the Financial Instruments section of this MD&A).

Current tax is higher in 2014 due primarily to higher U.S.-based taxable earnings from our Pipeline business. Our effective tax rate for the nine months ending September 30, 2014 was lower than the same period last year due to higher Canadian earnings which are subject to a lower tax rate relative to the U.S. and the gains on the sale of the Culliton Creek run-of-river development project and our 50% interest in Alton Gas Storage which are subject to the Canadian capital gains tax rate.

### Jordan Cove LNG Development Project

On March 24, 2014, we received a conditional order from the U.S. DOE to export LNG from the proposed Jordan Cove LNG export terminal to those countries that do not have FTA status with the United States. Under the DOE order, we are permitted to export natural gas to meet Jordan Cove's initial LNG capacity production of

six million tonnes per annum (mtpa). The DOE authorization is for a term of 20 years, commencing on the date of first export.

In the first quarter of 2014, we also received authorization from the DOE to import natural gas from Canada to serve the proposed Jordan Cove LNG terminal.

In July 2014, Jordan Cove LNG and the associated Pacific Connector Gas Pipeline received their collective Notice of Schedule for environmental review from the FERC. Receipt of this schedule is an important milestone in the regulatory process. FERC's schedule calls for a final Environment Impact Statement ("EIS") to be issued on February 27, 2015. Based on this schedule, we reviewed and updated the project timeline and expect to make a final investment decision in mid-2015. With a four-year construction period, commercial LNG production is targeted for mid- to late-2019. Once the FERC issues Jordan Cove LNG its Draft EIS, a public hearing process is initiated.

We continue to be in active negotiations to secure long-term arrangements to produce LNG for international customers. Our objective is to execute binding agreements by the first quarter of 2015 for all of Jordan Cove LNG's initial capacity of 6 million tonnes per annum.

We also continue to negotiate the engineering, procurement and construction contract with a joint venture formed by Kiewit and Black & Veatch for the design and construction of the LNG terminal. We expect the EPC contract to be completed in late 2014 or early 2015, following which a Class 1 cost estimate and schedule will be generated by the contractor.

We are making good progress in determining the optimal ownership interest for the Company in Jordan Cove LNG, with the objective of maximizing shareholder value while managing the risk profile associated with the project. Ultimately, the ownership structure may be driven by the desire of off-take customers to take an equity position in the project. Beyond off-take customers, we are also considering other strategic partners. In the second quarter of 2014, we engaged Macquarie Capital as our financial advisor for the Jordan Cove LNG project.

We've advanced the organizational structure of Jordan Cove LNG to ensure the appropriate resources are in place for the success of the project. Supporting this objective, in October 2014, we announced the appointment of Elizabeth (Betsy) Spomer as President and Chief Executive Officer of Jordan Cove LNG LLC and as an Executive Vice President of Veresen. Ms. Spomer brings over 30 years of experience in the energy industry, having spent the majority of her career in the LNG industry. With a final investment decision for Jordan Cove LNG expected in 2015, we plan to continue to augment our LNG team, adding professionals who will be required through the construction and operating phases. Ms. Spomer and her team will be based in Houston, Texas.

## LIQUIDITY AND CAPITAL RESOURCES

	Three months ended September 30		Nine months ended September 30	
(\$ Millions, except where noted)	2014	2013	2014	2013
<b>Cash flows</b>				
Operating activities	50.4	44.0	143.3	136.4
Investing activities	(39.0)	(31.4)	(104.9)	(94.2)
Financing activities	(205.0)	(14.8)	(38.4)	(32.9)
<b>Capitalization</b>				
	<b>September 30, 2014</b>		<b>December 31, 2013</b>	
Cash and short-term investments	26.2		26.6	
Senior debt <sup>(1)</sup>	1,011.6	38%	1,187.5	45%
Subordinated convertible debentures	51.7	2%	86.2	3%
Other long-term liabilities	50.2	2%	48.5	2%
Shareholders' equity	1,552.2	58%	1,305.7	50%
	2,665.7	100%	2,627.9	100.0%

(1) Includes current portion of long-term senior debt.

Overall, there has not been any significant change in our financial condition or that of our businesses compared with the positions as at December 31, 2013.

At September 30, 2014, we had cash and short-term investments of \$26.2 million (December 31, 2013 - \$26.6 million) and non-cash working capital of \$38.8 million (December 31, 2013 - \$43.6 million).

We expect to continue to utilize cash from operations, drawings on our Revolving Credit Facility, cash raised through our April 2014 common equity issuance (see Equity Financing Activities) and DRIP to fund our cash requirements. Our Revolving Credit Facility was drawn by \$44.1 million as at September 30, 2014.

### Investing Activities

For the nine months ended September 30, 2014, we used \$104.9 million of cash to fund our investing activities, compared to \$94.2 million in the same period last year. Significant investing activities for the nine months ended September 30, 2014 included:

- \$19.2 million in equity contributions to our jointly-controlled businesses;
- \$111.9 million of capital expenditures, primarily related to the construction of the Dasque-Middle run-of-river hydro facility (\$40.1 million), the St. Columban wind project (\$57.6 million), our Midstream business (\$10.0 million), and our operating power facilities (\$4.2 million);
- \$18.7 million of proceeds from the sale of assets; and
- \$11.2 million return of capital relating to Aux Sable Canada's sale of a 50% interest in the Septimus Gas Plant.

Investing activities for the same period last year included:

- \$53.2 million in equity contributions to our jointly-controlled businesses; and
- \$38.5 million of capital expenditures, primarily related to the construction of the Dasque-Middle-run-of-river hydro facility (\$18.1 million), or Midstream business (\$12.6 million), and our operating power facilities (\$5.6 million).

### Financing Activities

For the nine months ended September 30, 2014, we used \$38.4 million cash to fund our financing activities, compared to \$32.9 million cash used for the same period last year. Financing activities for the nine months ended September 30, 2014 included:

- \$272.9 million of Common Shares issued, net of issue costs;

- \$121.0 million of Common Share dividend payments;
- \$121.1 million of net repayments on our Revolving Credit Facility;
- \$198.7 million of long-term debt issued, net of issue costs;
- \$258.1 million of senior debt repayments; and
- \$12.3 million of Preferred Share dividend payments.

Significant financing activities for the same period last year included:

- \$116.2 million of Common Shares dividend payments;
- \$93.0 million of net draws from our Revolving Credit Facility;
- \$7.9 million of senior debt repayments; and
- \$6.6 million of Preferred Share dividend payments.

### **Equity Financing Activities**

On April 3, 2014 we issued 17.3 million Common Shares at a price of \$16.50 per share, providing gross proceeds of approximately \$284.6 million. The net proceeds from the Offering will be used to finance development costs relating to our proposed Jordan Cove LNG development project, to partially fund 2014 growth capital expenditures relating to our Dasque-Middle and St. Columban renewable power projects currently under construction, to reduce our outstanding indebtedness and for general corporate purposes.

### **Debt Financing Activities**

On June 10, 2014, we issued \$200 million of senior unsecured medium term notes maturing on June 13, 2019, bearing interest at 3.06% per annum. The net proceeds of the offering were used on July 10, 2014 to redeem all of our outstanding \$200 million senior notes, which were scheduled to mature on July 28, 2014.

In June 2014, the term of the Revolving Credit Facility was extended such that it now matures on May 31, 2018.

On May 30, 2014 we extinguished the remaining outstanding balance of \$50.4 million of the Clowhom term loan, which was scheduled to mature on February 21, 2016.

### Subsequent Event

On October 20, 2014, we redeemed the remaining issued and outstanding 5.75% Convertible Unsecured Subordinated Debentures, Series C due July 31, 2017. As at September 30, 2014, there was \$51.7 million principal amount of Series C Debentures issued and outstanding.

### **Ruby Acquisition Financing**

To fund our acquisition of the 50% convertible preferred interest in Ruby, we will utilize net cash proceeds from our October subscription receipt offering and drawings on a new unsecured non-revolving term loan ("New Credit Facility").

On October 1, 2014 we issued 56,120,000 subscription receipts at a price of \$16.40 per subscription receipt for gross proceeds of approximately \$920 million. This included the issuance of 7,320,000 subscription receipts on the exercise in full of the over-allotment option granted to the underwriters, which was exercised concurrently with the closing of the offering. The balance of the purchase price will be funded with a drawing under our New Credit Facility.

The gross proceeds from the issue of the subscription receipts will be held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the Ruby acquisition, and fulfillment or waiver of all other outstanding conditions precedent to closing the Ruby acquisition.

The New Credit Facility will rank *pari passu* with our senior unsecured obligations, including our existing Revolving Credit Facility. It will have a two-year term from the closing of the acquisition and will bear interest at a quoted floating rate plus a margin. Prepayments will be permitted at our option at any time and upon the occurrence of certain events, in each case without premium or penalty.

The New Credit Facility is expected to be in a form similar to our Revolving Credit Facility, and is expected to contain representations and warranties, affirmative and negative covenants (including requirements to meet certain financial ratios on an ongoing basis) and events of default that are customary for bank credit facilities of this nature.

## **DIVIDENDS**

### **Policy**

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

We pay dividends on our Common Shares on a monthly basis to common shareholders 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.

The holders of Series A Preferred Shares are entitled to receive fixed cumulative preferential cash dividends at an annual rate of 4.40%, payable quarterly. The dividend rate will reset on September 30, 2017 and every five years thereafter based on then-market rates.

The holders of Series C Preferred Shares are entitled to receive fixed cumulative preferential cash dividends at an annual rate of 5.00%, payable quarterly. The dividend rate will reset on March 31, 2019 and every five years thereafter based on then-market rates.

### **Sustainability of Dividends and Productive Capacity**

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

- earnings and cash flows we generate;
- ongoing maintenance of each business's physical and economic productive capacity;
- our ability to comply with debt covenants and refinance debt as it comes due; and
- our ability to satisfy any applicable legal requirements.

For a complete discussion of the significant risks and uncertainties affecting us, see the "Risks" section contained in our 2013 MD&A.

### **Dividends Paid/Payable Relative to Cash from Operating Activities and Net Income Attributable to Common Shares**

	Three months ended September 30		Nine months ended September 30	
(\$ Millions)	2014	2013	2014	2013
Cash from operating activities	50.4	44.0	143.3	136.4
Net income attributable to Common Shares	2.5	27.9	31.4	40.6
Dividends paid/payable	55.4	50.0	160.8	149.4
Less dividends paid in Common Shares under DRIP	(13.9)	(11.4)	(38.8)	(33.2)
Net dividends paid/payable	41.5	38.6	122.0	116.2
Excess of cash from operating activities over net dividends paid/payable	8.9	5.4	21.3	20.2
Deficiency of net income attributable to Common Shares over net dividends paid/payable	(39.0)	(10.7)	(90.6)	(75.6)

The excess of cash from operating activities over net dividends 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.

Net income attributable to Common Shares is generally less than dividends paid/payable as our net income includes certain non-cash expenses such as depreciation and deferred tax, and can include unrealized foreign exchange and fair value gains and losses which are not reflected in calculating the amount of cash available for the payment of dividends.

## **FINANCIAL INSTRUMENTS**

We and our jointly-controlled businesses periodically enter into interest rate hedges to manage interest rate exposures. For the three and nine months ended September 30, 2014, equity income from York Energy Centre includes a \$0.8 million and a \$8.5 million unrealized mark-to-market loss (\$0.6 million and \$6.4 million after tax), associated with an interest rate hedge. For the same periods last year, equity income from York Energy Centre includes a \$1.9 million and \$11.8 million unrealized mark-to-market gain, respectively (\$1.4 million and \$8.8 million after tax).

Veresen entered into forward foreign exchange contracts to manage the foreign exchange exposure relating to the acquisition of a 50% convertible preferred interest in Ruby for US\$1.425 billion. As at September 30, 2014, we committed to purchase US\$800 million at fixed Canadian rates for settlement at a future date which is intended to approximate the expected closing date of the acquisition. The weighted average foreign exchange rate of these contracts is approximately 1.116 Canadian dollars for each US dollar. For the three and nine months ended September 30, 2014, net income includes a \$4.9 million unrealized gain associated with the forward foreign exchange contracts (\$3.7 million after tax).

Subsequent to September 30, 2014 we committed to purchase an additional US\$625 million at fixed Canadian rates for settlement at a future date. The weighted average foreign exchange rate of these contracts is approximately 1.115 Canadian dollars for each US dollar. The weighted average foreign exchange rate of all our forward foreign exchange contracts totaling US\$1.425 billion is approximately 1.115.

## **CONTINGENCIES**

On August 18, 2014, we were named as a respondent in an application commenced by Energy Fundamentals Group Inc. in the Ontario Superior Court of Justice in Toronto on August 14, 2014. In the application, EFG seeks a declaration that, pursuant to a letter agreement dated July 27, 2005 between EFG and Fort Chicago Energy Partners L.P., the predecessor to Veresen, EFG has the option to acquire up to 20% of Veresen's equity interest in the Jordan Cove LNG terminal and related assets in Coos Bay, Oregon.

We believe that the option held by EFG applied only to the prior proposal to build an LNG import terminal and is not valid with respect to the current proposed liquefaction and LNG export terminal.

## **NEW ACCOUNTING STANDARDS**

Effective January 1, 2014, we adopted Accounting Standards Update ("ASU") 2013-04 "*Obligations Resulting from Joint and Several Liability Arrangements*". This ASU provides guidance on disclosure and measurement for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. This guidance was applied retrospectively and did not have a material impact to us.

In April 2014, the FASB issued ASU 2014-08 "*Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*". This ASU provides guidance for changes in criteria and enhanced disclosures for reporting discontinued operations. This guidance is effective for annual and interim periods beginning after December 15, 2014, and is to be applied prospectively. We are currently evaluating the impact of the standard.

In May 2014, the FASB issued ASU 2014-09, "*Revenue from Contracts with Customers*". This ASU provides guidance for changes in criteria for revenue recognition from contracts with customers. This guidance is effective for annual and interim periods beginning after December 15, 2016, and is to be applied retrospectively. We are currently evaluating the impact of the standard.

## **NON-GAAP FINANCIAL MEASURES**

Certain financial measures referred to in this MD&A are not measures recognized under US GAAP. These non-GAAP financial measures do not have standardized meanings prescribed by US 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 US 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 dividends. We consider these non-GAAP financial measures, together with other financial measures calculated in accordance with US GAAP, to be important factors that assist investors in assessing performance.

**Distributable Cash** - represents the cash we have available for distribution to common shareholders after providing for debt service obligations, Preferred Share dividends, and any maintenance and sustaining capital expenditures. Distributable cash does not include distribution reserves, if any, available in jointly-controlled businesses, project development costs, or transaction costs incurred in conjunction with acquisitions. Project development costs are discretionary, non-recoverable costs incurred to assess the commercial viability of greenfield business initiatives unrelated to our operating businesses. We consider transaction costs to be part of the consideration paid for an acquired business and, as such, are unrelated to our operating businesses. The investment community uses distributable cash to assess the source and sustainability of our dividends. The following is a reconciliation of distributable cash to cash from operating activities.

### Reconciliation of Distributable Cash to Cash From Operating Activities

(\$ Millions)	Three months ended September 30		Nine months ended September 30	
	2014	2013	2014	2013
Cash from operating activities	<b>50.4</b>	44.0	<b>143.3</b>	136.4
Add (deduct):				
Project development costs <sup>(1)</sup>	<b>28.5</b>	8.1	<b>58.8</b>	23.9
Change in non-cash working capital	<b>(15.1)</b>	12.0	<b>6.4</b>	20.3
Principal repayments on senior notes	<b>(2.7)</b>	(2.9)	<b>(8.6)</b>	(8.7)
Maintenance capital expenditures	<b>(0.9)</b>	(1.2)	<b>(4.7)</b>	(5.0)
Distributions earned greater (less) than distributions received <sup>(2)</sup>	<b>(2.8)</b>	10.6	<b>(3.5)</b>	10.3
Preferred Share dividends	<b>(4.1)</b>	(2.2)	<b>(12.3)</b>	(6.6)
Current tax on Preferred Share dividends	<b>1.6</b>	0.9	<b>4.8</b>	2.5
<b>Distributable cash</b>	<b>54.9</b>	69.3	<b>184.2</b>	173.1

(1) Represents costs incurred by us in relation to projects where the recoverability of such costs has not yet been established. Amounts incurred for the three and nine months ended September 30, 2014 relate primarily to the Jordan Cove LNG terminal project, the Pacific Connector Gas Pipeline project, and various other development projects.

(2) Represents the difference between distributions declared by jointly-controlled businesses and distributions received.

**Distributable Cash per Common Share** - reflects the per common share amount of distributable cash calculated based on the average number of common shares outstanding on each record date.

**EBITDA** - refers to earnings before interest, tax, 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.

## SELECTED QUARTERLY FINANCIAL INFORMATION

(\$ Millions, except where noted)	2014				2013		2012 <sup>(1)</sup>	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Operating revenues	82.0	89.3	92.0	78.8	84.5	89.8	71.6	67.7
Net income (loss) attributable to Common Shares	2.5	(2.4)	31.3	12.6	27.9	11.5	1.2	13.1
Net income (loss) per Common Share (\$) – basic and diluted	0.01	(0.01)	0.16	0.06	0.14	0.06	0.01	0.07
Distributable cash	54.9	63.7	65.6	55.8	69.3	49.2	54.6	56.5
Distributable cash per Common Share (\$) – basic and diluted	0.25	0.29	0.33	0.28	0.35	0.25	0.27	0.29
Cash from operating activities	50.4	47.9	45.0	81.6	44.0	55.0	37.4	65.1

Significant items that affected quarterly financial results include the following:

- Third quarter 2014 reflects lower earnings from Aux Sable and higher Jordan Cove related project development costs.
- Second quarter 2014 reflects lower earnings from Aux Sable and higher project development costs.
- First quarter 2014 reflected higher earnings from Aux Sable.
- Fourth quarter 2013 reflected continued weakness in ethane market conditions, increased finance costs and higher Corporate costs.
- Third quarter 2013 reflected improved margin-based lease revenues for Aux Sable and higher contributions from Hythe/Steeprock.
- Second quarter 2013 reflected continued weakness in NGL market conditions and increased finance costs.
- First quarter 2013 reflected continued weakness in NGL market conditions and increased administrative and finance costs.
- Fourth quarter 2012 reflected continued weakness in NGL market conditions, resulting in decreased fractionation margins, increased results from our Power business and increased administrative and finance costs to support the Hythe/Steeprock acquisition. Fourth quarter results also included a \$4.3 million and a \$16.5 million contribution to net income before tax and distributable cash, respectively, from Hythe/Steeprock.

## 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 Senior 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 September 30, 2014.

## INTERNAL CONTROLS 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 US GAAP. We assessed the design and effectiveness of internal controls over financial reporting as at September 30, 2014, 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 controls over financial reporting during the period ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.